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AN OPTIMISED ILLUSTRATIVE INVESTMENT MODEL OF THE ECONOMICS OF INTEGRATED RETURNS FROM CCS DEPLOYMENT IN THE UK/UKCS

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Research in North Sea Economics has been conducted in the Economics Department since 1973. The present and likely future effects of oil and gas developments on the Scottish economy formed the subject of a long term study undertaken for the Scottish Office. The final report of this study, The Economic Impact of North Sea Oil on Scotland, was published by HMSO in 1978. In more recent years further work has been done on the impact of oil on local economies and on the barriers to entry and characteristics of the supply companies in the offshore oil industry.

The second and longer lasting theme of research has been an analysis of licensing and fiscal regimes applied to petroleum exploitation. Work in this field was initially financed by a major firm of accountants, by British Petroleum, and subsequently by the Shell Grants Committee. Much of this work has involved analysis of fiscal systems in other oil producing countries including Australia, Canada, the United States, Indonesia, Egypt, Nigeria and Malaysia. Because of the continuing interest in the UK fiscal system many papers have been produced on the effects of this regime.

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Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy. The work on CO2 Capture, EOR and storage was financed by a grant from the Natural Environmental Research Council (NERC) in the period 2005 – 2008.

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AN OPTIMISED ILLUSTRATIVE INVESTMENT MODEL OF THE ECONOMICS OF INTEGRATED RETURNS FROM CCS DEPLOYMENT IN THE UK/UKCS

1. Background

The tightening of emission-reduction regulations, especially in power generation where hitherto free EUAs (EU Emission Allowances) will cease and emission rights will have to be purchased at auction from 2013, will encourage power generators to be more interested not only generally in reducing their CO_2 emissions into the atmosphere, but also in investing (solely or in partnership) in integrated CCS technology. This will especially be the case with the coal-fired power stations emitting CO_2 in excess of 1 $MtCO_2$/year, whose profits are most threatened by tighter emission control rules. In the circumstances, it may be expected that the typical coal power plant will invest in CO_2 emission reduction programmes. The investment portfolio will potentially include fuel switching, co-firing of hydrocarbon fuels and biomass, and CO_2 capture.

2. Introduction

Several studies have focused attention separately on the economics of investments in CO_2 capture, transport and storage. Few if any have adopted an integrated system approach. Yet, there are obvious advantages to this approach, in which maximizing the overall returns to investment is achieved through the optimisation of investments at each stage of the CCS chain, consistent with the feedback signals from the other stages.

Being a relatively new technology, investment in the integrated CCS supply chain faces a number of uncertainties, together making it particularly risky. At all stages the investment cost risks are very apparent. The uncertainties and risks are technological, economic, legal and geological in nature.

Technologically, at the capture stage there are uncertainties regarding which technology is the most cost effective, and how quickly and reliably it can be deployed on a wide scale. Abadie and Chamorro (2008) emphasise the riskiness of the prices of emission allowances and electricity. At the transport stage, uncertainties about the exact composition of the captured CO_2 to be transported make difficult a decision on the type of pipelines to construct or modify and re-use. Regarding the regulatory framework there are uncertainties concerning (a) the extent, stringency, and reach of emission-reduction controls, (b) the CO_2 price, and (c) the timely granting of any required planning permission. Geologically, at the storage stage, there are uncertainties pertaining to the behaviour of CO_2 as well as the oil yield-per-injected tonne of CO_2, in the case of CO_2-EOR. Regarding the economics of the CCS technology, there are uncertainties as to which business model is best suited to the early deployment of the technology. It could involve vertically-integrated ownership or trading relationships between independent parties.

The present study investigates the extent and impact of some of the key uncertainties and business arrangements surrounding the profitability of the integrated CCS investments. This is done by analyzing illustrative pairs of integrated same-source but different storage destination CCS investments.

3. Methodology

The imperative of CO_2-mitigation controls and the adoption of CCS technology bring together operators/investors in separate sub-sectors of the energy sector who hitherto have had no need of each other's services or co-investment in the manner envisaged by the technology. Thus, in order to remove the captured CO_2 from the atmosphere, the power plant investor requires the services of the CO_2 transport pipeline operator and oil/gas field operator, to respectively transport and store the CO_2 in geological formations. The interdependence potentially offers new business opportunities for all three investors. There are a number of business model options, with varying degrees of formalized collaboration and/or integration, to take advantage of these opportunities and minimise the riskiness of the investment in the novel CCS technology. Assuming the integrated but market trading approach of the present study, the investors' interactions and decisions will not be driven by unrestrained individual profit maximisation. Indeed, there are two sound economic grounds for expecting some degree of co-operation, relative openness, and risk-sharing among the three operators. Firstly, there are potentially strong motivational drivers of investments at both ends of the CCS chain. "Upstream", the technology is a virtual necessity for a power plant operator desirous of removing its carbon footprint from the atmosphere, in compliance with emission-reduction regulations. "Downstream", CO_2 storage investment, being a natural "fit" to oil/gas field operations is one option to the field operators desirous of extending field life and profitability. Secondly, CCS technology creates a niche/specialized industry of correlated or interdependent projects such that the business failure of one operator/investor jeopardizes the survivability of the others. For both reasons it is plausible to expect that the perceived in-built interdependency of the CCS technology investment will encourage investors to accept the notion that their business interests are best served with arrangements such as long-term mutually-beneficial supply contracts, based on substantial risk-sharing.

As illustrative case studies, a number of CO_2 capture sources and sinks were selected, and hypothetical investments. The two sources selected are the Drax and Longannet power stations while the sinks are the Forties oilfield and Morecambe South and Indefatigable gas fields. It is understood that there are no current plans for such investment projects, but the case studies here were selected to illustrate the potential risks and returns.

4. The Model

Model Approach

Assuming that from the perspective of the power plant investor, the destination of the captured CO_2 is important to the profitability or otherwise of the whole CCS investment, two integrated source-to-sink spreadsheet models were built in Microsoft Excel set up for use with Oracle's Crystal Ball software for probabilistic analyses and demonstration of the effects of different sink types on profitability. The two alternative sink types or CO_2 storage destinations are deliveries to (1) depleted gas fields for permanent storage, and (2) oilfields for EOR followed by permanent storage. Essentially, the models use the basic income and expenditure statements of the operators' CCS-related activities to calculate their cash flows. The models are fully stochastic in the key influencing variables because they incorporate as inputs a number of uncertain variables and parameters. Moreover, the models are decision-focused, designed to capture and assess the potential benefits and risk exposure of the investors, arising from the incremental costs of the CCS supply chain in an uncertain world.

The basic model, summarised in Tables 1 to 3 for the power plant, pipeline transportation and storage sink operations respectively, used the discounted cash flow approach to calculate, over a thirty-year period (2020 – 2050), the distributions of Net Present Values (NPVs), and Internal Rates of Return (IRRs). *OptQuest*, the optimising engine of Crystal Ball, was then used to determine the optimal values of the decision variables that will maximise the NPVs of the three classes of investors subject to a number of constraints, including specified risk levels. The optimisation route[1] was chosen because the method allows an explicit and simultaneous treatment of the system's objective function and the constraints in a transparent and consistent manner. Two sets of optimisations were performed, one each on the two types of models used in the study, with each model solution giving insights into the risks and uncertainties present in the projections.

*Time Horizon***:**
The study covered the period from 2020 to 2050, with the following notable dates:

- 2020 - First CAPEX - CO_2 capture, pipeline infrastructure, platform/well modification. Subsequent capacities and CAPEX build-up over nine years to 2029.

- 2023 – Initial CO_2-EOR shipment and delivery; CO_2-EOR and permanent storage injection starts in the respective sink types.

- 2025 - First CO_2-EOR oil produced.

- 2041 – Primary CO_2-EOR injection ends in the CO_2-EOR sinks.

- 2042 –CO_2 injection into permanent storage commences in EOR fields.

It is envisaged that CCS-related activities may continue beyond 2050 at the selected sites.

Discount Rate:
All the simulations and optimisations were performed using a common discount rate of 10 percent in real terms.

[1] Defined as finding the best feasible solution within a given domain.

Schematic Cash Flow Statements

Table 1

Schematic Cash Flow Statement of a CO_2 Capture (coal-fired) Plant

Items	2020	2021	………	2050
Plant Description				
Power plant nominal capacity (MW)				
Power plant electricity generation (GWh)				
Distance to sink (km)				
Emissions				
Cost of CO_2 EUA purchases/allowances				
Historical 2008 emission ($MtCO_2$/year)				
Emission Reduction target (%)				
Forecast emission ($MtCO_2$/year)				
Allocated emission				
Excess emission				
Historical emission factor (t/GWh)				
Target emission factor (t/GWh)				
Costs				
i. CAPEX				
Incremental capture CAPEX (£million)				
Unit capture CAPEX (£ per tonne CO_2)				
% of emission captured (%)				
Capture capacity/captured volume ($MtCO_2$ per year)				
total CAPEX				
ii. OPEX				
Coal price (£ per tonne)				
Capture parasitic effect (%)				
Quantity of fuel (coal) used (m.t.)				
Incremental fuel (tonnes of coal) used				
Incremental fuel OPEX (£million)				
Incremental non-fuel OPEX (e.g. CO_2 separation) (£m)				
Transportation cost (£m)				
Storage cost (£m)				
total OPEX				
Revenues				
unit price of captured carbon (£ per tCO_2)				
EUA savings (£m)				
total revenues (£m)				
Pre-tax cash flow				

The spreadsheet model of the power plant investor consists of four parts. The Plant Description section describes the plant's capacities (nominal and installed) and the distance to the sink. The Emissions section describes the CO_2 emissions situation of the power plant – that is, EUA purchases, historical and forecast emissions levels, as well as the target emission factor. The Costs section calculates the CAPEX and OPEX of the capture-related activities, based on the unit capture cost, proportion of the emitted CO_2 captured, the capture capacity and the amount captured. The Revenues section consists of two items – the unit price of the captured CO_2 and the EUA savings (shadow revenues). Depending on whether or not the captured CO_2 is commoditised or treated as a waste product, the unit price of the captured CO_2 is positive or zero. The EUA saving is the value of the avoided emissions.

Table 2

Schematic Cash Flow Statement of a CO_2 Pipeline Transportation Operator

Items	2020	2021	…….	2050
Costs				
CAPEX				
Pipelines CAPEX (£m)				
Unit pipeline CAPEX (£ per km)				
Compressors' CAPEX (@ 2% of pipeline CAPEX)				
Distance: power plant –to- storage sink (km)				
Total CAPEX				
OPEX				
Pipeline operations (£m)				
Compression facilities (£m)				
Other incremental OPEX (£m)				
Total OPEX (£m)				
Revenues				
Tariff margin				
Pipeline tariffs (£/tCO_2/100km)				
CO_2 volume shipped (MtCO_2/year)				
total revenues				
Pre-tax cash flow				

The pipeline operator's cash flow model consists of two sections – the Costs and Revenues, including the revenues. The capital expenditure on the compressors is assumed to be 2 percent of the pipeline CAPEX. On the revenue side, the pipeline tariffs are normalized to distance and volume shipped. The pipeline operator's revenues are described in greater detail below.

Table 3

Schematic Cash Flow Statement of a CO_2 Storage Operator

Items	2020	2021	……………..	2050
Services				
CO_2 Injection-oil output ratio				
Incremental oil production (mmbbl per year)				
Fresh CO_2 volume received and injected ($MtCO_2$/year)				
Volume of CO_2 re-injected ($MtCO_2$ per year)				
STOIIP (mmboe) (or, gas field storage capacity)				
Recovery factor (%)				
Costs				
i. CAPEX				
Incremental Storage CAPEX (£million)				
total CAPEX				
Platform modification (% of CAPEX)				
Well modification (% of CAPEX)				
Monitoring (% of CAPEX)				
ii. OPEX				
Volumes of CO_2-EOR purchased/shipped in ($MtCO_2$/yr)				
CO_2 transport cost (£m)				
Non-incremental OPEX: EUA purchased (£million):				
unit carbon price (€ per tCO_2)				
CO_2 emissions ($MtCO_2$/yr)				
Incremental cost: Injection OPEX rate (£ per tCO_2)				
Incremental cost: Injection OPEX (£ per tCO2)				
Monitoring OPEX as % of CAPEX (%)				
OPEX (monitoring) (£m)				
Cost of sale (£ m)				
total OPEX				
Revenues				
Oil price (£ per bbl)				
unit CO_2 storage fee (% margin of CO_2 cost)				
Incremental oil revenues (£m)				
(Incremental) Storage fees (£m)				
total revenues				
Pre-tax cash flow				

The storage sink operator's cash flow model consists of the Services, Costs and Revenues sections. The amount of detail required in the Services section depends on whether or not the sink is earmarked for Permanent Storage. Thus, whereas the input-output ratio or, CO_2-injection yield is relevant in the account of the CO_2-EOR operator, the ratio is irrelevant to a gas field operator who is only interested in the permanent storage of CO_2. Notably, on the costs (OPEX) side, payments on the volumes of CO_2 imported for storage will be non-zero only if CO_2 is commoditised. Payments for emission rights pertain mostly to CO_2-EOR sinks for ongoing production operations. On the Revenues side, oil revenues are only relevant to the CO_2-EOR sinks. However, storage fees accrue to the investors in both sink types.

The Objective Function:

The interdependence and/or integration of the investments in the three stages of the CCS value chain can be handled explicitly either as one portfolio of vertically-integrated investments, or as individual investments connected through trading. The present study is focused on the latter arrangement. Naturally, within the framework of their mutually-recognised interdependence, each investor will seek to maximise his own returns and, restrict his risk exposure. In stating this natural tendency formally, it may appear attractive to have an augmented or additive objective function in the returns of the investors. However, such an approach will mask the true nature of the interdependence. The CCS supply chain has its "upstream" and "downstream". CO_2 capture efforts and investment constitute the upstream since without them there will be nothing to transport and/or store geologically. As such, while the study considers the returns to the investments in CO_2 capture, transportation and storage as all being important, it nevertheless selected the returns to investment in CO_2 capture as being the primary returns, appearing exclusively in the model objective function, with the profitability of the other investors entering the model as constraints.

Formally, the objective function of the risk-constrained returns maximisation model is to:

Maximise: $NPV_c = \sum_{t=0}^{T}(P_t \times Q_t - C_t)\, e^{-rt}$ (1a)

where:

NPV_c = the Net Present Value of the CO_2 capture investment.

P_t = the price of the captured CO_2 at time t

Q_t = the volume of captured CO_2 at time t

C_t = the total incremental CAPEX of CO_2 capture.

t = time in years

T = terminal year

r = discount rate

Theoretically, $P_t \times Q_t$ in equation (1a) stands for the operator's total revenue derived from the sale of the captured CO_2, assuming $P_t > 0$. However, under the existing and immediate future EU-ETS rules, CO_2 may be considered a waste product, implying that $P_t = 0$, and the capture investor is expected not only to capture the emitted CO_2 but, also, ensure its removal from the atmosphere by paying the CO_2 transporter and storer for their services. In that case, the total revenue in equation (1a) is replaced by the total EUA (EU Emission Allowances) savings, being the only benefits derivable from the capture investment. In the context of the present study, EUA savings are the value of the avoided emission allowance purchases, consequent upon the investment in CO_2 capture. In symbols:

$$E_t = Y_t^{woc} - Y_t^{wc} - S_t \quad (2a)$$

where:

E_t = EUA savings at time t

Y_t^{woc} = CO_2 purchases without capture investment at time t

Y_t^{wc} = CO_2 purchases with capture investment at time t

S_t = CO_2 storage fee at time t

If

$Y_t^{woc} = Z_t(X_t + Q_t)$; and $Y_t^{wc} = Z_t(X_t)$

where:

Z_t = EU-ETS carbon price at time t

X_t = excess emissions at time t

Then:

$$E_t = Z_t Q_t - S_t \quad \text{...........................} \quad (2b)$$

Thus, for any given Q_t and S_t, the size of EUA savings or the fruits of CO_2 capture investment will increase the higher the EU-ETS allowance price for emissions.

Furthermore, the study also examines a novel mid-way arrangement between commoditising the captured CO_2 and treating it as a waste. Specifically, it is a form of barter trading in which the capture plant delivers, free-of-charge, the captured CO_2 to the interested oilfield operator for EOR. In return the capture plant investor enjoys a storage fee payment holiday during the entire CO_2-EOR phase or a part thereof, as may be negotiated. However, the capture plant will have to pay the gas or oilfield operator for the costs of permanent storage of the captured CO_2 in all cases.

Given the description of E_t in equation (2b), the objective function to equation (1a) can be written in a composite form as:

$$\text{Maximise: } NPV_c = \sum_{t=0}^{T}(E_t - C_t)\, e^{-rt} + \sum_{t=0}^{T}(P_t \times Q_t - C_t)\, e^{-rt} \quad (1b)$$

Where, the first term on the RHS represents the shadow revenue from capture regardless of the chosen sink for storage. The second term is positive only when CO_2 is commoditised while destined for storage in CO_2-EOR fields.

The Constraints

The net present value, NPV_c, of the CO_2 capture plant is maximised subject to the requirements that:

1. Given a 10 percent discount rate facing each of the three classes of CCS investors (CO_2 capturer, transporter and storer), their respective individual hurdle rate (or, Internal Rate of Return, (IRR)) was required to range from a minimum 10 percent, to a maximum of 20 percent.
2. The risk to the expected mean of the returns (measured as the standard deviation of the NPV) of the capture investor is minimised. That is,

   $$\sigma_c \leq \gamma \quad (3)$$

   where:

σ_c = *the standard deviation of the capture plant's mean NPV*

$\gamma =$ *upper limit of the acceptable risk to the capture investment*

Equation (3) is the risk constraint in the returns maximisation model. It translates the optimisation problem into one in which the goal of the capture plant investor is to determine the optimal expected NPV given a certain maximum level of risk he is prepared to take.

3. Non-negativity constraints. The respective NPVs of the capture, transport and storage investors must be positive:

$NPV_c, NPV_t, NPV_s > 0$

Where:

NPV_t, = the NPV of the pipeline investor

NPV_s = the NPV of the CO_2 storage investor

5. Model data

This section presents the data used in the study. The model variables which are broadly classified as decision or assumption variables are defined and discussed below according to the three stages of the CCS chain.

For the analysis, two power plants and two CO_2 storage sinks are selected to illustrate the economics of the integrated CCS supply chain. The two power plants are Drax (Yorkshire) with annual CO_2 emissions of between 18 and 21 $MtCO_2$/year in recent years (2005-2008), and Longannet (Fife)[2] with corresponding emissions of between 9 and 10 $MtCO_2$/year. The Forties (Central North Sea), Morecambe South (Irish Sea), and Indefatigable (Southern North Sea) fields are the illustrative storage sinks. Being gas reservoirs,

[2] Drax and Longannet are respectively the first and second largest coal power stations in the UK. Longannet, situated on the banks of the Firth of Forth has been operational since 1973. The power plant has four 600 MW generating turbines, a net output of 2,304 MW of electricity and an announced plan to retrofit its boilers to capture some CO_2 by 2014. By contrast, Drax which was opened in 1974, having a current generating capacity of 3,960 MW and, being the largest point source CO_2 emission in the UK, has no publicly announced CO_2 capture plan .

Morecambe South and Indefatigable are envisaged as suitable for permanent CO_2 storage, while CO_2 storage at the Forties oilfield is taken to be suited to Enhanced Oil Recovery (EOR) followed by permanent storage. According to the Scottish Centre for Carbon Storage (2009), the Forties field has a storage capacity of 138 $MtCO_2$ and a potential CO_2-EOR-induced incremental oil of 420 mmbbl[3].

The plant- and field-level data used in the study were those available in the public domain, either as published company data or in the literature. All the cost and revenue figures are in real 2008 terms.

Data on CO_2 Capture

The data used fall into the two categories of decision and assumption variables.

The decision variables (capture)**:**

The decision (or control) variables are the cost and revenue variables whose final calculated values optimise the investment returns, given the risks and uncertainties attached to the assumption variables. At the capture stage, the key decision variable is the level of investment (CAPEX)[4]. The CAPEX on retrofitting the power plant is assumed to be incurred incrementally over a period of ten years. The gradual build-up of carbon capture and storage technology on the power plants' generating capacity is consistent with the official Government thinking (see DECC, 2009[b].)

For Longannet it is assumed that the total capture CAPEX will range between £1 and £1.5 billion (see Kemp and Kasim, 2008). Given the uncertainties relating to CO_2 capture such as the percentage of CO_2 emissions that can be

[3] Scottish Centre for Carbon Storage (2009).

[4] The present study does not treat CAPEX as a stochastic variable because it is assumed that *ceteris paribus* the investor has a reasonable idea or control over the range of affordable investible funds. What is clearly beyond the investor's control are the market, geologic and technological risks, which the study appropriately treats as stochastic variables.

captured, the capture capacity and the unit capture capital cost, the capture plant investor cannot have a very accurate estimate of the project cost, hence the specified range. Clearly, the total CAPEX will depend on the effects of scale economies and learning-by-doing (LBD) which influences the unit capture cost over time and are discussed in more detail below.

For the larger Drax power plant, the capture CAPEX is assumed to range between £1.8 and £2 billion, with the ultimate CAPEX being dependent on the same effects.

The Assumptions (Capturer)

Current judgement about the future values of some of the model variables and the general techno-economic conditions are imperfect, hence the future performance of each of the proposed investments is uncertain. In Monte Carlo parlance, the uncertainties are labelled as assumptions, with each having a probability distribution of its possible occurrences. At the capture stage, the important probabilistic variables that drive the capture process include the following five variables:

i. The price of fuel in electricity generation
ii. The emission reduction target
iii. The percentage of emissions captured
iv. The potential effects of learning-by-doing
v. The EU-ETS carbon price

The uncertainties are discussed hereafter.

i. Price of fuel: Coal price (£ per tonne)

The central values of the range of historical and projected coal prices are as follows:

Table 4: The projected coal price 2020 – 2050 (£/tonne, real2008)

Year	Price
2000	28.91
2010	68.75
2020	50.00
2030	60.00
2040	70.00
2050	85.00

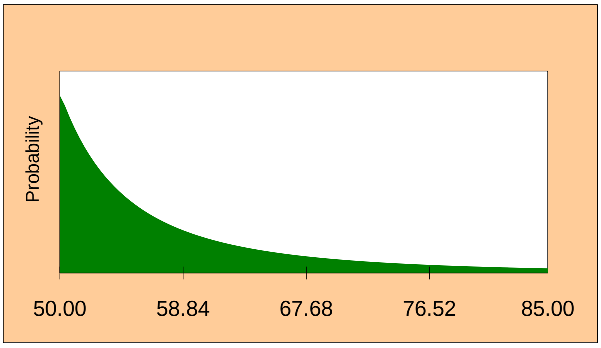
Sources: (a) 2000 – 2020: DECC

(b) 2021 -2050: Authors' own projection

The minimum price of coal in the data set is £50 per tonne while the projected maximum, in the period up to 2050, is £85 per tonne.

Crystal Ball's Fit Distribution subroutine can, using either one or, all of the chi-square, Kolmogorov-Smirnov or Anderson-Darling techniques, fit various probability distributions to a user's data to determine the best-fitting distribution. The subroutine was used to determine the best fit for the probability distributions used in the present study. For the coal price, the underlying probability distribution of the forecast values of the variable was found to be best characterised by a lognormal distribution with the following parameters in Fig 2:

Fig. 2: The Probability Distribution of the Projected Coal Price (£/tonne, real 2008)



Lognormal probability distribution with the following parameters (£/tonne):

Location	*43.10*
Mean	*49.80*
Standard deviation	*14.90*

ii. Emission Reduction Target

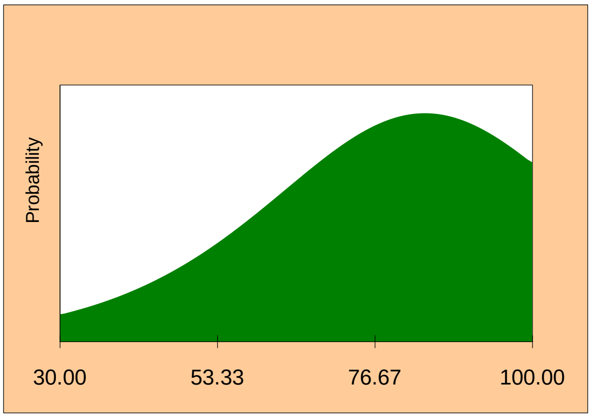
It is expected that with increasing CO_2 emission mitigation regulations, UK power plants will undertake emission reduction programmes with set performance targets. The target would include the rate at which renewable fuel sources and co-firing will replace fossil fuels, coupled with increasing CO_2 capture, if CO_2 capture investment is undertaken. Drax has an emission reduction target (ERT) of 30% over its 2008 emission level by 2030 (Drax, 2009), through a combination of fuel switching and co-firing coal with biomass. Lacking the corresponding data, it was assumed that Longannet would pursue roughly the same emission reduction target. For both power plants, the ERT is forecast to rise to nearly 100 percent by 2050.

Table 5: The Projected Emission Reduction Target of Selected Power Plants

Year	**Target (%)**
2020	30.00
2030	75.50
2040	98.50
2050	98.50

The best-fit to the underlying probability distribution of the forecast ERT was found to be the logistic probability distribution with the following parameters in Fig. 3:

Fig. 3: The Probability Distribution of the Projected Emission Reduction Target (%)



Logistic probability distribution with the following parameters (%):

Mean	*84.10*
Scale	*15.68*

iii. Percentage of Emissions Captured

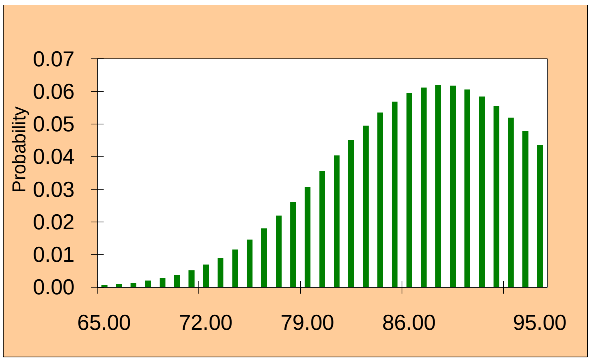
There are uncertainties regarding not only the proportion of emitted CO_2 that can technically be captured but also the speed of the build-up to full capture capacity. The full capture capacity is variously cited in the literature as being around 90 percent (DECC, 2010). The study assumes that this capture capacity is not achieved right from the onset. Rather, allowances were made for a gradual build-up from about 40 to 95 percent of emissions over the study period.

Table 6: The Projected Percentage of Emissions Captured by Selected Power Plants

Year	**Target (%)**
2023	40.00
2030	90.00
2040	95.00
2050	95.00

The best-fit of the underlying probability distribution was found to be binomial with the following parameters in Fig 4:

Fig. 4: The Probability Distribution of the Projected Percentage of Emissions Captured



Binomial probability distribution with the following parameters (%):

Probability	*0.293*
Trials	*302*
Selected range	*40.00 to 95%*

iv. Learning-by-doing and its Effects

In general, the experience gained through learning-by-doing impacts favourably on both capital and operating costs.

(a) Effects on CAPEX

There is a general expectation that as with all early technologies, the costs of the CCS technologies will reduce over time as a result of the gains from learning-by-doing. Characterising the experience curve as:

$$CAPEX_i = CAPEX_O i^{-y} \qquad (4)$$

where:

$CAPEX_i$ = *CAPEX of the ith unit installed*
$CAPEX_O$ = *CAPEX of the first unit*
y = *parametric constant*

Given an experience equation such as in equation (4) several authors since Wright (1936), including Arrow (1962) and Rubin **et. al** (2004) have observed and quantified the cost savings accompanying cumulative production as being 2^{-y} and the "learning rate" or, the percentage reduction in CAPEX for each doubling of capacity or cumulative output as being equal to ($1-2^{-y}$). Using USA data, Yeh and Rubin (2007) estimated that the learning rate is between 5 and 27 percent for seven technologies related to power generation. In the present study a learning rate of between 10 and 15 percent for unit CAPEX was assumed. Illustrating with the assumed CAPEX of the two selected power plants at

Longannet and Drax respectively, the differences these rates will make to the CAPEX of successive installations are shown below:

Fig. 5: Hypothetical CO_2 Capture CAPEX with LBD Effects at Longannet

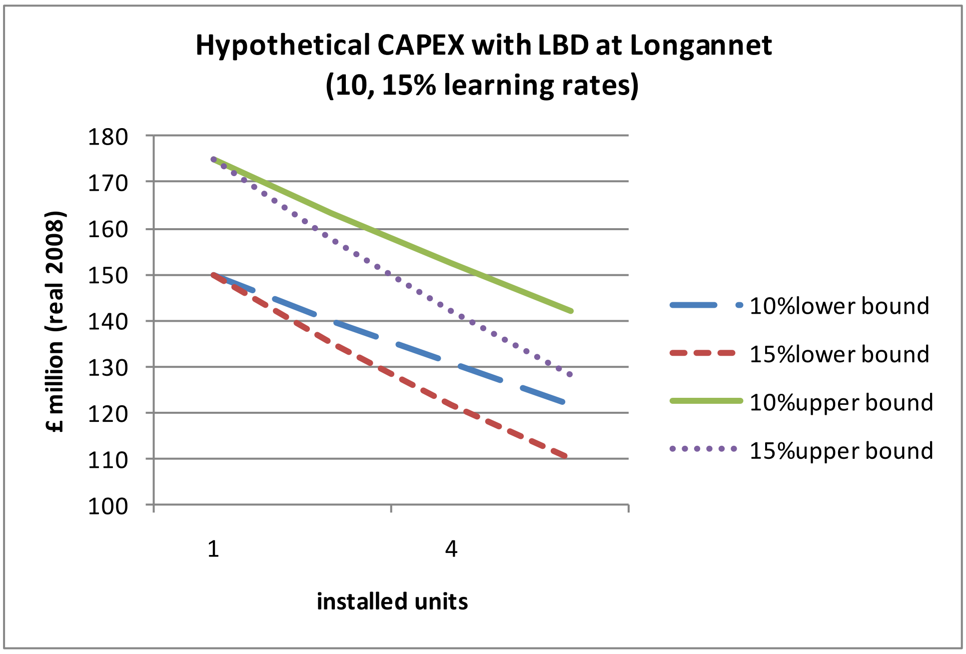
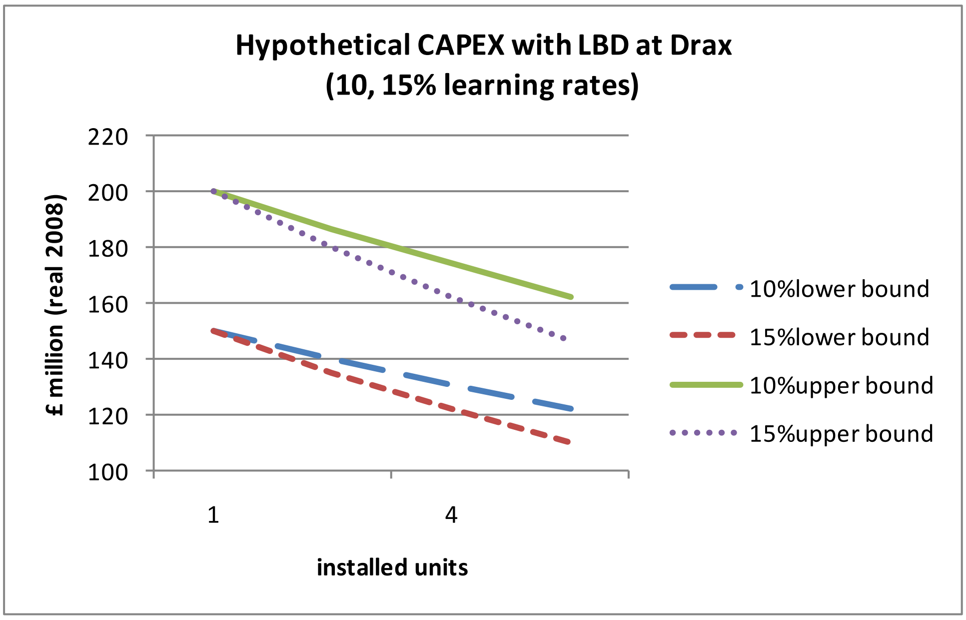


Fig. 6: Hypothetical CO_2 Capture CAPEX with LBD Effects at Drax



(b) Effects on OPEX

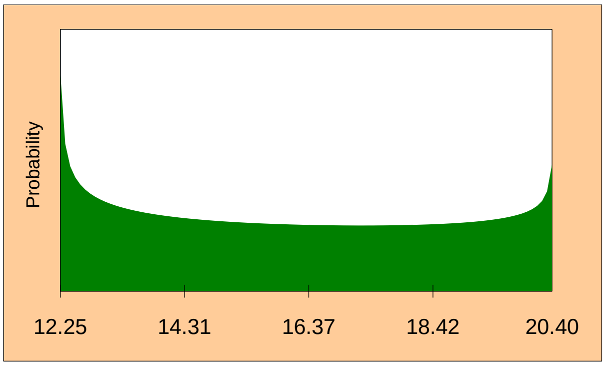
CO_2 capture requires not only additional CAPEX but also more energy and fuel costs. In the literature, estimates of this parasitic effect on costs vary from 10 to about 40 percent of OPEX (see Bellona, 2005, for example). The present study assumes that the effects are equal in the two power plants under study and that they range from a high of 20 percent reducing to about 12 percent over the study period.

Table 7: The Projected Parasitic Effect of CO_2 Capture on the OPEX of the Selected Power Plants

Year	Target (%)
2023	20.40
2030	18.19
2040	14.89
2050	12.25

The best-fit of the underlying probability distribution of the forecast was found to be a beta distribution with the following parameters in Fig. 7.

Fig. 7: The Probability Distribution of the Projected Capture Parasitic Effect on OPEX (%)



Beta probability distribution with the following parameters (%):

Alpha	*0.77*
Beta	*0.86*
Minimum	*12.25*
Maximum	*20.40*

v. The EU-ETS CO_2 Price

Considerable uncertainties remain about the carbon price in the EU-ETS market. The study assumes the carbon price may rise substantially but continue to be volatile in the range of £15 (€18) to £100 (€120) per tonne of CO_2 but, mean-reverting to a long-term price of £50/tCO_2 (€60/tCO_2). These figure are broadly consistent with DECC's projections as cited by Mott MacDonald (2010)[5].

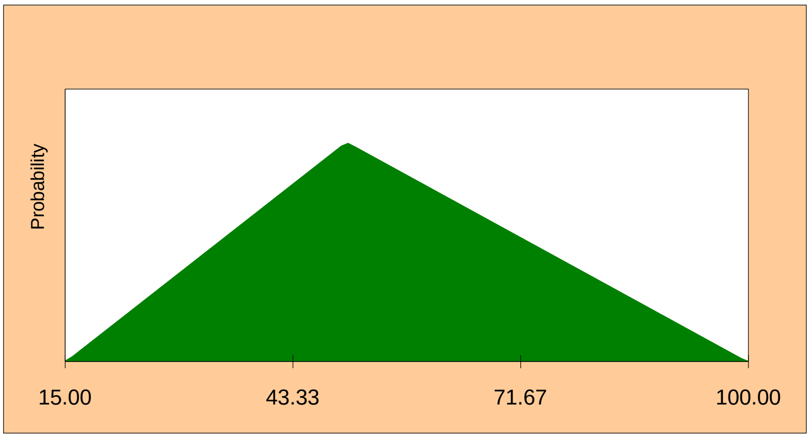
[5] In DECC's central case, the carbon price increases from £16.3/tCO_2 in 2020 to £70/tCO_2 in 2030 and £135/tCO_2 in 2040, with an average of £54.3/tCO_2.

Table 8: Projected Price of Carbon 2020-2050 (£/tCO_2)

Year	Price
2020	50.00
2030	70.00
2040	85.00
2050	100.00

The probability distribution of the assumed carbon price is assumed to be triangular with lower and upper bound values of £15 and £100/tCO_2, and, a mean value of £50/tCO_2 as shown in Fig. 8.

Fig.8: The Probability Distribution of the Carbon Price (£/tCO_2)



Triangular probability distribution with the following parameters (£/tCO_2):

Minimum	*15.00*
Maximum	*100.00*
Most likely	*50.00*

Storage Stage Data

<u>The storer's decision variables:</u>

At the storage stage, the key decision variables are the level of investment (CAPEX), and storage fee margin. The CAPEX is the incremental cost of converting or modifying existing facilities at the oil and/or gas fields, while the storage margin is a fraction of the CAPEX.

Both the Forties and Morecambe South fields have relatively large CO_2 storage capacities, enough to store, at least, the maximum CO_2 capture potential of Drax of up to 15 MtCO_2/year. For the Forties field, the incremental CAPEX for CO_2-

EOR and permanent CO_2 storage is assumed to range between £1.6 and £2 billion. Lower minimum CAPEX of £1 billion and maximum £1.5 billion are assumed for Morecambe South because less platform modifications are assumed to be required. The CAPEX in each field is assumed to be distributed among its component parts as follows:

Platform modification	50%
Well modification	40%
Monitoring	10%

In both fields, the unit CO_2 storage fee margin (distinct from any revenues from EOR) is assumed to range between 10 and 20 percent of the field operator's investment and operating costs.

<u>The Assumptions (Storer)</u>

Some of the uncertainties/assumptions regarding OPEX at the storage stage are common to both sink types, while others are peculiar to Forties the CO_2-EOR sink, as follows:

a. The common assumptions
   i. Injection OPEX
   ii. Monitoring OPEX
b. The distinct CO_2-EOR sink's assumptions
   i. CO_2-injection yield
   ii. Oil recovery factor
   iii. Oil price

The common assumptions are the Injection cost OPEX; and Monitoring cost OPEX; while the uncertainties relating to the oil price (where CO_2-EOR), prospective input-output ratio (yield of oil production per tCO_2 injected per year); oil recovery factor; and the investment cost of injection/re-injection facilities are peculiar to Forties. The key assumptions and their probability distributions are discussed in greater detail below.

The Common Assumptions: The Injection and Monitoring OPEX

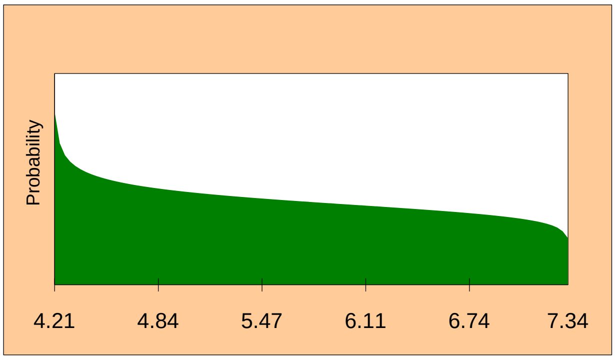
There are considerable uncertainties concerning the field operators' incremental OPEX (and CAPEX) attributable to CO_2 storage activities. The CCS technology is new, and of particular interest to the present study is the incremental OPEX attributable to CO_2 injection and monitoring for leakages. Various estimates of the cost per unit volume of CO_2 injected exist in the literature (see Poyry (2007), for example). Based on these, the study assumes a common injection OPEX of between £4.21 and £7.34 per tonne of CO_2 injected for both sink types, and a (common) monitoring OPEX of between 1.55% and 2.70% of their respective total CAPEX. The details are presented in Table 9.

Table 9: The Projected Injection and Monitoring OPEX Costs of Selected Storage Sinks

Year	**Injection cost (£/tCO_2)**	**Monitoring cost (% of accumulated CAPEX)**
2023	7.24	1.81
2030	6.30	2.65
2040	5.16	2.55
2050	4.22	1.95

The beta probability distribution best fitted the injection and monitoring OPEX, with the following parameters in Figs. 9 and 10:

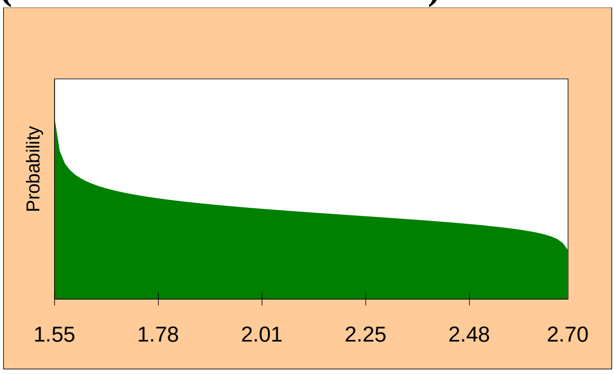
Fig. 9: The Probability Distribution of the Projected Injection OPEX Rate (£/tCO_2)



Beta probability distribution with the following parameters (%):

Alpha	*0.88*
Beta	*1.09*
Minimum	*4.21*
Maximum	*7.34*

Fig. 10: The Probability Distribution of the Projected Monitoring OPEX (% of incremental CAPEX)



Beta probability distribution with the following parameters (%):

Alpha	*0.88*
Beta	*1.09*
Minimum	*1.55*
Maximum	*2.70*

The Assumptions Specific to CO_2-EOR Sinks

i. CO_2 Injection Yield

It is assumed that the CO_2-EOR phase will be for a duration of 20 years, based on the SCCS (2009) formula of water-flooding for two-thirds of the period.

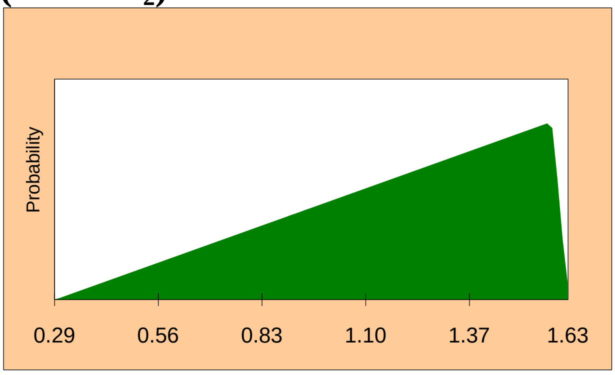
Considerable uncertainties exist about the CO_2 injection yield or, the amount of oil that can be produced from each tonne of CO_2 injected into wells for EOR. Estimates of the potential yield ranges from one to four barrels per tonne of CO_2 injected (for example, Bellona (2005) assumed 3 barrels per tonne of CO_2 injected while Tzimas et. al. (2005) assumed 0.33tonne of CO_2 required to provide an incremental barrel of oil). Based on a report by Synergy (2009) for the SCCS, this study assumes a conservative yield of between 0.29 and 1.63 barrels of oil per tonne of CO_2 injected.

Table 10: The Projected CO_2-Injection Yield at Forties

Year	**Yields (barrels/tCO_2)**
2018	0.29
2020	0.68
2030	1.63

The best-fit probability distribution was found to be a triangular probability distribution, with a likely yield of about 1.59 barrels of oil per tonne of CO_2 injected, as shown in Fig. 11.

Fig. 11: The Probability Distribution of the Projected CO_2-Injection Yield (bbl/tCO_2)



Triangular probability distribution with the following parameters (barrels/tCO_2):

Minimum	*0.29*
Maximum	*1.63*
Most likely	*1.59*

ii. The Oil Recovery Factor

One of the motivating factors driving CO_2-EOR investment considerations is the expectation that the investment would substantially increase the oil recovery factor (RF) of the CO_2-EOR flooded reservoir[6]. However, by how much the RF can be raised remains uncertain. For example the United States Department of Energy (2008) has demonstrated that there is no one common CO_2-EOR

[6] Indeed, BP (2006) estimated that CO_2-EOR may improve oil recovery rate to such an extent as to deliver about 4 billion barrels of incremental oil in the North Sea (UK and Norwegian sectors).

recovery rate. Much depends, among other factors, on the geological characteristics of the basin, the volume of remaining recoverable reserves, and the technology deployed. In order to provide an objective basis for the range of RF that may be expected in the UKCS, Table 8a shows the Department's estimated CO_2-EOR recovery rates for its "state-of-the-art" and Next Generation CO_2-EOR injection technologies in six onshore and offshore hydrocarbon provinces in the USA.

Table 11: CO_2-EOR Recovery Rates in the USA

Basin/Area	**Original-oil-in-place (bn barrels)**	**Remaining-oil-in-place (bn barrels)**	**CO_2-EOR technically recoverable (bn barrels)**		**Implied CO_2-EOR recovery rates (%)**	
			State-of-the-art	**Next generation**	**State-of-the-art**	**Next generation**
Alaska	67.3	45.0	12.4	23.8	18.4	35.4
California	83.3	57.3	5.2	13.3	6.2	16.0
Gulf Coast/East Texas	60.8	36.4	10.1	19.0	16.6	31.3
Oklahoma	60.3	45.1	9.0	20.1	14.9	33.3
Illinois	9.4	5.8	0.7	1.6	7.4	17.0
Louisiana Offshore (Shelf)	28.1	15.7	5.9	5.9	21.0	21.0

Sources: (a) USA Department of Energy 2006
(b) The implied CO_2-EOR recovery rates: authors' own calculation

Table 11 shows recovery rates ranging from 6 percent (in onshore California) to 21 percent (in offshore Louisiana) percent for the "state-of-the-art" technology and a range of 16 to 35 percent for the "next generation" technology.

Consistent with Bellona (2005), this study assumes a CO_2-EOR recovery rate of between 15 and 20 percent[7]. Applying this to the Forties field which was already experiencing a pre-CO_2-EOR injection RF in excess of 60 percent[8], the field may attain in excess of RF post CO_2-EOR.

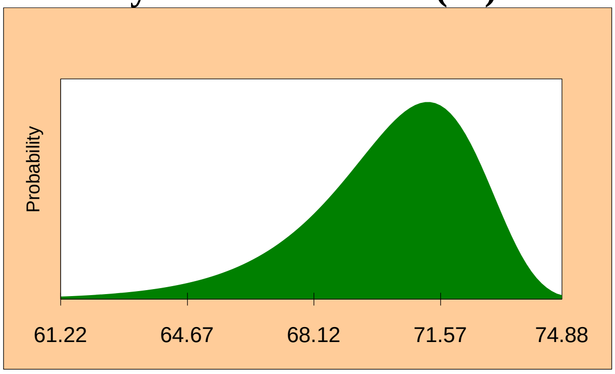
[7] Bellona (2005) citing USA data reported CO_2-EOR recovery rate ranging from 6.2 to 21 percent, with Louisiana Offshore recording the highest rate.
[8] BP (2003) reported a forecast RF of 62 percent and a plan to attain 70 percent prior to the sale of the field to Apache in 2003. Since buying the asset, Apache has increased the STOIIP to 5.2 billion barrels and improved

Table 12: The Projected Oil Recovery Factor at Forties

Year	**RF (%)**
2020	61.00
2030	71.00
2040	72.67

The best-fit probability distribution of the forecast RF was found to be the minimum extreme probability distribution with a scale of 1.89 and a likely RF of 71.23 percent, as shown in Fig. 12.

Fig. 12: The Probability Distribution of the Projected CO_2-EOR-Induced Recovery Factor at Forties (%)



Minimum Extreme probability distribution with the following parameters (%):

Most likely	71.23
Scale	1.89

iii. The Oil Price

There are considerable uncertainties about the future oil price, as reflected, for instance, in the EIA's forecast of world oil prices to 2035 presented below in Fig. 13.

"field efficiency" from 70 to 88 percent (follow the web link: http://www.apachecorp.com/explore/Browse_Archives/View_Article.aspx?Article.ItemID=335)

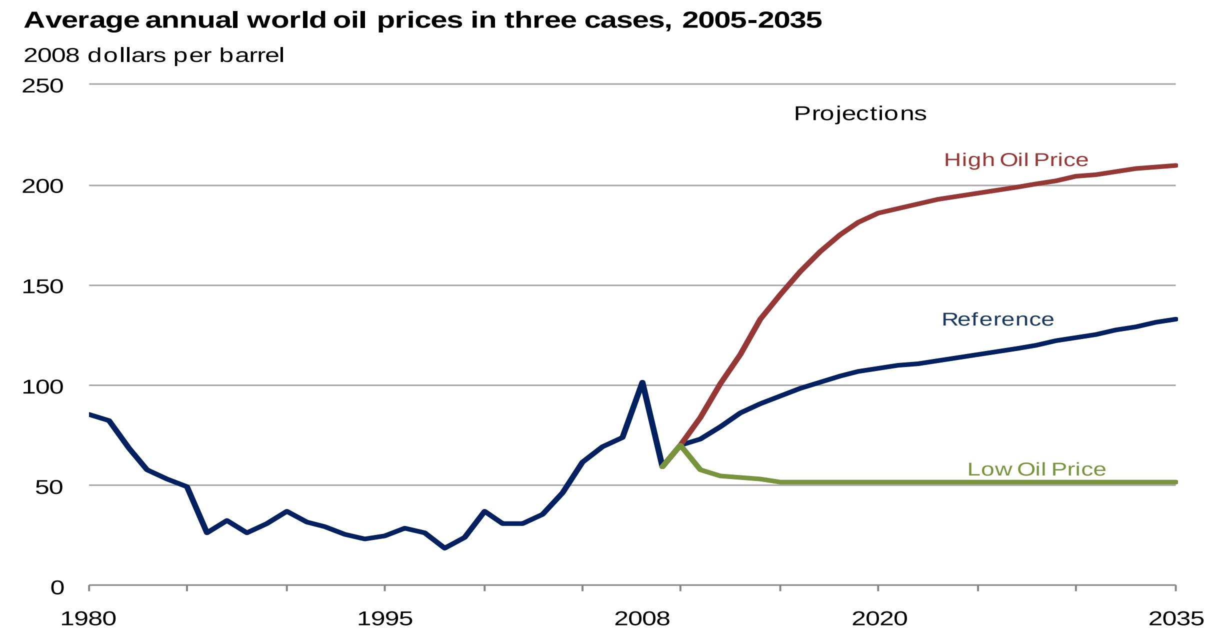
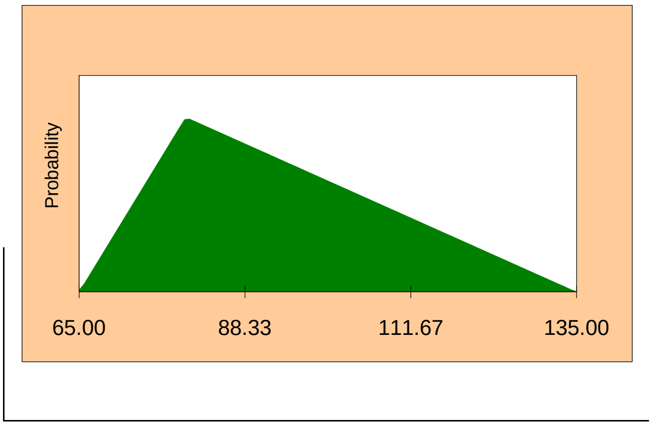


Fig. 13: Average annual world oil prices in three cases, 2005-2035
Source: U.S. Energy Information Administration, Annual Energy Review 2010

The study assumes the price of oil in the international oil market may rise in the longer term substantially and continue to be volatile in the range of £65 ($100) to £135 ($208) per barrel but, mean-reverting to a long-term price of £80 ($124) per barrel. This is close to the EIA's Reference scenario.

Furthermore, it is assumed that the probability distribution of the assumed oil price movement is triangular with the parameters shown in Fig. 14.

Fig. 14: The Probability Distribution of the Oil Price Trajectory (£/bbl)



Minimum Extreme probability distribution with the following parameters (%):

Minimum	*65.00 ($100)*
Maximum	*135.00 ($208)*
Most likely	*80.00 ($124)*

Pipeline transportation data

<u>The Assumptions (Transporter)</u>

As with the capture and storage operators, the CO_2 transporter also has to decide on his optimal level of investment. However, the transporter has a second decision variable – namely, acceptable transportation charges. This is because unlike the CO_2 capturer and storer who respectively have to accept exogenously-determined carbon and oil prices, the transport investor has a say in negotiating an acceptable level of the pipeline transportation charges. The study assumes that these charges comprise of a tariff (related to CAPEX) and a variable usage charge that is a margin over its OPEX (see DECC, 2009[b]). The study treats the latter - i.e. tariff margin - as a decision variable, with assumed values ranging between 10 and 15 percent. The former – i.e. the CAPEX-related component is treated as an assumption and is discussed below.

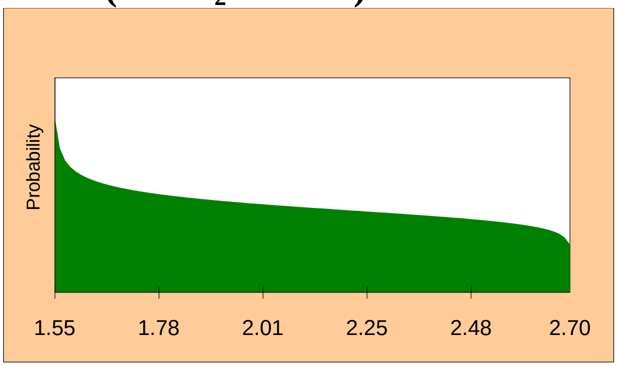
The tariff portion which is tied to the pipeline operator's CAPEX is treated as a relatively more uncertain variable, owing to the non-standardisation of rules governing pipeline capacity trading in the UKCS (DECC, 2009[b]). In the hydrocarbon province, the tariff depends on the local monopoly power of the asset owner, considering a number of factors such as the quality of the material being transported, the nature of the service provided (e.g. Send or Pay), and/or the level of service required. This study assumes that the pipeline transportation investor is able to charge a normalized (to distance and volume) pipeline tariff of between £1.55 and £2.59 per tonne of CO_2 transported per 100 kilometres (see Kemp and Kasim 2010). Kemp and Kasim showed that the normalized pipeline tariff (mirroring the average pipeline CAPEX) has a concave curvature, as the transporter passes on the benefits of the fruits of scale economies and full capacity utilization.

Table 13: The Projected CO_2 Pipeline Transportation Tariff (£/tCO_2/100 km)

Year	Normalised tariff
2023	2.49
2030	2.00
2040	1.70
2050	1.55

The best-fit probability distribution of the forecast normalised pipeline tariff was found to be the beta probability distribution with the following parameters:

Fig. 15: The Probability Distribution of the Projected Normalised Pipeline Tariff (£/tCO_2/100 km)



Beta probability distribution with the following parameters (£/tCO_2/100 km):

Minimum	*1.55*
Maximum	*2.70*
Alpha	*0.88*
Beta	*1.09*

6. Model Optimisation

Four optimisation exercises were run in order to determine, from the perspective of the point source CO_2 capture plant, the basis – that is, distance or sink type – of selecting the source-to-sink destination underpinning its capture investment decision. Specifically, CO_2 shipments from each of the two power plants in the study – Drax and Longannet – were delivered to the two alternative sink-type destinations, at different distances, in order to compare and contrast the relative influence of distance or sink type on profitability and investment decisions. In all cases, the constraints in the optimisation exercise are that the IRR of each investment type (CO_2 capture, transport and storage) must, at least equal the discount rate (10%).

The identified CO_2 delivery routes whose integrated CCS investment returns were investigated are:

Table 14: Distances of Alternative CCS Investments

Route	Distance (km)	Sink type
Longannet-to-Morecambe South	246	Permanent storage
Longannet-to-Forties	337	CO_2-EOR then Permanent storage
Drax-to-Indefatigable	250	Permanent storage
Drax-to-Forties	456	CO_2-EOR then Permanent storage

Assuming a common normalised CO_2 pipeline transportation CAPEX and charges, the Longannet-to-Morecambe South shipments enjoy a 37 percent transport cost advantage over the Longannet-Forties shipments. By the same token, the Drax-Indefatigable shipments have about 82 percent transportation cost advantage over the Drax-Forties shipments. Such transport cost advantages have led some authors and organisations to argue that initial CCS investments be directed towards permanent storage of CO_2 in the gasfields of the Southern North Sea (SNS) (see EEEGR, 2006, for example). However, whether these transportation cost advantages are persuasive enough to shift the investment decision in their favour is explored in detail in the results discussed below.

7. Results and Discussions

Case 1: The Longannet – Morecambe CCS Investments (CO_2 as a Waste Product)

The Returns to CO_2 Capture Plant (Longannet)

After 5000 simulations with 2,000 trials per simulation, the optimisation runs were stopped because there were no improving solutions while some of the model constraints remained unfulfilled. As such, the model solution at this point while being the best available is not optimised. At the best solution point, the calculated range of the NPV of the Longannet capture plant investment is from -£2.93 to -£1.32 billion, with the mean value being -£2.05 billion. The standard deviation of the forecast mean NPV is £250.66 million while the coefficient of variability is small at -0.122. The P10 and P90 values are -£2.37 and -£1.73 billion respectively. There is a 95 percent chance (2 standard deviations about the mean) that the mean NPV will be between -£2.55 and -£1.55 billion. The probability distribution of the capture plant's NPV is presented below in Fig. 16.

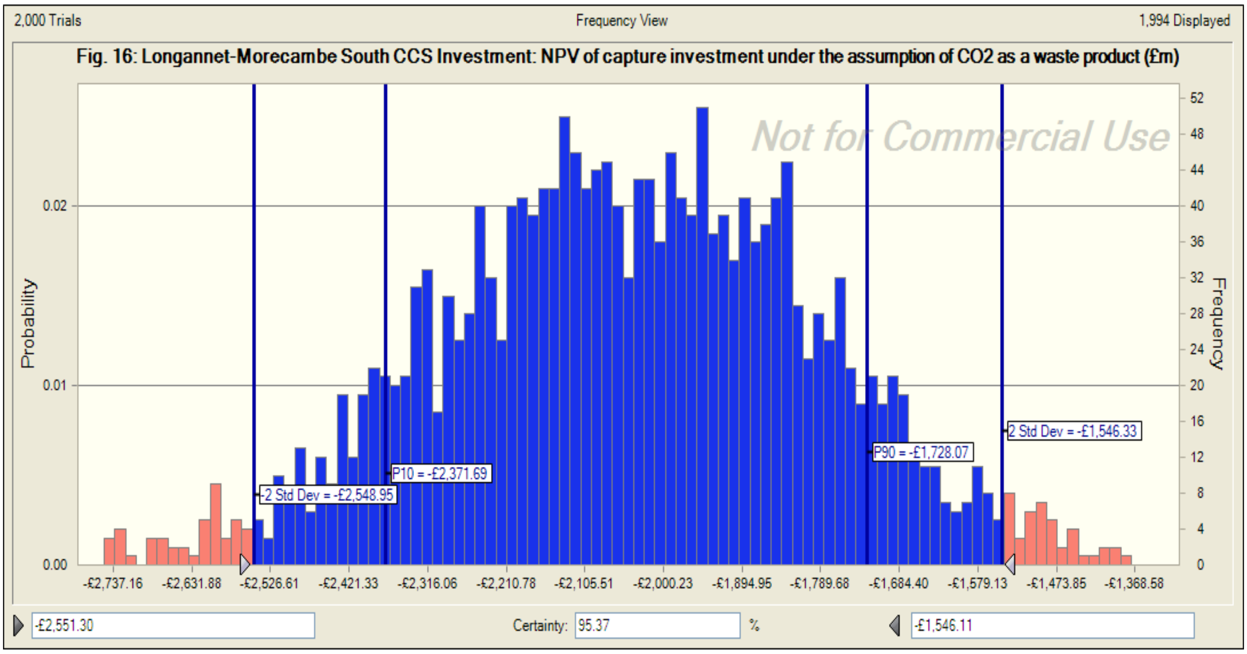
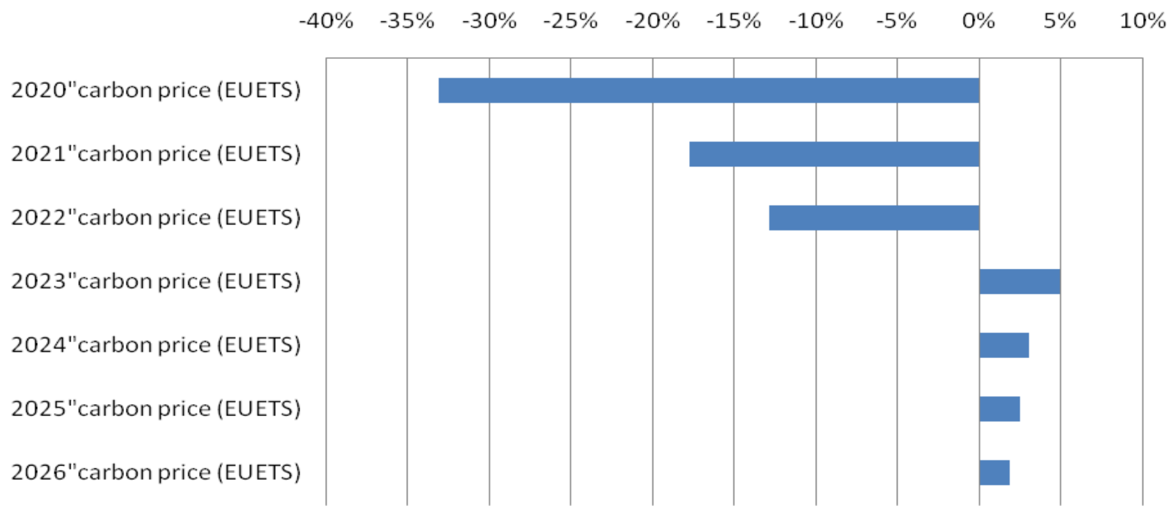


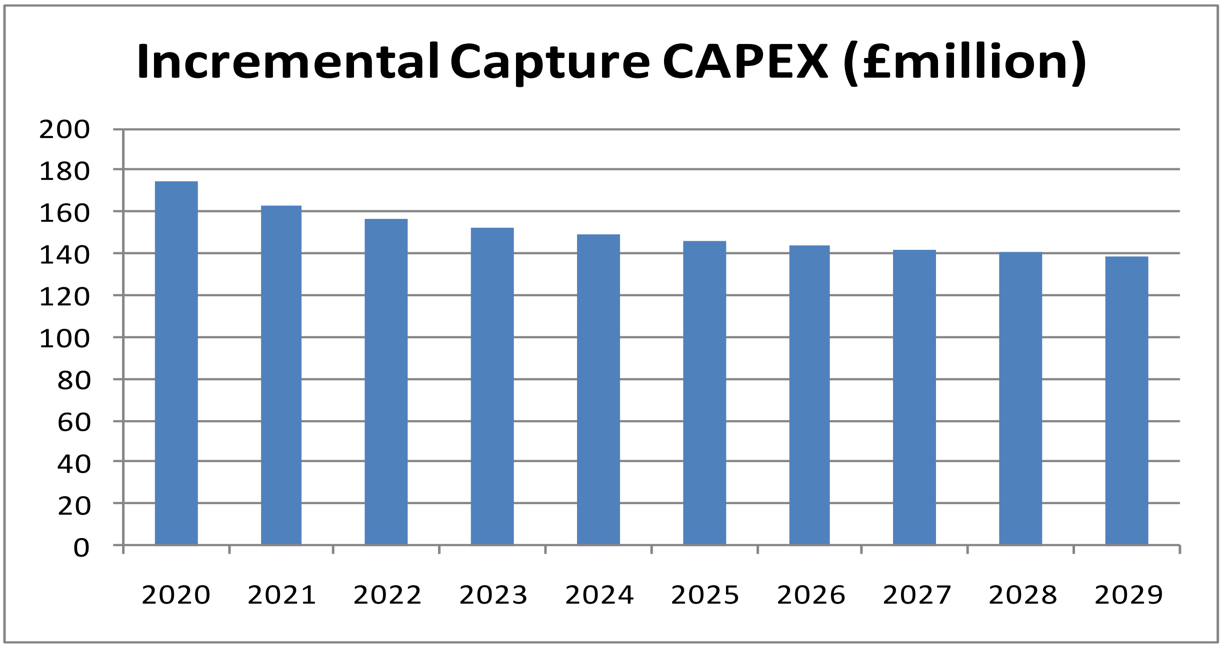
Fig. 16: Longannet-Morecambe South CCS Investment: NPV of capture investment under the assumption of CO2 as a waste product (£m)

Clearly, these negative figures are a violation of model constraints and would deter CO_2 capture investment. The sensitivity of the capture plant's NPV to the model variables is presented below in Fig. 17.

Fig. 17: Longannet-Morecambe South CCS Investment: Sensitivity of the capture investment to influencing variables



According to Fig. 17 the CO_2 capture investment is most sensitive to the price of carbon in the EU-ETS market. However, the sensitivity is time dependent and multi-directional, as expected. Initially, when the carbon price is relatively low the influence is most negatively felt, with the low carbon price reducing the NPV by about 33 percent. However, the negative impact of (a low) carbon price is short-lived. In the medium- to long-term, tightening emission regulations boost carbon prices, the attendant EUA savings (savings from not having to purchase emission rights), and the returns to capture investment. This result is consistent with the views that (a) higher carbon prices are required to encourage capture investment; and (b) there will be a floor (or threshold) carbon price that will trigger the investment.



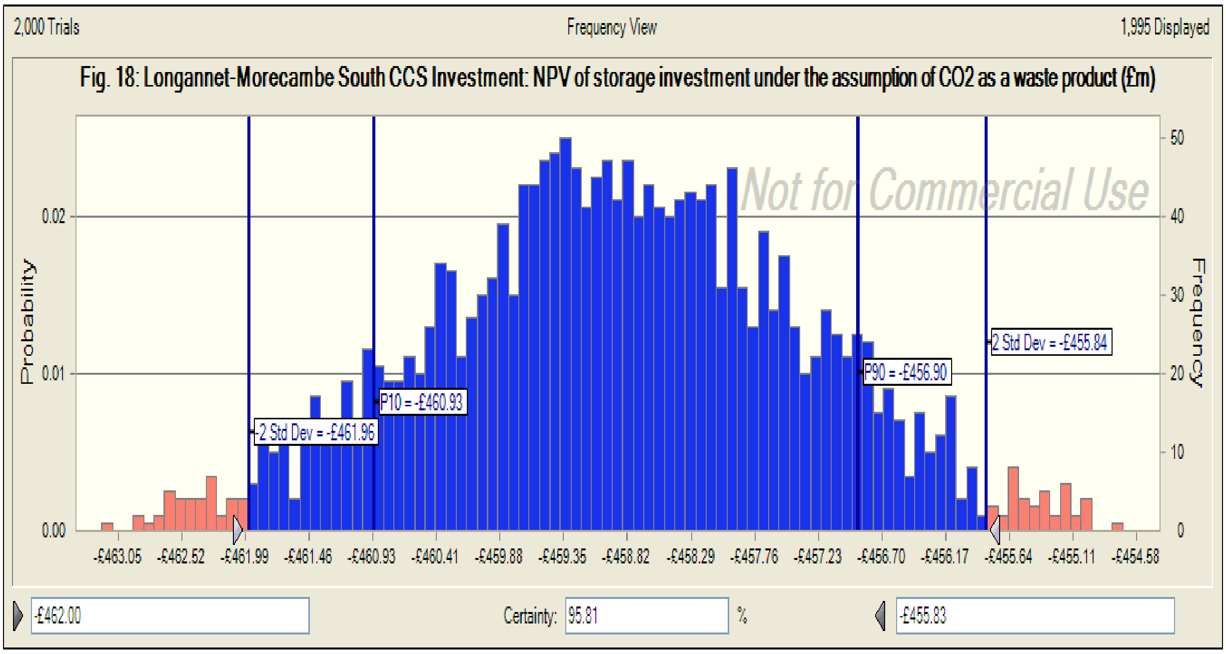
The capture CAPEX is £1.51 billion, which is at the upper end of the assumed CAPEX range. The optimised CAPEX of the capture-related activities, reflect the unit capture cost, proportion of the emitted CO_2 captured, the capture capacity, the amount captured, as well as the effects of scale economies and LBD.

Overall, on the basis of its negative forecast mean NPV, it is clear that the Longannet power plant will not engage in CO_2 capture activity or investment under the assumptions of this scenario.

However, in spite of its sub-optimality it is still useful to report this and similar scenario results below as a way of (1) drawing attention to the implications of the assumptions underpinning the scenario(s) run(s); and, (b) quantifying the scale of assistance that may be required to secure positive returns to investment.

The Returns to the Gas Field (Morecambe South)

At the best but not optimal model solution, the NPV of the gas field operator undertaking the permanent storage of the CO_2 ranges from -£463.71 to -£453.93 million, with a mean of -£458.90 million. This is a very narrow range, implying a low-risk investment with the near certainty of a substantial loss. Furthermore, the P10 and P90 values are -£460.93 and -£456.90 million respectively. There is a 95 percent chance that the mean NPV will be between -£462.00 and -£455.38 million. The narrow distribution of returns emanates from the fact that the fee to the storer is not subject to much risk. The probability distribution of the storer's NPV is presented below in Fig. 18.



The sensitivity of the storage NPV to the model variables are presented graphically in Fig. 19.

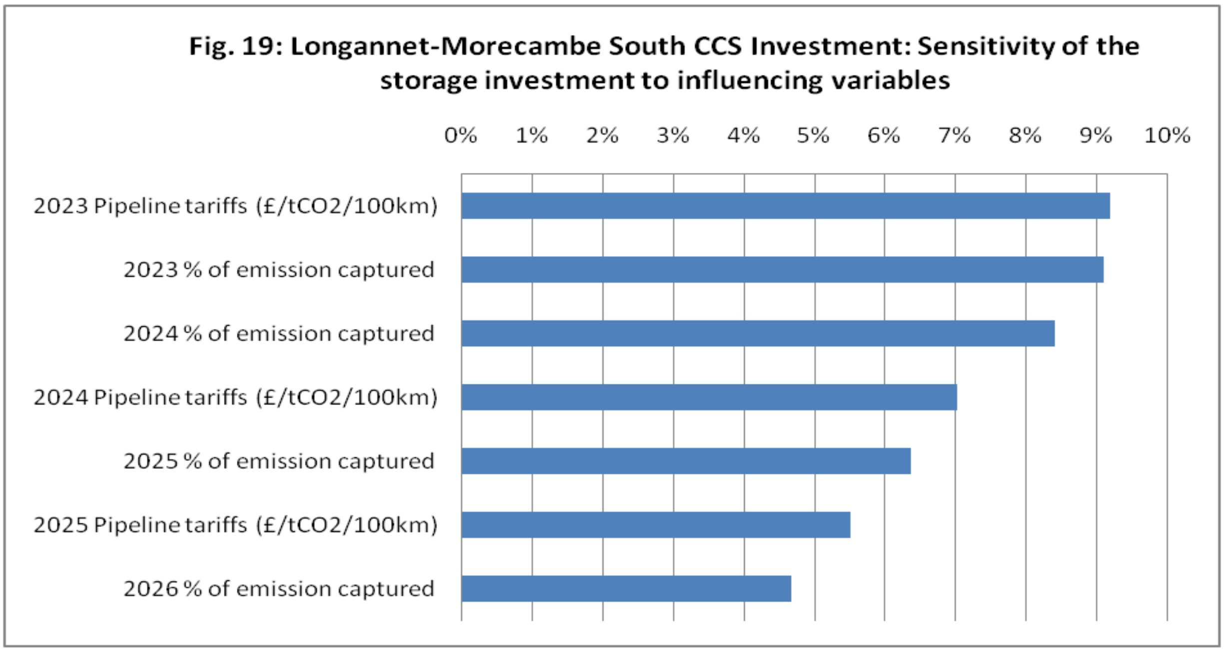
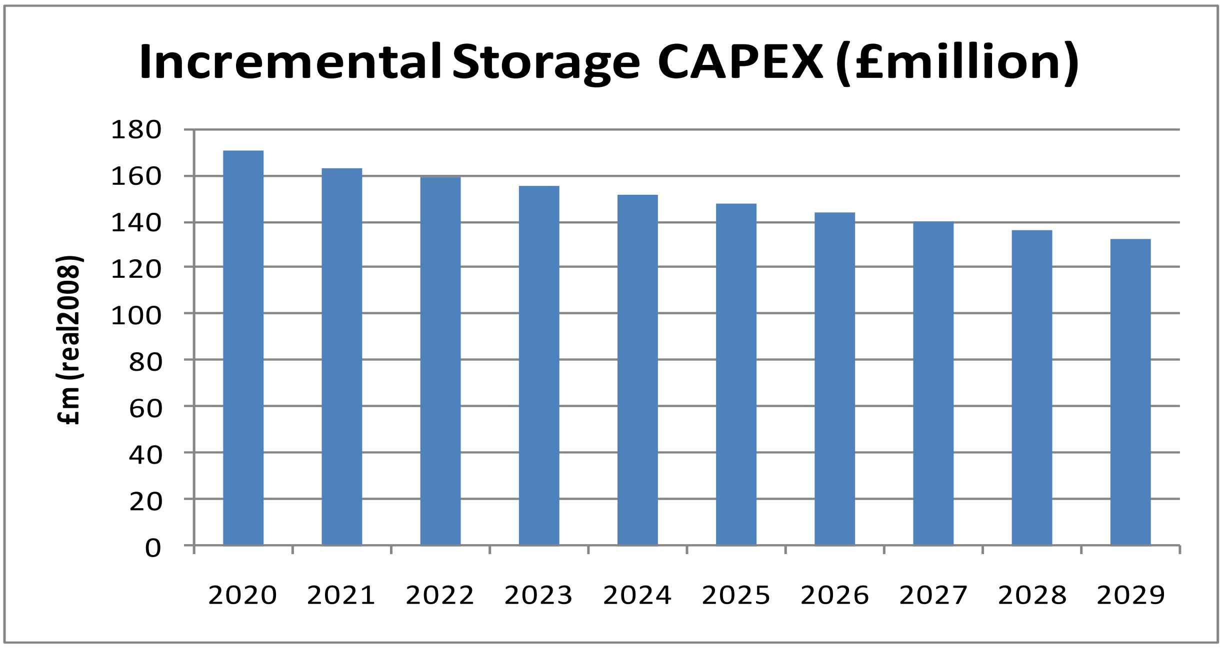


Fig. 19 shows the returns to the storage investment as being very sensitive to variations in the pipeline tariffs and the volumes of CO_2 that are captured. The volumes of CO_2 captured clearly have a direct effect on the revenues to the storer. The pipeline tariffs are also a function of the volume of CO_2 transported and received by the storer but there is no likely causal relationship.



The optimised incremental storage investment cost is £1.5 billion, which is the maximum investment assumed in the study.

Just as with the power plant at Longannet, the negative NPV of the Morecambe South field operator will discourage an investment in CO_2 storage activities under the circumstances.

The Returns to the CO_2 Pipeline Transport Investment

At the best but not necessarily optimal solution, the mean NPV of the pipeline operator ranges from £10.43 million to £60.92 million. The standard error of the mean is £0.07 million, with a standard deviation of £7.82 million and coefficient of variability of 0.21. The P10 and P90 values are £26.53 and £46.39 million respectively. There is a 95 percent chance that the mean NPV will be between £20.67 and £51.98 million. The probability distribution of the CO_2 transporter's NPV is presented below in Fig. 20.

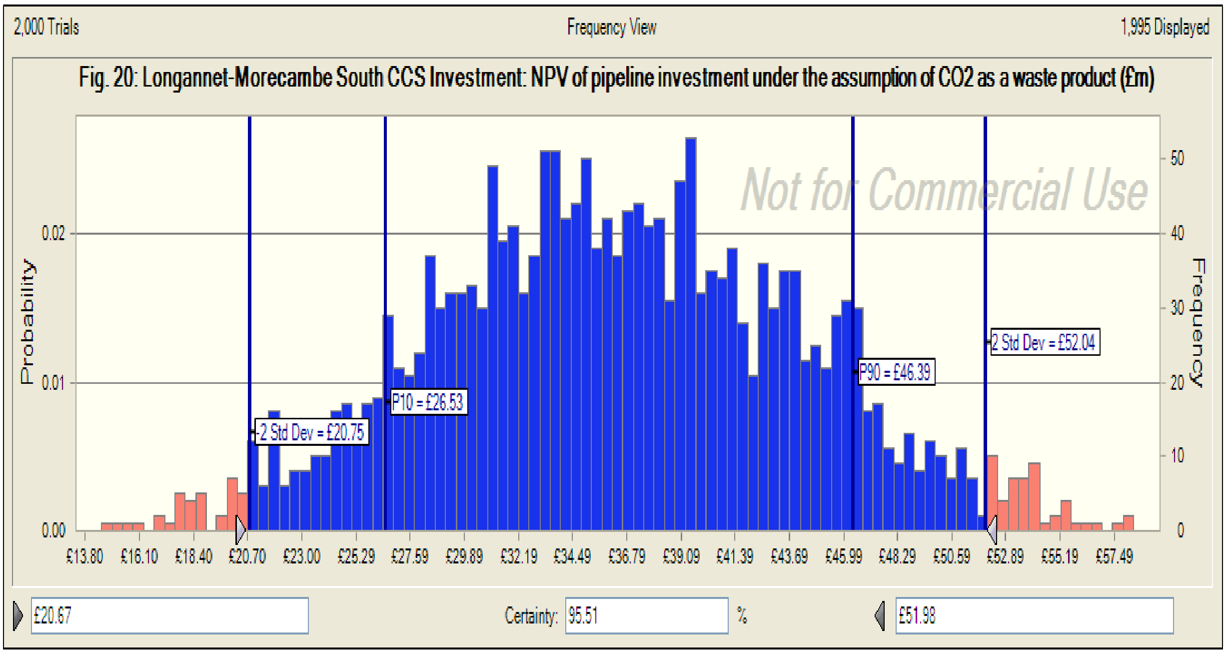
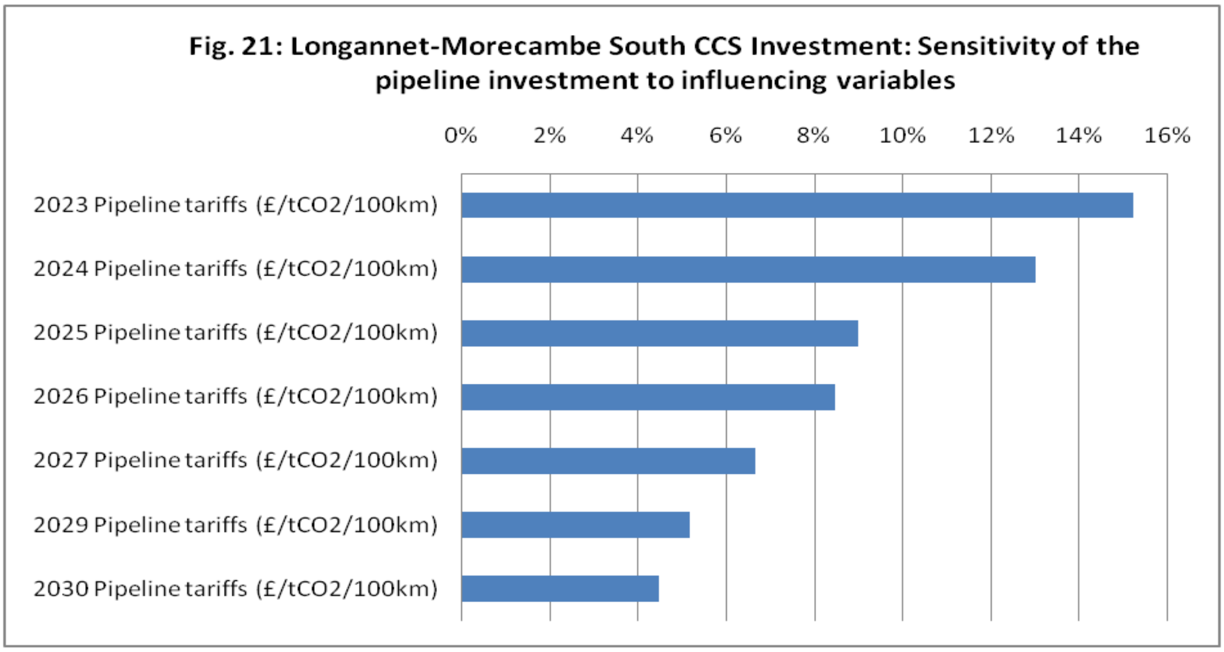
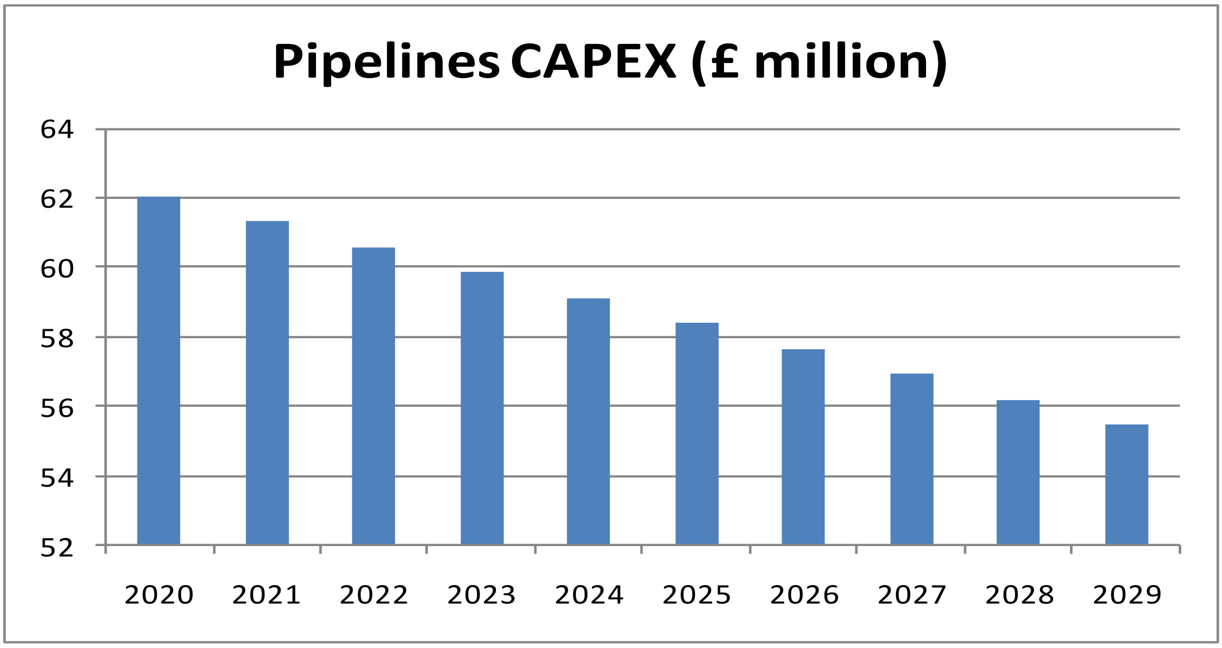


Fig. 20: Longannet-Morecambe South CCS Investment: NPV of pipeline investment under the assumption of CO2 as a waste product (£m)

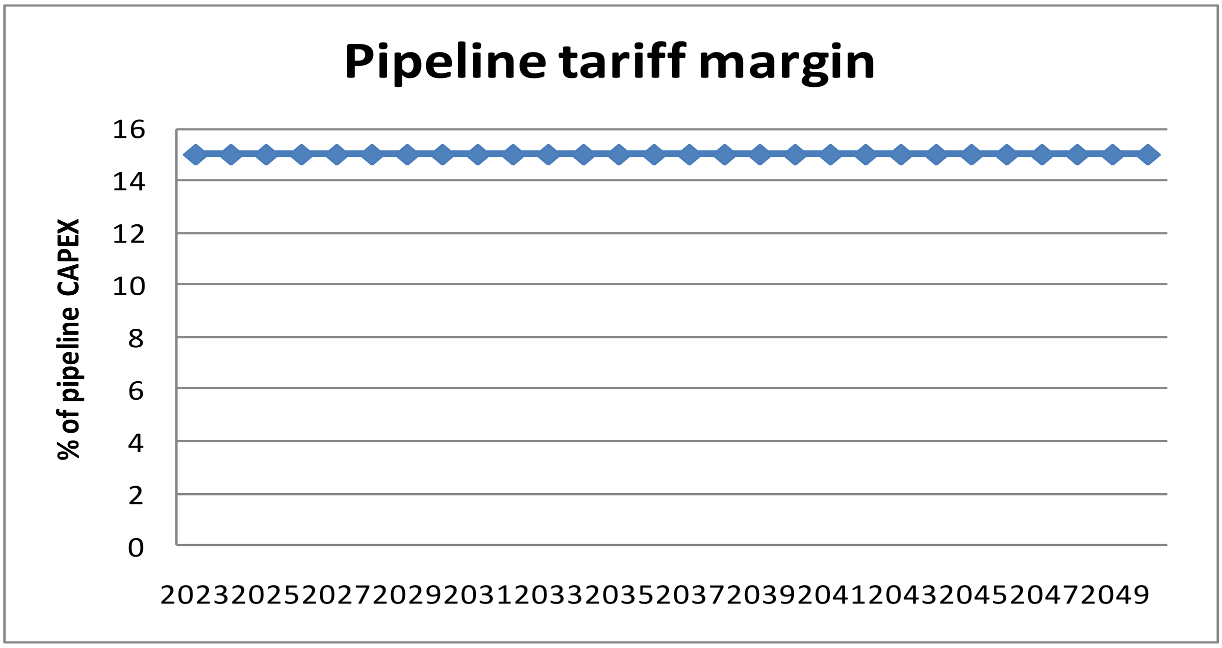
The sensitivity of the returns to the pipeline operator's investment is presented in Fig. 21.



As shown in Fig. 21, the pipeline operator's NPV is most sensitive to the normalised pipeline tariff. The two variables are positively related. Indeed, the result in Fig. 21 shows that a 1 percent increase in the normalised pipeline tariff will increase the pipeline operator's NPV by between 7 and 15 percent.



The pipeline operator's optimised CAPEX is £587.65 million. As shown below, the optimised pipeline tariff is 15 percent of CAPEX.



The constancy of the (tariff) margin confirms that the variations in the pipeline operator's NPV (see Fig. 21) are due largely to the CAPEX-related normalized tariffs.

Overall, of the three potential CCS investors in this scenario, the only one with a modest positive return on its investments is the CO_2 transport pipeline operator. However, with the capture and storage investors receiving negative returns to their investments, it is clear that the integrated CCS investment will not be undertaken under the assumptions of this scenario – i.e. source-to-sink proximity, and treating CO_2 as a waste product.

Case 2: The Longannet-Forties CCS Investments (CO_2 commoditised)

There exists a CO_2 commoditisation potential along Route 2 because of the possibility of CO_2-EOR. With the commoditisation potential, the study investigated the impacts on the integrated CCS investment of the three alternative ways in which the value of the capture CO_2 may be realised. The three alternative ways in which value is added to the captured CO_2 are:

i. Barter or payment-in-kind, in which the captured CO_2 is delivered free of charge to the oilfield operator for CO_2-EOR. In return, the capture investor enjoys a storage fee payment holiday during the CO_2-EOR phase for the first five years of the EOR activity but pays the fee thereafter.

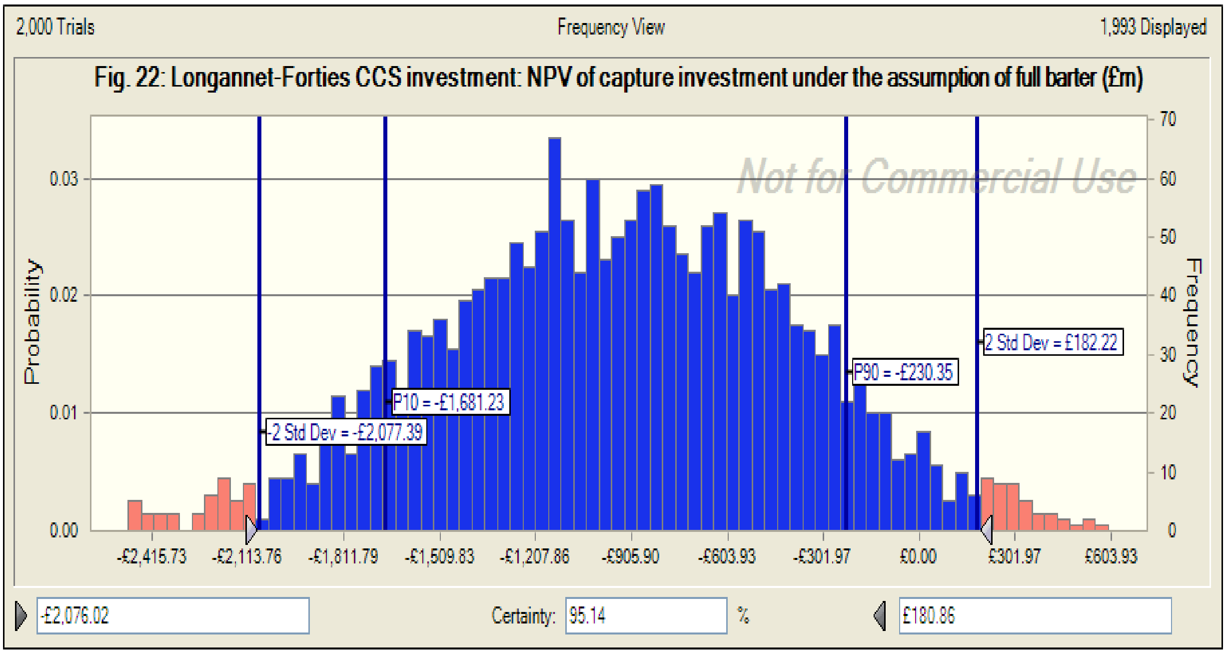
ii. Fully-receipted CO_2-EOR, in which the capture investor receives the full cash payment for the captured CO_2 delivered to the oilfield for EOR while still enjoying the storage fee payment holiday. He pays for storage in the post-EOR periods.

iii. Partially-receipted CO_2-EOR, in which the end-user (oilfield operator) does not pay for the entire CO_2-EOR stream but enjoys a payment holiday for the first five years of the EOR activity.

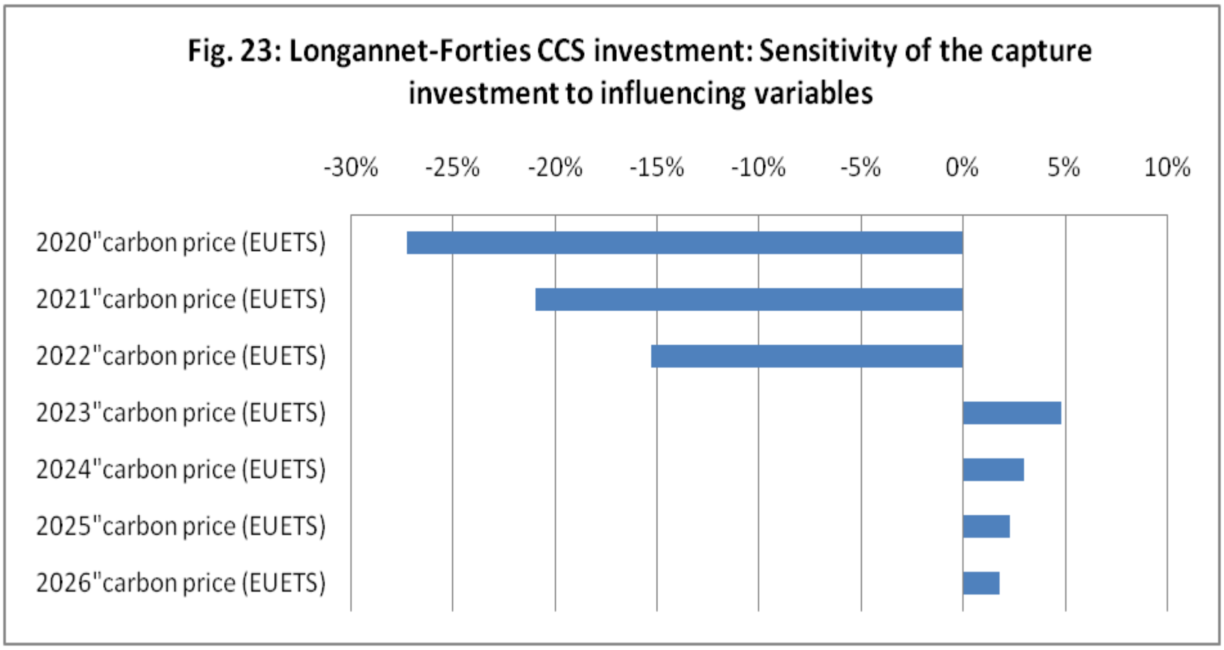
The results of the aforementioned scenario runs are considered first from the perspective of the capture investor.

The Returns to the CO_2 Capture Plant (Longannet) under CO_2-EOR Barter Assumptions (case i)

In the best solution of this scenario, the mean NPV of the capture investment ranges from £-2.91 to £0.69 billion, with a mean of -£947.58 million and a range width of £3.60 billion. The standard error of the mean is £12.63 million and the standard deviation and coefficient of variability are respectively £564.90 million and -0.60 respectively. The P10 and P90 values are -£1.68 million and -£230.35 million respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 22.



The sensitivity of Longannet's forecast NPV to variations in the model variables is presented below in Fig. 23.



As in the Longannet-to-Morecambe South scenario, the capture plant's NPV is most sensitive to carbon prices. Also, the pattern of a shift in the direction of influence as carbon prices increased in magnitude is the same. The capture plant's NPV was sensitive positively, also, to the percentage of emissions captured, indicating that the NPV improves with higher percentages of emission captured.

Comparing the returns to the capture investment of this scenario, in which CO_2 is commoditised and fully bartered, to the returns in the earlier scenario in which CO_2 was treated as a waste product reveals both returns to be negative and unattractive to the capture investor. Thus, while commoditising CO_2 may be a necessary condition to the profitability of capture investment, it is by no means sufficient. The way and manner of the commoditisation is obviously very important. A commoditisation approach that gives all the advantage to the storer is not likely to inspire the upstream (capture) investment. In the present case the returns to the storer are very attractive (mean NPV of £2.75 billion) and the returns to the transporter are also positive (mean NPV of £34 million).

The Returns to the CO_2 Capture Plant (Longannet) with Fully-Receipted CO_2-EOR Assumptions (case ii)

After 5000 simulations with 2,000 trials per simulation, the optimisation runs were stopped because there were no improving solutions while some of the model constraints remained unfulfilled, especially the non-negativity constraint of the oilfield investor's NPV. As such, the reported model solution while being the best is not optimal. At the best solution point, the forecast NPV of the Longannet capture plant investment in this scenario ranges from -£0.13 billion to £4.5 billion, with the mean value being £2.3 billion and a range width of £4.6 billion. The standard error of the mean is £16.8 million and the standard deviation and coefficient of variability are respectively £750.9 million and 0.34 respectively. The P10 and P90 values are £1.26 and £3.20 billion respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 24.

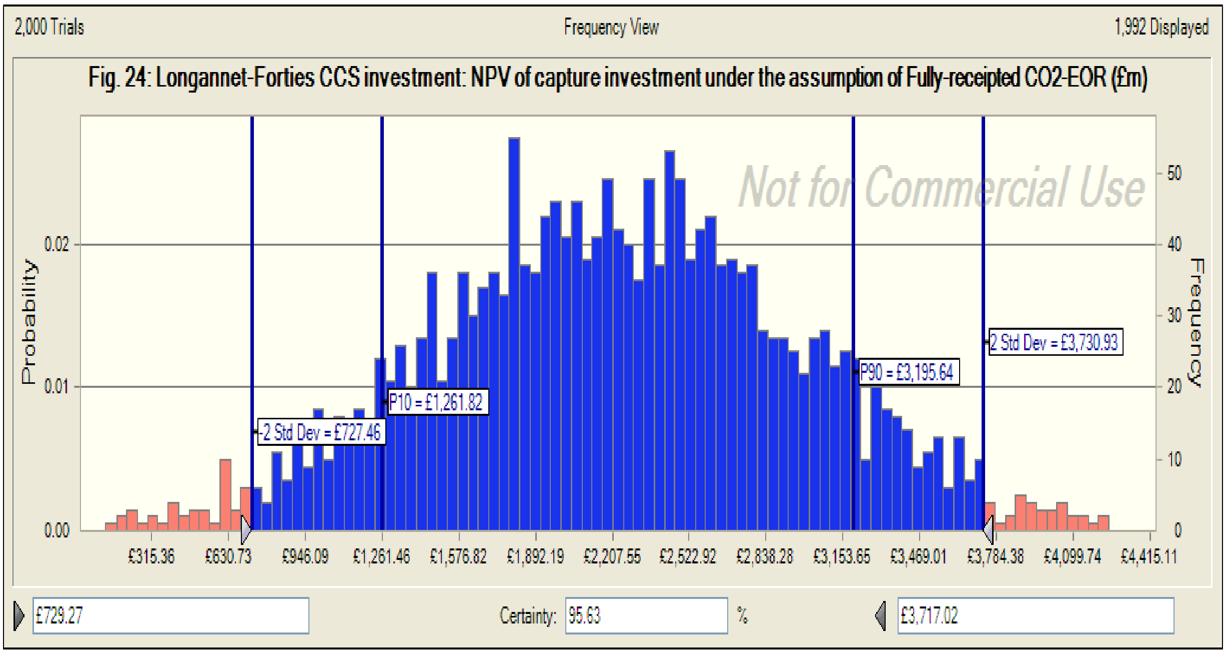


Fig. 24: Longannet-Forties CCS investment: NPV of capture investment under the assumption of Fully-receipted CO2-EOR (£m)

The sensitivity of Longannet's forecast NPV to variations in the model variables is presented below in Fig. 25.

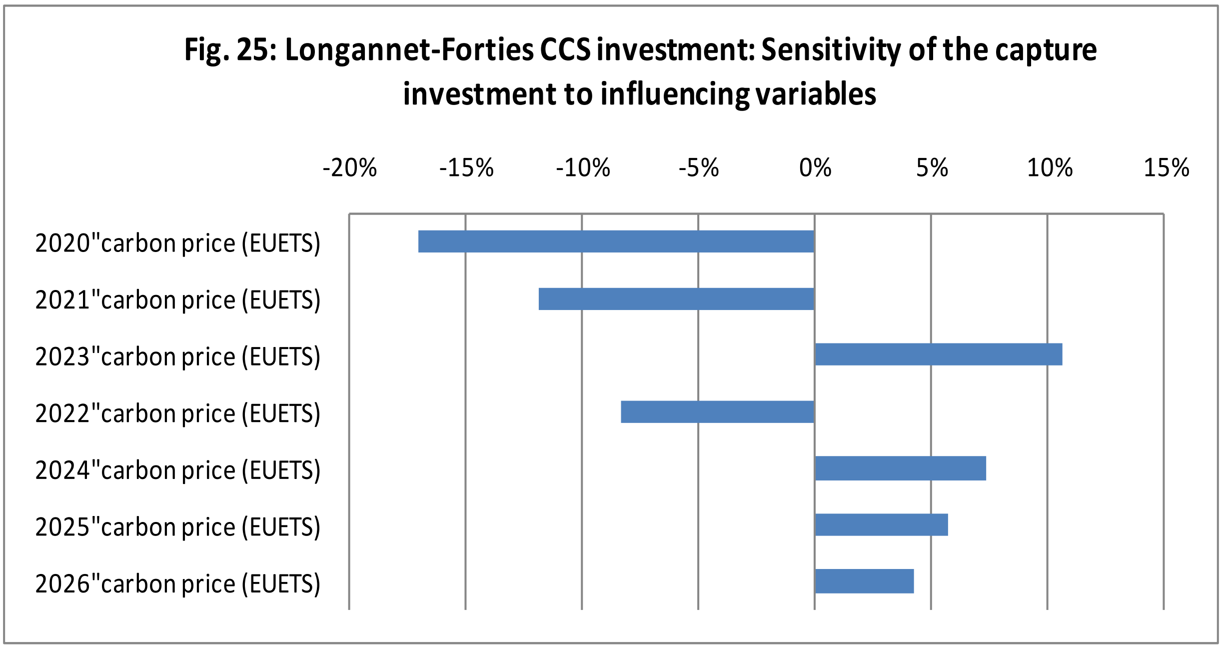


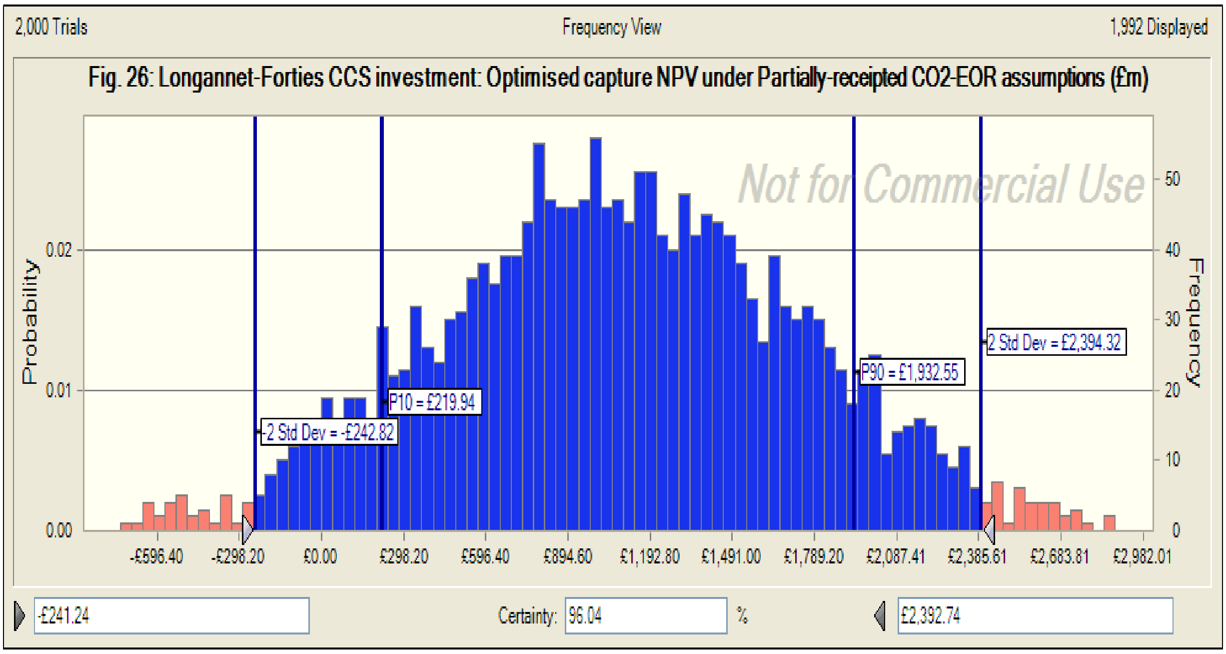
Fig. 25: Longannet-Forties CCS investment: Sensitivity of the capture investment to influencing variables

In Fig. 25, the key drivers of the variations in the capture NPV are not only the same as in the earlier scenario but also exhibit a similar behaviour pattern. Clearly, the sheer size of the magnitude of the returns to the capture investment (mean NPV = £2.3 billion) under the assumptions of this capture-friendly scenario is a strong incentive to undertake the investment. But the sub-optimality of this scenario is caused by the negative returns to the oilfield operator's investment. The mean NPV of the storer is -£438 million. Since a break in the CCS value chain nullifies the integrated CCS investment, the absence of the storage investment in this case implies that the capture investment would not be undertaken. An improved solution in which the fruits of CO_2 commoditisation are not treated as a zero-sum between the storage- and capture- investors must be sought. This is the thrust of the next scenario.

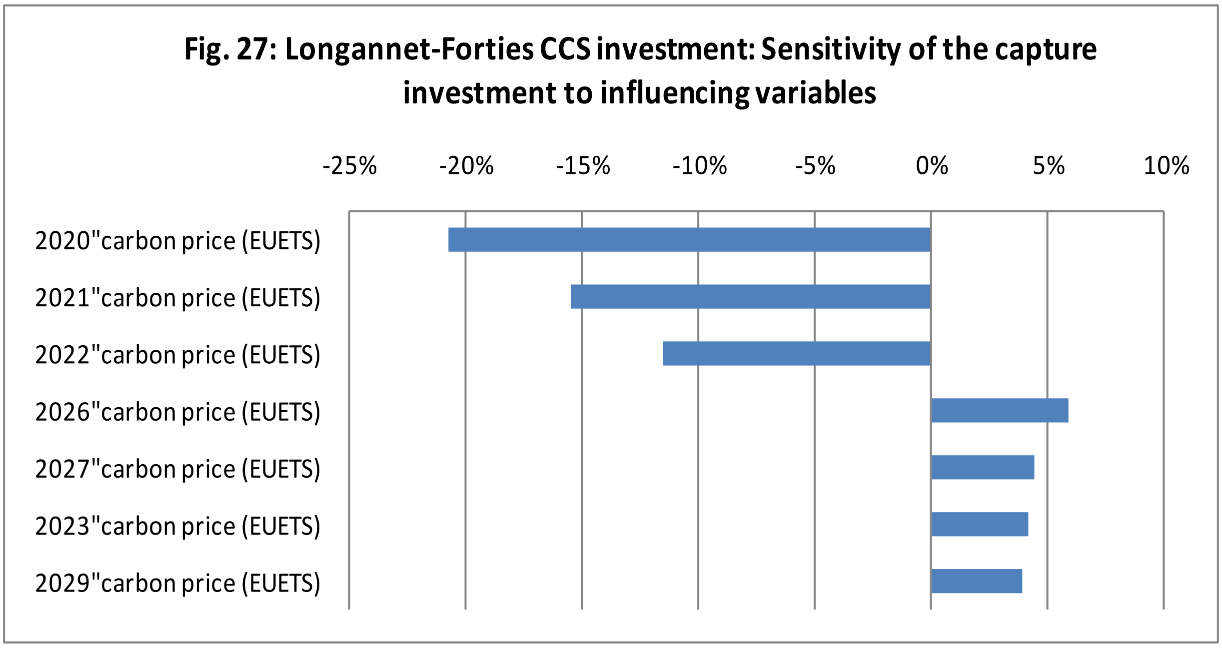
The Returns to the CO_2 Capture Plant (Longannet) under Partially-Receipted CO_2-EOR Assumptions (case iii)

After 5000 simulations with 2,000 trials per simulation, an optimal solution was found in which all the model constraints were satisfied.

The optimal NPV of the Longannet capture plant investment in this scenario ranges from -£1.16 billion to £2.96 billion, with the mean value being £1.08 billion and a range width of £4.11 billion. The standard error of the mean is £14.74 million and the standard deviation and coefficient of variability are respectively £659.29 million and 0.61 respectively. The P10 and P90 values are £0.22 billion and £1.93 billion respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 26.



The sensitivity of Longannet's optimal NPV to variations in the model variables is presented below in Fig. 27.

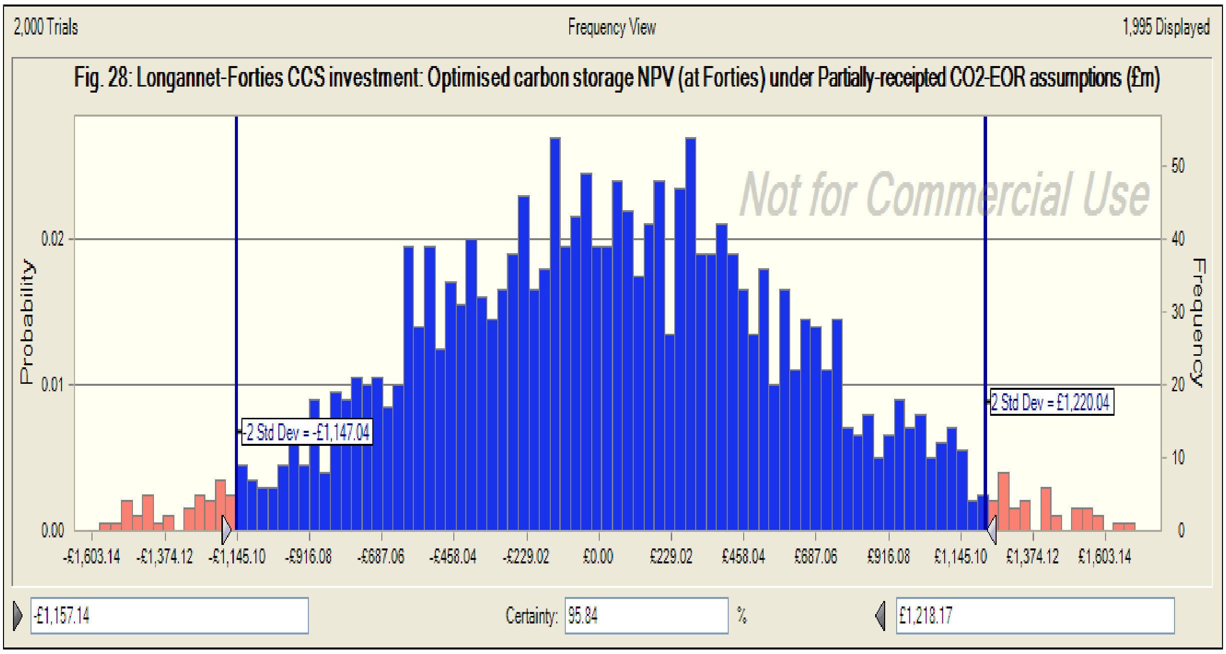


As in the earlier scenarios Fig. 27 shows that the NPV of the capture investment is most sensitive, in the same time-dependent manner, to the carbon price and the proportion of the emitted CO_2 that is captured.

The positive returns to capture investment under the assumptions of this scenario will encourage the investment. But, will the storage and pipeline infrastructure investor be similarly motivated to invest? The answers are now provided.

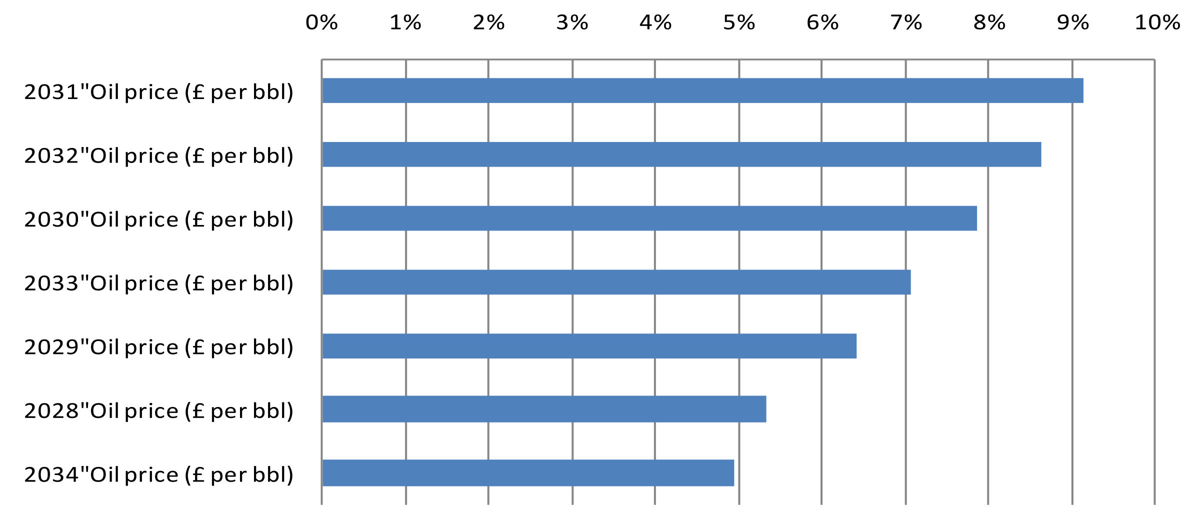
The Returns to the CO_2-EOR Investment (Forties) under Partially-Receipted CO_2-EOR Assumptions (case iii)

The optimal NPV of the CO_2 storage investment in this scenario ranges from -£0.92 to £3.48 billion, with the mean value being £727.60 million and a range width of £4.40 billion. The standard error of the mean is £13.47 million and the standard deviation and coefficient of variability are respectively £602.18 million and 0.83 respectively. The P10 and P90 values are -£0.05 and £1.51 billion respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 28.



The sensitivity of Forties' optimal NPV to variations in the model variables is presented below in Fig. 29.

Fig. 29: Longannet-Forties CCS investment: Sensitivity of the storage investment to influencing variables

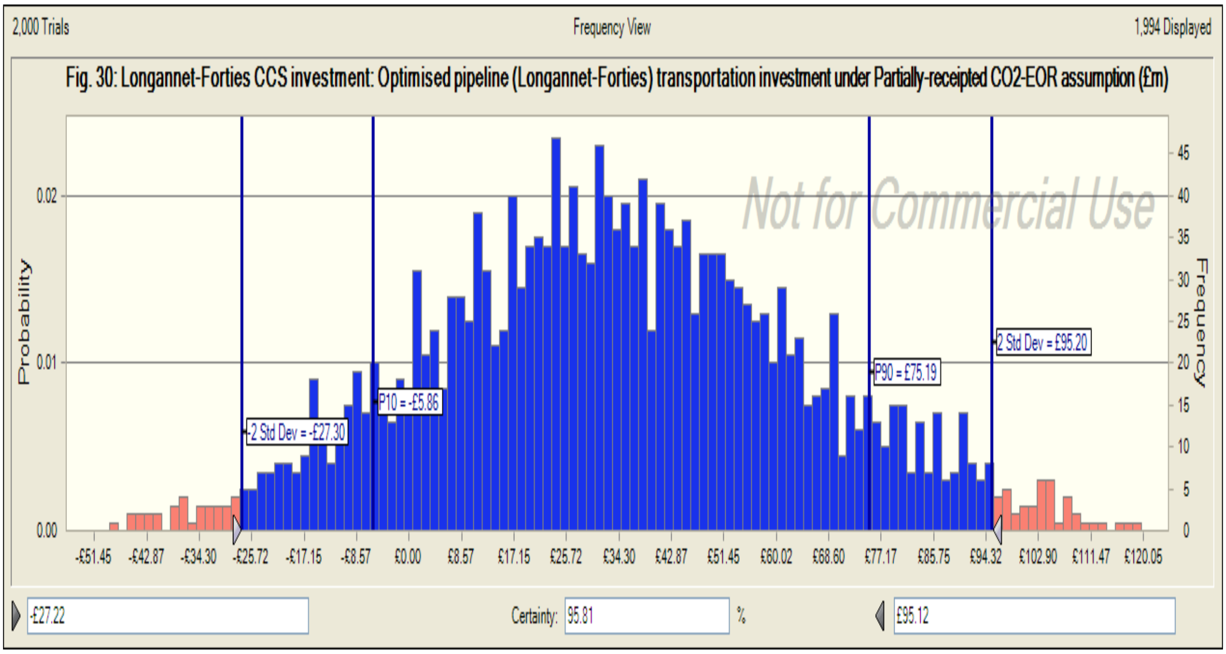


Clearly, the variations in the Forties field's investment returns are due predominantly to changes in the price of oil. However, the strength of the influence weakens over time.

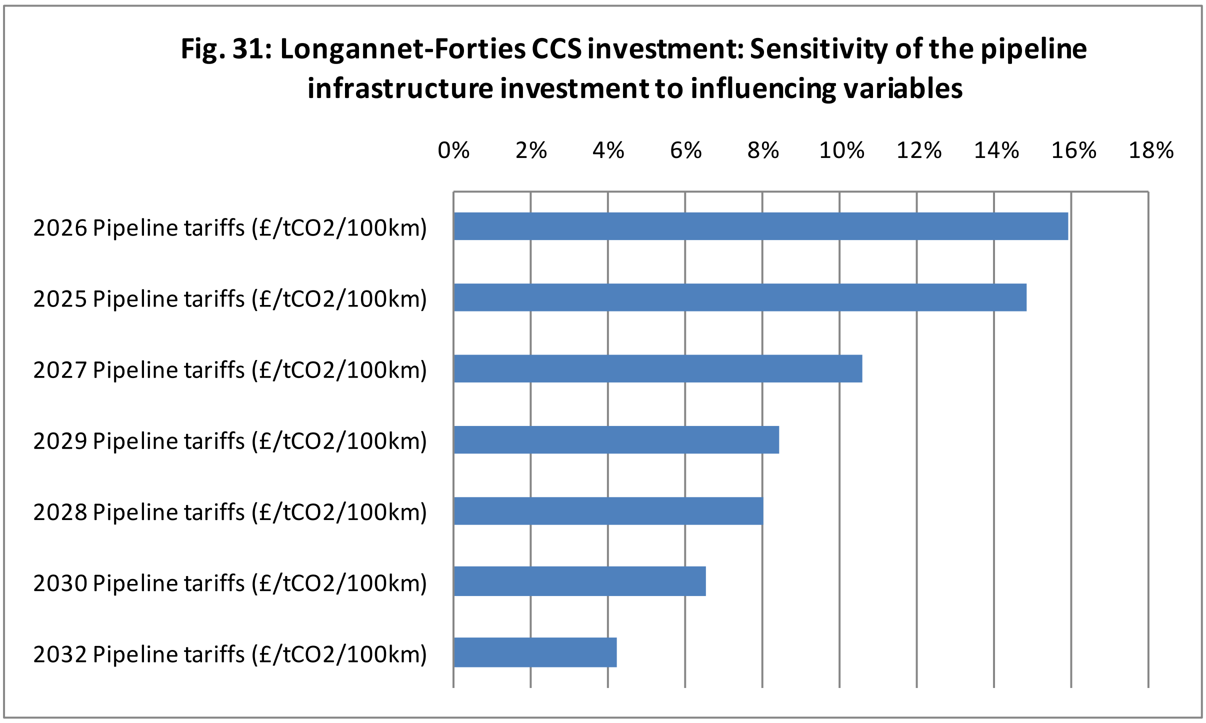
Under the assumptions, the investment produces a generally positive NPV. Thus, the model solutions considered so far in this scenario suggest that the carbon capture and storage investments will be undertaken. That leaves a consideration of the pipeline transportation investment.

The Returns to the Longannet-Forties Pipeline Transportation Investment under Partially-Receipted CO_2-EOR Assumptions

The optimised NPV of the pipeline infrastructure investment in this scenario ranges from -£60.22 million to £149.83 million, with the mean value being £33.95 million and a range width of £210.05 million. The standard error of the mean is £0.68 million and the standard deviation and coefficient of variability are respectively £30.62 million and 0.92 respectively. The P10 and P90 values are -£5.86 and £75.19 million respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 30.



The sensitivity of the pipeline infrastructure's optimal NPV to variations in the model variables is presented below in Fig. 31.



Predominantly, the variations in the pipeline operator's NPV are influenced by changes in the normalised pipeline tariffs, with the potency of influence diminishing over time.

The generally positive NPV of the pipeline transportation investment will probably encourage the investment to be undertaken, thus completing the integrated CCS investment.

A quick summary of the model solutions in the three scenarios or trading possibilities when CO_2 is commoditised is presented below.

Table 15: Summary Scenario Analysis of Integrated CCS Investment with Commoditised CO_2, Longannet – Forties

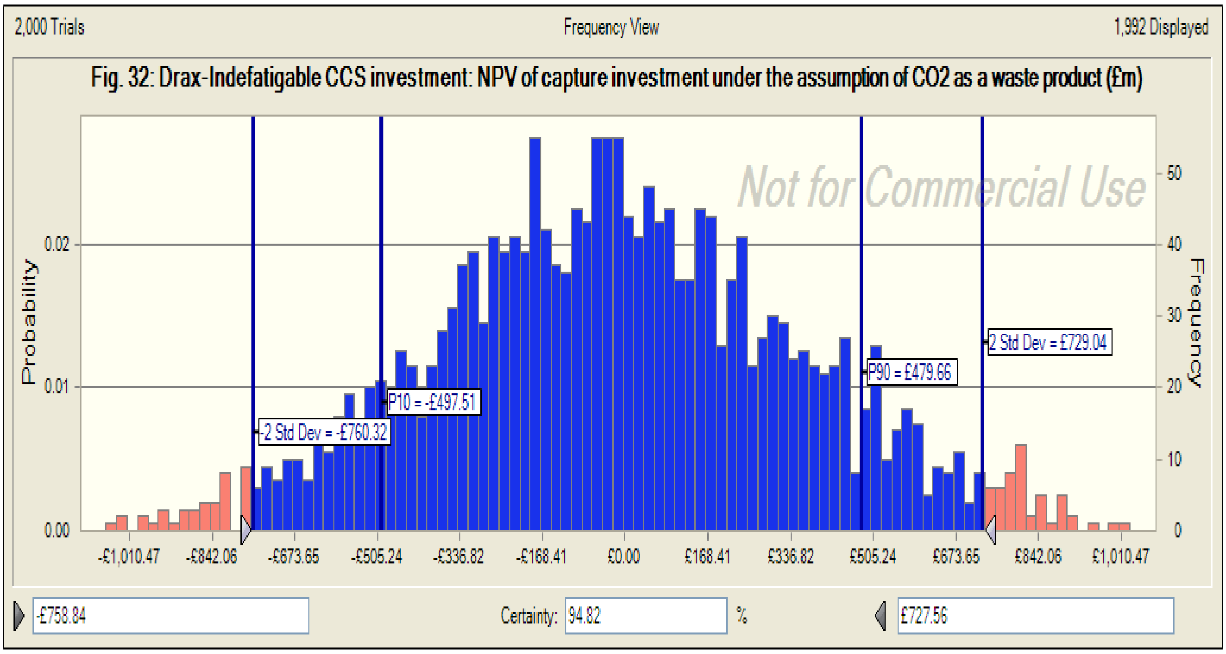
Item	Scenarios		
	CO_2-EOR fully bartered	**CO_2-EOR fully cash-receipted**	**CO_2-EOR partly bartered, partly cash-receipted**
	I	II	III
Mean NPV (capture) (£ billion)	-0.95	2.23	1.08
Mean NPV (transport) (£ billion)	0.34	0.34	0.34
Mean NPV (storage) (£ billion)	2.75	-0.44	0.73
Mean IRR (capture) (%)	<10	18.02	13.73
Mean IRR (transport) (%)	13.74	13.73	13.74
Mean IRR (storage) (%)	17.75	<10	12.21
Coefficient of variability of NPV (capture)	-0.60	0.34	0.61
Coefficient of variability of NPV (transport)	0.90	0.91	0.90
Coefficient of variability of NPV (storage)	0.20	-1.47	0.83

According to Table 15 the highest returns to CCS investment of about £2.15 billion are obtained under the assumptions of Scenario III. However, the relative narrow spread (£2.14 billion, £2.13 billion, and £2.15 billion) of the integrated returns across the 3 cases masks the important fact that Scenarios I and II are unlikely to be viable because they contain infeasible solutions. Scenario I is not feasible because even though it yields the highest returns (£2.75 billion) to the storage investment, the returns (-£0.95 billion) to the upstream capture investment are negative (and IRR below the discount rate) virtually guaranteeing the non-availability of storage for any captured CO_2. On the other hand, the highest returns (£2.23 billion) to the capture investment is achieved under Scenario III assumptions but, the result is unattractive to storage investment because of the negative NPV (-£0.44 billion).

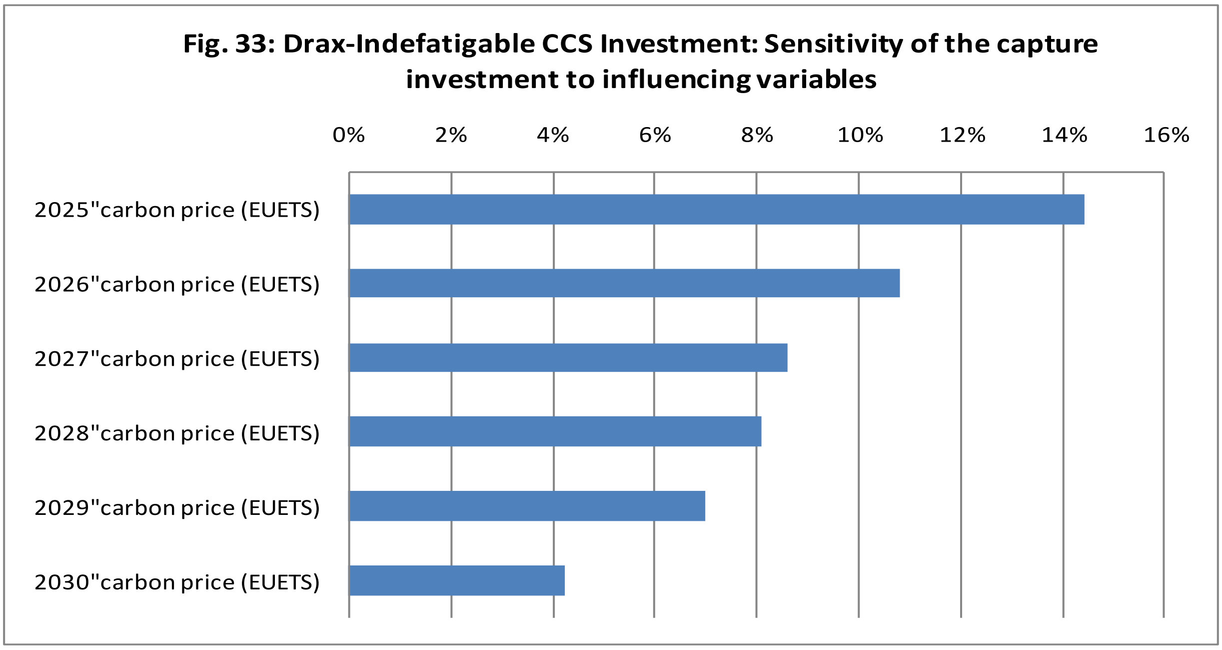
Case 3: The Drax – Indefatigable CCS Investments

The Returns to the CO_2 Capture Plant (Drax)

After 5000 simulations with 2,000 trials per simulation, the optimisation runs were stopped because there were no improving solutions while some of the model constraints remained unfulfilled, especially the non-negativity constraint on the returns to the capture investment. As such, the reported model solution while being the best is not optimal. At the best solution point, the forecast NPV of the Drax capture plant ranges from -£1.12 billion to -£1.20 billion, with the mean value being -£15.64 million. The standard deviation of the forecast mean NPV is £372.34 million while the coefficient of variability is relatively large at -23.80. The P10 and P90 values are -£497.51 and £497.66 million respectively. There is a 95 percent chance that the mean NPV will be between -£758.84 million and £727.56 million. The probability distribution of the capture plant's (Drax) NPV is presented below in Fig. 32.



The sensitivity of the optimised NPV to variations in the model variables is presented in Fig. 33.



In Fig. 33, the most influential variable on the power plant's NPV is seen to be the carbon price. In particular, in 2025, the impact of carbon price is strong enough for each percentage incresase in the price to improve the NPV by about 20 percent.

The total capture CAPEX is £1.94 billion, which is within the assumed range of £1.8 to £2.0 billion.

Overall, the capture investment will not be undertaken given its negative returns.

The Returns to the Gas Field (Indefatigable)

The best-solution NPV of the gas field operator undertaking the permanent storage of the CO_2 ranges from -£311.09 million to -£221.70 million, with a mean of -£266.24 million. The standard error of the mean is relatively small at £0.33 million, with the standard deviation and coefficient of variability being £14.77 million and -0.06 respectively. The P10 and P90 values are -£285.39 and -£246.34 million respectively. There is a 95 percent chance that the mean NPV will be between -£296.00 and -£236.73 million. The probability distribution of Indefatigable's NPV is presented below in Fig. 34.

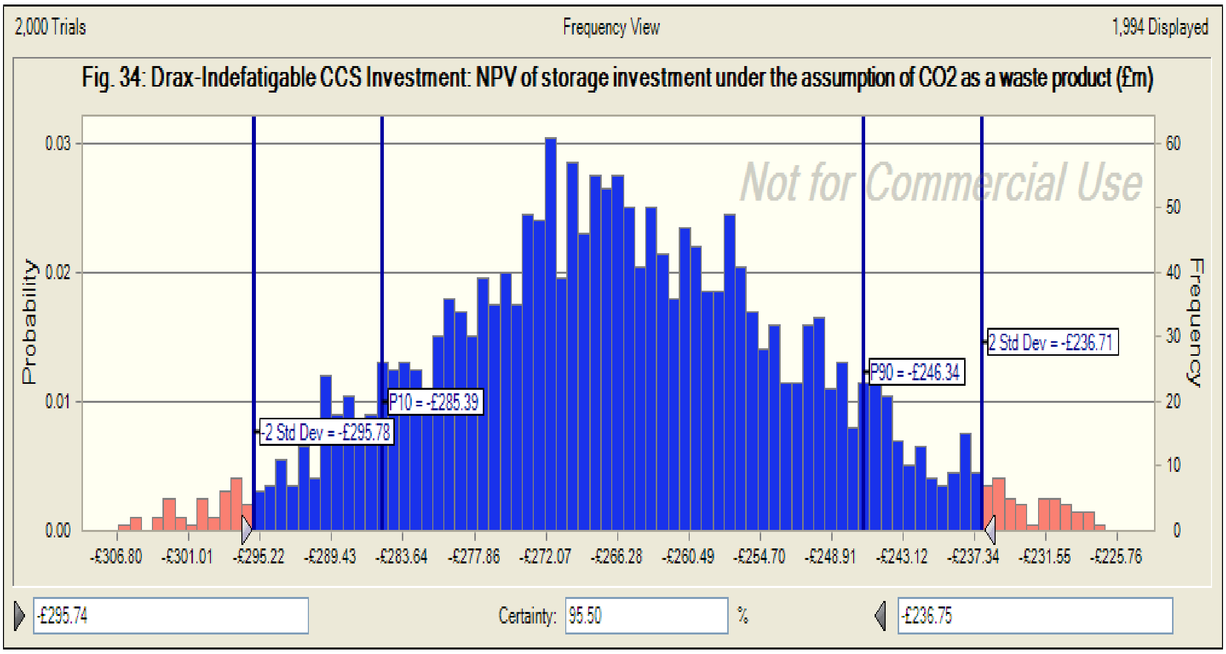


Fig. 34: Drax-Indefatigable CCS Investment: NPV of storage investment under the assumption of CO2 as a waste product (£m)

The sensitivity of the storage sink's operator's NPV to variations in the model variables are presented in Fig. 35.

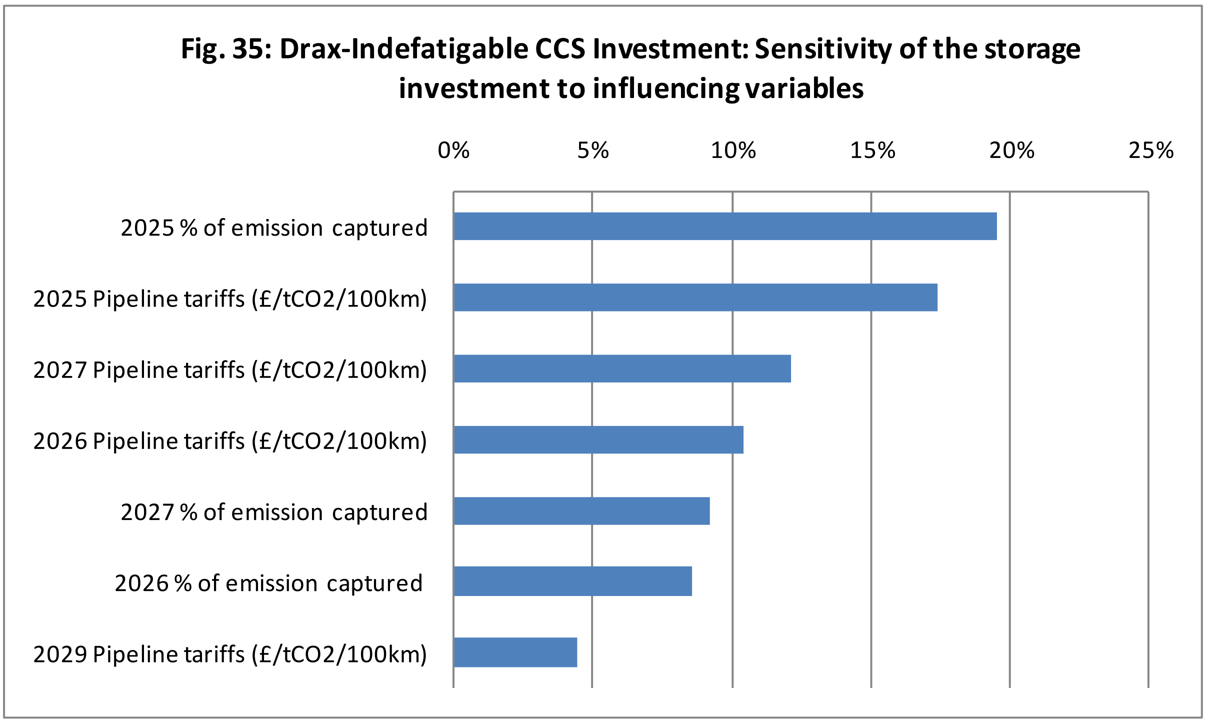


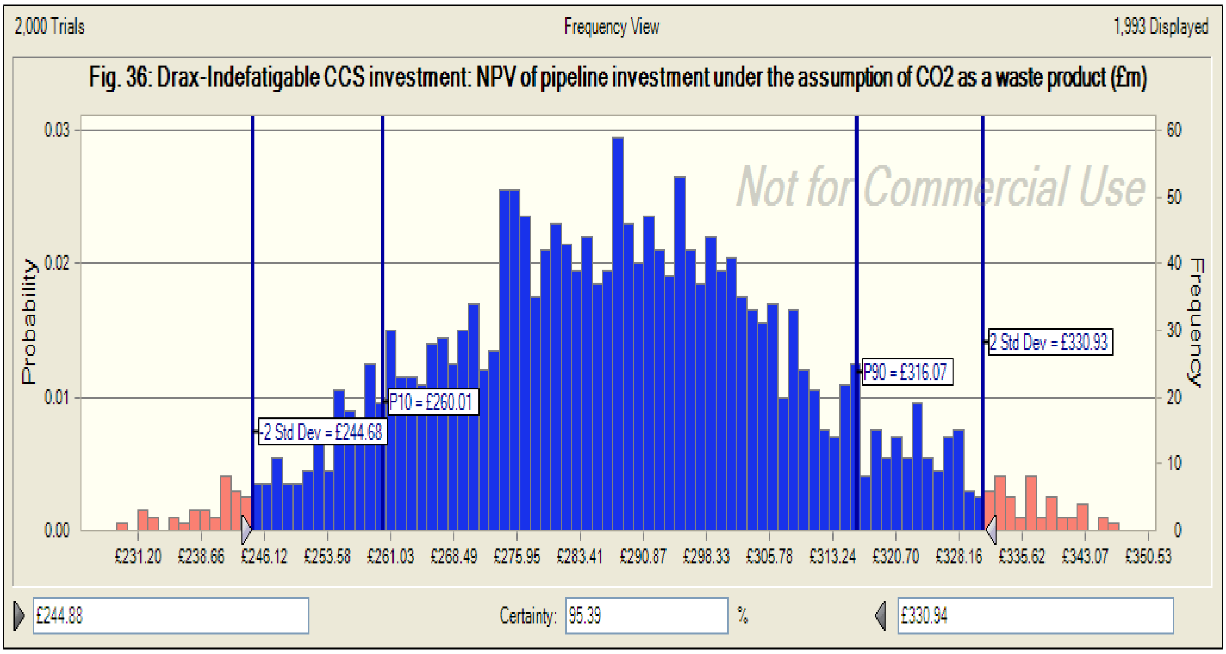
Fig. 35: Drax-Indefatigable CCS Investment: Sensitivity of the storage investment to influencing variables

In Fig. 35, the two most influential variables on the sink operator's NPV are seen to be the volume of emissions captured and the (associated) level of the normalised pipeline tariffs. Both influencing variables have positive relationships with the sink operator's NPV.

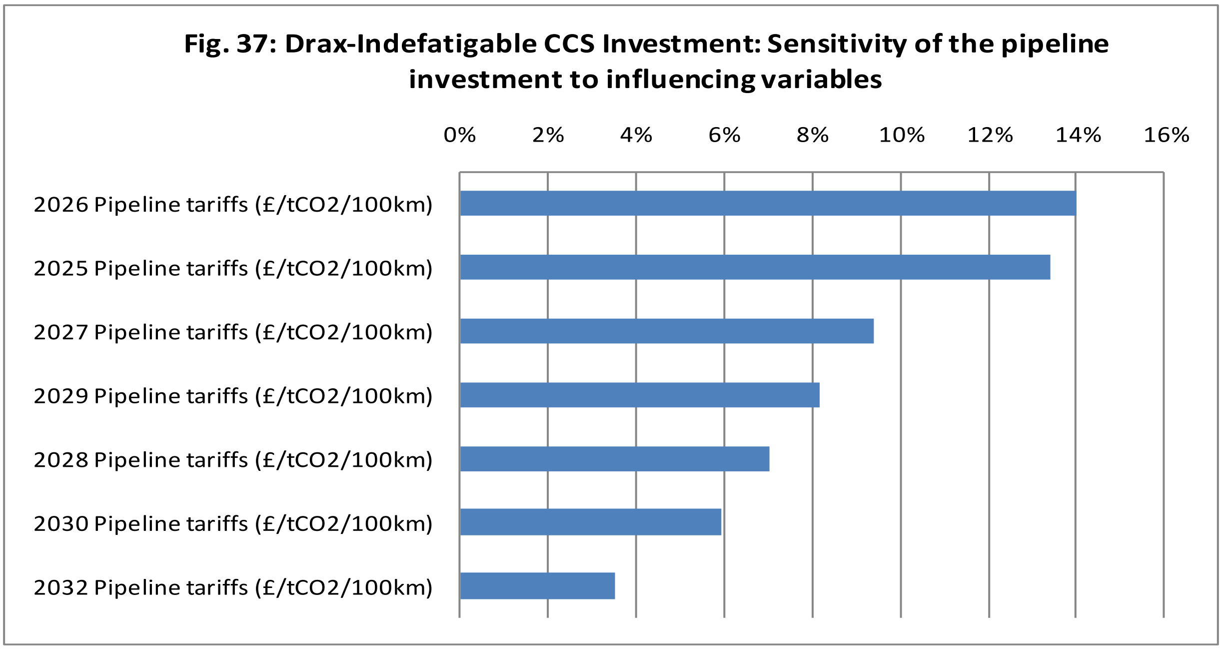
The best-solution incremental storage CAPEX at Indefatigable is £1.30 billion. Overall, the negative returns to the sink operator's investment would argue against the storage investment.

The Returns to the CO_2 Pipeline Transport Investment

The best-solution mean NPV of the pipeline operator is £288 million. The standard error of the mean is £0.48 million, with a standard deviation of £21.56 million and coefficient of variability of 0.07. The P10 and P90 values are £260.01 and £316.07 million respectively. There is a 95 percent chance that the mean NPV will be between -£244.88 and £331.47 million. The probability distribution of the CO_2 transporter's NPV is presented below in Fig. 36.



The sensitivity to variations in the model variables of the returns to the pipeline operator's investment is presented in Fig. 37.



The pipeline operator's NPV is most sensitive to pipeline tariffs, being positively related to the variable.

While the pipeline operator's optimised CAPEX is £468.47 million, the optimised average pipeline tariff is about 12.27 percent of CAPEX.

Overall, the pipeline operator's positive returns are an incentive to undertake the investment.

Case 4: The Drax – Forties CCS Investments

Following the logic of the Longannet – Forties investments it was found that in the case of Drax – Forties under case (i) assumptions (bartered CO_2-EOR) the mean NPV of the capturer was substantially negative. With case (ii) assumptions the mean NPV of the storer was also found to be substantially negative. Accordingly, these cases are not illustrated but summary results are shown in Table 15.

The Returns to the CO_2 Capture Plant (Drax) under Partially-Receipted CO_2-EOR Assumptions (case iii)

The optimised NPV of the capture investment in this scenario ranges from -£0.76 billion to £5.00 billion, with a mean of £2.11 billion. The standard error of the mean is £21.25 million and the standard deviation and coefficient of variability are respectively £950.30 million and 0.45 respectively. The P10 and P90 values are £0.89 billion and £3.34 billion respectively. The probability distribution of the capture plant's NPV is presented below in Fig. 38.

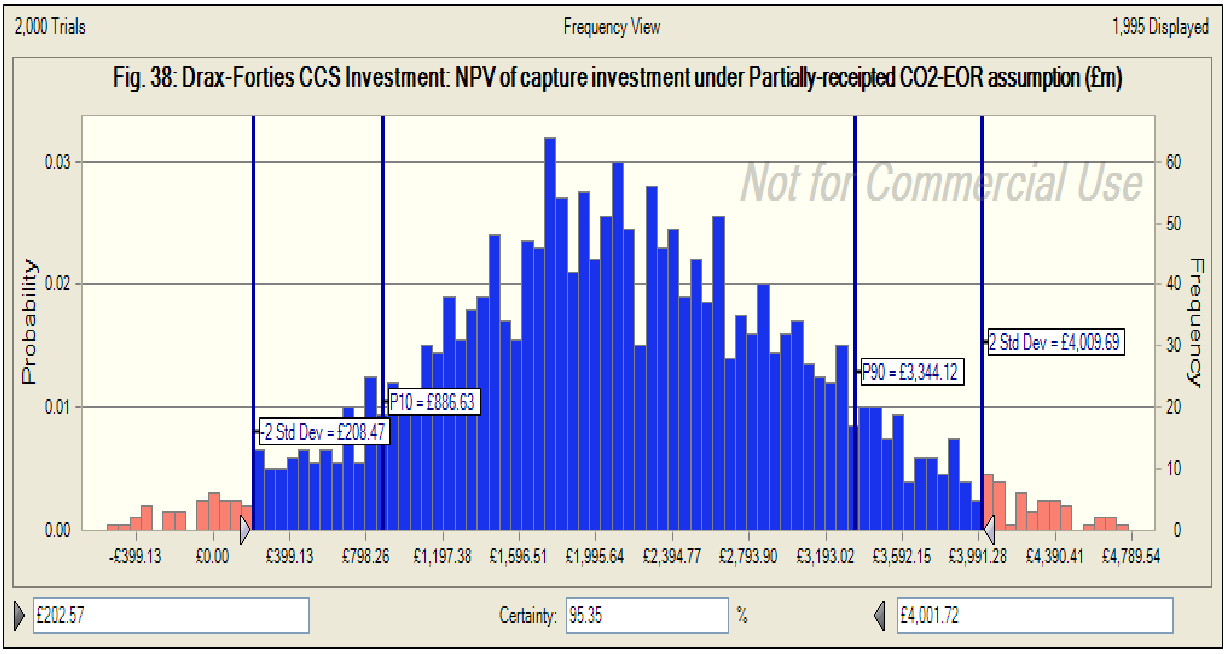
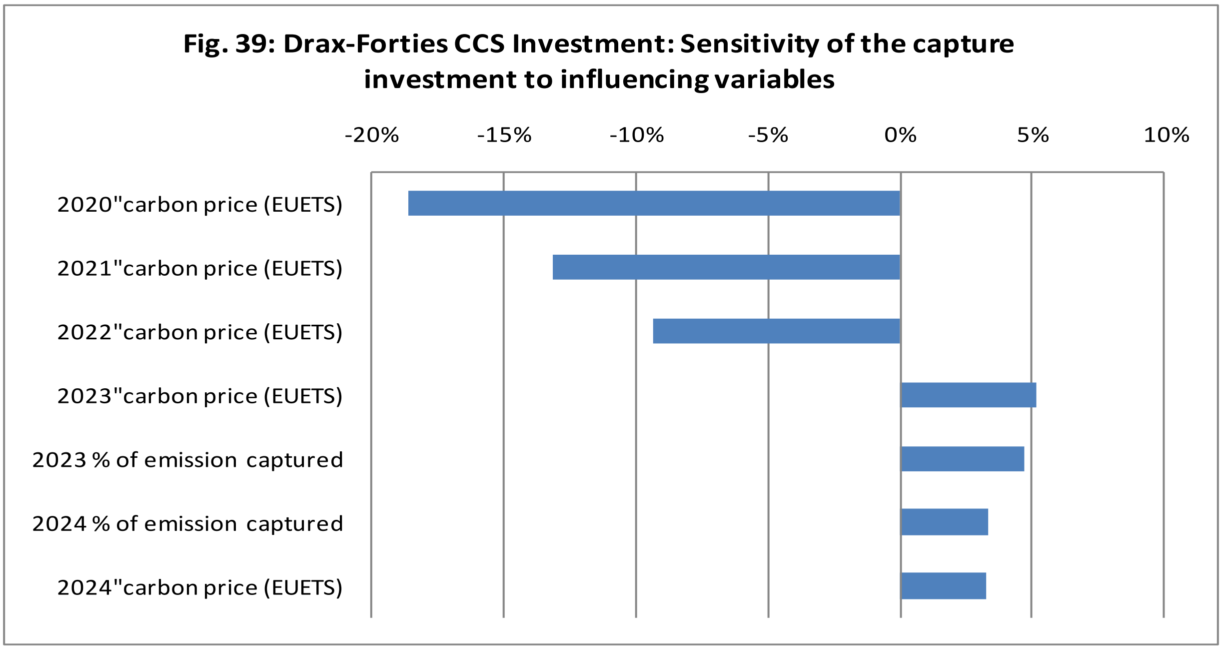


Fig. 38: Drax-Forties CCS Investment: NPV of capture investment under Partially-receipted CO2-EOR assumption (£m)

The sensitivity of the power plant's NPV to variations in the model variables is presented in Fig. 39.



In Fig. 39, variations in the carbon price and the fraction of CO_2 emissions captured are seen to be the most influential variables on the power plant's NPV. Consistent with some of the earlier results presented, the influence of carbon price is bi-directional, being negative and positive at low and high prices respectively. The correlation between the returns to capture investment and the percentage of emissions captured is positive.

Overall, the positive optimised returns to the capture investment may encourage the owners of the Drax power plant to undertake the investment. This result is similar to that of Longannet in the Longannet-Forties shipments scenario.

The Returns to the Oilfield (Forties) under Partially-Receipted CO_2-EOR (case iii)

The optimised NPV of the oil field operator undertaking the investment in CO_2-EOR and permanent storage of CO_2 ranges from -£0.55 billion to £5.83 billion, with a mean of £2.5 billion. The standard error of the mean is £20.77 million, with the standard deviation and coefficient of variability being £906.50 million and 0.36 respectively. The P10 and P90 values are £1.37 billion and £3.71 billion respectively. There is a 95 percent chance that the mean NPV will be between £2.89 billion and £6.59 billion. The probability distribution of the storer's NPV is presented below in Fig. 40.

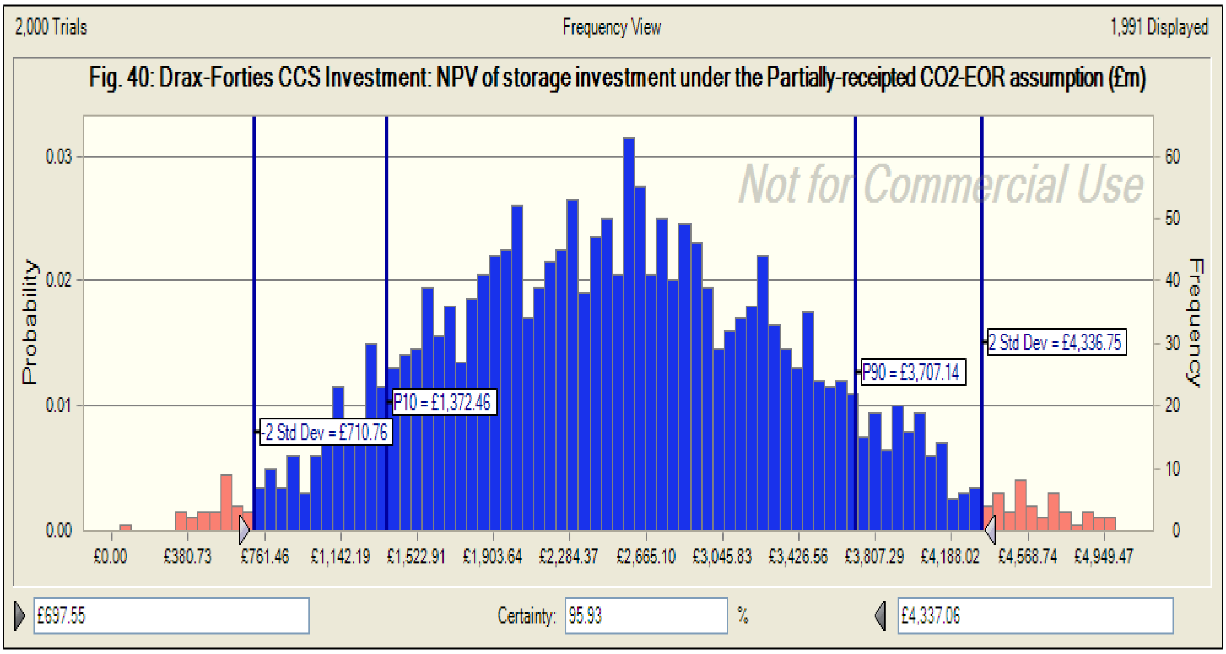
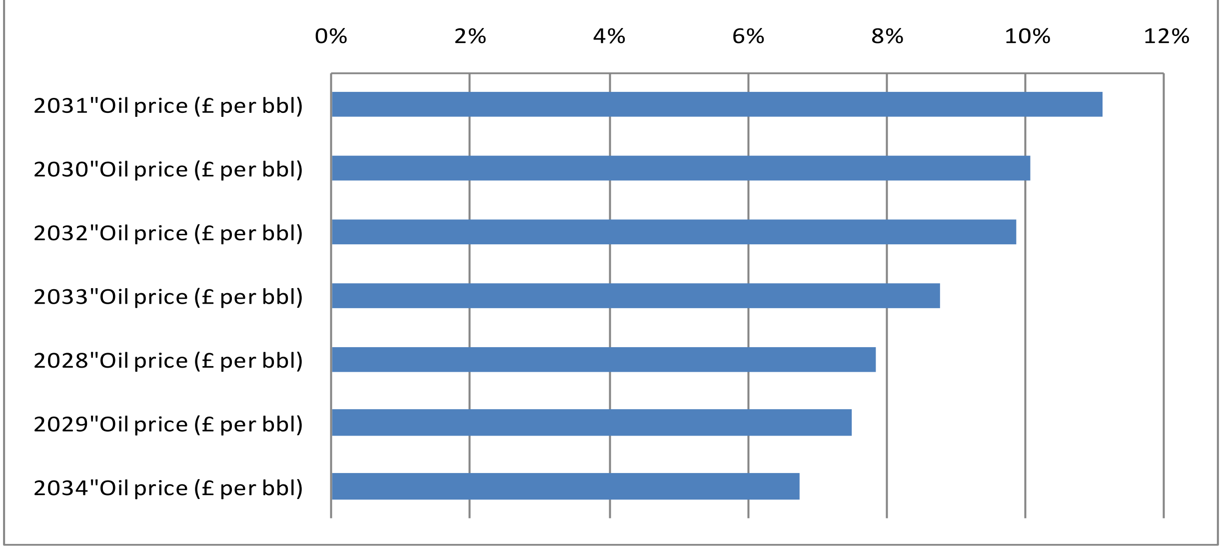


Fig. 40: Drax-Forties CCS Investment: NPV of storage investment under the Partially-receipted CO2-EOR assumption (£m)

The sensitivity of the sink operator's NPV to variations in the model variables is presented in Fig. 41.

Fig. 41: Drax-Forties CCS Investment: Sensitivity of the storage investment to influencing variables

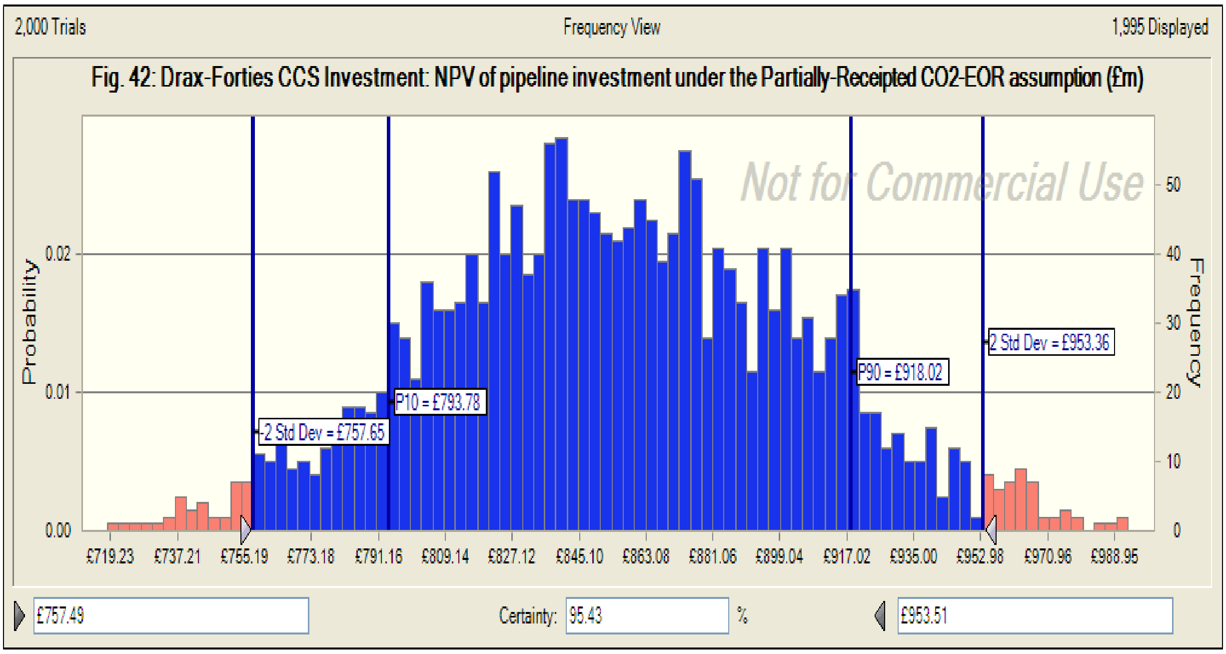


It is seen in Fig. 41 that variations in oil prices are the most influential variables on the (Forties) sink operator's NPV.

Overall, the positive returns to the oilfield operator's NPV is likely to encourage investment in CO_2 storage.

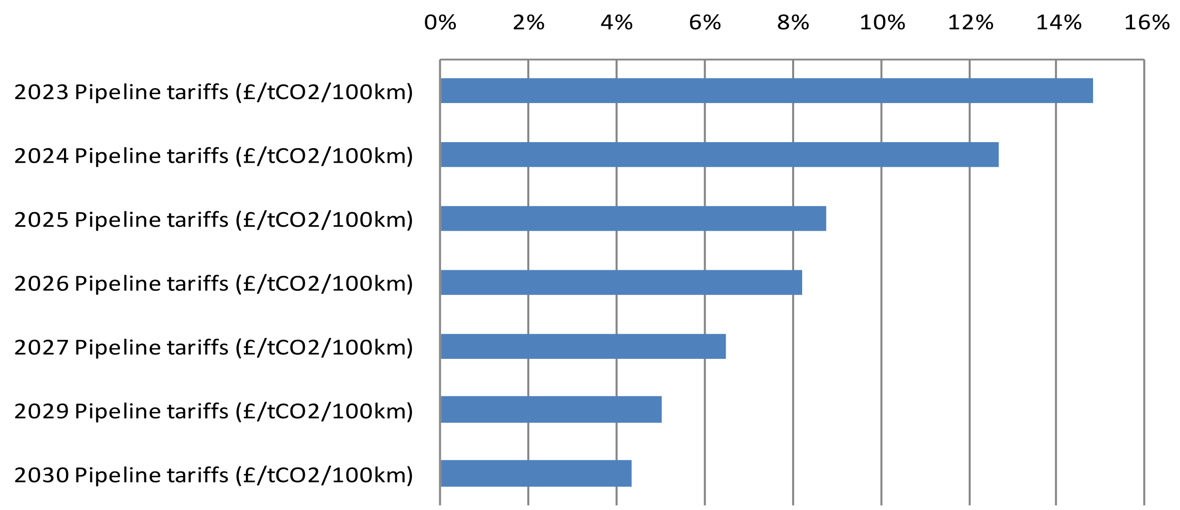
The Returns to the CO_2 Pipeline Transport Investment under Partially-Receipted CO_2-EOR Assumptions (case iii)

The optimised NPV of the pipeline operator ranges from £0.70 billion to £1.01 billion, with a mean of £855.50 million. The standard error of the mean is £1.09 million, with a standard deviation of £48.93 million and coefficient of variability of 0.06. The P10 and P90 values are £793.87 million and £918.02 million respectively. There is a 95 percent chance that the mean NPV will be between £763.12 million and £756.77 million. The probability distribution of the CO_2 transporter's NPV is presented below in Fig. 42.



The sensitivity of the pipeline operator's NPV to variations in the model variables is presented in Fig. 43.

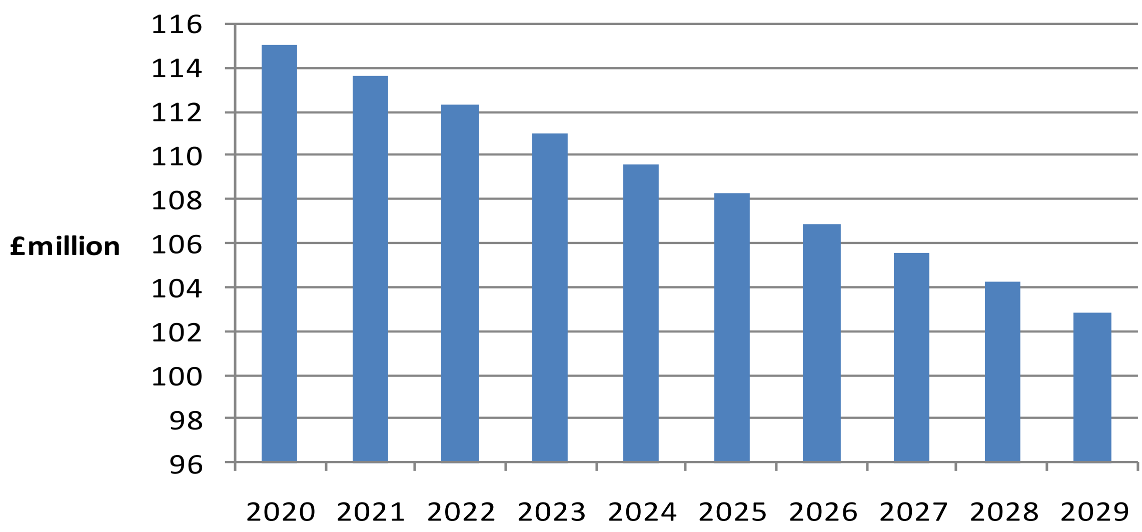
Fig. 43: Drax-Forties CCS Investment: Sensitivity of the pipeline investment to influencing variables



As in the other cases, the pipeline operator's NPV is seen in Fig. 43 to be most sensitive to variations in the pipeline tariffs.

The pipeline operator's optimised CAPEX is about £1.09 billion and the operator is able to negotiate an optimised pipeline tariff averaging 12.28 percent of CAPEX

Pipelines CAPEX: Drax-to-Forties (£ million)



Overall, the positive returns to investment will potentially encourage CO_2 pipeline transportation investment.

A summary and comparison of the returns to alternative integrated source-to-sink CCS investments

The results of the CCS investments along the four shipment routes are summarised in Table 16.

Table 16: Comparative summary results of CCS Investments

Case	Investor	Mean NPV (£m)	Entire NPV range (£m)[9]	Certainty level (%)	Certainty range (£m)	CAPEX (£m)	Incremental oil (mmbbl)
One[10]	Longannet	-2047.64	-2,930.76 to -1,316.83	95.37	-2,551.30 to -1,546.11	1050	
	Morecambe South	-458.90	-463.71 to -453.93	95.81	-462.00 to -455.83	1050	0.0
	Pipeline	36.39	10.43 to 60.92	95.51	20.67 to 51.98	587.65	
Two (case i)[11]	Longannet	-947.58	-2,907.51 to 689.53	2.34	178.72 to 3,178.47	1051	
	Forties	2,750.93	1,134.78 to 5,038.65	2.34	-486.68 to 1,680.54	1800	86.21
	Pipeline	33.95	-60.22 to 149.83	95.87	-26.52 to 96.50	606	
Two (case ii)[12]	Longannet	2,229.19	-132.71 to 4,508.65	89.22	178.72 to 3,178.47	1051	
	Forties	-437.55	-2,585.76 to 2,703.54	53.29	-486.68 to 1,680.54	1800	86.21
	Pipeline	33.52	-60.65 to 149.40	95.87	-26.52 to 96.50	606	
Two (case iii)[13]	Longannet	1,075.75	-1,158.04 to 2,956.36	91.02	178.72 to 3,178.47	1051	
	Forties	727.60	-922.45 to 3,478.18	92.37	-486.68 to 1,680.54	1800	86.21
	Pipeline	33.95	-60.22 to 149.83	95.87	-26.52 to 96.50	606	

[9] The width of the range of NPV values is in brackets.
[10] Longannet-Morecambe South: CO_2 as a waste product.
[11] Longannet-Forties: CO_2 commoditised, Bartered CO_2-EOR.
[12] Longannet-Forties: CO_2 commoditised, Fully-receipted CO_2-EOR
[13] Longannet-Forties: CO_2 commoditised, Partially-receipted CO_2-EOR

Table 16: Comparative summary results of CCS Investments (cont'd)

Case	Investor	Mean NPV (£m)	Entire NPV range (£m)[14]	Certainty level (%)	Certainty range (£m)	CAPEX (£m)	Incremental oil (mmbbl)
Three[15]	Drax	-15.64	-1,115.90 to 1,199.80	94.82	-758.84 to 727.56	1940	
	Indefatigable	-266.24	-311.09 to -221.70	95.53	-296.00 to -236.73	1300	0.0
	Pipeline	287.81	223.34 to 369.39	95.47	244.88 to 331.47	468.47	
Four (case i)[16]	Drax	-226.24	-2,930.30 to 2,707.08	31.58	202.57 to 4,001.72	1940	
	Forties	5,178.99	2,292.99 to 8,601.28	18.20	697.55 to 4,337.06	2000	145.46
	Pipeline	932.85	770.44 to 1,086.26	66.87	757.49 to 953.51	1090	
Four (case ii)[17]	Drax	5,381.06	2,546.69 to 8,527.37	8.77	202.57 to 4,001.72	1940	
	Forties	-428.31	-3,378.76 to 2,994.01	11.74	697.55 to 4,337.06	2000	145.46
	Pipeline	932.85	770.44 to 1,086.26	66.87	757.49 to 953.51	1090	
Four (case iii)[18]	Drax	2,109.08	-755.42 to 4,998.99	76.33	-929.80 to 2,799.15	1940	
	Forties	2,523.76	-549.61 to 5,830.09	33.49	2,888.35 to 6,585.92	2000	145.46
	Pipeline	855.50	693.08 to 1,008.90	95.10	763.12 to 956.77	1090	

Faced with the choice/results summarised in Table 16 the more attractive integrated CCS investment returns are those involving source-to-sink shipments to CO_2-EOR fields under the Partially-receipted CO_2-EOR scenario assumptions – that is Longannet-Forties (Case 2) and Drax-Forties (Case 4)

[14] The width of the range of NPV values is in brackets.
[15] Drax-Indefatigable CCS investment: CO_2 as a waste product
[16] Drax-Forties CCS investment: CO_2 commoditised, Bartered CO_2-EOR.
[17] Drax-Forties CCS investment: CO_2 commoditised, Fully-receipted CO_2-EOR
[18] Drax-Forties CCS investment: CO_2 commoditised, Partially-receipted CO_2-EOR.

integrated CCS investments. Of the two viable investments, the Drax-Forties integrated CCS investment is more capital intensive but yields higher returns to investment because of the higher volume of incremental oil produced. However, the scenario has the downside of being the riskiest with the least certainty of NPV realisation values. In general, the CCS investments with CO_2-EOR are potentially more profitable but are riskier on account of oil price risks.

8. Conclusions

This study has modelled and estimated the risks and returns relating to illustrative investments in CCS in the UK/UKCS. The risks in question are very considerable and were assessed by examining the investments under a range of assumptions regarding costs, revenues and risk: reward sharing mechanisms. In several of the scenarios the activities generated substantial losses on an integrated basis or one or more elements in the chain suffered losses which would prevent the whole scheme from proceeding. A scenario was found, however, which produced (substantial) positive returns to the integrated activity. The underlying assumptions necessary to produce this result are not necessarily very realistic, but they do highlight the elements of a viable scenario, particularly high prices for traded CO_2, high prices for oil, and a substantial EOR yield from the injection of CO_2.

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