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

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NORTH SEA ECONOMICS

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.

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

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 Investment Model of the Economics of Integrated Returns from CCS Deployment in the UK/UKCS

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An Optimised Investment Model of the Economics of Integrated Returns from CCS Deployment in the UK/UKCS

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Abstract

In spite of the UK Government's ambition for at least 20 GW of CCS to be deployed in the UK/UKCS by 2030, the attitude of potential investors thus far remains lukewarm. Several reasons have been adduced for this. The present paper makes a contribution to the debate on removing the barriers to CCS investment by investigating the criteria and scope for negotiation among the CCS investors of mutually acceptable prices for trading the captured CO_2 and storage services. A decision-making framework was deployed to design and implement an investment model, using the Net Present Value criterion. Stochastic optimisation was executed and optimal solutions found for the investors within a range of carbon prices and sequestration fees. This range permits negotiation among the participants in the CCS chain to the mutual benefit of all, compatible with a co-operative Nash-type equilibrium.

Keywords: Integrated CCS investment, CO_2 pricing, Optimized investment returns, CO_2-EOR

JEL classification*:* C61, Q49, L91, D40

1. Introduction

Several studies have focused attention on the economics of investments in CO_2 capture, transport and storage (CCS). Few have adopted an integrated system approach, especially against the backdrop of an official carbon price. Yet there are obvious advantages to this approach in which maximizing the overall returns 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 in the UK/UKCS, investment in the integrated CCS value chain faces a number of uncertainties. These are technological, economic, legal and geological in nature. 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. At the transport stage, uncertainties about the exact composition of the captured CO_2 to be transported make difficult a decision on the design of pipelines to construct or modify. At the storage stage, there are uncertainties regarding the development and deployment of the appropriate technology, the yield of the EOR from each tonne of CO_2 injected, and the oil price. At all stages there are cost uncertainties. Regarding the regulatory framework there are uncertainties concerning (a) the extent, stringency, and reach of emission-reduction controls, and, (b) the transfer of financial liability from the investor to the Government.

Regarding the economics, the determination of the price of the captured CO_2 remains uncertain. Abadie and Chamorro (2008) highlighted the riskiness of electricity and emission allowance prices as possible disincentives to capture investment. Also, there are uncertainties as to which business model is best suited to the early deployment of the technology. Kettunen, Bunn and Blyth (2011) demonstrated that uncertainty regarding carbon policy may encourage market concentration, with the relatively less risk averse, financially stronger, larger power plants being better able to undertake carbon-reduction investments. But vertical integration or trading relationships between independent parties are also distinct possibilities. Klokk et al. (2010) optimised an integrated CCS value chain without representing distinctly the individual stakeholders, though acknowledging that a single owner of the entire CCS value chain seems improbable.

Akin to the market-led, disaggregated industry model described in DECC (2012c), the present study contributes to understanding by optimising an integrated CCS value chain in which the stakeholders are distinct, independent, and trading among themselves on the basis of commercial contracts. Unlike the earlier studies, the overarching approach is one of stochastic optimisation. Also, while Klokk et al. chose sites in the Norwegian Continental Shelf, the present study involves sites in the UK/UKCS. The valuation of the captured CO_2 is positive in the present study but is zero-valued in Klokk et al.

2. The Model

The conceptual framework

This study develops an economic decision-making framework for the design of a CCS investment model to analyse the chain of activities involving trading among investors at the capture, transportation and EOR/storage stages, using the Net Present Value (NPV) criterion as its basis. The CO_2 storage investor uses q_1 as an input into producing oil which he sells at international prices. After the EOR phase, he stores q_2 in the depleted oilfield for a fee. Capture-favourable and EOR-favourable scenarios are examined. The capture-favourable case is where market and/or regulatory conditions favour a relatively high price for CO_2 and a relatively low storage fee. The EOR-favourable scenario arises when market and/or regulatory conditions combine to signal a relatively high storage fee and low CO_2 price.

From the perspective of the capture investor, let p_1 $(p_1>0)$ be the asking price of q_1 and p_2 $(p_2>0)$ the offer storage fee for storing q_2. From the perspective of the storage investor, let p_{1s} be the offer price for the captured CO_2 and p_{2s} the asking storage fee to store q_2. The study investigates the mechanics of determining the scope for negotiation within which lies the agreed prices p_1^* and p_2^* of the captured CO_2 and storage service respectively. One expects that $\{p_{1s}< p_1^*<p_1\}$ and, $\{p_2< p_2^*<p_{2s}\}$. Agreement on p_1^* and p_2^* are central to the decision to undertake CO_2 capture and/or EOR investment. The agreed p_1^* may be different from any official price such as the UK's Carbon Price Floor (CPF)[1].

Given that the capture point source and EOR sink are assumed to be some distance apart, a transport investor is needed to provide the infrastructure and service to deliver $Q(=q_1+q_2)$ from the supplier to the end-user. The related optimal transportation fee is determined, treating the transportation service as a utility.

The objective function

Within the framework of their interdependence, each investor will seek to maximise his own returns and restrict his risk exposure. Thus, the capture investor seeks to:

Maximise:

$$NPV_c = -C_0 + \sum_{t=1}^{T}\left\{\left(\phi_t q_{1t} + \omega_t q_{2t}\right) - \kappa_t\right\} D_t \qquad (2.1)$$

$$\phi = \left(z_t + p_{1t} - n_t - w_t\right);\ \omega = \left(z_t - p_{2t} - n_t - w_t\right);\ D_t = \left(1+r\right)^{-t}$$

where:

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

C_0 = Initial (project development phase) incremental CAPEX

z_t = Official carbon price for emission rights at time t

p_{1t}= the asking price of the captured CO_2 for EOR at time t

[1] Discussed in detail below.

p_{2t}= the capture investor's offer CO_2 storage fee at time t

q_{1t} = the volume of captured CO_2 for EOR at time t (t=1, 2 ...h)

q_{2t} = the volume of captured CO_2 for sequestration at time t (t=h+1, h+2 ...T)

n_t = unit CO_2 transportation cost at time t.

w_t= unit fuel and non-fuel capture OPEX (including CO_2 separation cost) at time t

κ_t=incremental CAPEX incurred at time t

t = time in years

h = end-year EOR phase

T = terminal year

r = the discount rate

D_t = the discount factor at time t

Equation (2.1) states the capture investor's objective of maximising the NPV. The revenues consist of receipts from the sale of the captured CO_2 ($p_{1t}q_{1t}$) and the shadow revenues, Z_t ($=z_tQ_t$), which are the savings from not having to purchase emission rights. The costs are the CAPEX, C_0 and κ_t, and, OPEX ($= n_tQ_t + w_tQ_t + p_{2t}q_{2t} = N_t + B_t + S_t$), where N_t, B_t, and *St* are respectively the annual transportation, capture, and storage costs. The elements of the cost and revenue components of the equation are discussed further in section 3.2. The necessary conditions for maximising the investor's current profit with respect to q_1 and q_2 require:

(a) Equalising his marginal revenue *(MR)* and marginal cost *(MC)* for q_1, and deriving the asking carbon price as:

$$p_{1t} = n_t + w_t - z_t = \beta_t \qquad \Rightarrow \forall z_t > 0 : p_{1t} < z_t \tag{2.1a}$$

From equation (*2.1a*) the capture investor's asking price is determined by his costs and the exogenously-determined official carbon price (unit shadow revenue). The latter (z_t) sets a ceiling to the asking price (p_{1t}).

(b) Equalising his *MR* and *MC* for q_2, and deriving the offer storage fee as:

$$p_{2t} = z_t - n_t - w_t < \beta_t \tag{2.1b}$$

The investor would not offer to pay a unit CO_2 storage fee exceeding his unit carbon revenue.

In the case of the storage investor, the objective function is to:

Maximise:

$$NPV_s = -C_0^s + \sum_{t=1}^{T} \left\{ \left(p_{2st} q_{2t} + p_t^s O_t \right) - p_{1st} q_{1t} - X_t - \kappa_t^s \right\} D_t \tag{2.2}$$

$$X_t = x_{it} \left(q_{1t} + q_{2t} \right); and\ O_t = g_t q_{1t}$$

where in addition to previous definitions:

NPV_s = the Net Present Value of the CO_2 storage project

$C^s{}_0$ = the initial CO_2-EOR CAPEX

$p^s{}_t$ = the international price of crude oil at time t

O_t = the amount of CO_2-EOR produced at time t

X_t = OPEX excluding CO_2 purchases at time t

x_{it} = unit OPEX excluding CO_2 purchases at time t for period i (i=1=EOR phase, 2=post-EOR.)

g_t =EOR yield per tonne of CO_2 injected at time t

κ_t^s = the incremental CAPEX incurred at time t

The important components of the storage investor's OPEX, X_t, are the EOR-phase injection, $q_{1t}x_{1t}$ *(t=1, 2 …h)* and, post-EOR injection and monitoring-for-leakage $q_{2t}x_{2t}$ *(t=h+1, h+2 …T)* expenditures. Assuming that the monitoring cost is a fraction, α, of CAPEX and that the injection cost is the same in both phases, then $x_{2t} = (x_{1t} + \alpha)$ and, $X_t = x_{1t} (q_{1t}+q_{2t}) + \alpha q_{2t}$, where the first term is the injection OPEX and the second is the monitoring one. The elements of the cost and revenue components of equation (2.2) are discussed in section 3.2. The EOR investor's necessary conditions for maximising profit with respect to q_{1t} and q_{2t} require:

(a) Equalising during the EOR phase his *MR* and *MC* for q_1, and deriving the offer carbon price as:

$$p_{1st} = p_t^s g_t - x_{1t} \qquad \Rightarrow \forall\, x_{1t} > 0 : p_{1st} < p_t^s g_t \tag{2.2a}$$

According to (*2.2a*) the investor's offer price for the CO_2 is determined by the oil price, EOR yield ratio, and unit variable cost. For any given oil price and unit OPEX, the carbon price would be less than the product of the oil price and the EOR yield ratio. The higher the yield ratio the more affordable is the carbon price.

(b) Equalising his post-EOR *MR* and *MC for* q_2, and deriving the asking storage fee such that:

$$p_{2st} \geq x_{2t} \tag{2.2b}$$

That is, the storage fee must cover the unit post-EOR OPEX.

The pipeline operator's objective is to:

Maximise:

$$NPV_a = -C_0^a + \sum_{t=1}^{T} \{ n_t (q_{1t} + q_{2t}) - y_t \} D_t \tag{2.3}$$

where in addition to previous definitions:

$C^a{}_0$= the pipeline operator's CAPEX

y_t = transportation OPEX at time t

The elements of the cost and revenue components of equation (2.3) are discussed in section 3.2.

The Constraints

The respective mean NPVs of equations (2.1), (2.2) and (2.3) are maximised subject to a simultaneous non-negativity constraint. That is,

$$\overline{NPV}_c, \overline{NPV}_s, \overline{NPV}_a > 0 \tag{2.4}$$

The simultaneous satisfaction of the non-negativity constraint guarantees that no investor in the CCS value enjoys positive returns to his investment while another investor in the chain suffers negative returns.

3. Case Study – The UK/UKCS

3.1 Overview

The Solution Approach

Integrated source-to-sink cash flow models were built to incorporate the model in equations 2.1 through 2.4 and applied to the UK/UKCS. The model solutions were obtained by alternatively maximising NPVs in equations (2.2) and (2.3), subject in each case to the simultaneous satisfaction of the non-negativity constraint in equation (2.4). Oracle's Crystal Ball software for *Monte Carlo* probabilistic analyses of investment returns, including *OptQuest* its optimising engine, were used to determine the optimal values of the decision variables.

The Time Horizon

The study covers a thirty-year period, 2020 – 2050, with the following notable dates:

Date	**Activity**
2020	First CAPEX of CO_2 capture, pipeline infrastructure, platform/well modifications.
2023	Initial CO_2-EOR shipment and delivery; CO_2-EOR injection starts at the EOR field.
2025	First CO_2-EOR produced.
2041	Primary CO_2-EOR injection ends.
2042	CO_2 injection into pure storage commences in the field.

It is envisaged that the CCS-related activities continue beyond 2050.

The Discount Rate

All the simulations and optimisations were performed using a discount rate of 10% to reflect the multiple risks involved. This rate is commonly used in studies on this subject. Thus Mott MacDonald (2010) employs 10%, as does Oil and Gas UK (2012). The UK Carbon Capture and Storage Cost Reduction Task Force (DECC, 2012c) uses 10% for capture and transport investments, and 14% for storage investments.

The CO_2 sources and sink

One hypothetical retrofitted onshore UK power plant with Pulverised Coal with Supercritical boiler and Flue Gas Desulphurisation (PCSCFGD) was used as a case study. Post-combustion CO_2 capture is assumed to be deployed. The medium CO_2-emitting power plant has a generating capacity of about 2,000 MW and annual emissions of between 9 and 10 MtCO_2/year. The plant is assumed to have a target of reducing its Emission Performance Standard (EPS) (emission factor) from about 592 (tCO_2/GWh) to about 505 (tCO_2/GWh) [2]. The plant is assumed to be located on the East coast of Scotland. After capture the CO_2 is compressed and transported about 340 kilometres to an offshore CO_2-EOR field *Z* located in the Central North Sea. The transportation of CO_2 to and its injection at field *Z* is assumed to commence before the closure of the field's CO_2-EOR "window of opportunity" (see Bachu (2004), and Kemp and Kasim (2010)).

The power plant and oil field data used in the study were largely obtained from the literature and public domain sources.

3.2 Model variables and data

Model variables in *OptQuest* are classified as being either stochastic or "decision" ones. In the model application, the cash flow statements of the

[2] For comparison, the EPS requirement on new coal-fired plants (until 2045) in the UK's Electricity Market Reform is 450 (tCO_2/GWh) (DECC, 2012a).

CCS investors include 16 cost and revenue variables, 10 of which are stochastic and the rest decision ones.

In projecting the future values of the stochastic variables it is notable that neither historic nor futures prices exist for most of them. Uncertainties regarding future outcomes are reflected in a two-stage approach. This involves making a deterministic or stochastic (where historic data were available) forecast of the influencing variables, and secondly by determining and using the best-fit probability distributions of the possible occurrences of the deterministic forecasts in the optimisation runs.

CO_2 capture investment

(a) the decision variables

The power plant owner has two decision variables. In equation (2.1) the cost-related one is the incremental CAPEX. The capture CAPEX is defined as the product of the unit capital cost (k) and the capture capacity (Q). The unit CAPEX, k, is assumed to range between £3[3] and £6 per tonne of the installed CO_2 capture capacity, with the lower end of the range being possible in the latter years owing to the benefits of learning-by-doing (LBD) effects[4]. κ_t is assumed to be incurred incrementally over a period of ten years. The gradual build-up of the capture capacity is consistent with UK Government thinking (see DECC, 2009b).

The second decision variable in equation (2.1) is p_{1t}, the asking price of the captured CO_2. The investor seeks to negotiate as high a price as possible up to the exogenously-determined CPF (z_t).

[3] Liang and Li (2012) estimated a unit CAPEX in US dollars equivalent to about £2/tonne for a post-combustion capture process in a Chinese cement plant. This translates, using Ho et al.'s (2011) relational findings about cement- and power-plant capture CAPEX, to about £3/tonne.
[4] For examples, see Rubin et al. (2007) and Yeh et al. (2007) on the quantification and benefits of LBD.

(b) the stochastic variables

The remaining variables in the capture investor's objective function in equation 2.1 are the OPEX and the shadow revenue Z_t. Of these Z_t and the capture OPEX, B_t, and their components are assumed to be stochastic while the transport OPEX, N_t, and the storage OPEX, S_t, are treated as being parametric and linked directly to their corresponding values in the cash flow statements of the transport and storage investors. The recognised stochasticity of N_t and S_t more directly influence the pipeline and storage activity and investments levels and are treated as such.

Table 1 presents the projected values of the stochastic variables and/or their determinants. Table 2 summarises the best-fit probability distribution of the projected values.

Table 1: Projected values of the capture investment stochastic drivers

Year	Coal Price (£/tonne) (real 2010)	Emission reduction target (%)	% of emission captured (%)	Capture-induced efficiency-loss	Carbon Price Floor (£/tCO_2)
2020	71	6	na	na	30
2023	71	6	40	20	42
2030	71	11	90	18	70
2040	70	14	95	15	75
2050	85	14	95	12	78

Sources and notes:

Na = not applicable

Column (1): (a) 2020-2030: DECC (2011) (b) 2031-2050: Authors' own projections.

Column (2): Average coal-based power industry projection (see for example, Drax (2011).

Column (3): The full capture capacity is variously cited in the literature as being around 90 percent (see DECC, 2009a, for example).

Column (4): In the literature, estimates of the parasitic effect vary from 10 to about 40 percent of OPEX (see Bellona, 2005, for example). The present study assumes that the parasitic effects range from a high of 20% reducing to about 12% due to LBD effects.

Column (5): The data range is broadly consistent with DECC's projections as cited by Mott MacDonald (2010). In DECC's central case, the carbon price increases from £16/tCO_2 in 2020 to £70/tCO_2 in 2030 and £135/tCO_2 in 2040, with an average of £54/tCO_2. The modelling follows this trend.

Table 2: Probabilistic variables of CO_2 capture investment

Probabilistic variable	Data range		Best-fit probability distribution	
	Minimum	Maximum	Type	Parameters
Coal price (£/tonne)	71.00[a]	97.00	Weibull	Location = 34.00; Scale = 43.00; Shape = 3.05
Emission reduction target (ERT) (%)	3.07[b]	14.78	Beta	Alpha = 0.91; Beta = 0.39
Percentage of emissions captured	40.00	95.00	Discrete Uniform	Min. = 40.00; Max = 95.00
Parasitic CO_2 capture effect on OPEX	12.25[d]	20.40	Beta	Alpha = 0.77; Beta = 0.86;
The Carbon Price Floor (CPF) (£/tCO_2)	70.00 (€60.00)	90.00[e] (€120.00)	Triangular	Min. = 70.00; Max. = 90.00; Likeliest = 70.00

[a] DECC (2011) central value of projected coal prices.
[b] Drax (2009)
[c] The full capture rate is variously cited in the literature as being around 90-95% (e.g. DECC, 2010).
[d] In the literature, estimates of the parasitic effect is in the range 10%-40% of OPEX (e.g. Bellona, 2005).
[e] The data range is broadly consistent with DECC's projections as cited by Mott MacDonald (2010).

i Coal price

A major component of the fuel and non-fuel capture OPEX, B_t, is the incremental cost of coal. The 2012-2030 coal price projections were obtained from DECC (2011) while the 2031-2050 projections were calculated by the authors, based on a stochastic price model[5]. A summary of the projected coal prices is presented in Table 1 while the price forecast methodology is presented in Appendix 1.1. The randomly generated time path of coal prices in is fitted to a number of probability distribution curves to determine a best fit for use in the stochastic optimisation. Using the Anderson-Darling (A-D) probability curve-fitting criterion in this and all other cases, the best-fitting probability distribution of the projected coal price was found to be the Weibull distribution[6,7]. This result is presented in Table 2. The cumulative probability distribution suggests that there is a 60% chance of realising a real2010 coal price of £75/tonne or less during the forecast period.

ii. Capture-induced plant efficiency loss

CO_2 capture substantially adds to a power plant's investment, energy and fuel costs. However, there is a general expectation that the experience gained through learning-by-doing (LBD) will mitigate the costs in the long-term. In the literature, estimates of the capture-induced parasitic effect on costs vary from 10% to about 40% of OPEX (see Bellona, 2005). The present study assumes that the effects could range from a high of 20% reducing to 12% over the study period. This range is close to the 25%, 18%, 15% and 13% in 2013, 2020, 2028, and 2040 respectively assumed in DECC (2012c). The projected plant efficiency losses are presented in Table 1.

[5] Unlike the other capture-related model variables with no historic data, the availability of historic data on coal prices permits the formulation, estimation and forecast of a stochastic price model.

[6] The Weibull distribution was the best-fitting under the Chi-square criterion during the period 1993-2011.

[7] The top three best fits are Weibull (0.323), Lognormal (0.334) and Gamma (0.343).

In Table 2, the best-fit of the underlying probability distribution of the forecast is a beta distribution[8]. The cumulative probability distribution suggests that there is a 30% chance that the capture-induced loss in plant efficiency can be reduced from about 20% to about 14% during the study period.

iii Carbon Price Floor (z_t)

In order to reduce risk and encourage low-carbon electricity generation, the UK Government has introduced a Carbon Price Floor (CPF) that became operational from April 2013 (HM Treasury, 2010, 2011). The CPF starts at around £16/tCO_2, rising linearly to £30/tCO_2 in 2020 and £70/tCO_2 in 2030. No official estimates are available for the period 2031-2050. This study acknowledges that the CPF may fluctuate during this later period. The official and projected CPFs are presented in Table 1. A triangular probability distribution of the deterministic forecast was assumed in Table 2. The minimum and maximum CPF values were respectively assumed to be £70/tonne and £90/tonne with the likeliest being £70/tonne. The cumulative distribution suggests that there is an 80% chance of the CPF not exceeding £83/tonne between 2031 and 2050.

(iv) Other (physical) influencing variables

The levels of the various costs and revenues discussed thus far depend on the amount of CO_2 captured, Q. However, Q itself is a function of the capture investor's emission reduction programme (*ERP*) and the capture capacity (*CC*) at any point in time. That is, $Q_t = f(ERP_t, CC_t)$.

Both ERP_t and CC_t, are stochastic and affect the investor's costs and revenues through their impact on Q_t.

[8] The A-D top 3 test results are: Beta (0.119), Uniform (0.232) and Weibull (0.318).

a. Emission reduction target/programme (ERP)

It is expected that, with increasing CO_2 emission mitigation regulations, UK power plants will undertake ERPs with set performance targets – that is, emission reduction targets (ERTs). ERTs include the rate at which renewable fuel sources and co-firing will replace fossil fuels, coupled with improvements in thermal efficiency through turbine upgrades. Some coal-fired power plants such as Drax and Longannet (see Drax, 2012 and ScottishPower, 2009) have recently achieved between 3% and 4% reduction in their CO_2 emission factors through turbine upgrade and co-firing coal with biomass. Higher and successful ERPs imply less CO_2 emissions to capture. Considerable uncertainty surrounds the future level and pace of ERPs. A summary of the deterministic projected ERT is presented in Table 1. As shown in Table 2, the best-fit distribution of the forecast ERT is the beta probability distribution[9]. The fitted distribution suggests that there is a 60% chance of achieving up to 15% annual emissions reduction by generating electricity through co-firing and turbine upgrades during the study period.

b. Emissions capture capacity (CC)

The emissions capture capacity *CC* is positively related to Q. The full capture capacity is variously cited in the literature as being around 90% to 99% of emissions (see DECC, 2012c). This study assumes that the capture capacity/rate is built up over time, increasing with experience from about 40% in 2020 to about 95% in 2050[10]. A summary of the projected capture rate is presented in Table 1.

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[9] The top 3 best fits ranked by the Anderson-Darling test criterion are: Beta (3.0), Logistic (3.417), and Maximum Extreme (3.555).

[10] The idea of a progressive roll-out of CO_2 capture capacity is consistent with CCSA (2011), and DECC (2012) who assumed the rate would increase from 85% in 2013 to 90% by 2020.

In Table 2, the best-fit probability distribution of the deterministic forecast is the discrete uniform distribution[11]. The cumulative probability distribution suggests that there is an 80% chance that a capture capacity of up to 84% of emissions would be attained during the study period.

CO_2 storage investment (Oilfield Z)

(a) The decision variables

At the EOR-storage stage, the two decision variables are the level of CAPEX and the storage fee. Relating to equation (2.2), the CAPEX, C^s_0 and κ_t^s are the incremental costs of converting or modifying existing facilities at the oil field, while the storage fee, p_{2s}, is assumed to be related to the OPEX. For Field *Z* the incremental CAPEX for CO_2-EOR and subsequent sequestration is assumed to range between £900 million and £1.2 billion[12]. The unit CO_2 storage fee is assumed to range between 10 and 20 percent above the unit field OPEX in the post-EOR period.

(b) The stochastic variables

Using equation (2.2) the key variables whose future time paths are uncertain are the oil price, p_t^s, EOR yield, g_t, and the injection (x_{1t}) and monitoring (α_t) cost components of OPEX, X_t. The projected values of these variables are presented in Table 3 while their best-fit probability distributions are presented in Table 4.

[11] Ranked by the Chi-Square test criterion which was the only one available for the forecast data. The top 3 best fits are: Discrete Uniform (44.212), Binomial (59.080), and Negative Binomial (68.744).

[12] For comparison, the Scottish Centre for Carbon Storage (SCCS) assumed that the CO_2-EOR CAPEX for the following large oilfields in the Central North Sea could be: Claymore £1.1 to £1.2 billion, Scott £1.2 billion and Buzzard £700 million (SCCS, 2009).

Table 3: Projected values of the storage investment stochastic drivers

Year	Injection cost (£/tCO_2) (real2010)	Monitoring cost (% of cumulative CAPEX)	Oil price £/bbl($) (real2010)	CO_2 injection yield (bbl/tCO_2)
2020	na	na	60 (100)	na
2023	7	2	80 (124)	0.29
2025	7	2	90 (140)	0.40
2030	6	3	95 (148)	0.68
2040	5	3	80 (124)	1.63
2050	4	2		

Sources and notes:

Column (1): Authors' own projections based on Poyry (2007)

Column (2): Authors' own projections based on Poyry (2007)

Column (3): Authors' own projections based on EIA (2010)

Column (4): Authors' own projections based on Senergy (2009).

Table 4: Probabilistic variables of CO_2 storage investment

Probabilistic variable	Data range		Best-fit probability distribution	
	Minimum	Maximum	Type	Parameters
Common uncertainties				
Injection OPEX (£/tCO_2)	4.21[a]	7.34	Beta	Alpha = 0.88; Beta = 1.09
Monitoring OPEX (% of accumulated CAPEX)	1.55	2.70	Beta	Alpha = 0.88; Beta = 1.09
CO_2-EOR yield (barrels/tCO_2)	0.20[b]	1.20	Triangular	Minimum = 0.20; Maximum = 1.20; Likeliest = 1.00
Oil price (£/bbl)	65.00[c] ($100.00)	135.00 ($208.00)	Weibull	Scale = 81.00; Shape = 4.31; Location = 3.00

[a] In the literature estimates lie in the range £4 - £8/tCO_2 (e.g. Poyry, 2007).

[b] Source: Senergy (2009).

[c] Source: EIA (2010).

i. oil price (p_t^s)

This study assumes that the price of oil in the world market will rise substantially in the long term but continue to be volatile. Consistent with the EIA (2010) Reference Scenario forecast, the mean-reverting long-term average price was assumed to be £80 ($124) per barrel with the respective lower and upper bounds of £64 ($100) and £106 ($165). The EIA projections end in 2035. In order to project oil prices beyond that date, this study used the same mean-reverting commodity price model as for coal, using a mean-reversion speed of 50% per annum and volatility of 25%. As shown in Table 4, the best-fit probability distribution of the projected oil price was found to be the Weibull distribution. There is a 60% chance that the real oil price will reach £80 per barrel or more during the study period.

ii. *CO_2-EOR yield* *(g_t)*

Considerable uncertainties exist about the CO_2 –EOR yield. Estimates in the literature range from 1 to 4 barrels per tonne of CO_2 injected. Bellona (2005) and Tzimas et al. (2005) in separate studies assumed 3 barrels per tonne of CO_2 injected[13]. This study uses a more conservative yield estimate based on a report by Senergy for the SCCS (2009). This increases from 0.20 to 1.20 barrels of oil per tonne of CO_2 injected, before diminishing returns set in about halfway through the EOR phase. The projected EOR yields are presented in Table 3.

In Table 4, the best-fit probability distribution is seen to be triangular with the likeliest yield of 1 barrel of oil per tonne of CO_2 injected. There is a 60% chance that up to one barrel of oil per tonne of CO_2 injected can be produced during the study period.

iii injection and monitoring OPEX (x_{1t} and α)

Various estimates of the cost per unit of CO_2 injected, x_{1t}, exist in the literature (see Poyry (2007), for example). Based on these this study assumes an annual injection OPEX of £4 to £7 per tonne of CO_2 injected

[13] See, also, USA Department of Energy (2006).

and an annual monitoring OPEX, α, of 2% to 3% of incremental CAPEX. Gains from LBD effects are assumed to contribute to reductions in both the injection and monitoring costs over time. The projected costs are summarised in Table 3.

In Table 4, the best-fit probability distribution of the projected injection OPEX is the beta distribution. There is a 60% chance that the injection cost will not exceed £6/tCO_2. The best-fit probability distribution of the projected monitoring OPEX is the beta distribution. The cumulative probability distribution suggests that there is a 60% chance that a value less than or equal to 2% of cumulative CAPEX can be achieved.

CO_2 transportation investment

(a) The decision variables

Given his objective function in equation (2.3), the CO_2 transporter is assumed to have some control over his CAPEX, C^a_0, and acceptable transportation charges, n_t. Treating the transporter as a utility company, transportation charges are assumed to be determined on a cost plus margin basis. The aggregate pipeline CAPEX for the onshore and subsea components is assumed to range between £1.6 million to £2.5 million per kilometre. This is more conservative than the £1.5 million to £1.9 million range in DECC (2012). It is assumed that the transportation charges are in two parts. One is a margin component specified as a percentage of OPEX, y_t (see DECC, 2009b). This study treats the tariff margin as a decision variable with assumed values ranging between 20 and 40 percent of OPEX.

(b) the stochastic variable

The second transportation charge is a tariff component related to the pipeline CAPEX which is treated as a stochastic variable, owing to the non-standardisation of rules governing pipeline capacity trading in the UKCS (DECC, 2009). Much depends on the local monopoly power of the asset owner and/or the level of service required. Tables 5 and 6 respectively show the projected normalized transportation tariff and its best-fit probability distribution.

Table 5: 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

Source: Authors' own estimates

Table 6: Probabilistic variable of CO_2 transportation investment

Probabilistic variable	**Data range**		**Best-fit probability distribution**	
	Minimum	Maximum	Type	Parameters
Normalised pipeline tariff (£/tCO_2/100 km)	1.55	2.70	Beta	Alpha = 0.88; Beta = 1.09; Min. = 1.55; Max. = 2.70

This study assumes that the pipeline investor is able to charge a normalized pipeline tariff of between £1.55 and £2.59 per tonne of CO_2 transported per 100 kilometres. The deterministic projected normalised pipeline tariff is presented in Table 5.

Table 6 indicates that the best-fit probability distribution of the projected normalised pipeline tariff is the beta distribution. There is a 60% chance of a normalised pipeline tariff of £2.15 or more during the study period.

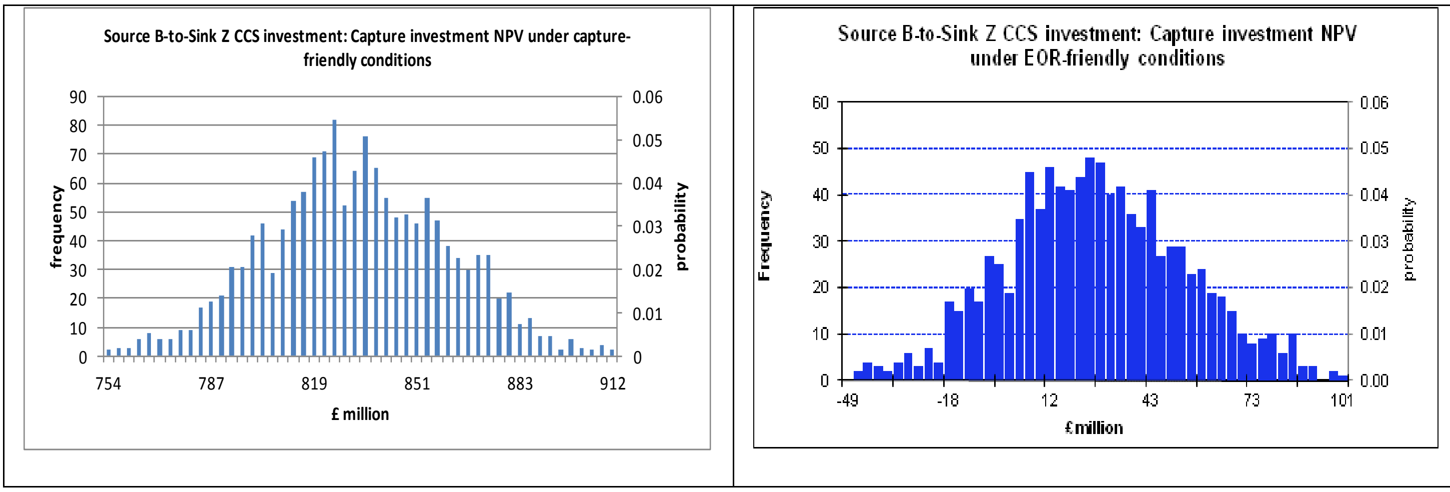
4. Model optimisation, results and discussion

In order to investigate the CCS investors' positions, the model in Section 2 was optimised from the respective perspectives of the capture and storage investors, with the transporter being treated as a utility. The numerical optimisation runs were performed with *Crystal Ball*, with each run consisting of 1000 Monte Carlo simulations and 1500 trials per simulation. Optimal results were obtained for High- and Medium Emitter scenarios but only the latter are presented and discussed below[14].

The returns to the CCS investors under two alternative investment climates are shown in Figures 1 to 6.

i. Returns to the capture investment under two investment scenarios.

Fig. 1: The NPV of the capture investment (£ million, 2010) (Plant B)



[14] The interested reader may obtain the High-Emitter results from the corresponding author. The High-Emitter case assumes the involvement in the CCS value chain of a high CO_2-emitting PCSCFGD power plant with annual emissions of between 18 and 21 $MtCO_2$/year.

A cumulative total of 199 $mtCO_2$ or an average 7 $mtCO_2$ per annum was emitted, captured, and stored. The optimal CAPEX for the capturer is £721 million. As seen in the LHP of Fig. 1, under capture-favourable assumptions, Plant B's NPV ranges from £753 million to £923 million, with a mean of £833 million. Underlying the investment returns are an optimal carbon price, p_1, of £43/tCO_2 and a post-EOR storage cost, p_2, of £36/tCO_2. In the RHP the NPV range is between -£51 million and £126 million, with a mean of £26 million under EOR-friendly assumptions. There is a much lower optimal carbon price, p_1, of £22/tCO_2 and a higher post-EOR storage cost, $p2$, of £37/tCO_2. There is a 10 percent chance of sustaining a negative NPV. Regardless of the predominant investment climate, the sensitivity of the capture investment NPV to the model's stochastic variables was tested with the results shown in Fig. 2 below.

Fig. 2: Sensitivity of capture investment NPV (£ million, 2010)

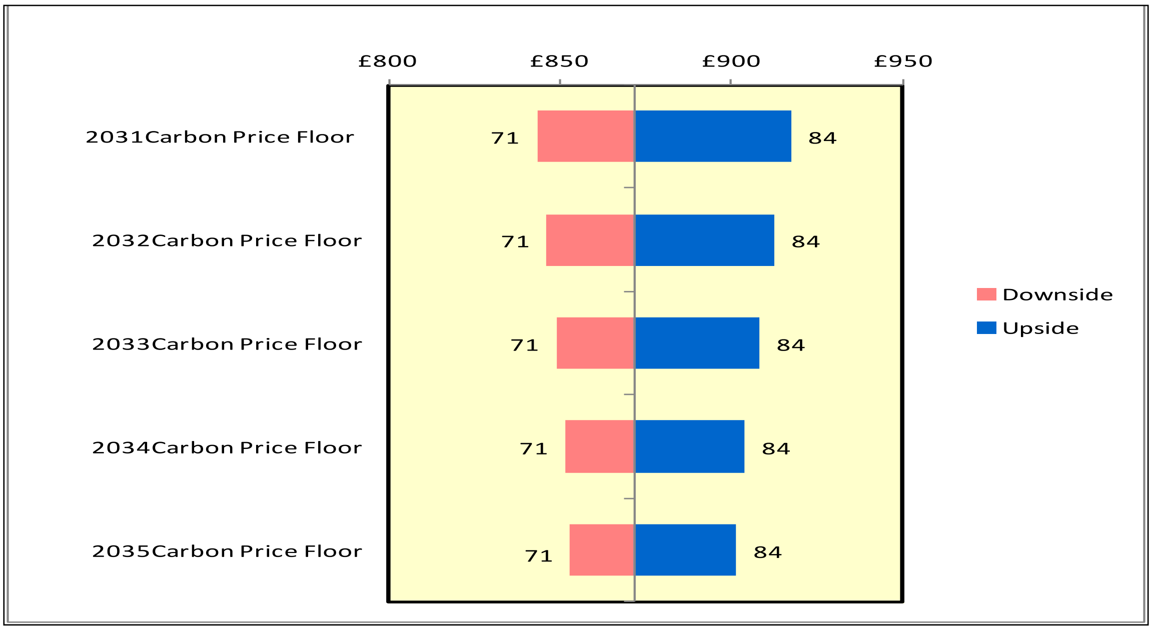
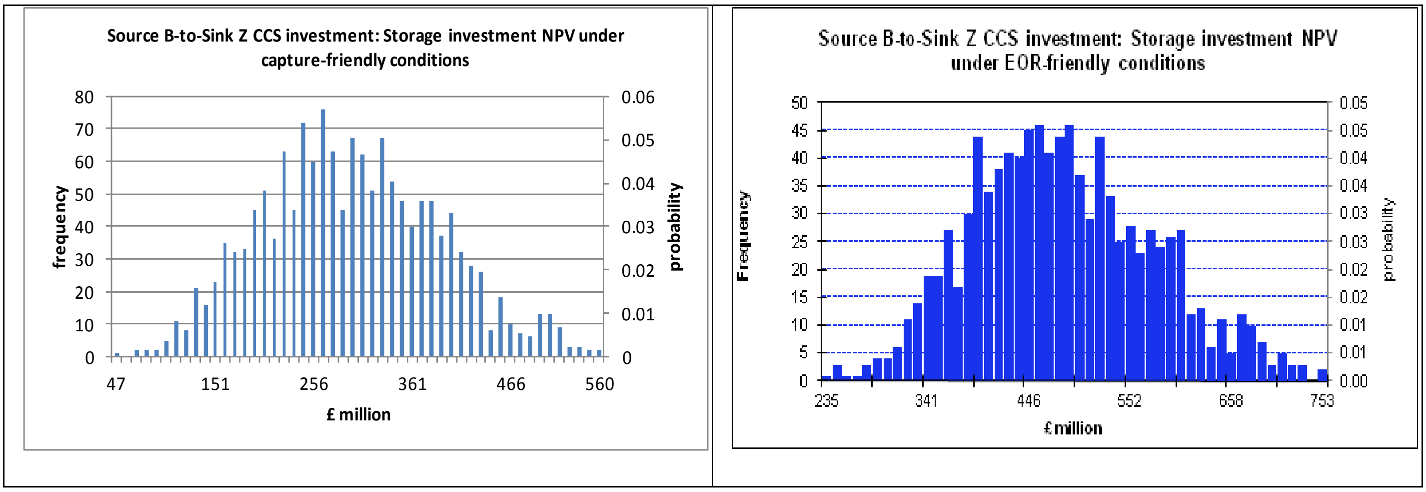


Fig. 2 shows that the returns to the capture investment are most sensitive to variations in the CPF, z_t, especially in the years 2031 through 2035.

The two CPF prices to which the capture investment NPV is most sensitive are £71/tCO_2 and £84/tCO_2. The latter is the upside of the variable while the former is the downside.

ii. Returns to the EOR investment under two investment scenarios.

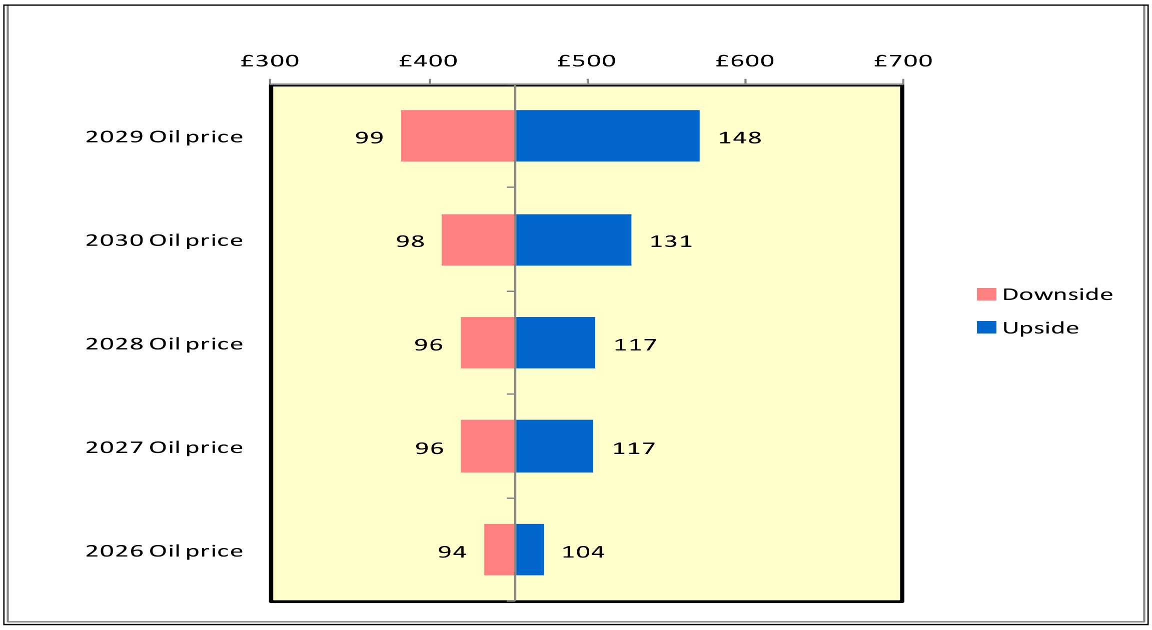
Fig. 3: The NPV of CO_2-EOR investment (£ million) (real2010) (Field Z)



The optimal CO_2-EOR investment in both scenarios was determined as £901 million. The total EOR is 131 mmbbls. Under the capture-favourable conditions in the LHP of Fig. 3, the NPV ranges from £4 million to £617 million with a mean of £298 million. The optimal oil price, p_t^s, during the EOR-phase is £110/bbl, while the optimal post-EOR storage fee, p_{2s}, received is £36/tCO_2. Under EOR-favourable conditions the minimum investment return is £229 million, with a maximum of £816 million and a mean of £484 million. Much of the improvement in this scenario emanates from the substantial reduction in the CO_2 cost from, p_{1s}, £43/tCO_2 to £22/tCO_2 and the higher storage fee, p_{2s}, of £37/tCO_2.

Both the coefficient of variability (not shown) and NPV range are significantly greater in the RHP than the LHP, underlining the point that even under more favourable conditions, returns to EOR investment remain risky. The main reason for this can be seen in Fig. 4 which shows the sensitivity of the NPV to oil prices.

Fig. 4: The sensitivity of the storage investment NPV (£ million, 2010)



Oil prices ranging from £94/bbl to £99/bbl are seen to have downside effects on the NPV while prices ranging from £104/bbl to £148/bbl have the opposite effect.

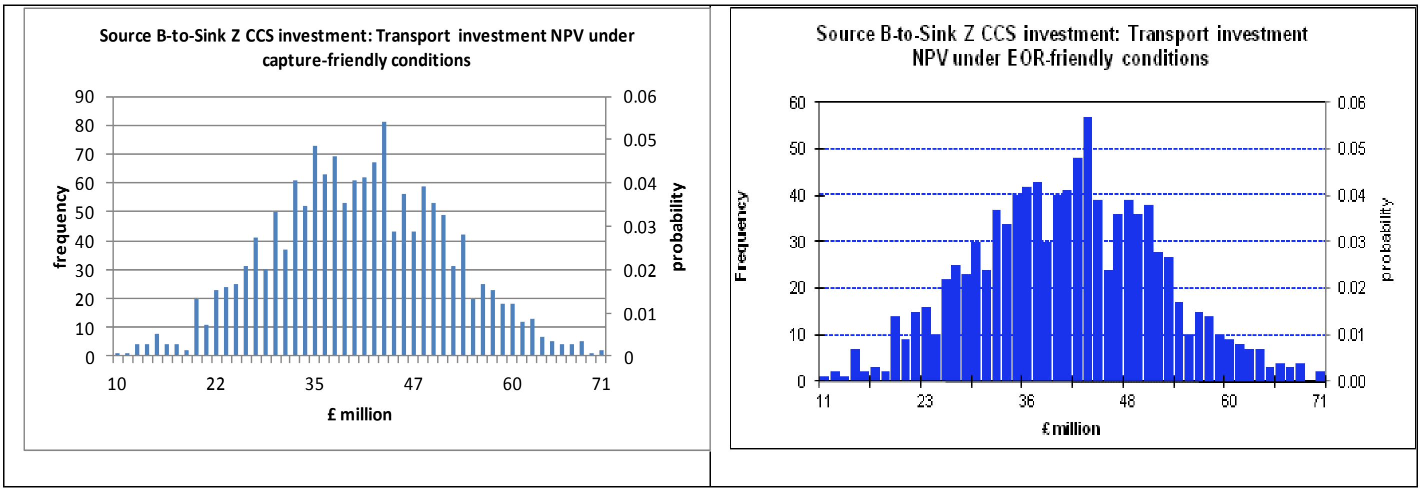
The ranges of the optimal carbon prices and storage fees from the respective perspectives of the capture and EOR/storage investors are summarised in Table 7.

Table 7: Summary of negotiable p_1 and p_2

Investment climate	Average captured CO_2 price (£/tCO_2)	Average storage fee (£/tCO_2)
Capture-favourable	(p_1=)43	(p_2=)36
EOR-favourable	(p_{1s}=)22	(p_{2s}=)37

iii. Returns to the transport investment under two investment scenarios

Fig. 5: The NPV of transport investment (£ million, 2010)



The optimal transport investment was determined as being £602 million. The differences in the capture- and EOR-friendly conditions make little difference to the profitability of the CO_2 transport investment. Fig. 5 shows that the returns are virtually the same in both scenarios, consistent with the utility-type investment. The NPV ranges from £4 million to £81 million with a mean value of £40 million.

Fig. 6: The Sensitivity of transport investment NPV (£/tCO_2/100 km) (real2010)

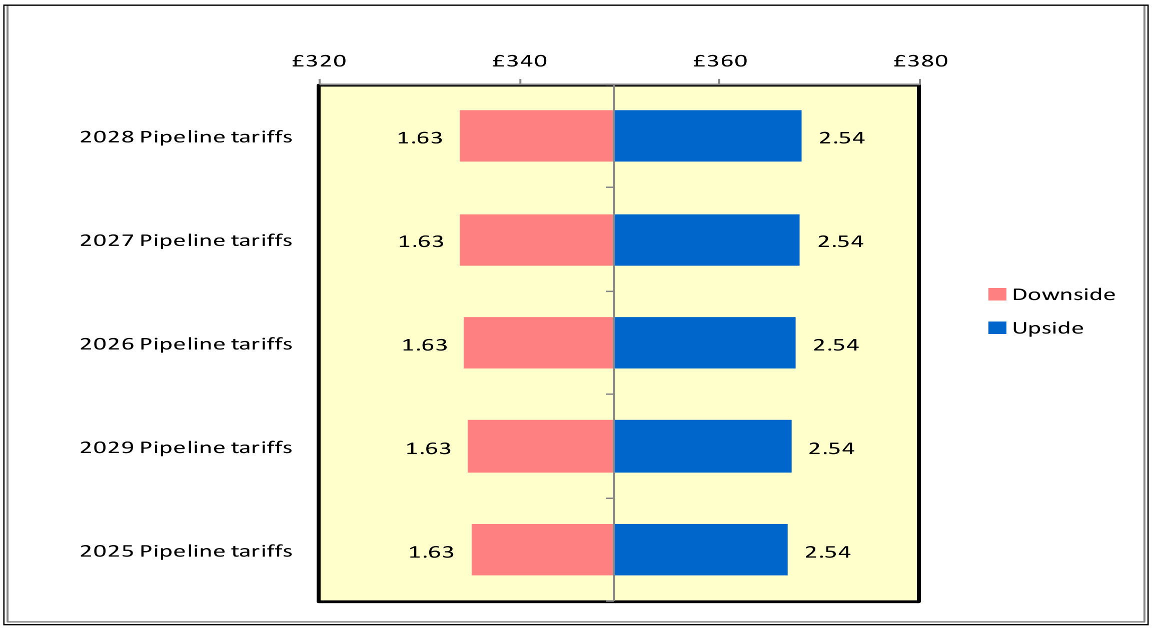


Fig. 6 above shows that the transport investor's NPV is very sensitive to the normalised pipeline tariff, with tariffs of £1.6 and £2.54 respectively having downside and upside effects on the NPV.

5. Summary and Conclusions

In this paper an optimised investment model of the CCS chain has been developed both to enhance understanding of the uncertainties and to discover the conditions under which CCS development and deployment can be achieved in the UK/UKCS. The chosen model involved trading relationships among investors at the capture, transportation, and EOR/storage stages of the CCS chain. Reflecting the various risks involved several stochastic variables were incorporated in the design of the objective functions of each of the three investors. A key feature of the modelling was the constraints imposed on the optimal solution for an investor at any one stage of the CCS chain being dependent on acceptable returns being expected by the other two investors in the chain. The modelling produced further insights into the nature of the problem by finding the optimal investment of each participant in the chain. A consequence of this procedure was that two values for the optimal CO_2 prices and storage fees were found, reflecting the separate perspectives of the capture and EOR/ storage investors. In the case of the Plant B the investor has an optimal asking CO_2 price of £43/tCO_2 while the storer's optimal offer price is £22/tCO_2. With respect to the EOR-storage fee the corresponding optimal values are an offer price of £36/tCO_2 from the capture investor's perspective and an asking price of £37/tCO_2 from the storer's viewpoint. Reflecting the mutual interdependence of the integrated CCS investments, while attempting to avert the tragedy of the anticommons (Parente, 2012), the parties can negotiate and reach a satisfactory agreement on the prices that would offer acceptable returns to their individual investments. The price differentials show the scope for negotiation between the two parties, with any value within the range ensuring that the overall chain of investments remains viable. The uncertainties and boundaries for negotiation among the parties can be reduced by the wider provision and sharing of the maximum amount of information on the likely costs of the various elements in the CCS chain, paving the way towards co-operative Nash equilibrium contractual terms. Both the broad range of prices of oil (£110/bbl to £114/bbl) and the traded CO_2 (£22/tCO_2 to £43/tCO_2) required to ensure the optimality of the model solutions may appear rather high. It should be noted, however, that the long-term oil price range is consistent with other studies including EIA (2010)[15]. Also, the CO_2 prices are consistent with those planned for the CPF. The CPF mechanism involves the extension of the

[15]SCCS (2009) suggests that oil prices above $100/bbl would be required to kick-start some CO_2-EOR projects in the UKCS.

Climate Change Levy (CCL) to fossil fuels used for power generation[16]. The results of this study are useful in quantifying the level of price support that may be required. Currently, EOR in the UKCS is fully subject to the North Sea oil taxation regime which entails tax at an overall rate of 81% on profits from fields developed before March 1993, and a rate of 62% on profits from fields developed after that date. Disincentives to EOR schemes can readily emerge, and tax reliefs for EOR projects could enhance investment incentives. For example, the new Brownfield Allowance could readily be extended to apply to CO_2 EOR projects.

[16] Government revenue from CPF is projected to reach £1.4 billion as early as 2015-2016 (HM Treasury, 2011).

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APPENDIX 1.1

Assuming that the log of the coal price (A_t=log (P_{coal}^t)) follows a mean reversion process of the Ornstein-Uhlenbeck stochastic type satisfying the differential equation:

$$dA_t = \tau(\overline{P_{coal}} - P_{coal}^t)dt + \sigma dW_t \quad (3.1)$$

where:

P_{coal}^t = *Coal spot price at time t*

$\overline{P_{coal}}$ = *Coal price reversion level*

T = *Speed of reversion to the reversion level*

Σ = *Instantaneous volatility*

dW_t = *Increment to a standard Brownian motion (Weiner process)*

The Weiner process (W_t) in equation (3.1) is assumed to be normally distributed with a mean of zero and a standard deviation of one. The Kalman filter methodology was employed to determine the parameter estimates (τ and σ) [17] from the expected terms of equation (3.1). On the basis of the estimated results, presented in Appendix 1.1b, the study used τ = 60% per annum, σ = 25% and DECC's (2011) projected coal price central value of around £70/tonne to randomly generate the projected coal prices[18]. These are presented in Appendix 1.2.

Kalman Filter Estimation Results

In order to obtain the two key parameters used in the projection, the historical data on coal prices (1991-2011)[19] were divided into sub-periods

[17] The historic UK's 1992-2011 coal prices dataset used to estimate the linear state-space model are in Appendix 1.1a. A summary of the Kalmer Filter estimation results are presented in Appendix 1.1b.

[18] Being randomly generated there are several possible time paths of the future coal price, but only one sample path is presented in Appendix 1.2

[19] Data obtained from DECC Quarterly Energy Prices (Table 3.2.1) - several years.

to get a clearer picture of a trend. By segmenting the dataset into sub-periods (for example, 1996-2011, 2000-2011 etc.) the estimated linear state-space model yielded (in the EViews econometric package used for the purpose) the following results:

period	volatility (σ)	reversion speed (τ)	log likelihood	probability of rejection	
				volatility	reversion speed
1991-2011	0.138	0.999	7.363	0.000	0.000
2000-2011	0.164	0.997	1.921	0.000	0.000
2003-2011	0.187	0.797	1.823	0.000	0.115
2004-2011	0.193	0.670	1.513	0.000	0.267
2005-2011	0.189	0.440	1.609	0.005	0.486
2006-2011	0.174	0.232	1.945	0.006	0.669

In summary, the estimated price volatility (σ) and mean-reversion (τ) speed parameters lie in the following ranges:

$14\% < \sigma < 20\%$

$23\% < \tau < 90\%$