NORTH SEA STUDY OCCASIONAL PAPER
No. 123

The Economics of CO_2-EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth

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January, 2012

DEPARTMENT OF ECONOMICS

ISSN 0143-022X

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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The Economics of CO_2-EOR Cluster Developments in the UK Central North Sea/Outer Moray Firth

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1. Introduction

The relatively low average oil recovery factor of 38 percent in the UKCS[1] suggests considerable opportunities exist to unlock the remaining reserves through tertiary production by utilising techniques which include CO_2-flooding. However, several studies to date generally confirm the view that individual projects are unlikely to be economically viable except under unrealistic assumptions. These studies have concentrated on individual sources, transportation routes and fields. An exception has been the Scottish Centre for Carbon Storage (SCCS) (2009) study, which carried out high level desktop techno-economic analyses of CO_2-EOR possibilities in three fields.

This new study examines in depth the economics of CO_2 enhanced oil recovery (EOR) cluster developments in the UK Central North Sea/Outer Moray Firth region. The study differs from the SCCSC (2009) study in important respects. Firstly, whereas the SCCS study assumed zero-price CO_2 delivered to the selected oilfields for EOR, the present study examines two scenarios with positive prices for the imported CO_2. Secondly, nine CO_2-EOR fields are considered.

In the present study, using the hub-and-spoke approach, St Fergus in north-east Scotland could be a possible onshore hub. Existing,

[1] Charles Hendry, UK Minister of State for Energy at Offshore Europe 2011.

refurbished, backbone pipelines plus extensions to them, acting as the spokes, could be linked to a number of fields in the Central North Sea/Outer Moray Firth region with EOR potential. The study employs Monte Carlo simulation analysis to analyse the risk economics of CO_2-EOR emanating from such developments. The outputs of the study emphasise the returns to investors in the CO_2 EOR activity under alternative fiscal and carbon pricing assumptions.

2. The Backbone Pipelines

The study assumes that the following three backbone pipelines can be refurbished and deployed in any CO_2-EOR project:

1. St. Fergus – Cruden Bay – Forties (commissioned in 1973 and decommissioned in 1993 but still in place).
2. St. Fergus – Goldeneye (commissioned in 2003 and still in use).
3. St. Fergus – Miller (commissioned in 1992, now decommissioned but still in place).

It is believed that the old Cruden Bay-Forties pipeline can be refurbished for use again. The pipeline to the Miller is available for shipping CO_2-EOR as this is a condition of the field decommissioning. The St. Fergus-Goldeneye pipeline should also be available for CO_2 transport. Details of the pipeline schemes employed in the present study are shown below in Table 1.

Table 1: Transportation of CO_2-EOR based on 3 potential pipeline backbones

Field name	Backbone	Extensions from	Section	Length (km)			Diameter	
				Total	Existing	New	existing (in)	new (in)
Forties	St. Fergus - Cruden Bay - Forties	none	none	177	177		36	
Alba	St. Fergus - Cruden Bay - Forties	Forties - Alba - Balmoral	Forties - Alba	47		47		8
Nelson	St. Fergus - Cruden Bay - Forties	Forties - Nelson	Forties - Nelson	35		35	20	8
			Sub-total	**259**	**177**	**82**		
Goldeneye	St. Fergus - Goldeneye	none	none	102	102		20	
Buzzard	St. Fergus - Goldeneye	Buzzard_Goldeneye Junction	Buzzard - Goldeneye Junctio	2		2		8
			Sub-total	**104**	**102**	**2**		
Brae Alpha	St. Fergus - Miller	Miller - Brae	Miller - Brae	8		8	18	8
Scott	St. Fergus - Miller	Miller_Telford Junction - Scott - Tartan - Claymore	Telford - Scott	10		10	9	8
Claymore	St. Fergus - Miller	Miller_Telford Junction - Scott - Tartan - Claymore	Tartan - Claymore	27		27	24	8
Tartan	St. Fergus - Miller	Miller_Telford Junction - Scott - Tartan - Claymore	Scott - Tartan	17		17		8
Miller	St. Fergus - Miller	none	none	240	240		30	
			Sub-total	**302**	**240**	**62**		
			Grand total	**664**		**145**		

3. A Brief Profile of the Selected CO_2-EOR Fields

The nine selected fields for prospective EOR are Alba, Brae, Buzzard, Claymore, Forties, Miller, Nelson, Scott and Tartan.

<u>Alba</u>

Alba is located about 190 kilometres north-east of St. Fergus in Block 16/26. The field, lying in a water depth of 138 metres came on stream in 1994. The OOIP has been estimated to be around 1 billion barrels, of which about 414 mmbbls had been produced as at the end of 2010 (DECC website). Assuming a real oil price of \$90 per barrel, it is estimated that the field's COP date could be 2024. CO_2 for EOR could be delivered to Alba from the St. Fergus hub via an estimated 47-kilometre extension of the St. Fergus-Cruden Bay-Forties pipeline.

<u>Brae complex</u>

The Brae complex consists of the three fields tied to the Brae Alpha platform. These consist of Central, South and West Brae. The fields are located about 230 kilometres north-east of St. Fergus and lie in a water depth averaging about 106 metres. The fields' estimated recoverable reserves originally present totalled 392 mmbbls of which about 387 had been produced as at the end on 2010, with the water cut averaging about 70% (DECC) in 2010. By 2010, the collective production of the three fields at the Brae A Platform was 11,451 b/d with gas in addition. As of 2011, the three accumulations between them had 34 producer and 4 injector wells (Marathon, 2011).

Assuming a real oil price of $90 per barrel, the estimated COP date for the fields in the complex is around 2019. The present study assumed that CO_2-EOR could be delivered to the Brae Alpha platform by an approximately 13 kilometre pipeline extension of the St. Fergus-Miller pipeline.

<u>Buzzard</u>

The Buzzard field was discovered in June 2001. It is located about 62 kilometres from St. Fergus and lies in a water depth of about 100 metres. The field's OOIP is estimated at about 1.2 billion barrels of which about 550 mmbbls are estimated to be recoverable. First oil was produced in 2007, while cumulative oil production stood at 259 mmbbls at the end of 2010. It is envisaged that when fully developed Buzzard may have 27 producers and 11 injector wells. By 2011, 21 wells had been drilled (Offshore Technology, 2011). With a $90 real oil price the COP date could be in 2033.

Buzzard lies between St. Fergus and Goldeneye which was proposed by a Scottish Power-led consortium as CO_2 storage reservoir. It is assumed in the present study that a short-length 8-inch (203mm) pipeline would be connected to the St. Fergus – Goldeneye backbone pipeline to deliver CO_2-EOR to the field.

Claymore

Claymore is located about 141 kilometres from St. Fergus in Block 14/19 and, in a water depth of about 104 metres. The field was discovered in June 1974 and production commenced in 1977. The OOIP has been estimated at about 1.46 billion barrels with estimated proven reserves of about 596 million barrels. By the end of 2010 cumulative production totalled 583 mmbbls and the watercut was 74%. At a real $90/bbl crude oil price, the estimated COP date is 2027. CO_2 for EOR could be shipped to Claymore via pipeline extensions (as detailed in Table 1) to the St. Fergus-Miller line.

Forties

The Forties field was discovered in October 1970 and production started in September 1975. The field is located in Block 21/10, about 171 kilometres from St. Fergus and lies in a water depth of 107 metres. The field's estimated OOIP is about 5.1 billion barrels of which at least 2.8 billion barrels are estimated to be recoverable. As the end of 2010, cumulative production totalled 2.6 billion barrels. The level of the field watercut in that year was 87%. Recently Forties had 81 producer and 22 injection wells tied-back to 5 platforms[2] – Forties Alpha, Bravo, Delta, Echo and Charlie. Assuming a real oil price of $90/bbl, the estimated COP date could be 2043. This study assumes that the old 36-inch (914 mm) diameter Cruden Bay – Forties pipeline could be re-furbished and used to deliver CO_2 to Forties and neighbouring fields such as Alba and Nelson included in the present study.

Miller

The Miller oilfield was discovered in 1982 in Block 16/7b. Production started in June 1992. The field is located about 242 kilometres from St.

[2] See SUBSEAIQ (2011).

Fergus and lies in a water depth of 100 metres. The field's original recoverable reserves were estimated at about 320 mmbbls of oil and 14.9 billion cubic metres (bcm) of gas. However, by 2007 cumulative oil and gas production stood at 331 mmbbls and 18 bcm respectively, with a watercut of about 90%. The field is currently being decommissioned. Miller had 10 producer and 6 injector wells (Wylde et. al, 2006).

BP the operators of the field considered but later dropped its proposed CCS (Decarbonised Fuel 1) project. But a new scheme could see CO_2 being shipped to Miller and some neighbouring fields, using the existing 242 kilometre 30-inch (762 mm) St. Fergus – Miller gas backbone pipeline. In the present study, it is assumed that the line could be extended to deliver CO_2-EOR to fields including Brae, Claymore, Scott and Tartan.

Nelson

The Nelson oilfield was discovered in Block 22/11, in March 1988 and, production started in February 1994. The field is located about 176 kilometres from St. Fergus in a water depth of 87 metres. The OOIP was estimated at about 790 mmbbls (Kunka et. al, 2003) and the original recoverable reserves were estimated at about 470 mmbbls. As at the end of 2010, cumulative production stood at about 425 mmbbls, with a watercut of about 89%. Oil export is via the Forties Pipeline System. Nelson has recently produced from 24 producer and 7 injector wells. The estimated COP date is 2027, at an assumed real oil price of $90/bbl. The study assumes that CO_2 for EOR could be delivered to Nelson via a 35 kilometre 20-inch (508 mm) diameter pipeline extension of the St. Fergus – Cruden Bay – Forties line.

Scott

Scott was discovered in January 1984 and first oil was produced in September 1993. The field is located in Block 15/21a, about 146 kilometres from St. Fergus in a water depth of 140 metres. The field's OOIP is estimated at about 946 mmbbls of which 393 mmbbls had been produced by the end of 2010. The field watercut in that year was about 91%. Oil has been produced at Scott from 20 producing and 17 injection wells. The produced oil is exported to the Forties Pipeline System. At an oil price of $90 the field's estimated COP date is 2016. It is assumed that CO_2 for EOR could be delivered to Scott via a 10-kilometer 9-inch (219 mm) pipeline extension of the St. Fergus - Miller line as extended to Telford and detailed in Table 1.

Tartan

The Tartan oilfield was discovered in January 1975 and commenced production in January 1981. The field is located about 144 kilometres from St. Fergus in Block 15/16, lying in a water depth of 140 metres. The initial URR was estimated at around 112 mmbbls. Cumulative production was 109 mmbbls as at the end of 2010. The field watercut was about 80% in that year. Tartan has recently produced from 8 platform producers and 6 subsea water injection wells. At $90 oil price, Tartan's estimated COP date is 2027. The study assumes that the required CO_2-EOR could be delivered through a 17 kilometre 8-inch (203 mm) diameter pipeline extension to the St. Fergus-Miller line from Scott.

4. Model Description

A financial simulation model was constructed to determine the profitability or otherwise of CO_2-EOR in the selected fields, given certain operational and environmental assumptions. The following are the model's key assumptions and data:

(a) **Timeline**

Even though the selected oilfields will have different COP dates for the purpose of this study it was assumed that their EOR investment would share a common investment timeline as follows:

- 2020 – 1st CAPEX – well re-work and modification of surface facility plus pipeline refurbishment and new build commence.
- 2023 – CO_2 injection commences.
- 2025 – 1st incremental oil produced
- 2050 end of study period

(b) **Wells and injection rates**

- Production wells remain in use while, following BERR (2007), 50% of existing injection wells may be re-used with modifications.

- The number of injection wells required to ensure a reasonable sweep in each CO_2-EOR case is determined by the assumed sink injection rate[3], with higher injection rates requiring less injection wells and associated surface facilities. Depending on the degree of resilience required in a network, BERR (2007) used a per well injection rate ranging between 0.75 – 1.25 $MtCO_2$/year in their study, while BP contemplated an injection rate of 0.5 $MtCO_2$/year at Miller. The present study assumes per well injection rates in the range of 0.5 – 1.25 $MtCO_2$/year.

[3] And the required producer-to-injector ratio needed to roughly maintain a constant reservoir pressure.

- The assumed injection rate and the likely number of re-usable wells determine the volume of CO_2 demand for EOR and later permanent storage.

- Following BERR (2007) it is assumed that the CO_2 injection wellheads are located on platforms above the waterline (for ease of access downhole for well workover, maintenance, repair etc).

(c) **CAPEX**

The present study attempts a detailed breakdown of a field's required incremental EOR CAPEX. Each field's incremental CAPEX was assumed to be an aggregation of the following individual items:

i. **Recycle system:** Recycle systems are required to separate and recycle the produced CO_2 in a CO_2-EOR project. Since existing gas and oil pumping systems are unsuited to CO_2 compression, a recycle investment is a new spend in virtually all cases. The total recycle plant investment cost was calculated as the product of the unit recycle cost and the re-injection capacity[4]. A unit capital recycle cost of £5.7 million per tonne of recycled CO_2 was assumed.

ii. **Surface facility:** Each CO_2-EOR field will require a facility to distribute the imported CO_2 among the wellheads of the injection wells. The distribution facility can be a sub-sea wellhead, or a fixed platform, depending on the number of wells involved, the vehicle (existing pipelines with pressure limitations or, new purpose-built pipelines) and pressure of the arriving CO_2. Fixed platforms that can accommodate pressure-

[4] A product of the per well injection rate and the number of injectors in a field.

boosting pumps would be required where the CO_2 arrival pressure is too low for direct injection and needs to be boosted for distribution to more than two injection wells. Following BERR (2007) the present study assumes that new fixed injection platforms are installed adjacent to the existing production platforms in the selected fields. In determining the capital cost of topside design modification, the unit injection capital cost (of a new injection platform) per million tonnes of CO_2 injected per year (£/MtCO_2/year) was derived from BERR (2007) as follows:

- £7 million @ water depth < 100m
- £14 million @ water depth > 100m

iii. **Well rework/conversion:** The cost of re-working an existing water flood injection well for CO_2 injection consists of fixed and depth-related components. The present study assumes that the total well conversion cost is about three times higher than the cost of the topside design modification outlined above. An alternative well conversion cost would have assumed a combination of a fixed and variable per metre of water depth cost.

iv. **Pipelines:** Studies such as BERR (2007) have established that most of the pipelines in the UKCS, including the three backbone pipelines in the present study can with some modification be re-used because they are still metallurgically suitable. The capital investments on the pipeline infrastructure in the present study consist of the costs of (a) modifying in particular the design pressure[5] but, also, as may be necessary, the anti-corrosion properties of the existing pipelines for re-use, and (b) constructing new pipelines connecting the fields to the relevant backbone. Sizing each pipeline for the anticipated maximum volume of CO_2-EOR to be transported in it involved CAPEX assumed to consist of fixed and variable per diameter (in millimetres) - distance (in kilometres) components.

v. **Monitoring:** The capital element of monitoring costs constitute a small component of the overall CAPEX. The present study assumes that the monitoring hardware constitutes 3 percent of CAPEX.

Given the prevalent uncertainties surrounding the investment cost of CO_2-EOR projects worldwide in general and the UKCS in particular, the CAPEX in the present study is assumed to be a stochastic rather than a deterministic variable. Being stochastic, the possible values of each oilfield's CAPEX can be defined by different types of probability distributions. The present study assumes that these values are characterised by a normal distribution. The mean of the distribution is the deterministic value arrived at through a summation of the various CAPEX components outlined above and, its standard deviation is 10% of the mean. The values of the CAPEX components vary across the nine fields.

(d) **OPEX**

[5] Increasing the pressure range from the conventional 90 and 180 bars to 200 and 300 bars (BERR, 2007).

The OPEX comprises of the costs of purchasing the (imported) CO_2, recycling, emissions (EU-ETS and Carbon Price Floor (CPF)), and, Operations and Maintenance (O & M) as follows:

i. **Carbon prices:** Typically at a CO_2-EOR oilfield, CO_2 is emitted, imported, produced, and recycled. The various sources of CO_2 may attract different prices or costs. Emitted CO_2 from oil production is subject to EU-ETS prices. However, there is as yet no agreed framework or a price-determination mechanism for the imported CO_2.

   The EU-ETS carbon prices were used to estimate the cost of emissions in the course of EOR production. Because of the uncertainties surrounding the future levels of these prices, the study assumes that the EU carbon price is stochastic, having a triangular probability distribution with the minimum, maximum and most likely values respectively being £28.74 (€33.05), £44.33 (€50.98) per tonne and £35.82 (€41.09).

   Three plausible carbon prices could potentially be placed on the fresh imported CO_2. These are the EU-ETS, the CPF, or, prices negotiated by the exporter and importer of the CO_2. For the CO_2-EOR field operator the carbon price should be competitive with the price(s) of alternative EOR technologies. In a joint study, the IEA and OECD (2004) concluded that CO_2-EOR could be applied to a majority of the world's oilfields, provided the CO_2 were available at relatively low prices.

Given the centrality of the appropriate pricing[6] of the imported CO_2 to the decision to invest or not in a CO_2-EOR project, the present study investigated the issue in detail. Two extreme sets of the price of the imported CO_2 were assumed. In the first case referred to as the Low Price scenario, it was assumed that relatively low carbon prices are arrived at through transfer pricing in a vertically-integrated consortium or negotiation between independent entities. The carbon price is assumed to be uncertain or stochastic, following a triangular probability distribution with the minimum, maximum and most likely respective values being £0, £20, and £5 per tonne.

Higher carbon prices will obtain under the UK's CPF rules. According to the legislation CPF prices start at £16/tCO_2 in 2013 are expected to rise linearly to £30 in 2020, with the prospect that they could increase to £70 in 2050. Because of the inherent uncertainties, especially post-2030, (not explicitly mentioned in the CPF rules), the study assumes that the CPF prices are stochastic and follow a triangular distribution with the respective minimum, maximum and most likely values being £30, £110 and £76 for the post-2030 period.

ii. **Incremental O&M:** Each field's initial annual O&M costs are assumed to range between 3% and 5% of its CAPEX. The costs are further assumed to be stochastic with a triangular probability distribution such that the minimum value is 3% of CAPEX, the maximum value is 5% of CAPEX, with 4% of CAPEX being the most likely value.

[6] Other conditions recommending CO2-flooding as the best option include the reservoir characteristics and local supply conditions (IEA/OECD, 2004).

(e) **Key relationships**

An understanding of the nature and pervasiveness of the following intricate relationships in the CO_2-EOR process is central to investment returns:

i. **Fresh and recycled CO_2 relationships**

The study assumes that, in order to forestall early CO_2 breakthrough, WAG (water alternating gas) schemes would be undertaken in the selected CO_2-EOR fields. Initially fresh CO_2 has to be imported and injected into each field in order to kick-start CO_2-EOR operations. However, there will be a reducing demand for fresh CO_2 once a CO_2 breakthrough has occurred and more field-produced CO_2 is captured and re-injected. The relative duration of the injection period of the imported vis-à-vis recycled CO_2 clearly has cost implications. Therefore, it is important to construct a model that enhances an understanding of the relationship between the fresh/imported CO_2, the field produced-and-recycled CO_2, and the produced hydrocarbon gas, even though the latter is not of much interest to the present study. Using USA (Kinder Morgan) data the relationships between the annual volumes of fresh CO_2 injected, produced and recycled, as well as the hydrocarbon gas produced were established by estimating the following VAR model:

$$fresh_t = a_o + a_1 fresh_{t-1} + a_2 recy_{t-1} + a_3 hcgas_{t-1} + a_4 oil_{t-2} \qquad (1)$$
$$recy_t = b_0 + b_1 fresh_{t-1} + b_2 recy_{t-1} + b_3 hcgas_{t-1} + b_4 oil_{t-2} \qquad (2)$$
$$hcgas_t = c_0 + c_1 fresh_{t-1} + c_2 recy_{t-1} + c_3 hcgas_{t-1} + c_4 oil_{t-2} \qquad (3)$$

where:

$fresh_t$ = the volume of fresh CO_2 purchased and injected at period $_t$

$recy_t$ = the volume of CO_2 produced and recycled at time $_t$

$hcgas_t$ = the volume of hydrocarbon gas produced at time $_t$

oil_t = CO_2-EOR oil produced at time $_t$

The volume of oil produced at *t-2* was exogenous.

In equation (1) the volume of fresh or imported CO_2 in the current period is a function of the volumes of CO_2 imported and recycled, as well as the volumes of hydrocarbon gas and oil produced historically. Equation (2) states that the volume of in-field produced and recycled gas in the current period depends on the immediate past volumes of imported and recycled CO_2 as well as the volumes of hydrocarbon gas and oil produced. Equation (3) in which the produced hydrocarbon gas is the dependent variable follows the same logic as the equations (1) and (2). Exogenising oil production in the model emphasises the point that the CO_2-EOR process is driven by the remaining oil resources.

ii. CO_2 Input-EOR output yield

The quantity of EOR is proportional to the amount of CO_2 injected. But this proportion varies from field to field depending on the relative efficiency of their WAG schemes. Moreover, the proportion is not constant over time but varies due to diminishing returns to continued CO_2 injection. Various estimates of the potential yield of CO_2 injection (or CO_2 usage) exist in the literature (see for examples Bellona, 2005; Tzimas et al, 2005, Senergy 2009). Conceivably, the wide range in the estimates is due to the differing aims of CO_2-EOR. Thus, the estimated CO_2 usage would be different if the CO_2-EOR aim was to (a) minimise CO_2 injection and maximise EOR oil, or (b) maximise CO_2 injection (for sequestration/storage purposes) and extract any level of EOR oil; or (c) co-optimise CO_2 injection and EOR oil production. In the expectation that co-optimisation would be the goal of CO_2-EOR in the UKCS, the present study assumes a modest yield of the oil produced being between 0.38 and 0.63 tonnes of CO_2 per barrel of EOR oil. In order to capture the non-linearity in the input-output relationship, a quadratic relationship as in equation (4) was assumed.

$$O_t = a_o + a_1 I_t + a_2 I_t^2 + \mu_t \qquad (4)$$

where:
O_t = oil produced at time t
I_t = Amount of CO_2 injected at time t
μ_t = the error term

However, because of the uncertainties surrounding CO_2 yield the study treated it as a stochastic variable with a triangular probability distribution whose minimum, maximum and most likely values are respectively 0.38, 0.63 and 0.55 tonnes of injected CO_2 per barrel of EOR oil.

Furthermore, given the uncertainties surrounding the CO_2 yield, the produced oil is assumed to be a stochastic variable characterised by a normal probability distribution with time-varying parameters. The means of the distributions are the (deterministic) values calculated using the input-output formula. The standard deviation of the distribution for each year was calculated as a percentage of the distribution mean for that year. In order to reflect the notion that the near-term uncertainty regarding how much oil can be produced from each tonne of CO_2 injected is less than in the longer-term, these percentages are increased progressively from about 4% in the earlier years to about 20% percentage in the later years.

(f) **Expected revenues**

Oil prices: Incremental oil revenues are earned from the CO_2-EOR projects. **C**onsiderable uncertainties surround the levels of future oil prices. The study assumes that oil prices would typically be volatile during the study period (2020-2050), in the range of \$90 (£57) and \$195 (£122) per barrel, mean-reverting to about \$128 (£80) per barrel. The oil price distribution is assumed to be stochastic with a triangular probability distribution with the respective aforementioned minimum, maximum and most likely values.

5. Results

Alba

The results of the simulations under the alternative Low and CPF scenarios are summarised in Table 3 below. The Low Price scenario in this is a set of three scenarios under pre-tax, 81% and 62% tax rates. The net cash flows are discounted at 10% to the base year of 2020. The results highlight the central (modal) values of the variables.

Table 2: A summary of the model solutions for the Alba oilfield

	Low CO_2 price scenario			CPF price scenario
	Pre-tax	**81% tax**	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 32-67)	41.93	41.93	41.93	43.22
Purchased CO_2 ($MtCO_2$)	17.50	17.50	17.50	17.50
Recycled CO_2 ($MtCO_2$)	64.53	64.53	64.53	64.53
CO2 stored (MtCO2)	16.30	16.30	16.30	16.30
Hydrocarbon gas produced ($MtCO_{2e}$)	3.29	3.29	3.29	3.29
CAPEX (£m)	407.56	407.56	407.56	407.56
CAPEX per barrel (£)	9.72	9.72	9.72	9.43
Carbon price:				
a. Imported CO_2 cost (£/tCO_2)	8.28	8.28	8.28	77.77
b. EU-ETS emission cost (£/tCO_2)	36.69	36.69	36.69	36.64
c. EU-ETS emission cost (€/tCO_2)	42.19	42.19	42.19	42.14
OPEX (£m)	1092.24	1092.24	1092.24	2247.81
OPEX per barrel (£)	26.05	26.05	26.05	52.01
Annual OPEX (£m)	35.23	35.23	35.23	72.51
oil price per barrel (£)	87.73	87.73	87.73	85.46
oil price per barrel ($)	140.37	140.37	140.37	136.74
CO_2 usage (tonne/barrel)	0.51	0.51	0.51	0.52
No. of injector wells	2.50	2.50	2.50	2.50
Mean NPV (£m)	298.77	54.17	111.55	-158.05
Mean IRR (%)	0.16	0.12	0.14	0.07
Discount rate (%)	10.00%	10.00%	10.00%	10.00%
Tax (£m)	0.00	1747.22	1337.37	0.00
NPV/I		**0.17**	**0.35**	

The model solutions presented above in Table 2 indicate that about 42 mmbbls additional EOR oil could potentially be produced from a cumulative total injection of about 18 $MtCO_2$ of purchased CO_2.

Adopting Kinder Morgan (2011) and using the field's estimated 2010 emissions per barrel figure of 0.03 tonnes, it is calculated that about 93% of the purchased CO_2 would be stored at Alba. The central value of the calculated total CAPEX in both the Low and CPF price scenarios is £408 million, and the per barrel CAPEX is about £10.

While the cumulative OPEX is the same £1.09 billion in the three Low Price scenarios, this is more than double in the CPF price scenario. While the annual OPEX is £35.23 million in the Low Price scenarios it is higher at £72.51 million in the CPF price scenario. The reason for the difference lies in the huge divergence in the prices of the purchased CO_2. While the average price of the imported CO_2 is calculated to be £8.28/tCO_2 in the Low Price case, it is £77.77/tCO_2 in the CPF case.

In the Low Price simulations, the mean NPV is £299 million under the pre-tax assumptions and £54 million under the 81% tax rate. In the 62% tax rate scenario the mean NPV would rise to about £112 million. Ordinarily, the positive mean NPVs in the Low Price scenarios would argue for an EOR investment while the negative mean NPV of the CPF pricing scenario would argue against it. The study considered a more rigorous investment profitability criterion – namely, the NPV/I ratio. The ratio of 0.17 under the 81% tax rate is unlikely to inspire an EOR investment in the UKCS, but 0.35 under the 62% tax rate just might trigger it. The graphical representations of the probability distributions of the NPV in the respective Low- and CPF- Price scenarios are presented below in Figures 1 to 4.

Figure 1: Alba: Low price scenario: Probability distribution of the NPV (pre-tax)

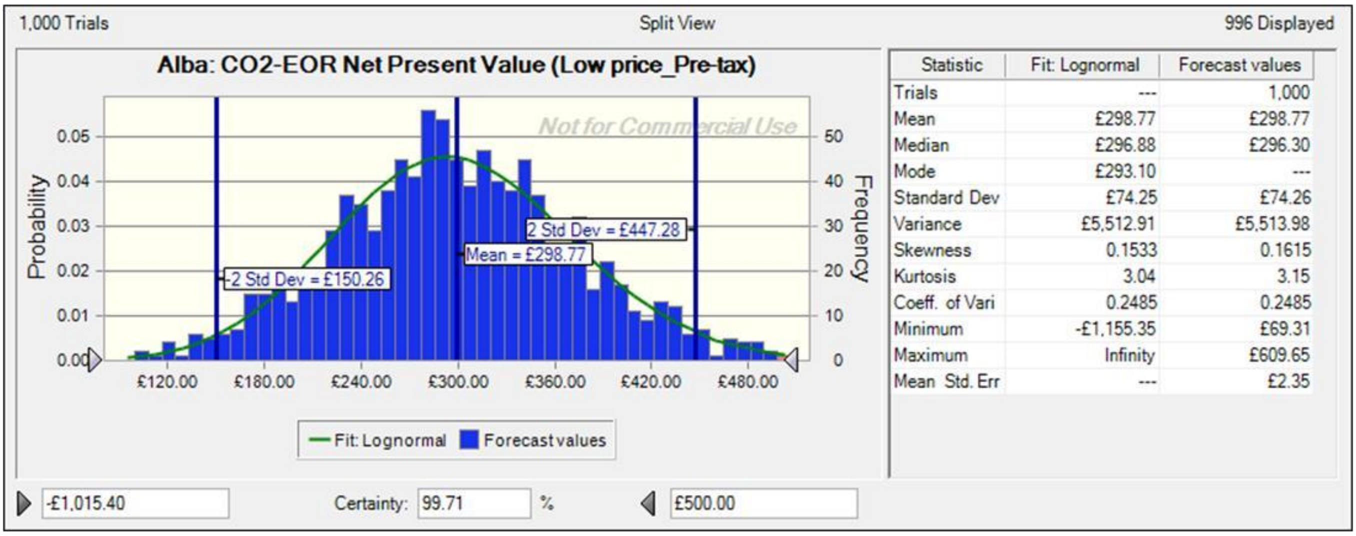


Figure 2: Alba: Low price scenario: Probability distribution of the NPV (81% tax rate)

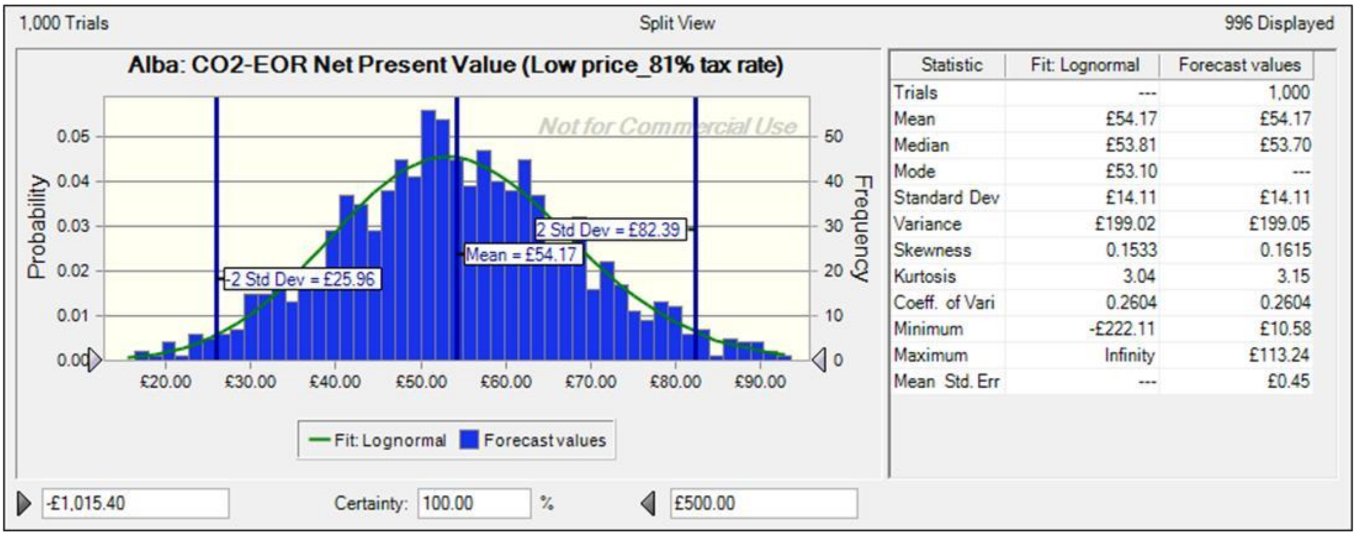


Figure 3: Alba: Low price scenario: Probability distribution of NPV (62% tax rate)

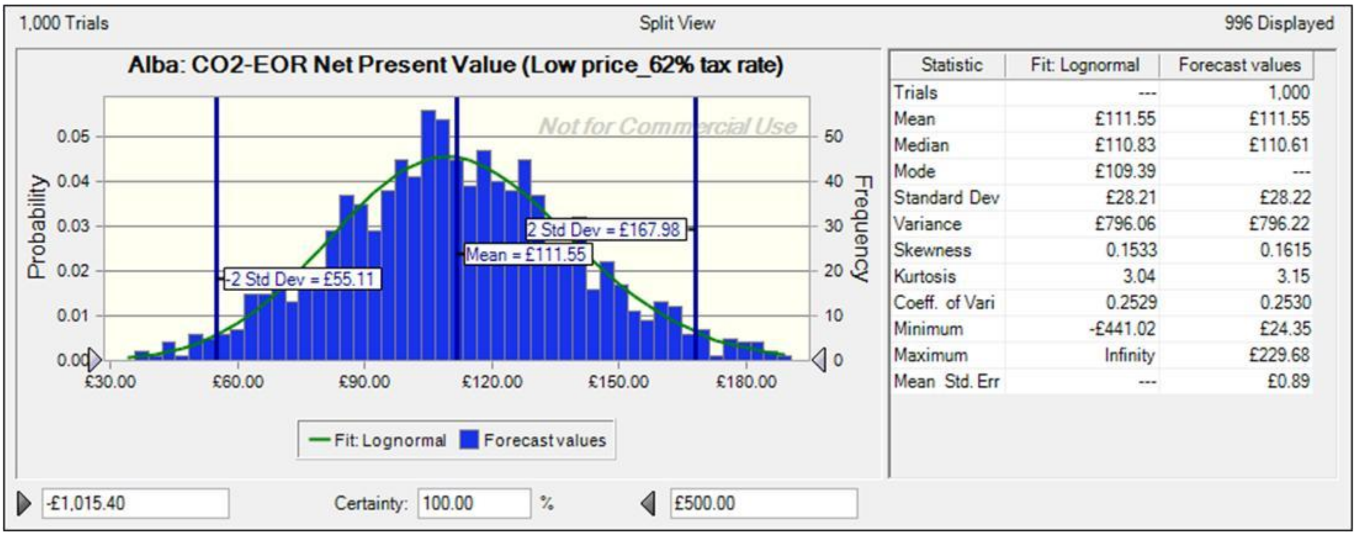
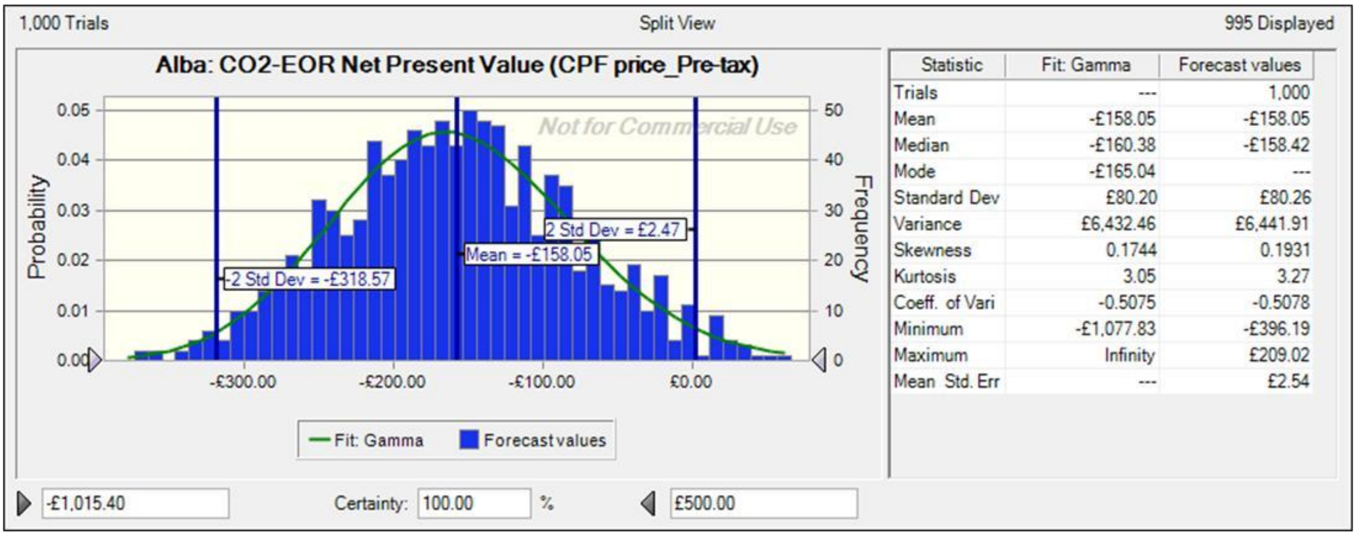


Figure 4: Alba: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 1 - 4 reveal that assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the NPV in the Low Price scenarios would be in the range of £40 million to £273 million, while it would range from a loss-making -£238 million to -£78 million under CPF pricing. There is a 95% chance that the NPV would range -£319 million to £2 million under CPF pricing and between £26 million and £447 million in the Low Price scenarios. Overall, the introduction of the CPF prices is seen to lead not only to a negative mean NPV but, also, higher investment risks, as indicated by the higher values of the coefficient of variability.

Since the curve-fitting results show that all the probability distributions are positively skewed (albeit, moderately), and therefore non-normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the lognormal distribution, while that of the CPF pricing it is the gamma distribution. One implication of the log normality of the Low Carbon Price distributions is that most of the (higher) NPV forecast values occur to the left of the distributions' modes, increasing the chances that the modal returns to investment would be attained.

Brae complex

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for the Brae complex are summarised in Table 3 below. The significant differences between and across the model solutions are highlighted.

Table 3: A summary of the model solutions for the Brae complex

	Low CO_2 price scenario			CPF price scenario
	Pre-tax	81% tax	62% tax	Pre-tax
EOR oil (mmbbls) (range 30-54)	32.81	32.81	32.81	34.11
Purchased CO_2 ($MtCO_2$)	14.00	14.00	14.00	14.00
Recycled CO_2 ($MtCO_2$)	51.53	51.53	51.53	51.53
CO2 stored (MtCO2)	10.45	10.45	10.45	10.45
Hydrocarbon gas produced ($MtCO_{2e}$)	2.73	2.73	2.73	2.73
CAPEX (£m)	315.95	315.95	315.95	315.95
CAPEX per barrel (£)	9.63	9.63	9.63	9.26
Carbon price:				
a. Imported CO_2 cost (£/tCO_2)	9.44	9.44	9.44	77.63
b. EU-ETS emission cost (£/tCO_2)	36.27	36.27	36.27	36.51
c. EU-ETS emission cost (€/tCO_2)	41.71	41.71	41.71	41.99
OPEX (£m)	1132.39	1132.39	1132.39	2039.87
OPEX per barrel (£)	34.52	34.52	34.52	59.80
Annual OPEX (£m)	36.53	36.53	36.53	65.80
oil price per barrel (£)	87.77	87.77	87.77	85.66
oil price per barrel ($)	140.43	140.43	140.43	137.06
CO_2 usage (tonne/barrel)	0.52	0.52	0.52	0.53
No. of injector wells	2.00	2.00	2.00	2.00
Mean NPV (£m)	190.18	34.12	70.73	-175.27
Mean IRR (%)	0.15	0.11	0.13	0.06
Discount rate (%)	10.00%	10.00%	10.00%	10.00%
Tax (£m)	0.00	1173.35	898.12	0.00
NPV/I		**0.11**	**0.24**	

The model solutions presented in Table 3 indicate that about 33 mmbbls additional EOR oil could potentially be produced from a cumulative total injection of about 14 $MtCO_2$ of purchased CO_2. The additional EOR oil would extend the field life beyond the business-as-usual date through a combination of higher oil prices and CO_2-EOR technology.

The maximum injection capacity of about 2.50 $MtCO_2$/year from the two wells which the study assumed could be re-used for EOR would be reached by 2026. The volume of the produced hydrocarbon gas would increase to about 0.10 $MtCO_{2e}$/year in 2027, remaining in the range of 0.10-0.14 $MtCO_{2e}$/year. Using the field's estimated 2010 emission per barrel figure of 0.10 tonnes, it is calculated that about 75% of the purchased CO_2 would be stored at the Brae complex. The central value of the calculated total CAPEX in both the Low and CPF price scenarios is £316 million and, the per barrel CAPEX is £10.

While the cumulative OPEX is the same £1.13 billion in the three Low Price scenarios, at £2.04 billion it is substantially higher in the CPF Price scenario. Also, while the annual OPEX is £36.53 million in the Low price scenarios it is higher at £65.80 million in the CPF Price scenario. While the average price of the imported CO_2 is calculated to be £9.44/tCO_2 in the Low Price case, it is £77.63/tCO_2 with CPF pricing.

In the Low Price simulations, the mean NPV is highest at about £190 million under the pre-tax assumptions and £34 million under the 81% tax rate. The simulation runs with the lower 62% tax rate yield a mean NPV of about £71 million. Ordinarily, the positive mean NPVs in the Low Price scenarios would argue for the EOR investment while the negative mean NPV of the CPF pricing scenario of -£175 million argue against it. However, under the more rigorous investment profitability criteria of the NPV/I ratio, the likelihood of the CO_2-EOR investment not being undertaken is reinforced by the low ratios of 0.11 and 0.24 at the 81% and 62% tax rates. The graphical representations of the probability distributions of the NPV in the Low and CPF price scenarios are presented below in Figures 5 - 8. The importance of the CO_2 prices in determining the results is very clear.

Figure 5: Brae: Low price scenario: Probability distribution of the NPV (pre-tax)

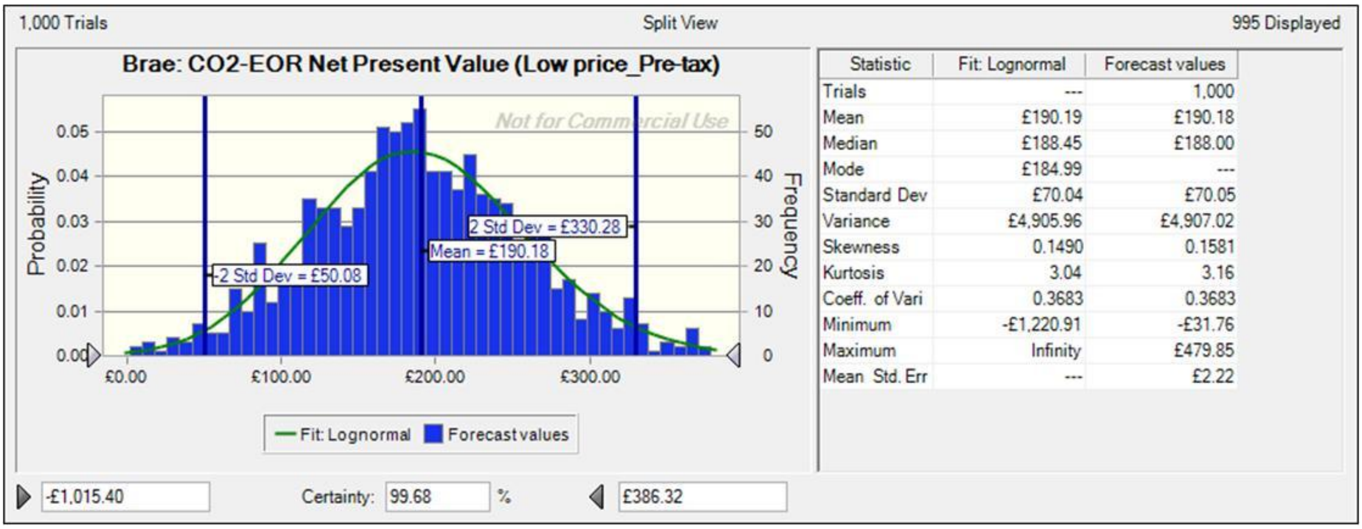


Figure 6: Brae: Low price scenario: Probability distribution of the NPV (81% tax rate)

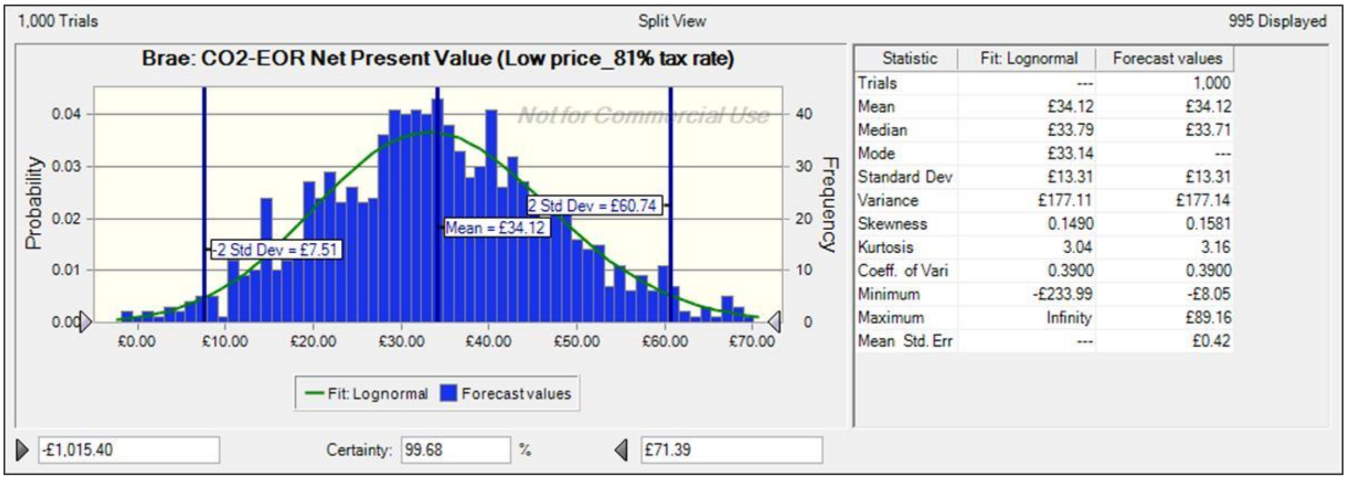


Figure 7: Brae: Low price scenario: Probability distribution of NPV (62% tax rate)

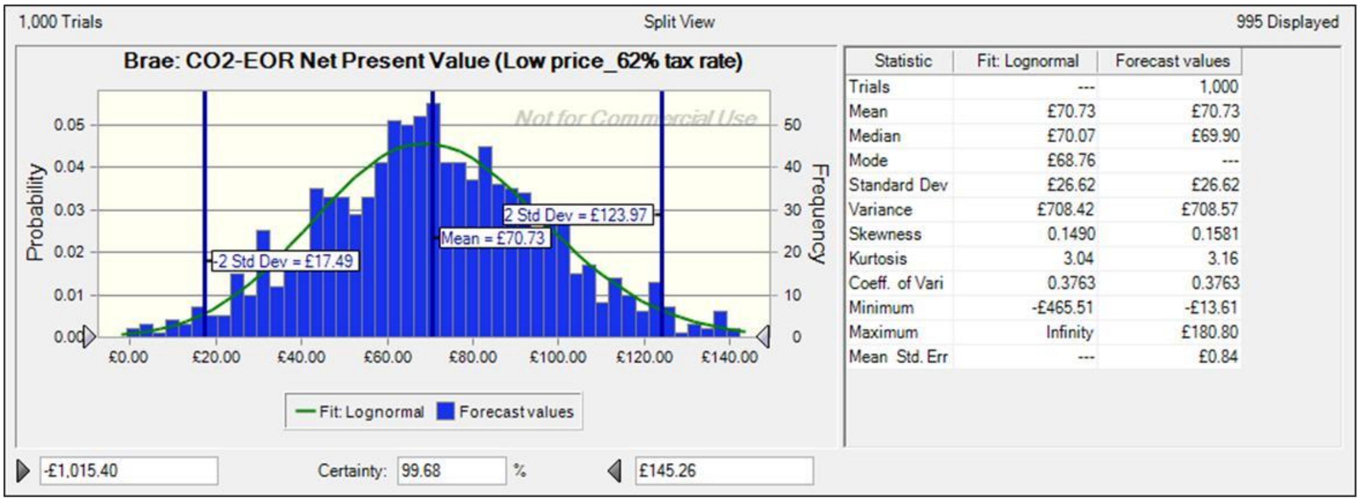
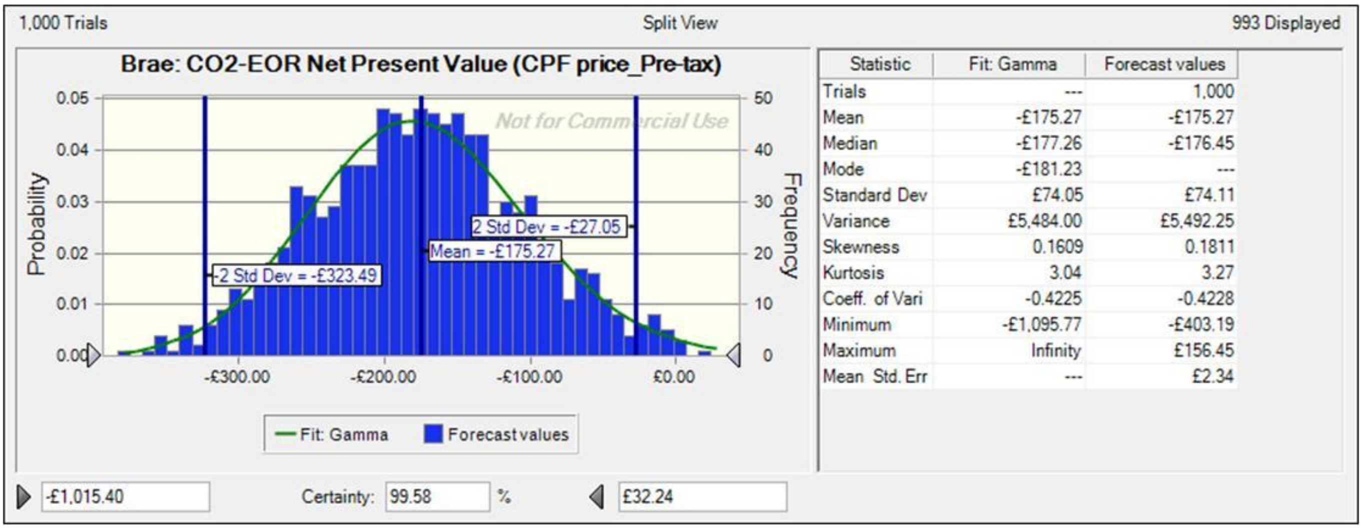


Figure 8: Brae: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 5 - 8 reveal that assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the NPV in the Low Price scenarios would be in the range of £21 million to £260 million, while it would range from a loss-making -£249 million to -£101 million under the CPF pricing. There is a 95% chance that the NPV would range from -£323 million to -£27 million under the CPF pricing and between £8 million and £330 million in the Low Price scenarios. Overall the introduction of the CPF prices is seen to lead not only to a negative mean NPV but, also, higher investment risks, as indicated by the higher value of the coefficient of variability.

The curve-fitting results show that all the probability distributions are positively skewed (albeit, moderately), and therefore non-normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the lognormal distribution, while that of the CPF pricing is the gamma distribution. One implication of the log normality of the Low Carbon Price distributions is that most of the (higher) NPV forecast values occur to the left of the modes, increasing the chances that the modal returns to investment would be attained.

Buzzard

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for Buzzard are summarised in Table 4 below. The significant differences between and across the model solutions are in highlights.

Table 4: A summary of the model solutions for Buzzard

		Low CO_2 price scenario		CPF price scenario
	SCCS	Pre-tax	62% tax	Pre-tax
EOR oil (mmbbls) (range 80-145)	79 - 111	93.82	93.82	91.69
Purchased CO_2 ($MtCO_2$)	46.00	38.50	38.50	38.50
Recycled CO_2 ($MtCO_2$)	na	141.65	141.65	141.65
CO2 stored (MtCO2)	na	38.47	38.47	38.47
Hydrocarbon gas produced ($MtCO_{2e}$)	na	6.92	6.92	6.92
CAPEX (£m)	700.00	862.05	862.05	862.05
CAPEX per barrel (£)	6.63 - 8.86	9.19	9.19	9.40
Carbon price:				
a. Imported CO_2 cost (£/tCO_2)	0.00	9.55	9.55	76.97
b. EU-ETS emission cost (£/tCO_2)	na	36.42	36.42	36.08
c. EU-ETS emission cost (€/tCO_2)	na	41.88	41.88	41.49
OPEX (£m)	1485.00	1759.56	1759.56	4346.61
OPEX per barrel (£)	12.16 - 17.09	18.76	18.76	47.40
Annual OPEX (£m)	55.00	56.76	56.76	140.21
oil price per barrel (£)	50	97.15	97.15	97.15
oil price per barrel ($)	70	155.44	155.44	155.44
CO_2 usage (tonne/barrel)	0.41 - 0.48	0.52	0.52	0.51
No. of injector wells	na	5.50	5.50	5.50
Mean NPV (£m)	na	1018.67	382.89	-30.93
Mean IRR (%)	10	0.20	0.17	0.09
Discount rate (%)	3.5	10.00%	10.00%	10.00%
Tax (£m)	na	0.00	3377.34	0.00
NPV/I			**0.51**	

The model solutions presented in Table 4 indicate that about 94 mmbbls additional EOR oil could potentially be produced from a cumulative total injection of about 39 $MtCO_2$ of purchased CO_2. The additional EOR oil would contribute substantially to the business-as-usual oil and extend the field life.

The assumed maximum injection capacity of about 7 $MtCO_2$/year from the field's five injection wells would be reached in 2025. The volume of the produced hydrocarbon gas would increase significantly for the first time in 2026 to about 0.19 $MtCO_{2e}$/year. Thereafter, the produced gas would remain in the range of 0.23 $MtCO_{2e}$/year and 0.33 $MtCO_{2e}$/year. Cumulatively, about 6.92 $MtCO_{2e}$ of hydrocarbon gas would be produced. Using the field's current very low CO2 emissions per barrel of oil produced, it is calculated that about 99% of the purchased CO_2 would be stored. The central value of the calculated total CAPEX in both the Low and CPF Price scenarios is £862 million and, the per barrel CAPEX is about £9.

The cumulative OPEX is £1.76 billion in the three Low Price scenarios and £4.35 billion in the CPF Price scenario. The annual OPEX is £56.76 million in the Low Price scenarios and £140.21 million in the CPF price scenario. While the average price of the imported CO_2 is calculated to be £9.55/tCO_2 in the Low price case, it is £76.97/tCO_2 under CPF pricing.

In the Low Price scenarios the mean NPV is £1.02 billion under the pre-tax assumptions and £382.89 million under the 62% tax rate. The positive post-tax mean NPV in the Low Price scenarios would argue for an EOR investment while the negative pre-tax mean NPV of the CPF pricing scenario of about -£30.93 million would argue against it. A further scrutiny of the CO_2-EOR investment under the NPV/I profitability index would not reject the investment under the Low Price case. The ratio of 0.51 is likely to be acceptable.

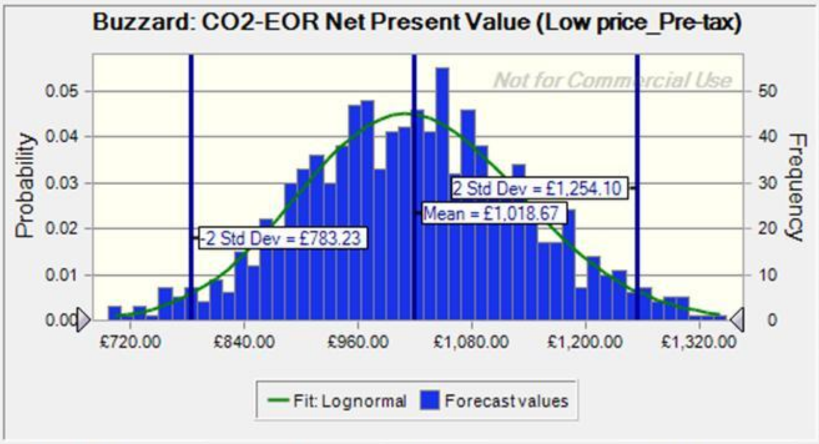
An attempt was made to compare the study's model solutions with those of a similar study carried out by the SCCS (2010). The main similarity between the two studies lies in the assumption that the Buzzard EOR project is developed as part of a cluster sharing common infrastructure and risks. However, there are important differences. Firstly, the present study is on a larger scale in which nine EOR fields are considered in three clusters while the SCCS study considered three fields (Buzzard, Claymore and Scott) in one cluster. Secondly, and perhaps more importantly, the SCCS study assumed the price of the imported CO_2 to be zero while the present study assumed low but positive carbon prices. Thirdly, the oil price assumptions for the period (2020-2050) are very different, with those in the present study averaging more than double those in the SCCS one. Fourthly, the SCCS study is deterministic while the model in the present study is stochastic. The SCCS results are presented in the first column in Table 4.

The predicted volume of EOR oil in the present study (94 mmbbls) lies within the 79 mmbbls - 111 mmbbls range of the SCCS study. However, some of the assumptions underlying the SCCS production and some other results were not clear, making it difficult to understand the precise basis of any convergence or divergence of the results. Thus the SCCS study does not explicitly state the number of injectors in its analysis. This number is important to an understanding of the basis of any convergence/divergence of the results regarding the project CAPEX and production. That notwithstanding, the closeness of the results in certain respects is noteworthy. For instance, the SCCS study's imported CO_2 is higher but by less than 20%. The present study's CAPEX of about £862 million is about 23% higher than that of the SCCS one. An explanation for the higher total and average CAPEX lies in the present study's relative conservatism regarding the range of the EOR yield per tonne of injected CO_2. Thus, at 0.52 tonne/barrel the present study's CO_2 usage is beyond the 0.41 tonne/barrel - 0.48 tonne/barrel range of the SCCS study.

This study's Low Price scenario aggregate OPEX of £1.76 billion is about 19% higher than that in the SCCS study. However, it would be recalled that the price of the imported CO_2, which is an important component of OPEX, is assumed to be zero in the SCCS study. Nevertheless, the present study's corresponding OPEX per barrel of £18.76 is only slightly beyond the £12.16 to £17.09 range in the SCCS study.

The graphical representations of the probability distributions of the NPV in the respective Low- and CPF- Price scenarios are presented below in Figures 9 – 11.

Figure 9: Buzzard: Low price scenario: Probability distribution of the NPV (pre-tax)



Statistic	Fit: Lognormal	Forecast values
Trials	---	1,000
Mean	£1,018.67	£1,018.67
Median	£1,016.05	£1,019.06
Mode	£1,010.82	---
Standard Dev	£117.72	£117.72
Variance	£13,858.57	£13,857.58
Skewness	0.1338	0.1307
Kurtosis	3.03	3.00
Coeff. of Vari	0.1156	0.1156
Minimum	-£1,622.17	£696.24
Maximum	Infinity	£1,484.93
Mean Std. Err	---	£3.72

Figure 10: Buzzard: Low price scenario: Probability distribution of NPV (62% tax rate)

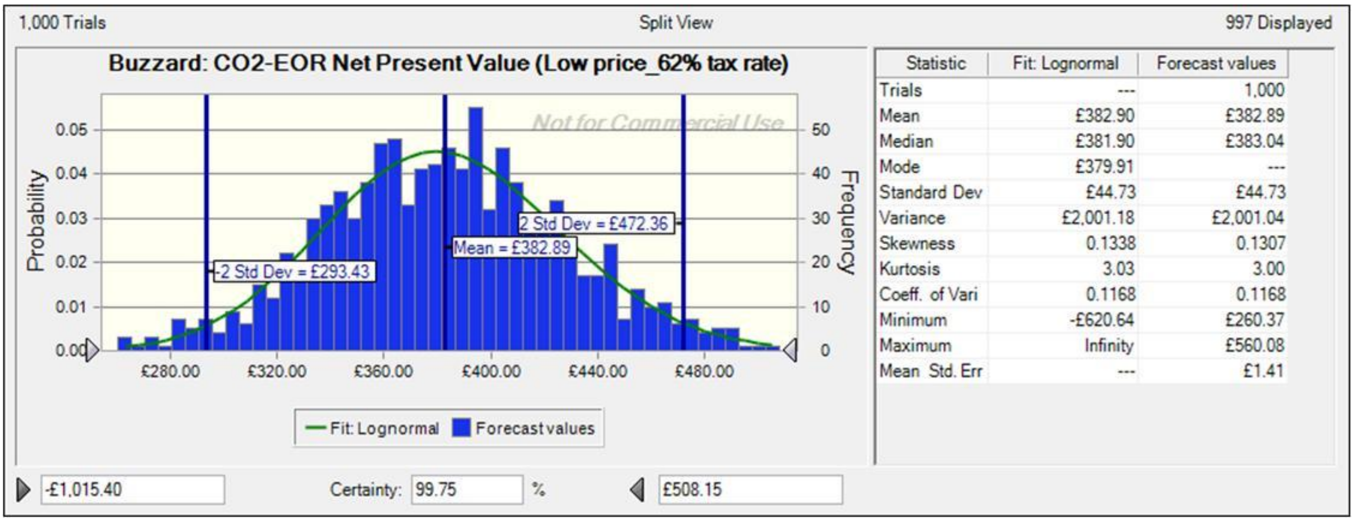
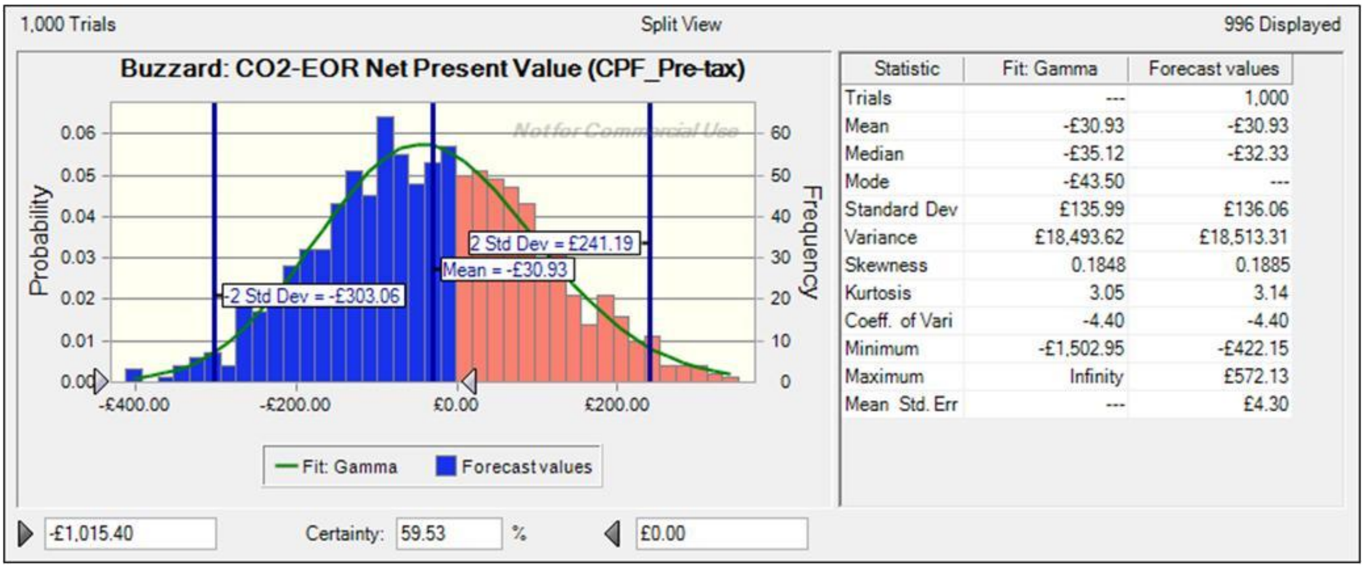


Figure 11: Buzzard: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 9 – 11 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £338 million to £1 billion, while it would range from a loss-making -£167 million to a positive NPV of £105 million under the CPF pricing. There is a 95% chance that the NPV would range from -£303 million to -£31 million under the CPF pricing and between £293 million and £1.3 billion in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but to higher investment risks, as indicated by the higher value of the coefficient of variability.

However, since the curve-fitting results show that all the probability distributions are positively skewed (albeit, moderately), and therefore non-normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the lognormal distribution, while that of the CPF pricing is the gamma distribution.

Claymore

The results of the Monte Carlos simulations under the Low and CPF Carbon Price scenarios for the Claymore field are summarised in Table 5 below. The significant differences between and across the model solutions are in highlights.

Table 5: A summary of the model solutions for the Claymore field

		Low CO_2 price scenario			CPF price scenario
	SCCS	**Pre-tax**	**81% tax**	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 64-107)	119 - 163	68.94	68.94	68.94	68.58
Purchased CO_2 ($MtCO_2$)	49.40	28.00	28.00	28.00	28.00
Recycled CO_2 ($MtCO_2$)	151.50	103.02	103.02	103.02	103.02
CO2 stored (MtCO2)	49.20	21.54	21.54	21.54	21.54
Hydrocarbon gas produced ($MtCO_{2e}$)		5.40	5.40	5.40	5.40
CAPEX (£m)	1100 - 1200	719.30	719.30	719.30	719.30
CAPEX per barrel (£)	7.36 - 9.24	10.43	10.43	10.43	10.49
Carbon price:					
a. Imported CO_2 cost (£/tCO_2)		9.31	9.31	9.31	75.04
b. EU-ETS emission cost (£/tCO_2)		36.54	36.54	36.54	36.46
c. EU-ETS emission cost (€/tCO_2)		42.03	42.03	42.03	41.93
OPEX (£m)	2430.00	1838.09	1838.09	1838.09	3336.02
OPEX per barrel (£)	14.91 - 20.19	26.66	26.66	26.66	48.65
Annual OPEX (£m)	90.00	59.29	59.29	59.29	107.61
oil price per barrel (£)	50	88.56	88.56	88.56	84.28
oil price per barrel ($)	70	141.70	141.70	141.70	134.85
CO_2 usage (tonne/barrel)	0.30 - 0.41	0.53	0.53	0.53	0.52
No. of injector wells	na	4.00	4.00	4.00	4.00
Mean NPV (£m)	206 - 703	569.40	103.61	212.87	-19.33
Mean IRR (%)	na	0.16	0.12	0.14	0.10
Discount rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%
Tax (£m)	na	0.00	3324.22	2544.47	0.00
NPV/I			**0.16**	**0.33**	

The model solutions presented in Table 5 indicate that about 69 mmbbls EOR could be produced from a cumulative total injection of about 28 $MtCO_2$ of purchased CO_2. The additional EOR oil would extend the field life beyond the business-as-usual COP date. Cumulatively, about 5.40 $MtCO_{2e}$ of hydrocarbon gas would be produced. Based on the field's estimated 2010 emissions per barrel of oil produced figure of 0.09 tonnes, the stored CO_2 is 77% of the purchased CO_2. The central value of the calculated total CAPEX is £719 million and, the per barrel CAPEX is £10.

The cumulative OPEX is £1.84 billion in the three Low Price scenarios but £3.34 billion in the CPF price scenario. While the annual OPEX is £59.29 million in the Low Price scenarios it is £107.61 million in the CPF price scenario. The average price of the imported CO_2 is calculated to be £9.31/tCO_2 in the Low Price case, and, £75.04/tCO_2 under CPF pricing.

In the Low Price case the mean NPV is £569.40 million pre-tax and £103.61 million under the 81% tax rate. Ordinarily, the positive post-tax mean NPV in the Low Price scenarios would argue for an EOR investment while the negative pre-tax mean NPV of the CPF pricing scenario of -£19.33 million would argue against it. A further scrutiny of the CO_2-EOR investment under the NPV/I ratio shows that while at 0.16 the investment under the Low Price case seems unattractive at the applicable (81%) tax rate, the higher 0.33 ratio in the 62% tax rate scenario may be acceptable.

The study's model solutions were compared with those in SCCS (2010) which are reproduced in the first column of Table 5.

The predicted 69 mmbbls volume of EOR oil in the present study falls short of the 119mmbbls to 163 mmbbls of the SCCS study. The present study has lower volumes of purchased and recycled CO_2. Both the CAPEX and OPEX in the SCCS study are higher than those in the present study. However, both the per barrel CAPEX and OPEX of the present study are higher than those in the SCCS study. The lower per barrel CAPEX and OPEX in the SCCS study appear to be based on an assumed higher level of operational efficiency. The CO_2 yield factors are higher in the SCCS study being in the range of 2.44 to 3.33 barrels of EOR oil per tonne of CO_2 injected against the calculated 1.89 barrels in the present study.

The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 12-15.

Figure 12: Claymore: Low price scenario: Probability distribution of NPV (pre-tax)

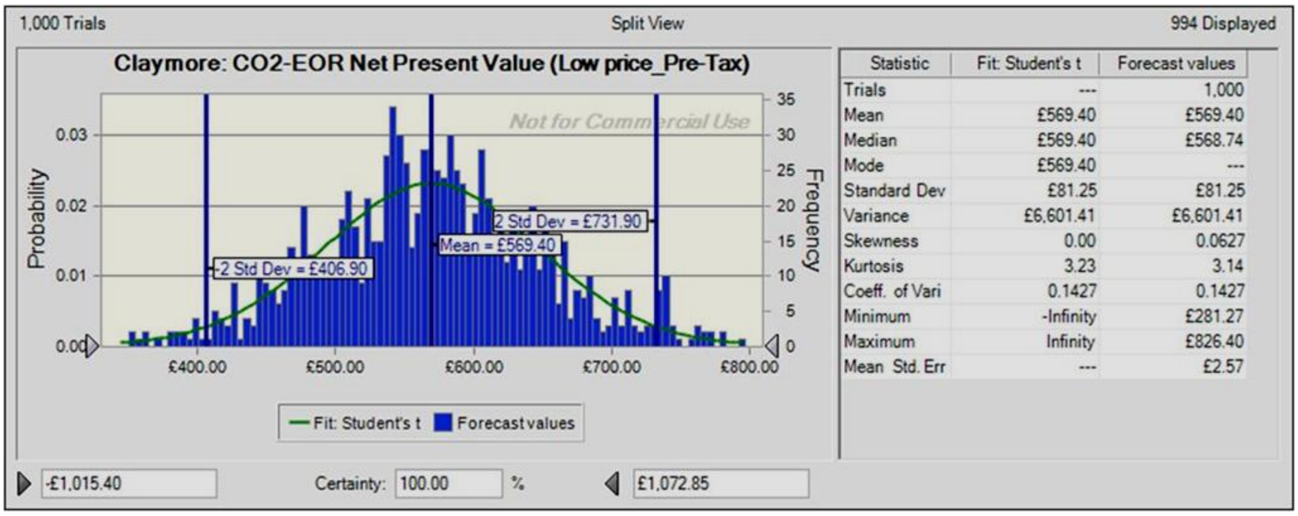


Figure 13: Claymore: Low price scenario: Probability distribution of NPV (81% tax rate)

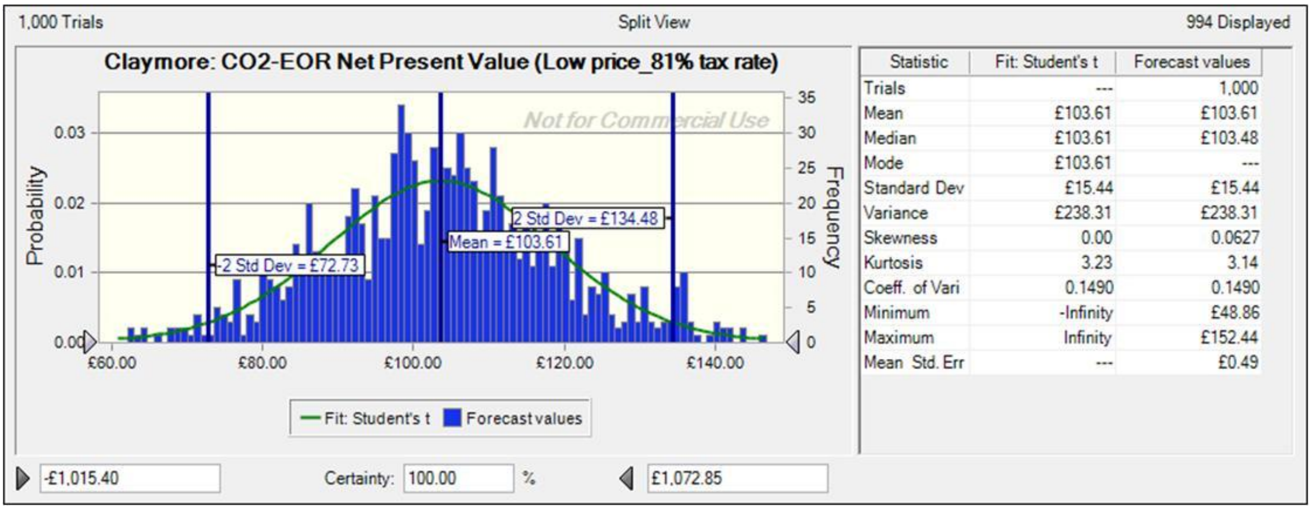


Figure 14: Claymore: Low price scenario: Probability distribution of NPV (62% tax rate)

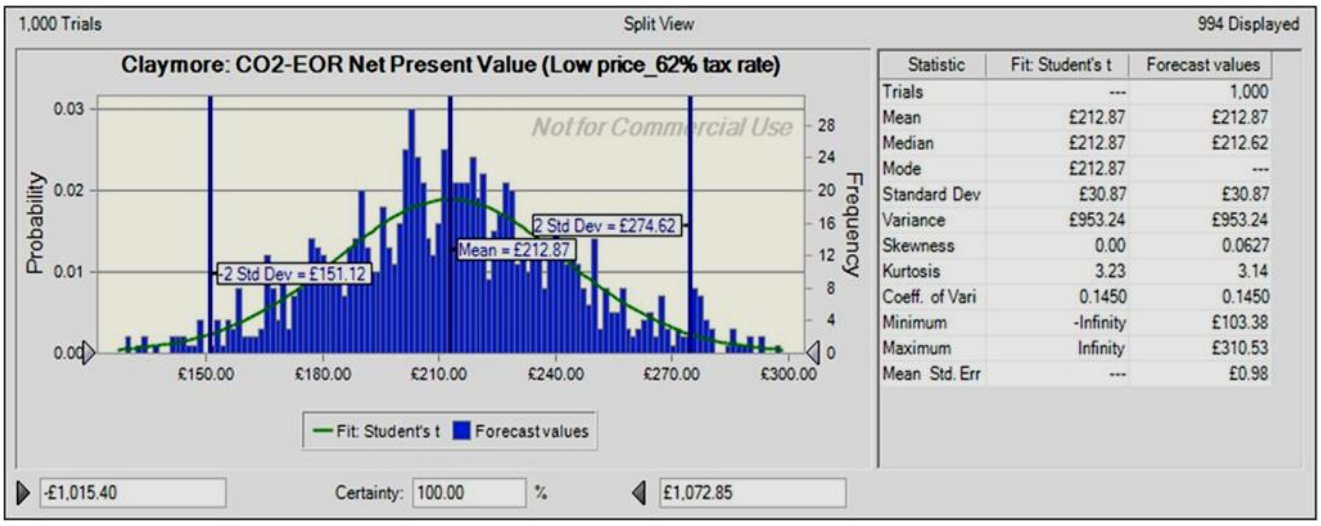
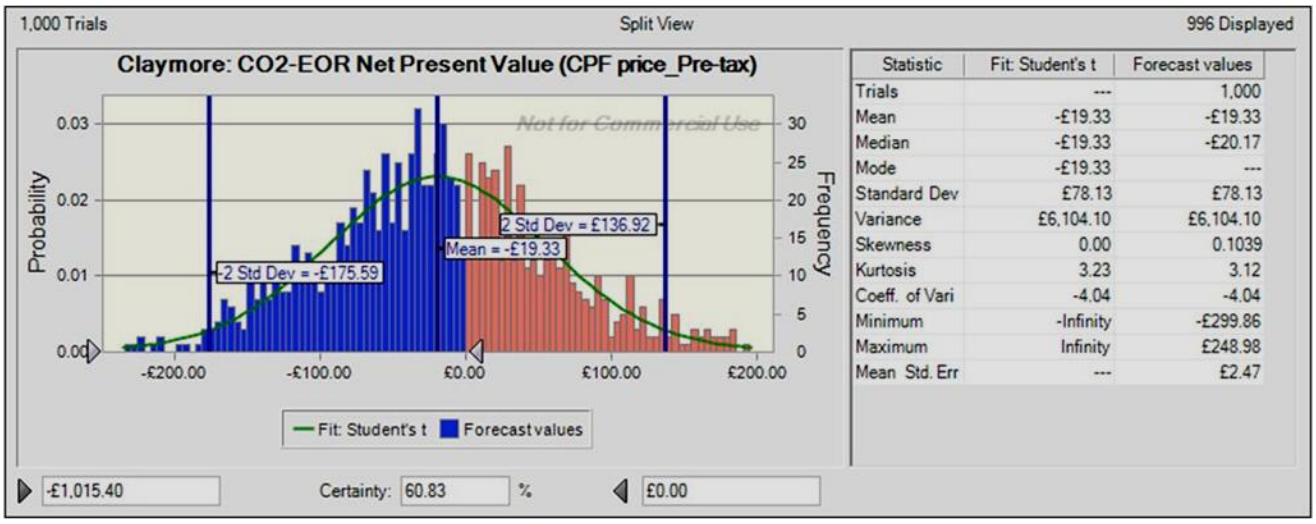


Figure 15: Claymore: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 12 – 15 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £88 million to £651 million, while it would range from a loss-making -£97 million to a positive NPV of £59 million under the CPF pricing. There is a 95% chance that the NPV would range from -£176 million to £137 million under CPF pricing and between £73 million and £407 million in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but also to higher investment risks, as indicated by the higher value of the coefficient of variability.

Since the curve-fitting results show that all the probability distributions are positively skewed (albeit, moderately), and therefore non-normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under both the Low Price and CPF pricing scenarios is the student's t distribution, which more closely resembles the normal probability distribution especially regarding the symmetry of the forecast NPV values around their mean.

Forties

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for the Forties field are summarised in Table 6 below. The significant differences across the model solutions are in highlights.

Table 6: A summary of the model solutions for the Forties field

	Low CO_2 price scenario			CPF price scenario
	Pre-tax	**81% tax**	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 177-295)	188.70	188.70	188.70	186.34
Purchased CO_2 ($MtCO_2$)	77.00	77.00	77.00	77.00
Recycled CO_2 ($MtCO_2$)	283.27	283.27	283.27	283.27
CO2 stored (MtCO2)	77.00	77.00	77.00	77.00
Hydrocarbon gas produced ($MtCO_{2e}$)	14.00	14.00	14.00	14.00
CAPEX (£m)	1624.00	1624.00	1624.00	1624.00
CAPEX per barrel (£)	8.61	8.61	8.61	8.72
Carbon price:				
a. Imported CO_2 cost (£/tCO_2)	8.45	8.45	8.45	67.80
b. EU-ETS emission cost (£/tCO_2)	36.61	37.00	36.64	36.00
c. EU-ETS emission cost (€/tCO_2)	42.10	42.00	42.14	41.00
OPEX (£m)	5287.63	5287.63	5287.63	10099.41
OPEX per barrel (£)	28.02	28.02	28.02	54.20
Annual OPEX (£m)	170.57	170.57	170.57	325.79
oil price per barrel (£)	83.41	83.00	83.41	86.00
oil price per barrel ($)	133.46	133.00	133.46	137.00
CO_2 usage (tonne/barrel)	0.52	0.52	0.52	0.53
No. of injector wells	11.00	11	11.00	11
Mean NPV (£m)	1284.79	233.78	480.31	-725.68
Mean IRR (%)	16.29	11.78	0.14	6.68
Discount rate (%)	10.00%	10.00%	10.00%	10.00%
Tax (£m)	0.00	7153.7	5475.67	0
NPV/I		**0.15**	**0.32**	

The model solutions presented in Table 6 indicate that about 189 mmbbls additional EOR oil could potentially be produced from a cumulative total injection of about 77 $MtCO_2$ of purchased CO_2. The additional EOR oil would extend the field life beyond the business-as-usual COP date. Cumulatively, about 14.0 $MtCO_{2e}$ of hydrocarbon gas would be produced. Based on the field's estimated 2010 emissions per barrel of oil produced figure of virtually zero, the stored CO_2 is almost 100% of the purchased CO_2. The central value of the calculated total CAPEX in both the Low and CPF Price scenarios is £1.62 billion and, the per barrel CAPEX is about £9. While the cumulative OPEX is £5.29 billion in the three Low Price scenarios, it is virtually double at £10.10 billion in the CPF scenario. Also, while the annual OPEX is £170.57 million in the Low price scenarios it is much higher at £325.79 million in the CPF price scenario. While the average price of the imported CO_2 is calculated to be £8.45/tCO_2 in the Low Price case, it is £67.80/tCO_2 under CPF pricing.

In the Low Price scenario simulations the mean NPV is £1.28 billion under the pre-tax assumptions and £233.78 million under the applicable 81% tax rate. Ordinarily, the positive post-tax mean NPV in the Low Price scenarios would argue for an EOR investment while the negative pre-tax mean NPV of the CPF pricing scenario of -£725.68 million would argue against it. A further scrutiny of the CO_2-EOR investment under the NPV/I ratio shows that, while at 0.15 the investment seems unattractive at the applicable 81% tax rate under the Low Price case, the higher 0.32 ratio in the 62% tax rate scenario might be acceptable to some investors. The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 16-19.

Figure 16: Forties: Low price scenario: Probability distribution of the NPV (pre-tax)

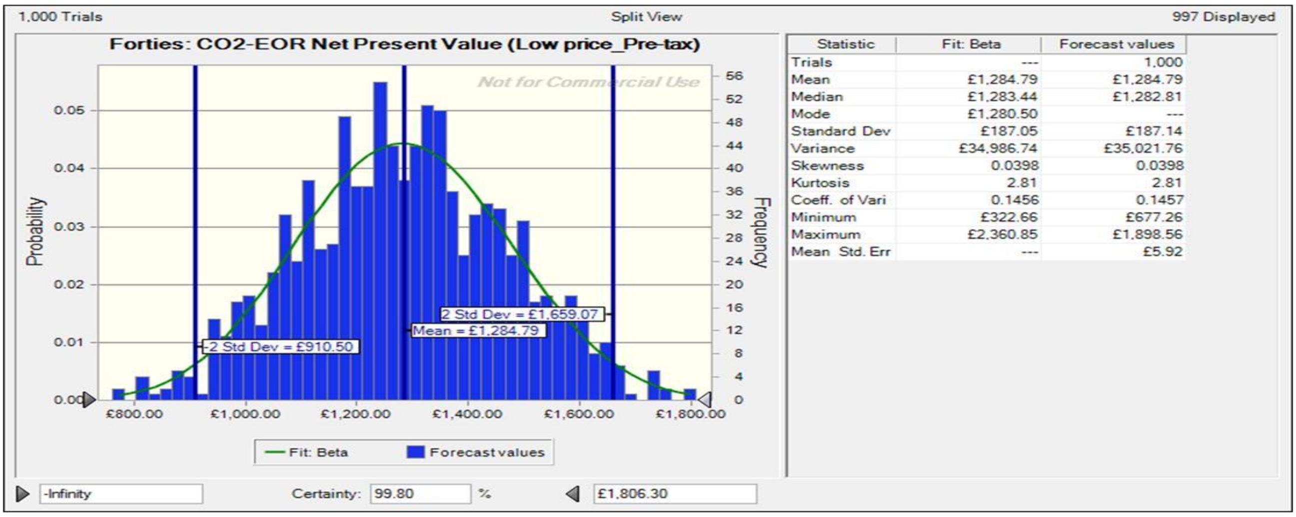


Figure 17: Forties: Low price scenario: Probability distribution of NPV (81% tax rate)

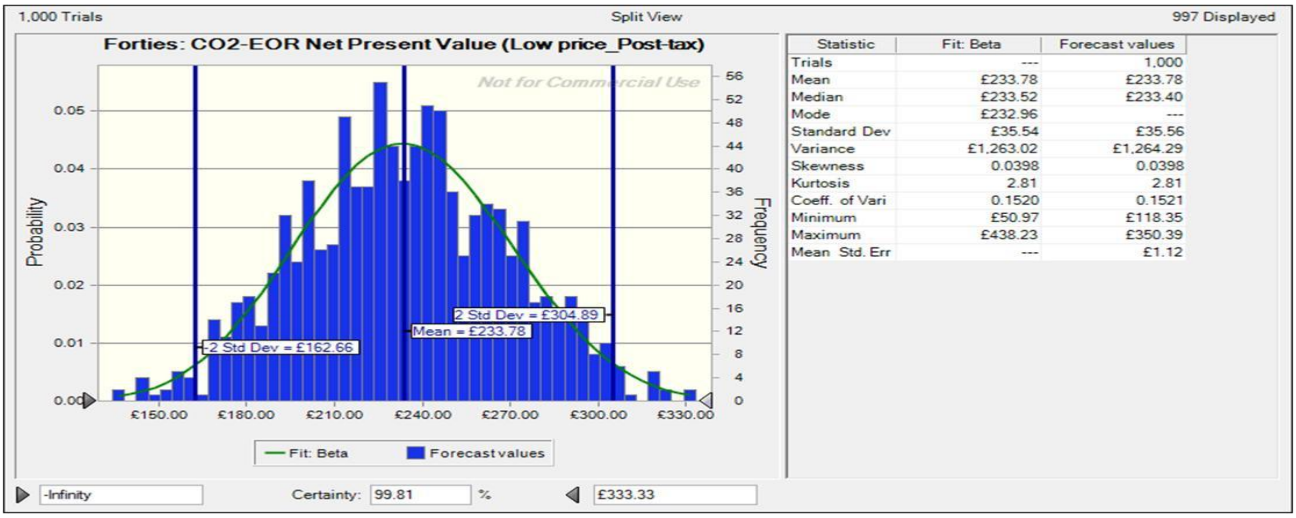


Figure 18: Forties: Low price scenario: Probability distribution of NPV (62% tax rate)

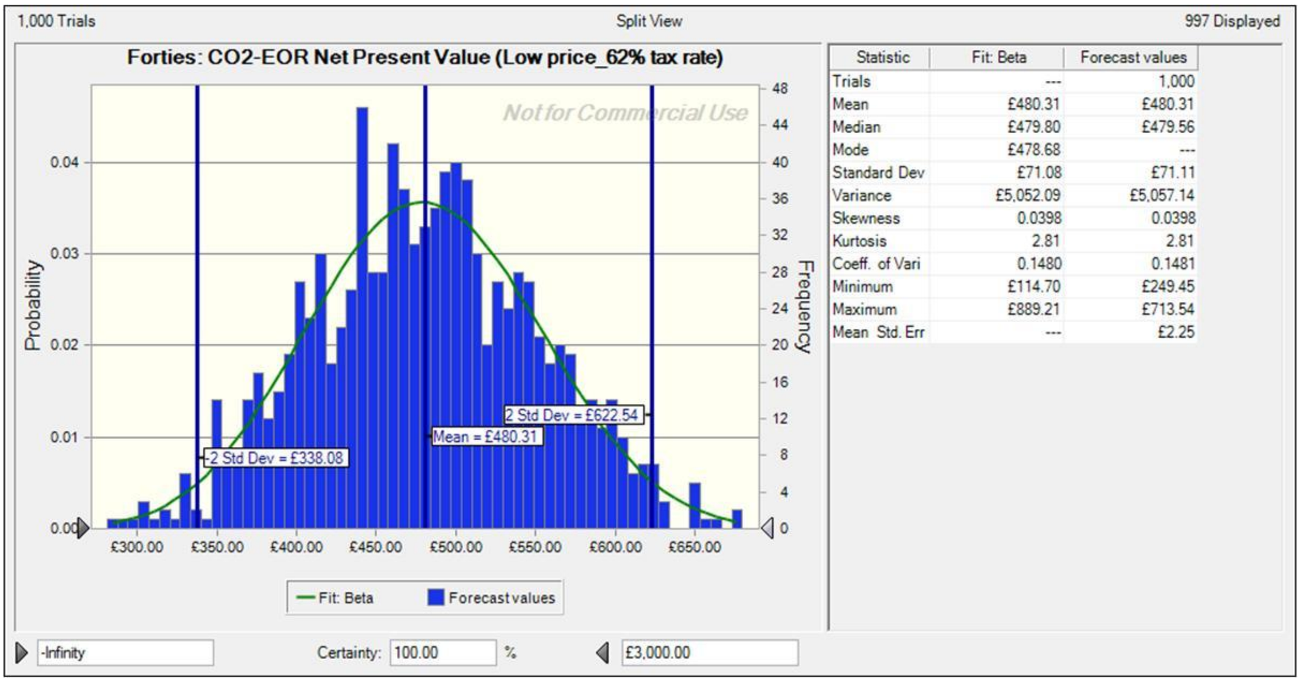
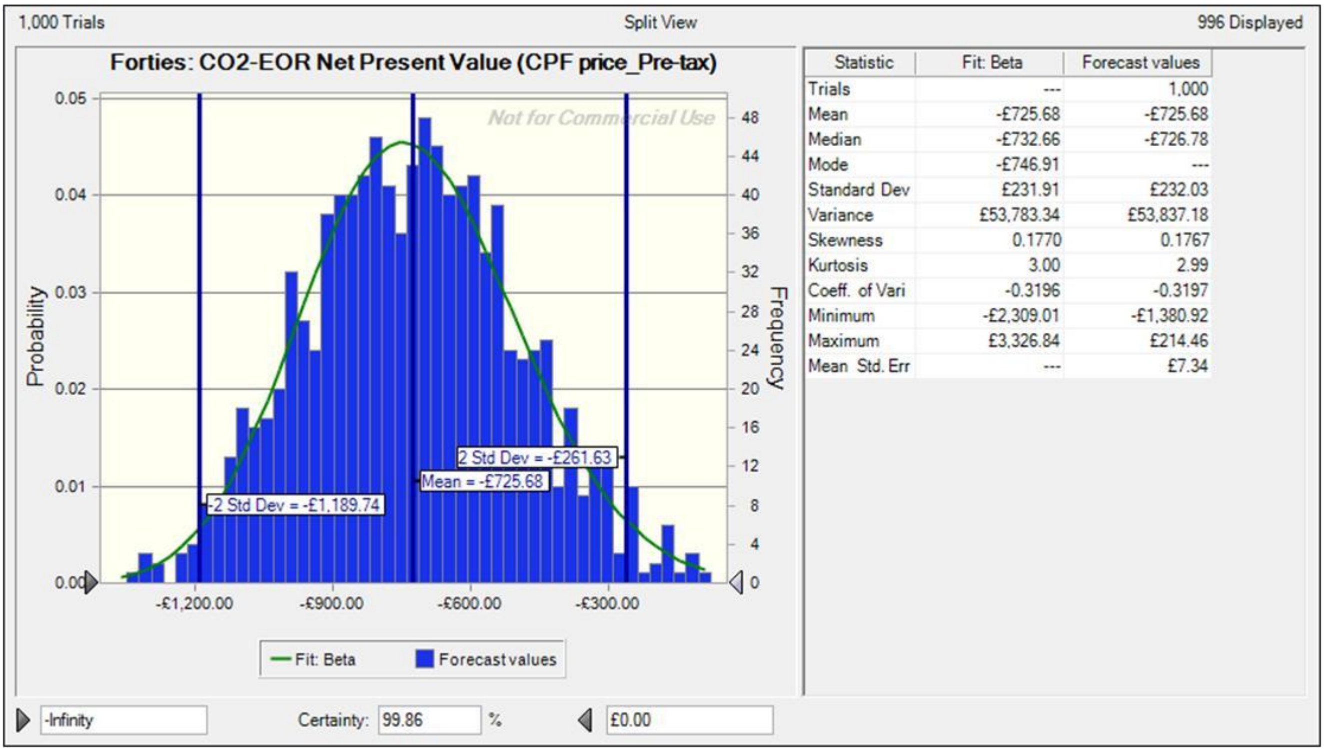


Figure 19: Forties: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 16 – 19 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £198 million to £1.5 billion, while it would range from a loss-making -£958 million to -£494 million under the CPF pricing. There is a 95% chance that the NPV would range from -£1.2 billion to -£262 million under the CPF pricing and between £163 million and £1.7 billion in the Low Price scenarios. The introduction of CPF prices is seen to lead not only to a negative mean NPV but, also, higher investment risks, as indicated by the higher value of the coefficient of variability.

Since the curve-fitting results show that all the probability distributions are non-normal, the confidence interval results should be interpreted with caution. Unlike the earlier fields considered, the best-fit of the NPV forecast values under both the Low Price and CPF pricing scenarios is the beta distribution, suggesting that the forecast NPV values are constrained to occur within an interval defined by minimum and maximum values (as in a triangular probability distribution).

Miller

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for the Miller field are summarised in Table 7 below. The significant differences across the model solutions are in highlights.

Table 7: A summary of the model solutions for the Miller field

	Low CO_2 price scenario		CPF price scenario
	Pre-tax	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 48-80)	53.07	53.07	53.07
Purchased CO_2 ($MtCO_2$)	21.00	21.00	21.00
Recycled CO_2 ($MtCO_2$)	77.27	77.27	77.27
CO2 stored (MtCO2)	21.00	21.00	21.00
Hydrocarbon gas produced ($MtCO_{2e}$)	4.08	4.08	4.08
CAPEX (£m)	601.32	601.32	601.32
CAPEX per barrel (£)	11.33	11.33	11.62
Carbon price:			
a. Imported CO_2 cost (£/tCO_2)	8.87	8.87	71.72
b. EU-ETS emission cost (£/tCO_2)	36.46	36.46	35.58
c. EU-ETS emission cost (€/tCO_2)	41.92	41.92	40.91
OPEX (£m)	1056.46	1056.46	2485.14
OPEX per barrel (£)	19.91	19.91	48.01
Annual OPEX (£m)	34.08	34.08	80.17
oil price per barrel (£)	84.04	84.04	84.40
oil price per barrel ($)	134.47	134.47	135.03
CO_2 usage (tonne/barrel)	0.53	0.53	0.52
No. of injector wells	3	3	3
Mean NPV (£m)	377.50	140.52	-170.74
Mean IRR (%)	15.74	13.22	0.00
Discount rate (%)	10.00%	10.00%	10.00%
Tax (£m)	0.00	1770.15	0.00
NPV/I		**0.26**	

The model solutions presented in Table 7 indicate that about 53.07 mmbbls additional EOR could potentially be produced from a cumulative total injection of about 21 $MtCO_2$ of purchased CO_2. Cumulatively, about 4.0 $MtCO_{2e}$ of hydrocarbon gas would be produced. Based on the field's estimated 2007 emissions per barrel of oil produced, the stored CO_2 is almost 100% of the purchased CO_2. The central value of the calculated total CAPEX in both the Low and CPF price scenarios is £601.32 million and, the per barrel CAPEX is £11. While the cumulative OPEX is £1.06 billion in the three Low Price scenarios, it is £2.49 billion in the CPF Price scenario. Also, while the annual OPEX is £34.08 million in the Low price scenarios it is £80.17 million in the CPF Price scenario. While the average price of the imported CO_2 is calculated to be £8.87/tCO_2 in the Low Price case, it is £71.72/tCO_2 under CPF pricing.

In the Low Price scenario simulations, the mean NPV is £377.50 million under the pre-tax assumptions and £140.52 million under the 62% tax rate. Ordinarily, the positive post-tax mean NPV in the Low Price scenarios would argue for an EOR investment while the negative pre-tax mean NPV of the CPF pricing scenario of -£170.74 million would argue against it. A further scrutiny of the CO_2-EOR investment under the NPV/I ratio shows that under the Low Price case at 0.26 the investment may be unattractive at the 62% tax rate. The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 20 - 22.

Figure 20: Miller: Low price scenario: Probability distribution of the NPV (pre-tax)

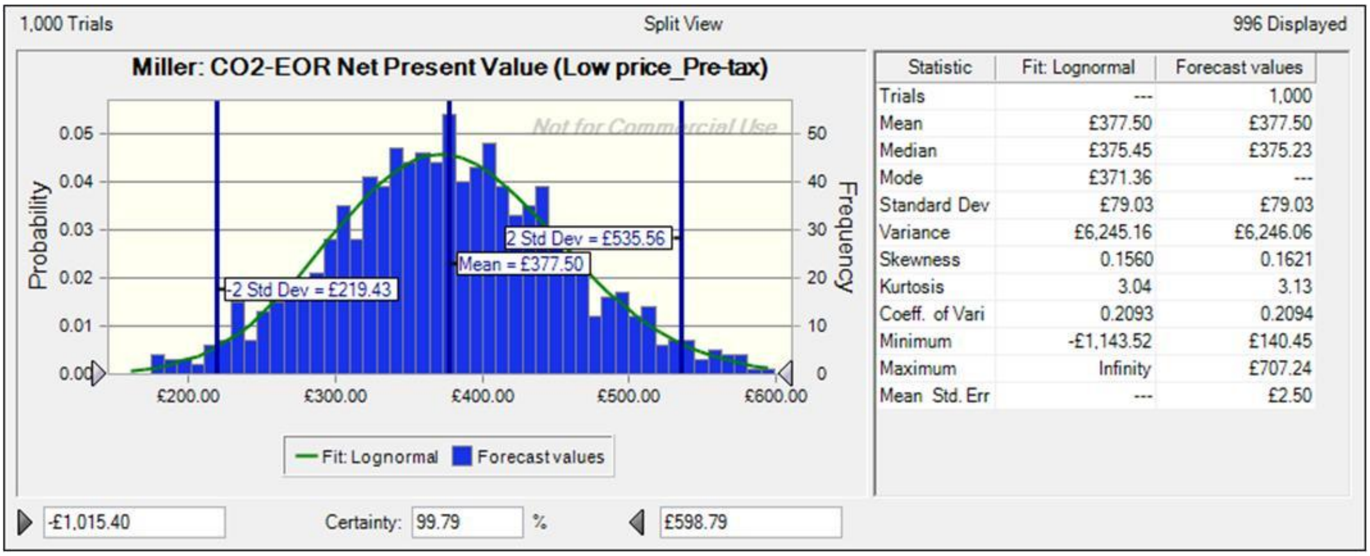


Figure 21: Miller: Low price scenario: Probability distribution of NPV (62% tax rate)

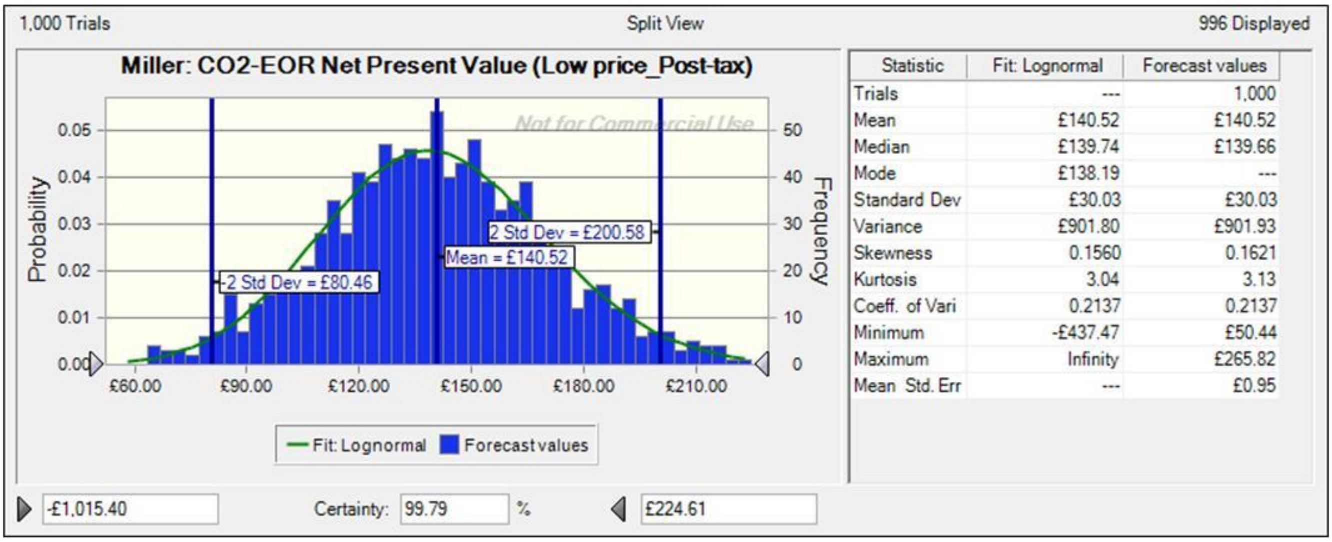
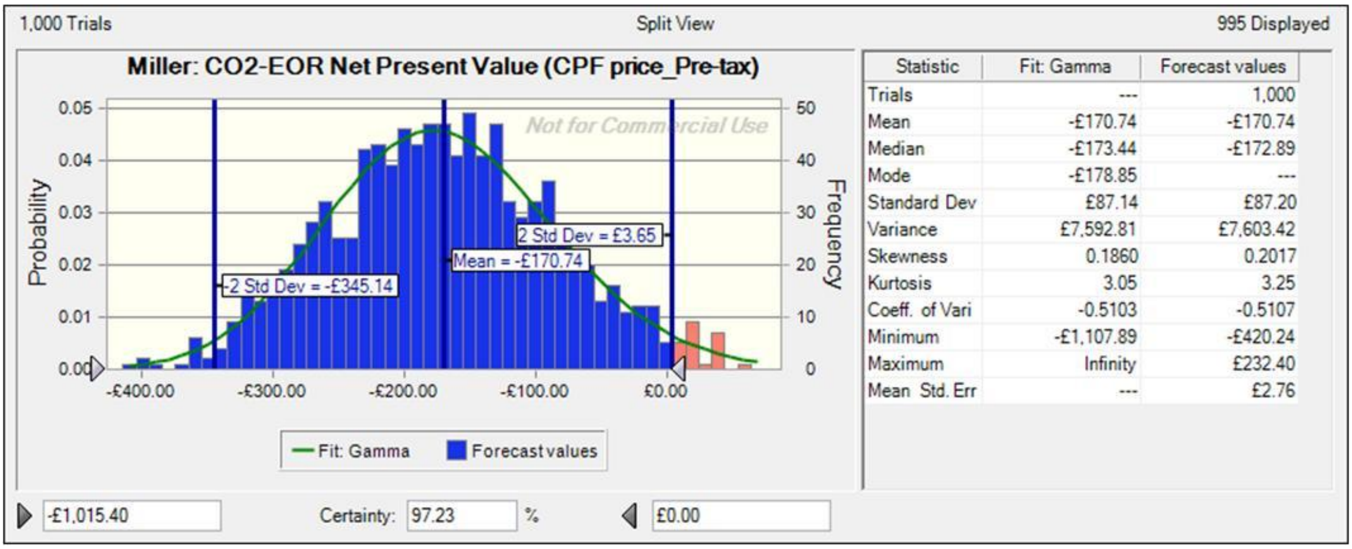


Figure 22: Miller: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 20 – 22 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that NPV in the Low Price scenarios would be in the range of £110 million to £457 million, while it would range from a loss-making -£258 million to -£84 million under the CPF pricing. There is a 95% chance that the NPV would range from -£345 million to a positive NPV of £4 million under the CPF pricing and between £80 million and £536

million in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but to higher investment risks, as indicated by the higher value of the coefficient of variability.
However, since the curve-fitting results show that all the probability distributions are not normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the lognormal distribution, while that of the CPF pricing is the gamma distribution.

Nelson

The results of the Monte Carlo simulations under the Low and CPF scenarios for the Nelson field are summarised in Table 8 below. The significant differences across the model solutions are in highlights.

Table 8: A summary of the model solutions for the Nelson field

	Low CO_2 price scenario			CPF price scenario
	Pre-tax	**81% tax**	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 52-94)	61.82	61.82	61.82	61.82
Purchased CO_2 ($MtCO_2$)	24.50	24.50	24.50	24.50
Recycled CO_2 ($MtCO_2$)	90.15	90.15	90.15	90.15
CO2 stored (MtCO2)	20.11	20.11	20.11	20.11
Hydrocarbon gas produced ($MtCO_{2e}$)				
CAPEX (£m)	559.78	559.78	559.78	559.78
CAPEX per barrel (£)	9.06	9.06	9.06	9.06
Carbon price:	0.00	0.00	0.00	0.00
a. Imported CO_2 cost (£/tCO_2)	7.93	7.93	7.93	67.94
b. EU-ETS emission cost (£/tCO_2)	36.75	36.75	36.75	35.69
c. EU-ETS emission cost (€/tCO_2)	42.27	42.27	42.27	41.04
OPEX (£m)	1375.06	1375.06	1375.06	2946.50
OPEX per barrel (£)	22.24	22.24	22.24	45.97
Annual OPEX (£m)	44.36	44.36	44.36	95.05
oil price per barrel (£)	84.43	84.43	84.43	86.61
oil price per barrel ($)	135.09	135.09	135.09	138.58
CO_2 usage (tonne/barrel)	0.53	0.53	0.53	0.53
No. of injector wells	3.50	3.50	3.50	3.50
Mean NPV (£m)	464.72	84.74	173.87	-174.87
Mean IRR (%)	17.01	12.02	14.35	7.39
Discount rate (%)	10.00%	10.00%	10.00%	10.00%
Tax (£m)	0	2648.72	2027.42	0.00
NPV/I		**0.17**	**0.34**	

The model solutions presented in Table 8 indicate that 61.82 mmbbls EOR could potentially be produced from a cumulative total injection of about 24.50 $MtCO_2$ of purchased CO_2. The EOR would extend the field life beyond the business-as-usual COP date.

Cumulatively, about 4.8 $MtCO_{2e}$ of hydrocarbon gas would be produced. Based on the field's estimated 2010 emissions per barrel of oil produced figure of 0.07 (t/bbl), the stored CO_2 is almost 82% of the purchased CO_2. The central value of the calculated total CAPEX is £559.78 million and, the per barrel CAPEX is £9.06.

The cumulative OPEX is £1.38 billion in the three Low Price scenarios and £2.95 billion in the CPF price scenario. While the annual OPEX is £44.36 million in the Low Price scenarios it is £95.05 million in the CPF price scenario. While the average price of the imported CO_2 is calculated to be £7.93/tCO_2 in the Low Price case, it is £67.94/tCO_2 under CPF pricing.

In the Low Price scenario simulations, the mean NPV is £464.72 million under the pre-tax assumptions and £84.74 million under the 81% tax rate. The mean NPV with 62% tax rate is £173.87 million, while under the pre-tax CPF price scenario it is negative -£174.87 million. A further scrutiny of the CO_2-EOR investment under the NPV/I ratio shows that under the Low Price case, while at 0.17 the investment seems unattractive at the 81% tax rate, the higher ratio of 0.34 with 62% tax rate might prove attractive to some investors. The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 23 – 26.

Figure 23: Nelson: Low price scenario: Probability distribution of the NPV (pre-tax)

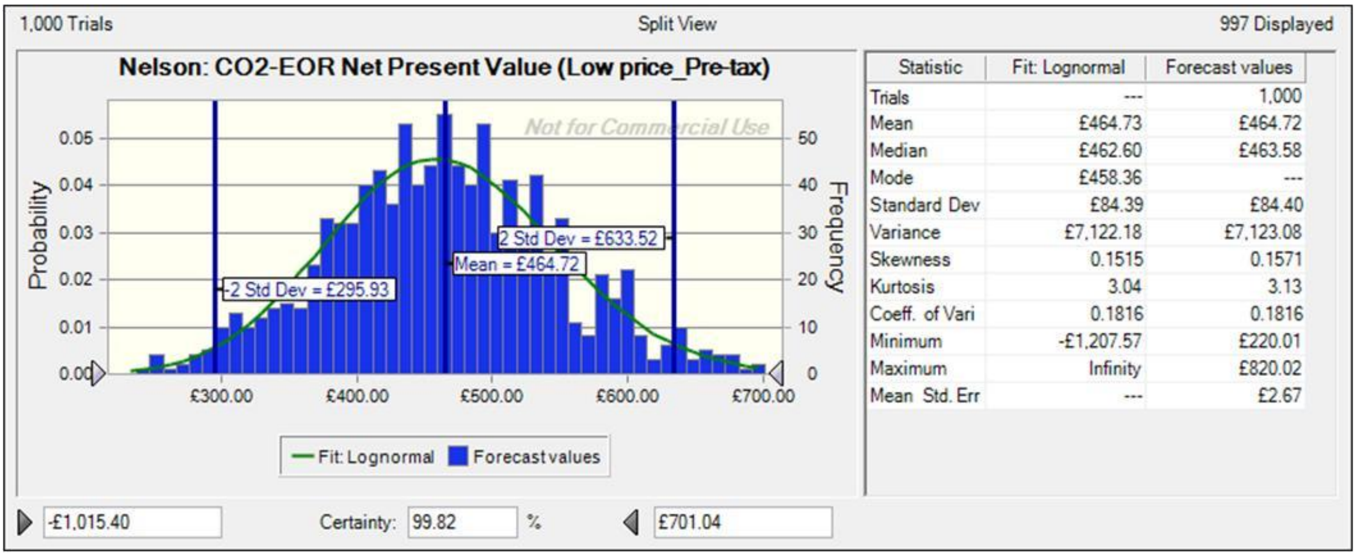
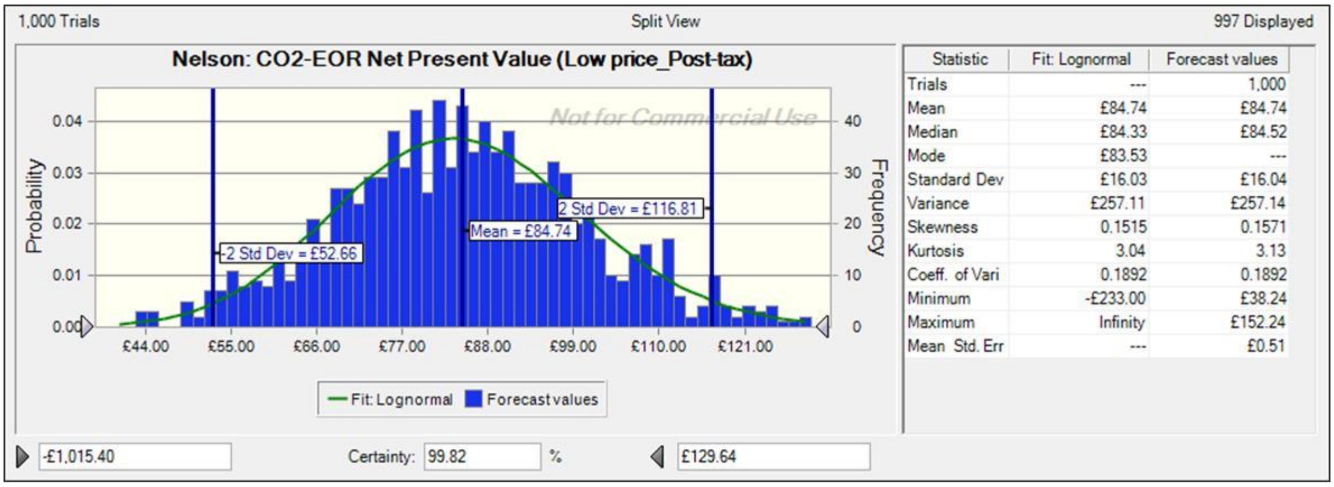
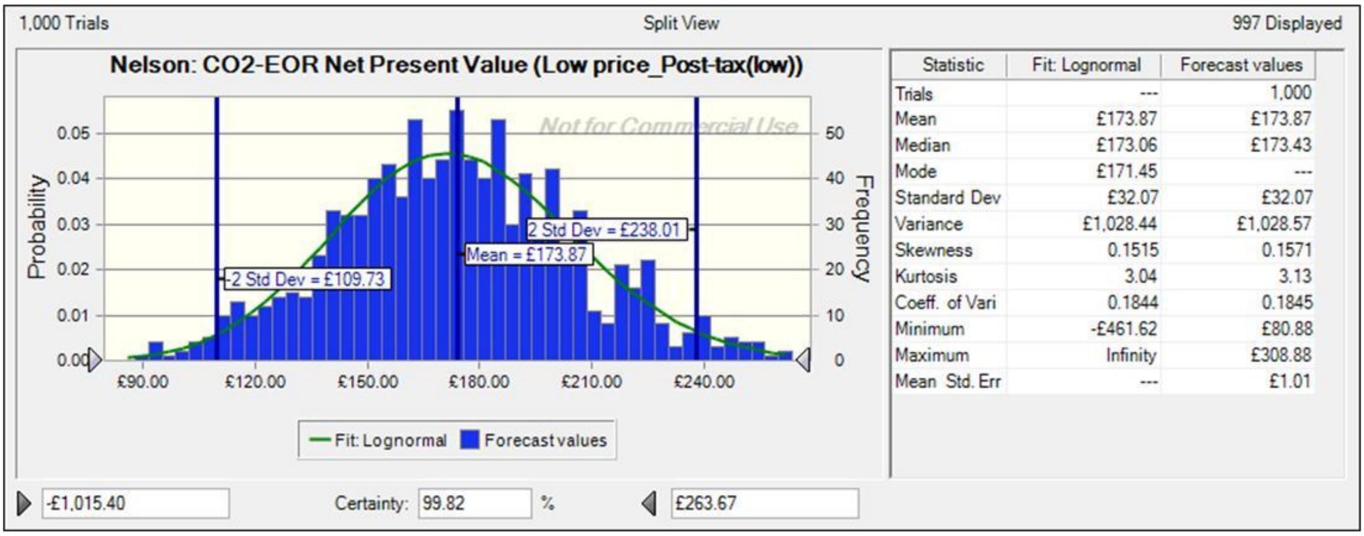


Figure 24: Nelson: Low price scenario: Probability distribution of NPV (81% tax rate)



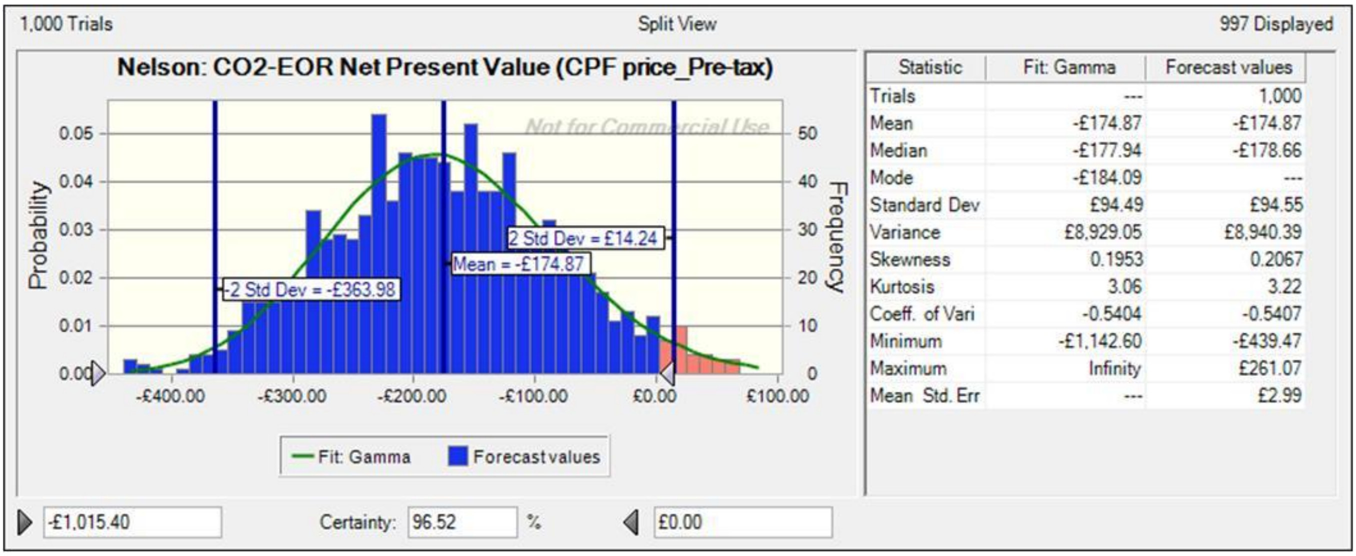
Statistic	Fit: Lognormal	Forecast values
Trials	---	1,000
Mean	£84.74	£84.74
Median	£84.33	£84.52
Mode	£83.53	---
Standard Dev	£16.03	£16.04
Variance	£257.11	£257.14
Skewness	0.1515	0.1571
Kurtosis	3.04	3.13
Coeff. of Vari	0.1892	0.1892
Minimum	-£233.00	£38.24
Maximum	Infinity	£152.24
Mean Std. Err	---	£0.51

Figure 25: Nelson: Low price scenario: Probability distribution of NPV (62% tax rate)



Statistic	Fit: Lognormal	Forecast values
Trials	---	1,000
Mean	£173.87	£173.87
Median	£173.06	£173.43
Mode	£171.45	---
Standard Dev	£32.07	£32.07
Variance	£1,028.44	£1,028.57
Skewness	0.1515	0.1571
Kurtosis	3.04	3.13
Coeff. of Vari	0.1844	0.1845
Minimum	-£461.62	£80.88
Maximum	Infinity	£308.88
Mean Std. Err	---	£1.01

Figure 26: Nelson: CPF price scenario: Probability distribution of NPV (pre-tax)



Statistic	Fit: Gamma	Forecast values
Trials	---	1,000
Mean	-£174.87	-£174.87
Median	-£177.94	-£178.66
Mode	-£184.09	---
Standard Dev	£94.49	£94.55
Variance	£8,929.05	£8,940.39
Skewness	0.1953	0.2067
Kurtosis	3.06	3.22
Coeff. of Vari	-0.5404	-0.5407
Minimum	-£1,142.60	-£439.47
Maximum	Infinity	£261.07
Mean Std. Err	---	£2.99

Figures 23 – 26 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £69 million to £549 million, while it would range from a loss-making -£269 million to -£80 million under CPF pricing. There is a 95% chance that the NPV would range from -£364 million to a positive NPV of £14 million under the CPF pricing, and between £53 million and £633.52 million in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but to higher investment risks, as indicated by the higher value of the coefficient of variability.

However, since the curve-fitting results show that all the probability distributions are not normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the lognormal distribution, while that of the CPF pricing is the gamma distribution.

Scott

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for Scott are summarised in Table 9 below. The significant differences across the model solutions are in highlights.

Table 9: A summary of the model solutions for the Scott field

		Low CO_2 price scenario			CPF price scenario
	SCCS	**Pre-tax**	**81% tax**	**62% tax**	**Pre-tax**
EOR oil (mmbbls) (range 105-224)	71-101	152.14	152.14	152.14	145.62
Purchased CO_2 ($MtCO_2$)	52.00	59.50	59.50	59.50	59.50
Recycled CO_2 ($MtCO_2$)	na	218.90	218.90	218.90	218.90
CO2 stored (MtCO2)	na	45.35	45.35	45.35	45.35
Hydrocarbon gas produced ($MtCO_{2e}$)		10.88	10.88	10.88	10.88
CAPEX (£m)	1200.00	1512.28	1512.28	1512.28	1512.28
CAPEX per barrel (£)	11.88-16.90	9.94	9.94	9.94	10.38
Carbon price:					
a. Imported CO_2 cost (£/tCO_2)	0.00	7.93	7.93	7.93	66.93
b. EU-ETS emission cost (£/tCO_2)	na	36.75	36.75	36.75	36.57
c. EU-ETS emission cost (€/tCO_2)	na	42.27	42.27	42.27	42.06
OPEX (£m)	1215	3077.51	3077.51	3077.51	6738.07
OPEX per barrel (£)	12.03-17.11	20.23	20.23	20.23	46.27
Annual OPEX (£m)	45.00	99.27	99.27	99.27	217.36
oil price per barrel (£)	50	84.43	84.43	84.43	83.32
oil price per barrel ($)	70	135.09	135.09	135.09	133.31
CO_2 usage (tonne/barrel)	0.51-0.73	0.53	0.53	0.53	0.52
No. of injector wells	na	8.50	8.50	8.50	8.50
Mean NPV (£m)	na	1288.60	235.21	482.30	-264.75
Mean IRR (%)	na	0.18	0.12	0.15	0.82
Discount rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%
Tax (£m)	na	0.00	6662.46	5099.66	0.00
NPV/I	na		**0.17**	**0.35**	

The model solutions presented in Table 9 indicate that about 152 mmbbls additional EOR oil could potentially be produced at an average rate of about 5.85 mmbbls/year from a cumulative total injection of about 60 $MtCO_2$ of purchased CO_2. The additional EOR oil would extend the field life well beyond the business-as-usual COP date of 2016.

Cumulatively, about 11.25 $MtCO_{2e}$ of hydrocarbon gas would be produced. Based on the field's estimated 2010 emissions per barrel of oil produced figure of 0.09 tonnes, the stored CO_2 is about 77% of the purchased CO_2. The central value of the calculated total CAPEX is £1.51 billion and, the per barrel CAPEX is £10.

While the cumulative OPEX is £3.08 billion in the three Low Price scenarios, it is £6.74 billion in the CPF price scenario. Also, while the annual OPEX is £99.27 million in the Low Price scenarios it is £217.36 million in the CPF price scenario. While the average price of the imported CO_2 is calculated to be £7.93/tCO_2 in the Low price case, it is £66.93/tCO_2 under CPF pricing.

In the Low Price scenario simulations, the mean NPV is £1.29 billion under the pre-tax assumptions and £235.21 million under the 81% tax rate. The mean NPV with the 62% tax rate is £482.30 million, and the mean NPV under the CPF assumptions is -£264.75 million. A further scrutiny of the CO_2-EOR investment under the NPV/I ratio shows that under the Low Price case while at 0.17 the investment seems unattractive at the 81% tax rate, the higher 0.35 ratio with the 62% rate might be attractive to some investors.

The study's model solutions were compared with those in SCCS (2009) which are reproduced in the first column of Table 9.

The predicted 152 mmbbls volume of EOR oil in the present study is higher than the 71 mmbbls to 101 mmbbls range of the SCCS study. An explanation of the difference relates to the higher volumes of purchased CO_2. Both the CAPEX and OPEX in the SCCS study are lower than those in the present study. The higher investment and recurrent outlays in the present study are due to a combination of scale and cost of CO_2. While the per barrel CAPEX of the present study is lower, the per barrel

OPEX is substantially higher. The lower per barrel CAPEX and OPEX in the SCCS study appears to be based on a combination of the assumed higher level of operational efficiency and cost-free imported CO_2.

The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 27 – 30.

Figure 27: Scott: Low price scenario: Probability distribution of the NPV (pre-tax)

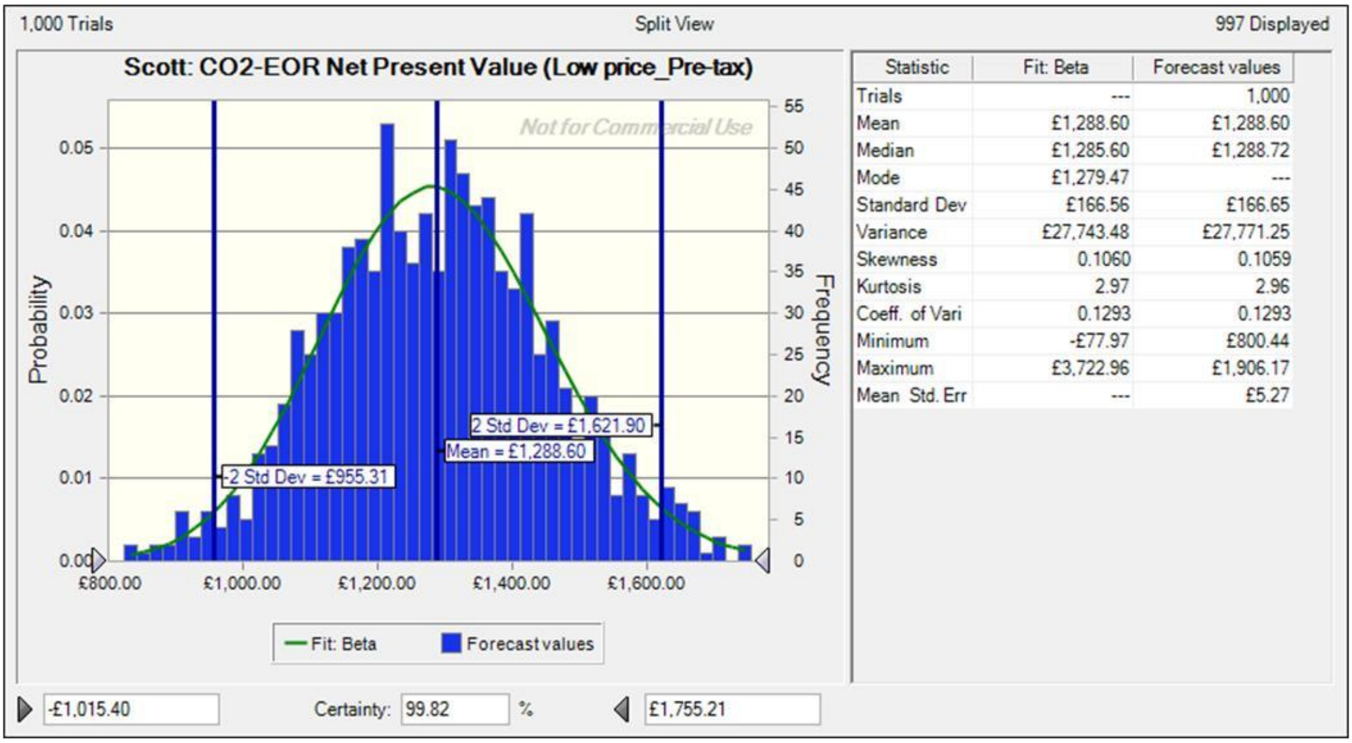


Figure 28: Scott: Low price scenario: Probability distribution of NPV (81% tax rate)

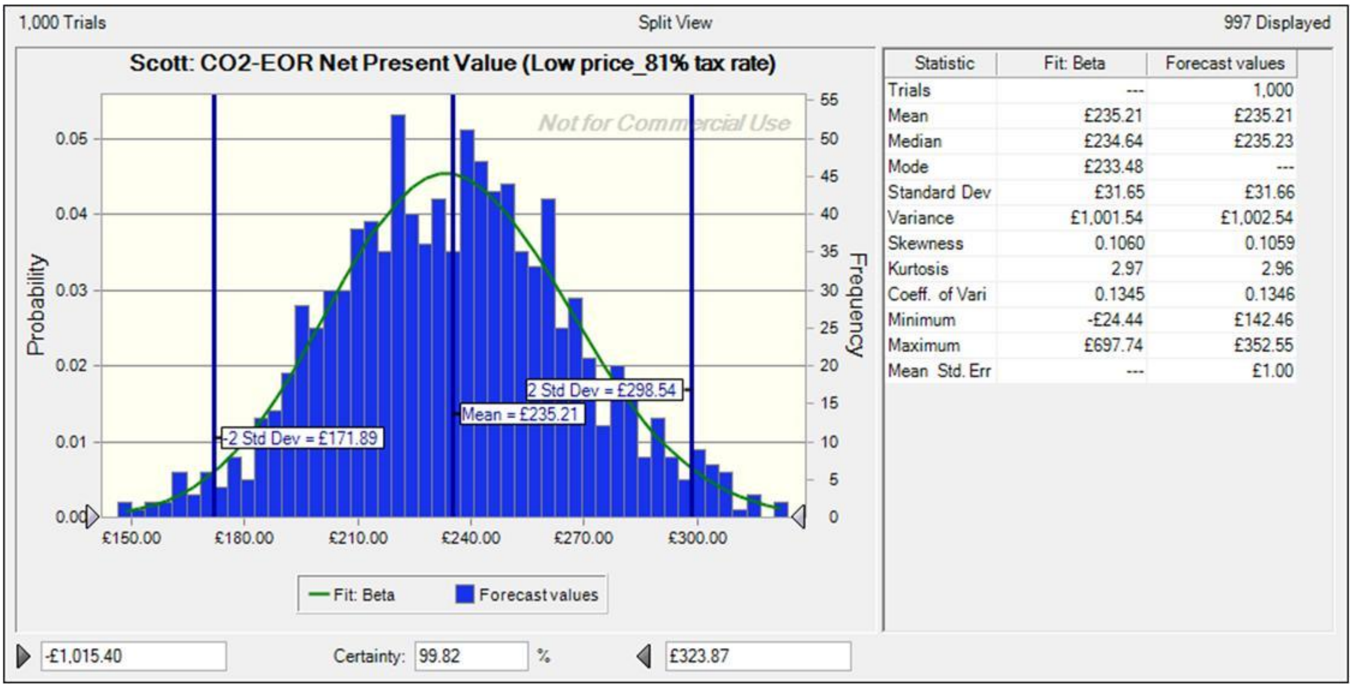


Figure 29: Scott: Low price scenario: Probability distribution of NPV (62% tax rate)

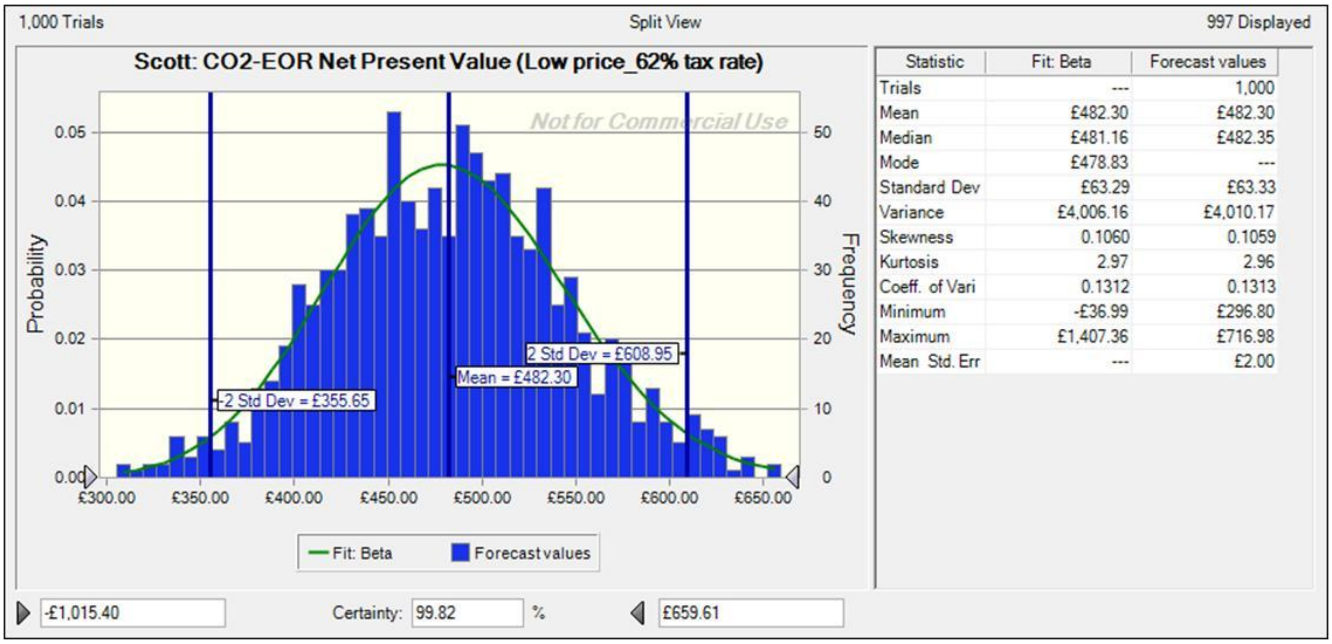
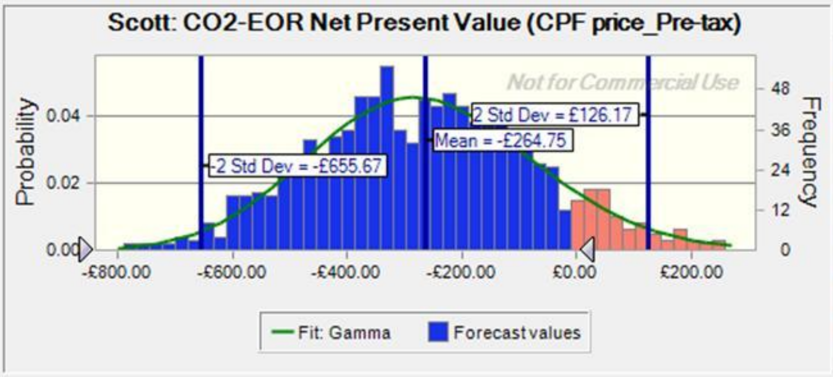


Figure 30: Scott: CPF price scenario: Probability distribution of NPV (pre-tax)



Statistic	Fit: Gamma	Forecast values
Trials	---	1,000
Mean	-£264.75	-£264.75
Median	-£270.68	-£269.36
Mode	-£282.57	---
Standard Dev	£195.38	£195.46
Variance	£38,173.13	£38,204.37
Skewness	0.1824	0.1781
Kurtosis	3.05	3.06
Coeff. of Vari	-0.7380	-0.7383
Minimum	-£2,407.16	-£815.52
Maximum	Infinity	£554.85
Mean Std. Err	---	£6.18

Figures 27 – 30 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £204 million to £1.5 billion, while it would range from a loss-making -£460 million to -£69 million under the CPF pricing. There is a 95% chance that the NPV would range from -£656 million to a positive NPV of £126 million under the CPF pricing, and between £172 million and £1.6 billion in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but to higher investment risks, as indicated by the higher value of the coefficient of variability.

However, since the curve-fitting results show that all the probability distributions are non-normal, the confidence interval results should be interpreted with caution. The best-fit of the NPV forecast values under the Low Price scenarios is the beta distribution and the forecast NPV values of the and CPF pricing are best characterised with a gamma probability distribution..

Tartan

The results of the Monte Carlo simulations under the alternative Low and CPF scenarios for the Tartan field are summarised in Table 10 below. The significant differences between and across the model solutions are in highlights.

Table 10: A summary of the model solutions for the Tartan field

	Low CO_2 price scenario			CPF price scenario
	Pre-tax	81% tax	62% tax	Pre-tax
EOR oil (mmbbls) (range 48-80)	51.26	51.26	51.26	51.76
Purchased CO_2 ($MtCO_2$)	21.00	21.00	21.00	21.00
Recycled CO_2 ($MtCO_2$)	77.27	77.27	77.27	77.27
CO2 stored (MtCO2)	4.95	4.95	4.95	4.95
Hydrocarbon gas produced ($MtCO_{2e}$)	3.95	3.95	3.95	3.95
CAPEX (£m)	475.40	475.40	475.40	475.40
CAPEX per barrel (£)	9.27	9.27	9.27	9.18
Carbon price:				
a. Imported CO_2 cost (£/tCO_2)	9.21	9.21	9.21	71.72
b. EU-ETS emission cost (£/tCO_2)	37.01	37.01	37.01	35.58
c. EU-ETS emission cost (€/tCO_2)	41.14	41.14	41.14	41.14
OPEX (£m)	1221.86	1221.86	1221.86	2612.00
OPEX per barrel (£)	23.84	23.84	23.84	50.46
Annual OPEX (£m)	39.41	39.41	39.41	84.26
oil price per barrel (£)	83.93	83.93	83.93	84.40
oil price per barrel ($)	134.29	134.29	134.29	135.03
CO_2 usage (tonne/barrel)	0.53	0.53	0.53	0.52
No. of injector wells	3.00	3.00	3.00	3.00
Mean NPV (£m)	407.49	74.40	152.53	-140.73
Mean IRR (%)	17.21	12.15	14.50	7.53
Discount rate (%)	10.00%	10.00%	10.00%	10.00%
Tax (£m)	0.00	2108.78	1614.13	0.00
NPV/I		**0.17**	**0.35**	

The model solutions presented in Table 10 indicate that about 51.26 mmbbls EOR could potentially be produced from a cumulative total injection of 21 $MtCO_2$ of purchased CO_2. The additional EOR would extend the field life beyond the business-as-usual COP date.

Cumulatively, about 4 $MtCO_{2e}$ of hydrocarbon gas would be produced. The imported CO2 is eventually all stored but, because there are significant emissions from power generation the stored CO_2 equates to 24% of the purchased CO_2. The central value of the calculated total CAPEX in both the Low and CPF price scenarios is £475.40 million, and the per barrel CAPEX is £9.27.

While the cumulative OPEX is £1.22 billion in the three Low Price scenarios, it is £2.62 billion in the CPF price scenario. Also, while the annual OPEX is £39.41 million in the Low Price scenarios it is £84.26 million in the CPF price scenario. While the average price of the imported CO_2 is calculated to be £9.21/tCO_2 in the Low price case, it is £71.72/tCO_2 under CPF pricing.

In the Low Price scenario simulations, the mean NPV is £407.49 million under the pre-tax assumptions and £74.40 million under the 81% tax rate. While the mean NPV at the 62% tax rate is £152.53 million that of the pre-tax CPF price scenario is negative at -£140.73 million. Ordinarily, the positive post-tax mean NPV in the Low Price scenarios would argue for an EOR investment while the negative pre-tax mean NPV of the CPF pricing scenario would argue against it. Under the Low Price the 0.17 NPV/I ratio makes the investment seem unattractive at the 81% tax rate, but the higher ratio of 0.35 with the 62% rate might prove attractive to some investors. The graphical representations of the probability distributions of the NPV in the respective Low and CPF price scenarios are presented below in Figures 31 – 34.

Figure 31: Tartan: Low price scenario: Probability distribution of the NPV (pre-tax)

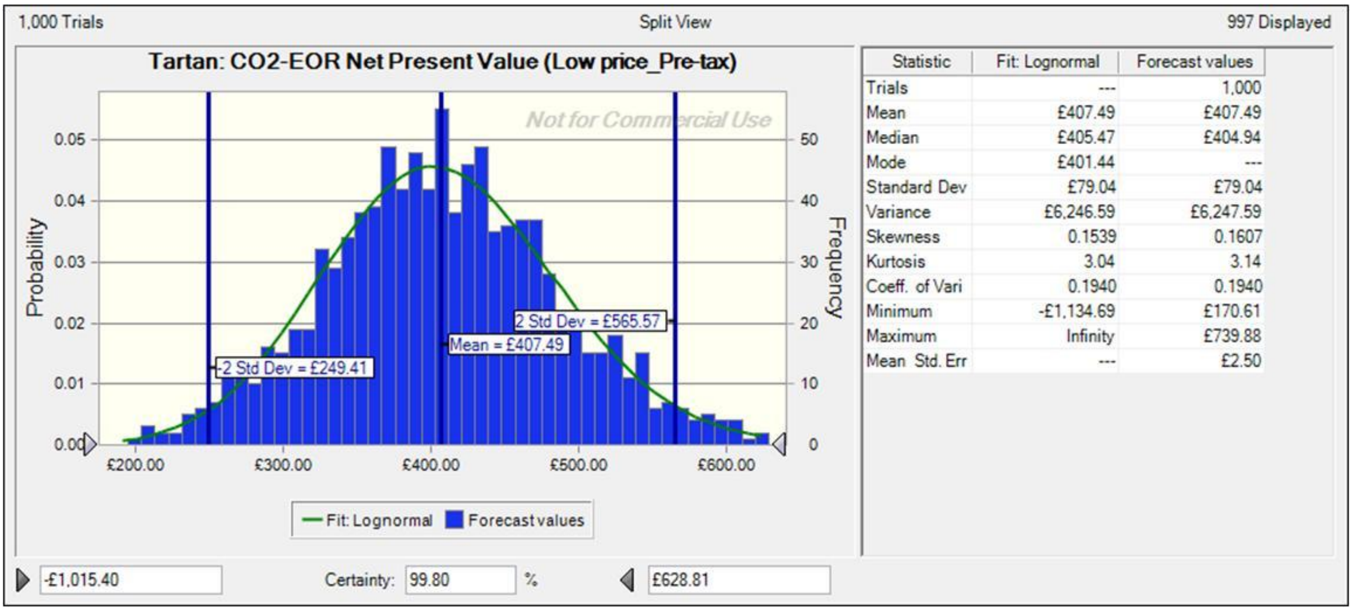


Figure 32: Tartan: Low price scenario: Probability distribution of NPV (81% tax rate)

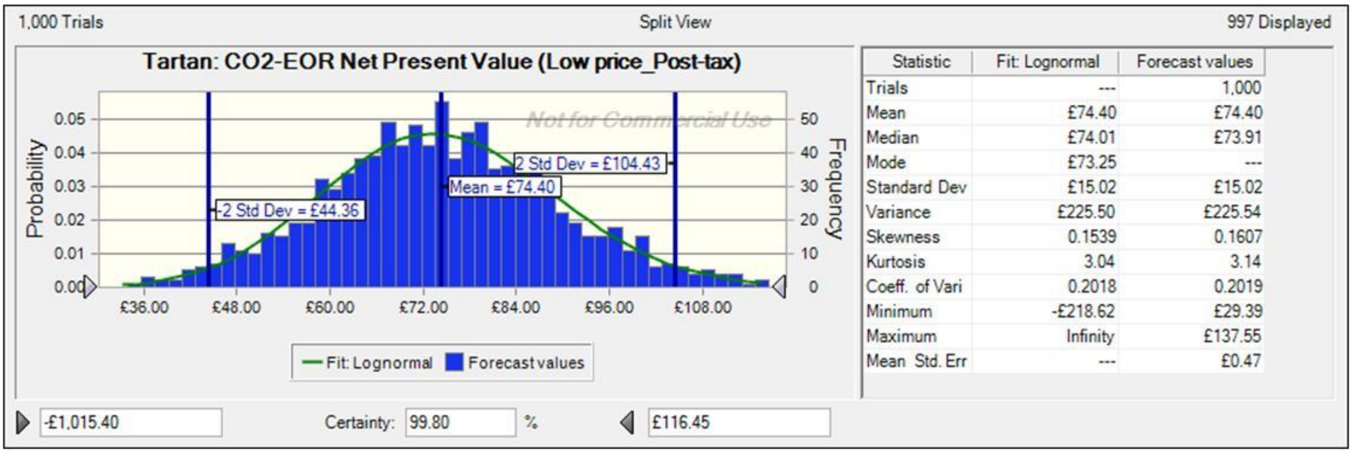


Figure 33: Tartan: Low price scenario: Probability distribution of NPV (62% tax rate)

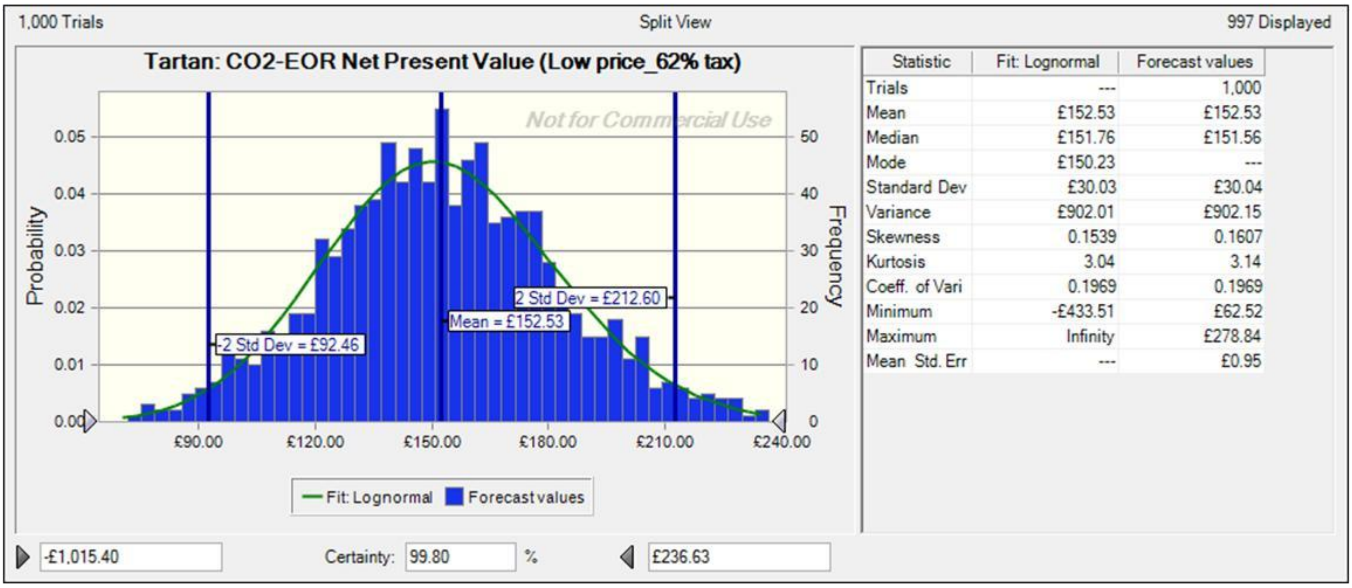
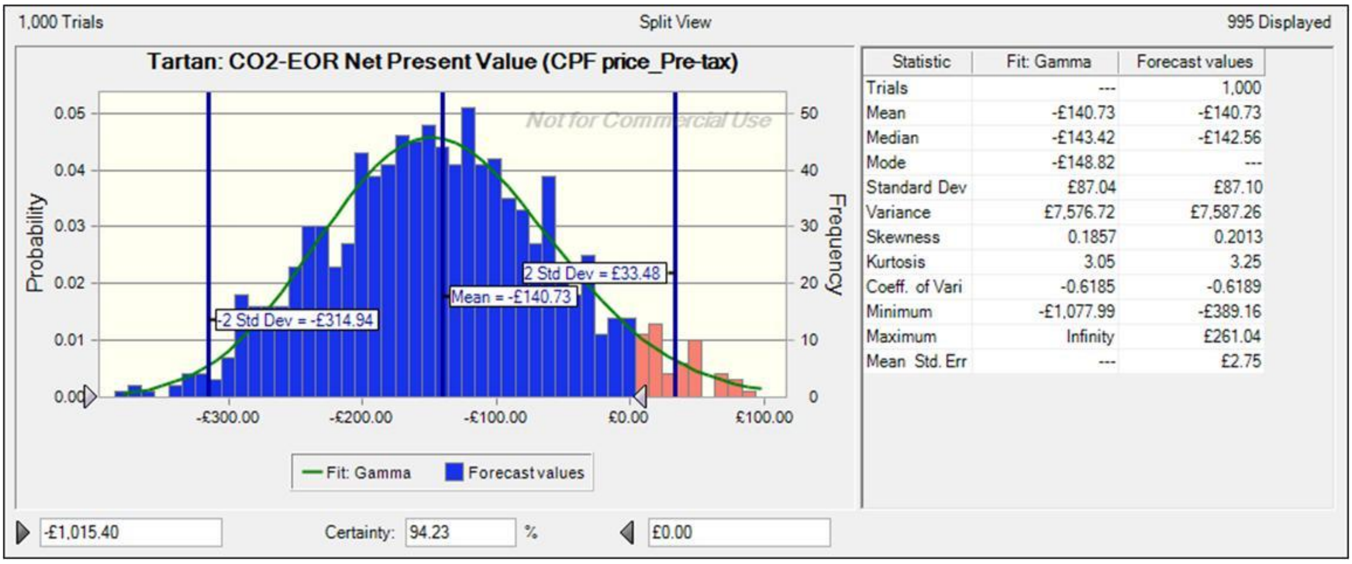


Figure 34: Tartan: CPF price scenario: Probability distribution of NPV (pre-tax)



Figures 31 – 34 reveal that, assuming the forecast NPV values are characterised by normal probability distributions, there is a 68% probability that the return on investment in the Low Price scenarios would be in the range of £59 million to £487 million, while it would range from a loss-making -£228 million to -£54 million under CPF pricing. There is a 95% chance that the NPV would range from -£315 million to a positive NPV of £33 million under the CPF pricing and between £44 million and £566 million in the Low Price scenarios. The introduction of the CPF prices is seen to lead not only to a negative mean NPV but to higher investment risks, as indicated by the higher value of the coefficient of variability.

Also, since as in the earlier cases considered, the curve-fitting results show that all the probability distributions are not normal, the confidence interval results should be interpreted with caution. In common with some of the earlier fields considered, the best-fit of the NPV forecast values under the Low Price scenarios is the lognormal probability distribution, while it is the gamma distribution in the CPF pricing scenario.

6. Conclusions

This study has examined the possible economic viability of a set of nine interconnected field CO_2 EOR investments in the Central North Sea/ Moray Firth regions of the UKCS. These investments were considered within the framework of a hub, spoke, and cluster development involving a CO_2 collection hub in the St Fergus area and the substantial use of existing pipelines in the region to transport the CO_2 to the nine fields. Major economies of scale relating both to the preparation of CO_2 for transportation to the fields in supercritical form and in the transport costs themselves may be expected from the development of a hub at St Fergus and the substantial use of existing pipelines. The nine oil fields chosen for CO_2 EOR investments have potential for extra production based on the relationship between their current expected recovery and the resources in place.

Analysis of the economics of the CO_2 EOR investments was conducted with financial simulation modelling incorporating the Monte Carlo technique to reflect the substantial risks involved. It is clear that there are major risks relating to the investment costs in the fields, the oil price, the price paid to purchase CO_2, and the EOR from the injection of the CO_2. Thus all of these were defined as stochastic variables in the modelling. There is a particular uncertainty surrounding the CO_2 price employed for the trading of the commodity for EOR purposes. Accordingly, two scenarios were developed in the study. In one the CFP prices proposed in Budget 2011 (with increases to 2050) was employed. In the second case a much lower price was employed to reflect negotiations between the sellers and buyers of the commodity.

The results of the modelling highlight the high investment risks. Under the CFP price scenario the returns to the investments expressed in terms of net present values (NPVs) are generally negative before tax. In some cases the losses are large. Under the low CO_2 transfer price case mean NPVs are often positive, but risks of negative outcomes remain. Where returns are positive the tax system can reduce the returns to levels which raise doubts regarding their acceptability to investors. Several of the fields are currently subject to tax at 81% which would also apply to CO_2 EOR investments. In general it is clear that financial incentives, including taxation, are required before large scale investments will take place in the UK/UKCS.

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