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Tax Incentives for CO_2-EOR in the UK Continental Shelf

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

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

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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1. Introduction

The UK Government has routinely introduced tax incentives to maximise economic oil and gas extraction in the UKCS, including for EOR schemes. But CO_2-EOR schemes have thus far been excluded, despite the widespread acknowledgment that a major barrier to the deployment of CCS investments in general and CO_2-EOR in particular, is their relative costliness in relation to the revenues. Yet, CO_2-EOR could provide roughly 60% of the estimated 1.5 billion barrels of oil producible through EOR (DECC, 2009). The present study explores how the economics of CO_2-EOR investments might benefit from an extension to it of several possible tax incentives including the Brown Field Allowance (BFA) and an investment uplift akin to that proposed for ultra high pressure, high temperature fields.

2. Methodology

It is assumed that, having resolved the technical, engineering, geological and CO_2 feedstock issues, the single most important consideration militating against a CO_2-EOR investment is the project costs in relation to the prospective revenues. This study attempts to solve the problem by investigating a package of targeted fiscal incentives that might make the projects more attractive by reducing the difference between pre-tax and post-tax returns.

In order to demonstrate that fiscal incentives are needed to encourage first-mover technical- and financial risks relating to commercial scale CO_2-EOR projects, a hybrid spreadsheet model (in Excel) reflecting real-world financial and physical (reservoir simulation, production) conditions was formulated from the perspective of private sector investors, and optimised with respect to project net present value (NPV), subject to the constraints of profit non-negativity, and oil production determined by reservoir engineering principles underpinned by physical laws relating to the CO_2-injection-oil yield. The yield factor embodies decreasing EOR in relation to the cumulative amount of CO_2 injected. The input assumptions and parameters are based on a literature review and knowledge of real-world conditions.

CO_2-EOR projects are normally designed as a closed loop system in which the process is kick started with imported CO_2. The produced oil contains some CO_2 which is captured, recompressed, combined with more imported CO_2 and re-injected to produce oil. The process is repeated for as long as profitability continues. Apart from producing more oil, the assumed continuous CO_2 recycle process serves the two useful purposes of (a) steadily reducing the project OPEX by eventually reducing the amount of purchased CO_2, and, (b) ensuring that the produced CO_2 is not released to the atmosphere. The following vector autoregressive model in Kemp and Kasim (2013) relating the annual volumes of the fresh (or purchased) and recycled CO_2 and the hydrocarbon gas produced at the oilfield was used to reservoir engineering principles into the financial model.

$$fresh_t = a_o + a_1 fresh_{t-1} + a_2 recy_{t-1} + a_3 hcgas_{t-1} + a_4 oil_{t-2} + \varepsilon_{1t} \quad (2)$$

$$recy_t = b_0 + b_1 fresh_{t-1} + b_2 recy_{t-1} + b_3 hcgas_{t-1} + b_4 oil_{t-2} + \varepsilon_{2t} \quad (3)$$

$$hcgas_t = c_0 + c_1 fresh_{t-1} + c_2 recy_{t-1} + c_3 hcgas_{t-1} + c_4 oil_{t-2} + \varepsilon_{3t} \quad (4)$$

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*
t	= *time*
ε_{it}	=*error term* $i = 1,2,3$

The error term captures any "incidental sequestration"[1] that may occur in the reservoir. The volume of oil produced at *t-2* is exogenous and a proxy for the remaining oil reserves.

Given the optimised cash flow streams, a scenario analysis technique was then deployed to investigate the financial consequences to the streams of various tax allowances that might be applied to encourage CO_2-EOR investments. In particular, the analysis addressed the specific question of whether or not the CO_2-EOR projects could be economically developed. The following are the key assumptions and parameters of the scenario analysis:

3. Assumptions

i. Key model assumptions:

Whilst the detailed assumptions and parameters of the optimisation model can be found in Kemp and Kasim (2013), the following are especially noteworthy:

a. Timeline

Platform modification, well re-work, pipeline refurbishment and/or new build as well as field re-opening where necessary are assumed to

[1] Defined as the injected CO_2 that is trapped within the geologic formation and does not come back up with the EOR oil. Between 5% and 10% of the purchased CO2 remain permanently trapped or sequestered in the reservoir (Melzer, 2012).

commence in 2020. The injection of purchased and recycled CO_2 commences in 2023, initially with the former alone. The (percentage) preponderance of purchased CO_2 in the total amount injected annually, while remaining constant in absolute terms, reduces over time and ceases in 2042. First oil is produced in 2025, rising to a peak and declining thereafter at an increasing pace towards the end of the study period in 2050, reflecting diminishing returns to the CO_2 EOR activity. The exact date is determined by the economic limit.

b. Oil and CO_2 transfer prices

Oil prices are expected to be volatile during the period. As an example the EIA (2014) forecast a Reference scenario oil price ranging from $97 to $142 per barrel (real 2012). The present study assumed $120 per barrel in real terms, given that the projects commence several years into the future, namely 2020.

Two delivered CO_2 prices are considered. One is zero and the other a relatively modest price of £9/tCO_2[2]. The zero carbon price is assumed in the study to be a proxy for commercial incentivisation, given the acknowledged need for cheap EOR injectants to incentivise the investment (DECC, 2009)[3].

ii. Scenario analysis : assumptions and parameters

Two sets of scenarios were run with the current and hypothetical levels of the BFA and investment uplift allowances respectively.

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[2] The average price is $25 or £16 per tonne Onshore USA (Melzer, 2012). This price is tied/coupled to the oil price by a certain percentage (1.5% to 2.5%), where carbon prices are stated as per mcf of CO_2 (NEORI, 2012)

[3] DECC – PILOT Meeting – 10 November 2009.

(i) The BFA: Unit and maximum available allowance variations

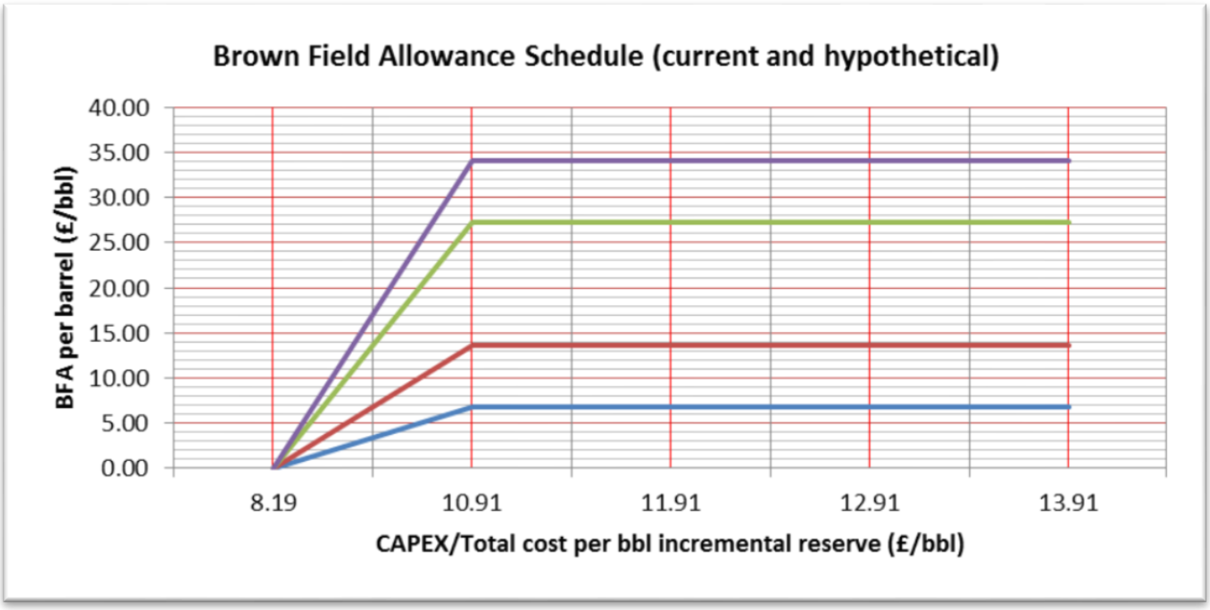
As from the 7th September 2012, qualifying EOR projects that "maximise economic recovery of hydrocarbons" are entitled to claim Brown Field Allowances (BFAs). Qualifying projects include those designed to maximise oil and gas tertiary production in and around existing producing fields. Because of concerns regarding cost apportionment across the upstream/downstream boundaries, the BFA does not apply to CO_2-EOR projects. Given the assurance that the possible eventual inclusion of CO_2-EOR projects would be kept under review (DECC, 2013)[4] this study assumes that these projects could be included in the future.

Currently, the maximum BFA per barrel of incremental reserves is around £6.82 (£50/tonne) for qualifying projects whose expected minimum capital cost (CAPEX) is around £8.19/barrel (£60/tonne) of incremental reserve. The maximum allowance is for a project having a verified CAPEX of around £10.91 (£80/tonne) or more. There are caps on the aggregate allowance for a PRT-paying project of £500 million, £250 million for a non-PRT one.

In the experimental runs, the BFA per barrel was increased to (£13.64/bbl., £100/tonne), (£27.29/bbl., £200/tonne), and (£34.11/bbl., £250/tonne), with the overall caps removed where expedient. Fig. 1 summarises the variations in the unit BFAs included in the experimental runs.

[4] DECC, BFA Guidance

Fig. 1: Brown Field Unit Allowance variations



In Fig. 1 the BFAs in per barrel terms are drawn along the y-axis and the expected CAPEX per barrel of incremental reserves along the x-axis.

(ii) Investment uplift allowance

In order to further incentivise exploration and production activities in the UKCS, the Government has committed to a new cluster area allowance for u-HPHT oil and gas projects. As its name implies, the u-HPHT uplift is a tax relief additional to the original oil and gas production CAPEX relieved on 100% first year basis. The confirmed minimum level of the proposed allowance is 62.5% of the qualifying CAPEX incurred in a cluster area. The study experimented with hypothetical allowances of 62.5%, 70%, 75% and 80% for CO_2 EOR projects.

iii. PRT, Supplementary Charge and tax-basis variations

For both sets of experiments involving the BFA and uplift allowances, the sensitivities of the resulting NPVs with respect to PRT and SC rate variations were tested.

a. PRT rate variations

The Petroleum Revenue Tax (PRT) is a field-based tax on the profits of oil and gas operators in the UK/UKCS. The current rate is 50%. Kemp and Kasim (2013) demonstrated that exempting taxable fields which engage in CO_2-EOR from PRT payments would significantly improve the profitability of CO_2-EOR investments. However, given that the government might not be inclined to levy a zero rate, the study experimented with reduction to 25% and 17.5% rates respectively.

b. Supplementary Charge – rate

Oil and gas companies in the UK/UKCS pay Supplementary Charge (SC) on their ring fence profits at the current rate of 32%. Experimental runs were conducted by reducing the SC from the current 32% to 25%.

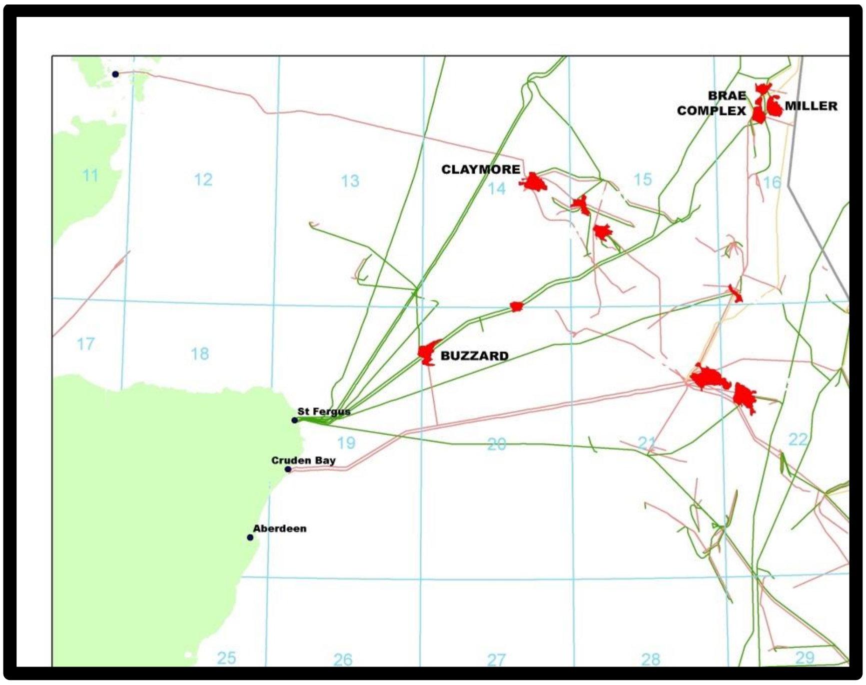
c. Supplementary Charge – allowances

Two allowances are considered. One is the current BFA which is CAPEX-based for qualifying projects and the other is a hypothetical Total cost-basis, including partial or full OPEX. Total cost with full OPEX is the sum of the CAPEX and the cumulative OPEX up to the last date of CO_2 purchases. The second case is total cost with partial OPEX only which adds only the development phase OPEX to the CAPEX.

4. Selected Fields

Four fields of varying sizes and CO_2-EOR potential were selected as case studies. These are Brae, Buzzard, Claymore and Miller. Map 1 shows the relative geographical locations of the selected fields while Table 1 shows a summary of their EOR potential and relevant project costs.

Map 1: Location of selected case study oilfields in the UKCS



Source: adapted from Kemp and Kasim (2013)

Map 1 shows that the selected fields are in relative close proximity to one another and, can form a cluster area along the St-Fergus-to-Miller backbone 30-inch pipeline (Kemp and Kasim, 2013).

Table 1: Summary of cost profiles of selected hypothetical CO_2 EOR Projects in the UKCS

	Brae	Buzzard	Claymore	Miller
Potential EOR (mmbbls)	33	94	69	53
Investment cost (£m. real)	316	802	719	601
Investment cost per barrel ($/bbl.)	15	15	17	18
Lifetime Operating cost` (£m. real) (excl. CO_2 cost)	838	996	1320	698
Operating cost per barrel ($/bbl.)	41	17	31	21
Lifetime Operating Cost (£m. real) (incl. CO_2 at £9/tCO_2)	1132	1760	1838	1056
Operating Cost (incl. CO_2) per barrel ($/bbl.)	55	30	43	32

Source: Kemp and Kasim (2013)

Brae

The Brae oilfield complex is located some 230 km from St. Fergus, the assumed onshore CO_2 gathering and distribution hub. The field lies at a water depth of 106 metres. The estimated OOIP is 610 mmbbls. Production started in 1983, and thus Brae is PRT-paying. The water cut reached 73% in 2012. Table 1 indicates that an estimated 33 million barrels of CO_2-EOR oil could be produced with a CAPEX real cost of £316 million or about £9.6 ($15.4) per barrel. The total project cost including the cumulative OPEX is £1.4 billion, or about £44 ($70) per barrel if the CO_2 was purchased at the price of £9/tCO_2. If commercial incentivisation resulted in the delivered cost of the CO_2 being zero, the total project cost reduces to £1.2 billion or about £35 ($56) per barrel.

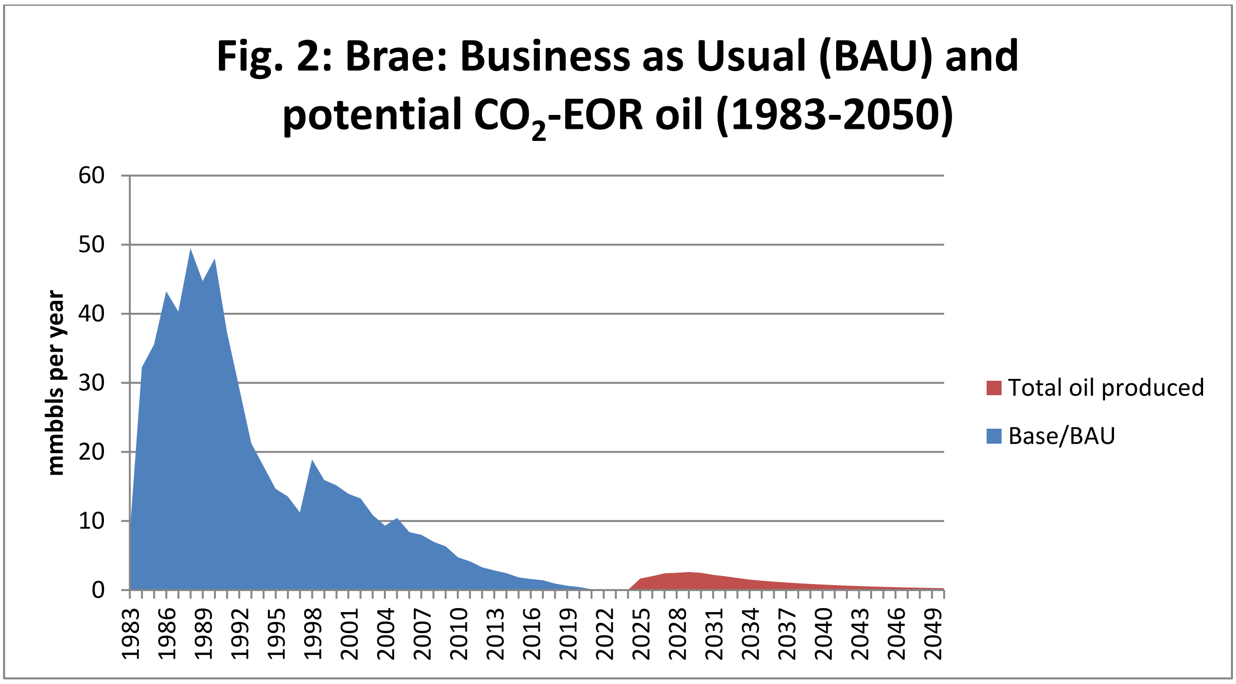


Fig.2 shows the historic and EOR potential of the Brae field complex. The business-as-usual (BAU) schedule is the estimated production without CO_2-EOR, while the total oil schedule includes the addition from EOR.

Buzzard

Buzzard is located 62 km from St. Fergus and lies at a water depth of 100 metres. The field's OOIP is c.1200 mmbbls with water cut at 21% in 2012, suggesting a greater volume of potential CO_2-EOR oil than Brae. Buzzard is a non-PRT-paying field.

Table 1 indicates the field's estimated CO_2-EOR potential of 94 mmbbls, producible with a real CAPEX cost of £802 million, or about £8.6 ($13.7) per barrel. If the delivered cost of the captured CO_2 is zero, the estimated total project cost is £1.8 billion or about £19 ($31) per barrel. Paying a positive price for the captured CO_2 of £9 per tonne results in a total project cost of £2.6 billion or about £27 ($44) per barrel.

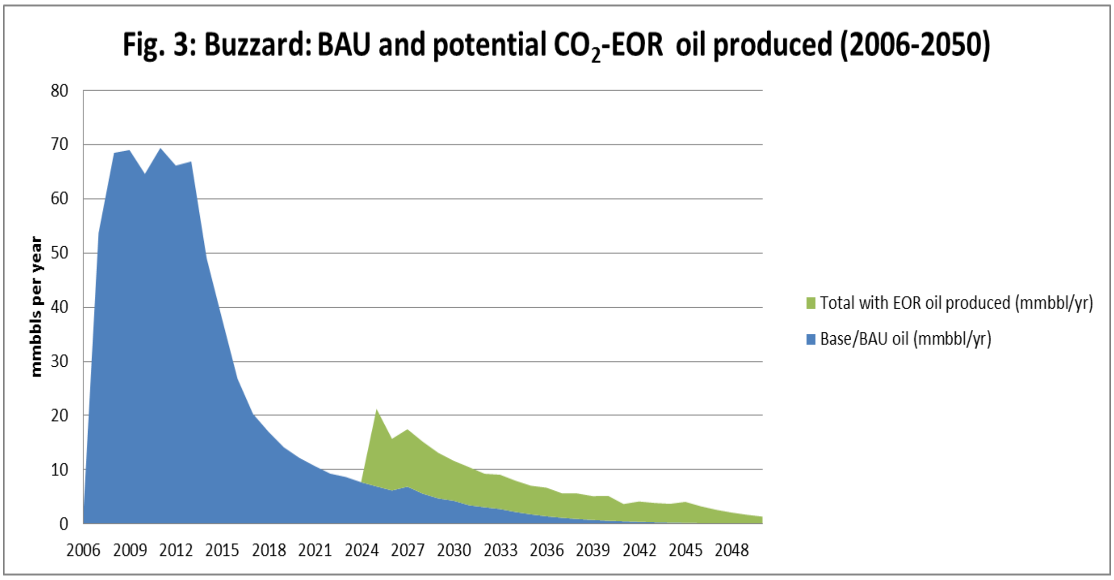


Fig. 3 shows the production profile of the potential additional oil at Buzzard and the field life extension as a result of CO_2-EOR, if the investment was undertaken.

Claymore

Claymore is located some 141 km from St. Fergus and lies at a water depth of 104 metres. The field's estimated OOIP is 1460 mmbbls. Production started in 1977 and so Claymore is a PRT-paying field. The field is relatively mature with water cut at 78% in 2012.

Table 1 shows that the estimated incremental CO_2-EOR oil is 69 mmbbls produced at a real capital cost of £719 million or about £10.4 ($16.7) per barrel. The total project cost is estimated at $2.0 billion or about £29.6 ($47.3) per barrel, if the captured CO_2 was delivered at zero cost. This increases to £2.6 billion or about £37.1 ($59.3) if the captured CO_2 was delivered at a price of £9/tCO_2.

Fig. 4: Claymore: BAU and CO_2-EOR oil produced (1977-2050)

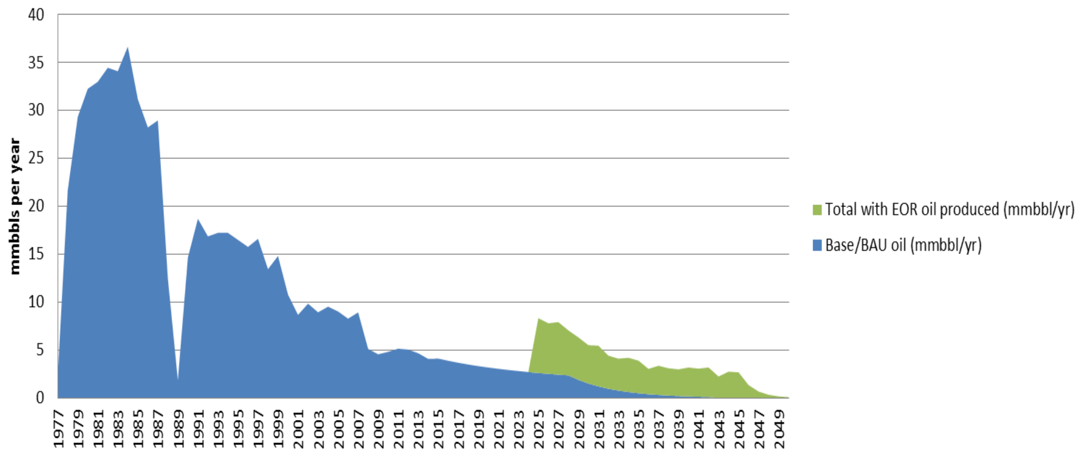


Fig. 4 shows the difference which the CO_2-EOR project can potentially make to the field's production profile both in terms of the annual increases in production and the field life extension.

Miller

Miller is located 242 km from St. Fergus to which it is linked by a 30-inch gas pipeline. The pipeline is the backbone serving the cluster of four fields in the sample formed around it. Miller lies at a water depth of 100 metres. Oil production ceased in 2007, but the study assumes that it can be re-opened for CO_2-EOR under favourable techno-economic conditions. As a reopened field it is assumed that like Argyll/Ardmore/Alma it will be a non-PRT field.

The estimated incremental CO_2-EOR oil is 53 mmbbls at a real CAPEX of £601 million or about £11.3 ($18.1) per barrel. If the delivered captured CO_2 was zero-valued, the estimated total project cost is £1.3 billion or about £24.5 ($39.2) per barrel. However, if the CO_2 was delivered at £9/tCO_2, the estimated project cost rises to £1.7 billion or about £31.3 ($50.0) per barrel.

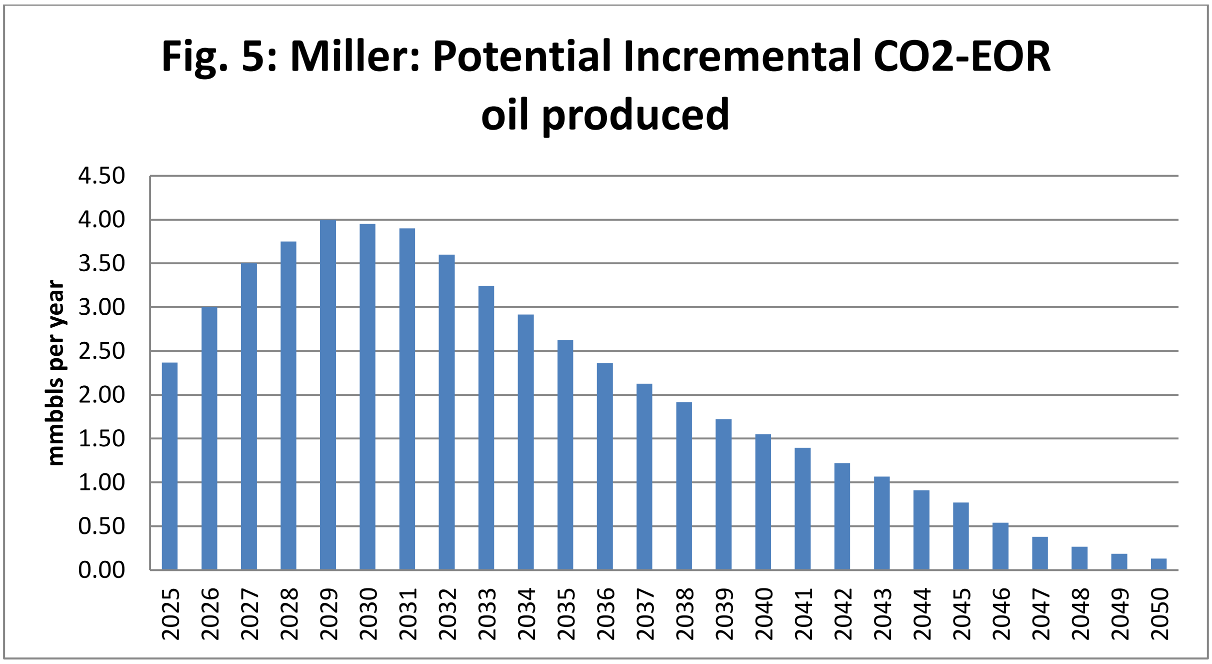


Fig. 5 shows the potential CO_2-EOR oil production profile. In this case there is no BAU oil projection because the field has already ceased production. The production profile shows output being ramped up in four years (2025-2029) reaching a peak in 2029 of 4 mmbbls. This is followed by a three-year production plateau (2029-2031) and decline from 2032.

5. Financial Simulations Undertaken

Experimental runs were conducted to investigate the financial consequences on project profitability of various tax schemes as discussed above. In each set, a base scenario was first developed, its profitability index (NPV@10%/I@10% discount rate) analysed, and then subjected to variations in some of the original data input/parameter assumptions. A hurdle rate of NPV/I > 0.3 is conventionally assumed to be desired for investments in the UKCS.

6. Results

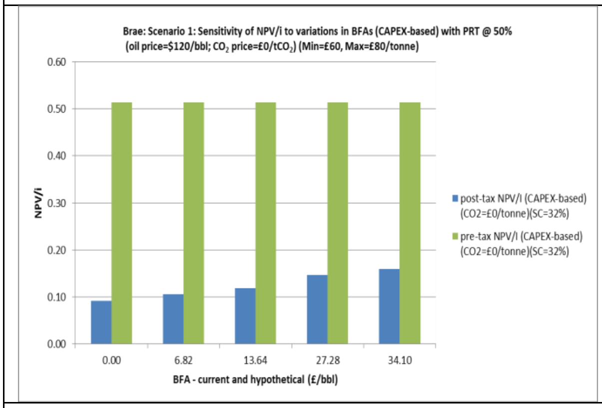
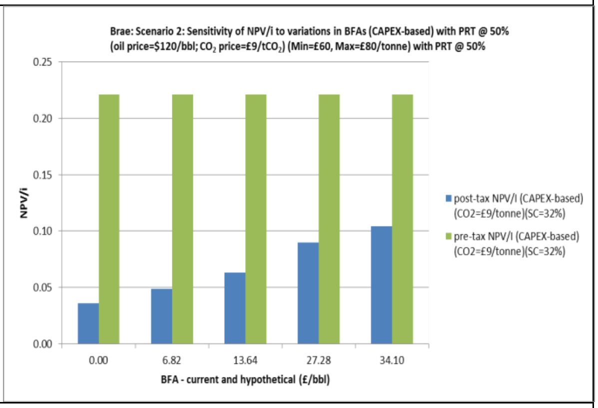
The field-by-field experimental results are presented in Tables 2 to 6. The graphical summaries are in two sets of panels. The left hand side (LHS) panels include an assumed commercial incentivisation scheme which delivers CO_2 at zero price to the fields as well as tax incentives, while the right hand side (RHS) panels are based on the fiscal incentives and payment for CO_2 of £9/tCO_2 in real terms.

(a) Brae

The potential efficacy of BFAs to incentivise CO_2-EOR

The results of the experiments investigating the possible effectiveness of an enhancement of BFAs for CO2-EOR at Brae are presented in Table 2. The project hurdle rate is a minimum NPV/I ratio of 0.3 in this and all other cases. The basis of the allowance is the project's CAPEX.

Table 2: Brae: Sensitivity of NPV/i to variations in PRT, given BFAs (CAPEX-based) and captured CO_2 prices.

<table>
<tr><td>Current and hypothetical BFAs with captured CO_2 price=£0/tCO_2</td><td>Current and hypothetical BFAs with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig.2.1a: Base scenario: PRT @ 50%</td><td>Fig. 2.2a: Base scenario: PRT @ 50%</td></tr>
<tr><td>
</td><td>
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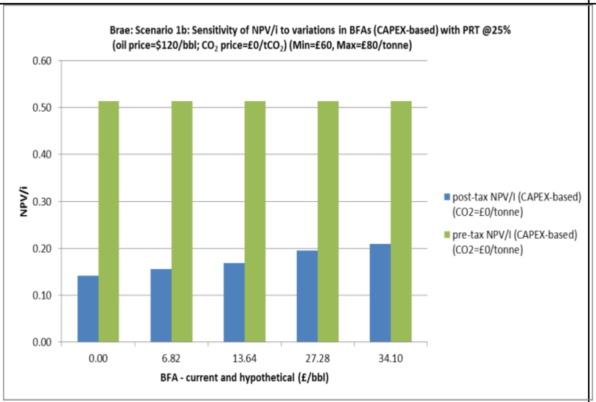
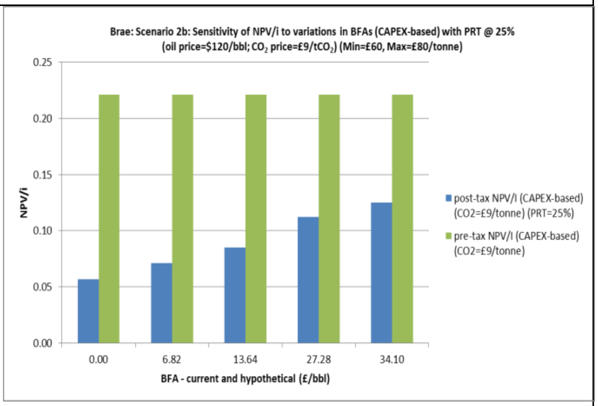
<tr><td>Fig. 2.1b: PRT @ 25%</td><td>Fig. 2.2b: PRT @ 25%</td></tr>
<tr><td>
</td><td>
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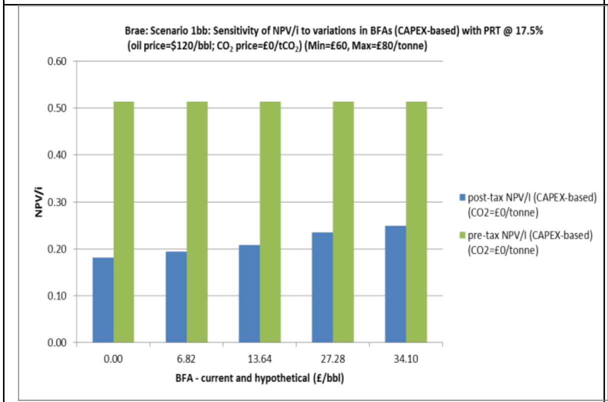
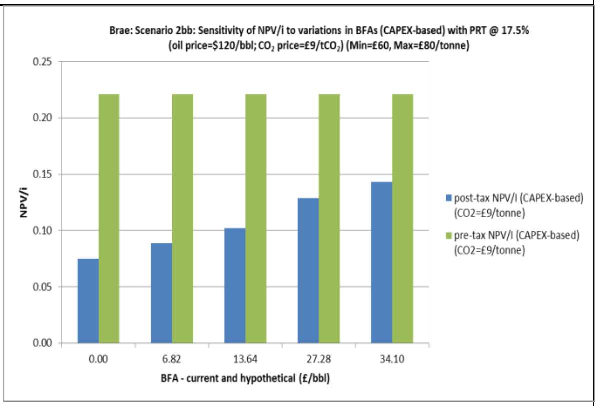
<tr><td>Fig. 2.1c: PRT @ 17.5%</td><td>Fig. 2.2c: 6 PRT @ 17.5%</td></tr>
<tr><td>
</td><td>
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</table>

Fig.2.1a summarises the results of the base case with combined commercial and fiscal incentives. Before tax the NPV/I ratio exceeds 0.5. Under the status quo of paying PRT at 50% and not receiving any BFAs

for CO_2-EOR projects, the NPV/I is a mere 0.091, clearly non-viable from the perspective of the field operator. Selected current and hypothetical larger levels of the BFA were applied to the CO_2-EOR project. Thus, the NPV/I improves by 15% to 0.105 if the current level of the BFA was extended to the CO_2-EOR project. This is still significantly below the investment hurdle rate. Successive increases in the BFA up to five times the current level raised the potential NPV/I to a maximum 0.159. Clearly the combined incentivisation scheme is inadequate, at the chosen levels of the BFA and current PRT. It may be noted that this conclusion remains the same even when the SC rate was reduced to 25% as the maximum NPV/I increased by only 3% to 0.163.

Fig. 2.2.a summarises the corresponding results of the base case scenario with fiscal incentives only with the investor paying £9 per tonne in real terms for its CO_2 feedstock. Unsurprisingly, the project economics are much worse. The pre-tax NPV/I ratio becomes 0.22. The best post-tax NPV/I ratio is 35% lower (at NPV/I = 0.104) than with the commercial incentive case.

Fig. 2.1b summarises the results of reducing the PRT rate to 25% in the fiscal-with-commercial incentives base case. Halving the PRT rate increases the profitability index along with the most generous BFA by 31% (NPV/I = 0.209). Halving the PRT rate is insufficient to reach the investment hurdle.

Fig. 2.2b summarises the results of halving the PRT rate in the fiscal-incentive-only base case scenario. The 20% improvement in this scenario's NPV/I ratio (to 0.125) over its base case, is lower than its corresponding fiscal-plus-commercial incentive case (Fig. 2.1b). Again, the profitability of the fiscal-incentive-only case does not match that of the corresponding combined incentives, and the NPV/I ratio is well below 0.3 even with a very large BFA.

In Fig. 2.1c, the PRT rate is reduced further to 17.5%. This produces a 57% improvement in the NPV/I ratio to 0.249 (from 0.159) but with a very large BFA. This is still below the investment hurdle.

Fig.2.2c representing the fiscal-incentive-only scenario corresponds to the combined incentives scenario summarised in Fig. 2.1c. The maximum attainable NPV/I is 0.143 with a very large BFA, representing a 38% improvement, but still insufficient to reach the investment hurdle.

The conclusion from the results summarised in Fig. 2.1a though Fig. 2.2c is that, even with very high levels of BFAs (up to five times the current level) combined with lower PRT (down to 17.5%) and captured CO_2 for EOR at zero cost may be inadequate to encourage CO_2-EOR at Brae.

The potential efficacy of investment uplifts to incentivise CO_2-EOR

Figs. 3.1a to 3.2c summarise the results of applying various commercial and fiscal incentives to the CO_2-EOR investment incorporating the investment uplift for SC. The commercial incentive is as defined above while the two levels of fiscal incentives now include lower PRT and investment for SC uplift at 0%, 62.5%, 65%, 70%, 75% and 80% of incremental CAPEX.

Table 3: Brae: Sensitivity of NPV/i to variations in PRT, with investment uplifts for SC and CO_2 prices

Current and hypothetical investment uplifts (CAPEX-based) with captured CO_2 price=£0/tCO_2

Current and hypothetical investment uplifts (CAPEX-based) with captured CO_2 price=£9/tCO_2

Fig.3.1a: Base scenario: PRT @ 50%

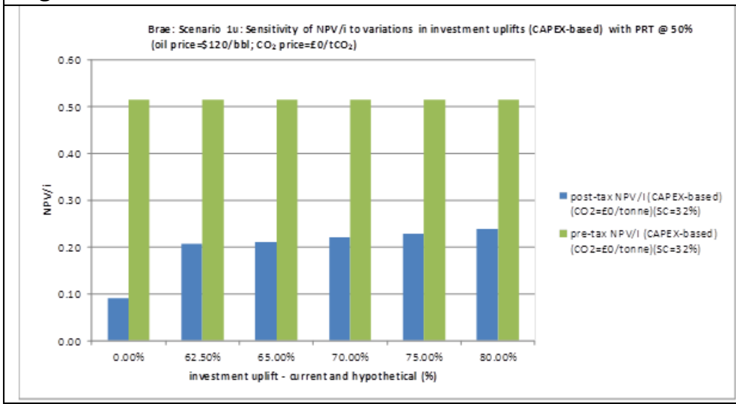


Fig. 3.2a: Base scenario: PRT @ 50%

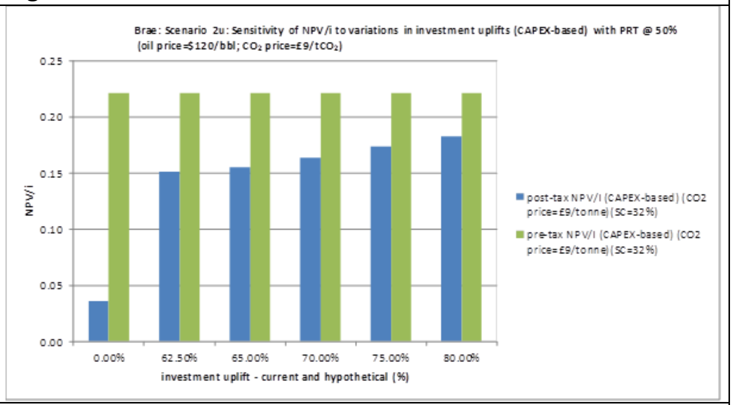


Fig. 3.1b: PRT @ 25%

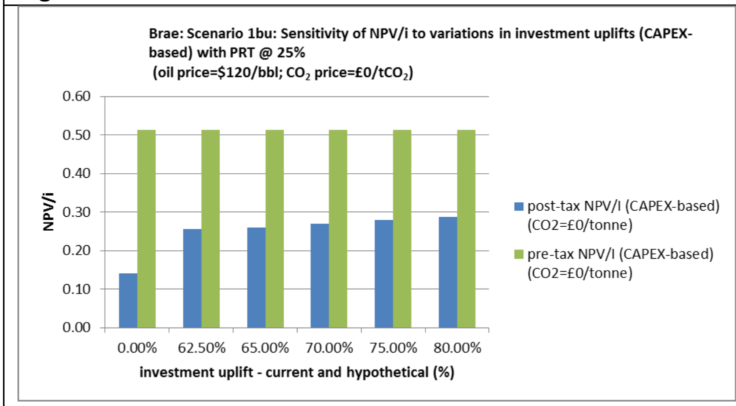


Fig. 3.2b: PRT @ 25%

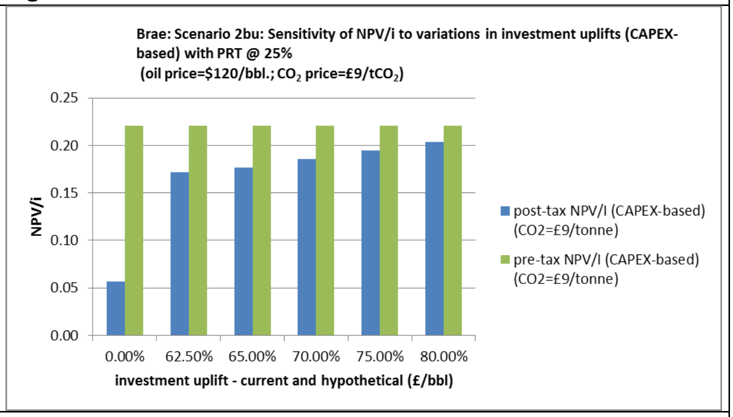


Fig. 3.1c: PRT @ 17.5%

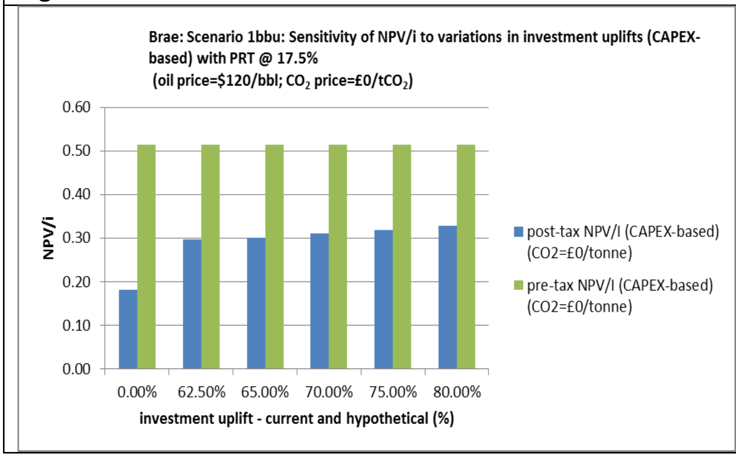


Fig. 3.2c: PRT @ 17.5%

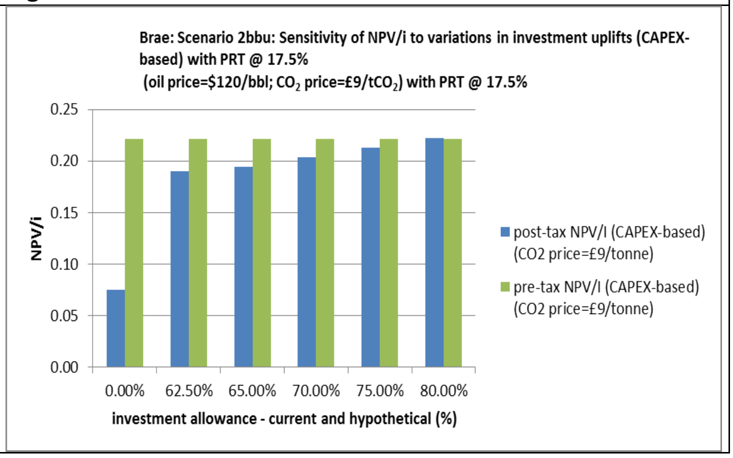


Fig. 3.1a shows that at the current rates of PRT and SC commercial incentivisation alone (i.e. without investment uplift allowance) would generate an NPV/I = 0.091. However, combining the commercial incentive with 62.5% investment uplift yields a stronger improvement in

the project's profitability (126%) than does an application of the current BFA level (15%). Nevertheless, the profitability index at NPV/I = 0.206 is still below the assumed hurdle rate. Increasing the investment uplift to 80% increases the NPV/I to 0.238.

The results summarised in Fig. 3.2a of the base case scenario of the fiscal-incentives-only regime follows the same reasoning as the corresponding combined incentivisation in Fig. 3.1a. Paying £9/tCO_2 dampens the investment returns relative to the zero carbon price scenario at each level of the investment allowance. The combined incentivisation scheme is much preferable to the investor.

The results when the PRT rate in the case of combined incentives is lowered to 25% are summarised in Fig. 3.1b. With an allowance of 62.5% the NPV/I ratio = 0.256 which is 24% higher than the base case scenario. The allowance was increased in stages to 80%, at which point the NPV/I = 0.288 which is 21% higher than the corresponding base case scenario and close to the assumed hurdle of 0.3.

Fig. 3.2b summarises the experimental results when the PRT rate is reduced to 25% from the fiscal-incentive-only base case scenario. When the investment allowance is 62.5% the NPV/I ratio is 0.172. This is an improvement of 14% over the base case scenario, but 33% lower than the corresponding combined incentives case. The NPV/I at the assumed maximum rate of 80% is 0.204. This represents an 11% improvement over the base case, but 29% less than the corresponding combined incentives package.

Figs 3.1c and 3.2c summarise the results when the PRT rate is reduced further to 17.5%

Before applying the investment uplift, the reduction in the PRT rate from 50% to 17.5% increased the profitability index by 99% to 0.181 (from 0.091) but this is still well below the investment hurdle. Applying the investment uplift rate of 62.5% increases the profitability index further by 44% to 0.296 which is very close to the assumed hurdle. The hurdle rate of NPV/I = 0.300 is exactly satisfied when the allowance is raised to 65% rate. Significantly, only 64% of the maximum available allowance of £800 million would have been used up. Increasing the allowance to 80% improves the profitability index to 0.328.

There are two noticeable features of Fig. 3.2c. Firstly, the fiscal incentivisation through the investment uplift allowance coupled with reduction in the PRT rate was not strong enough to reach the required profitability threshold. This is in spite of the major narrowing of the pre- and post-tax profitability index as the allowance rates increased. Indeed, at the assumed 80% maximum allowance rate, the post-tax NPV/I (=0.222) is marginally higher than the pre-tax one (0.221). Other things being equal, this is undesirable.

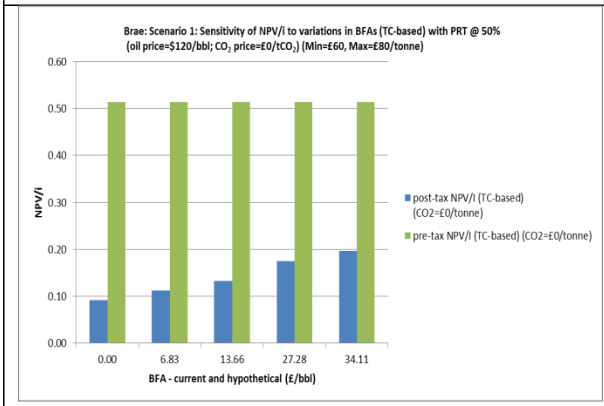
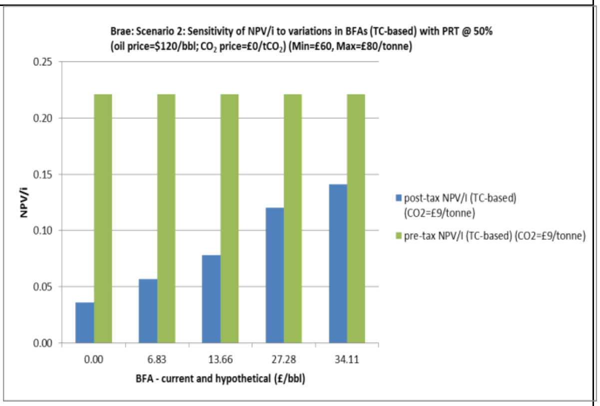
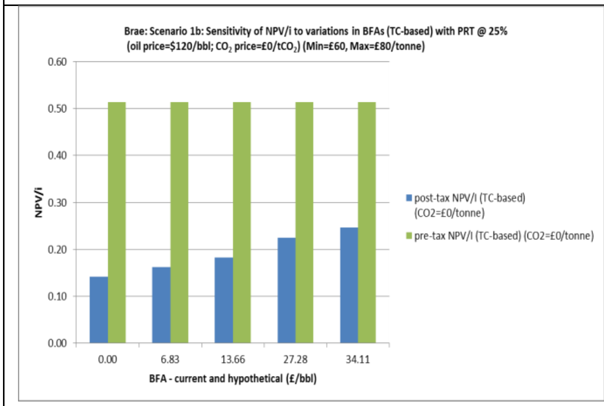
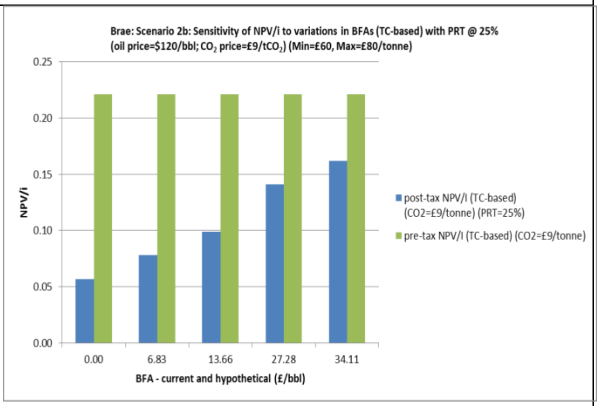
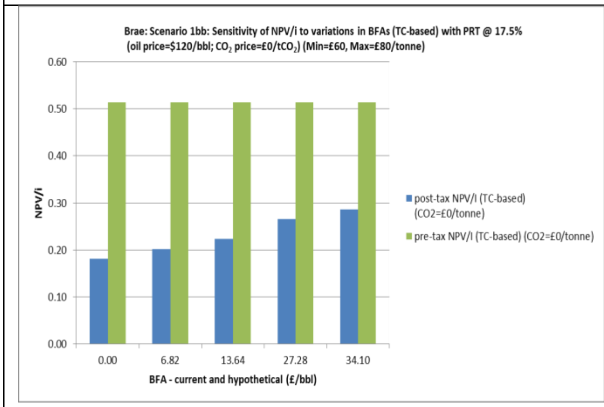
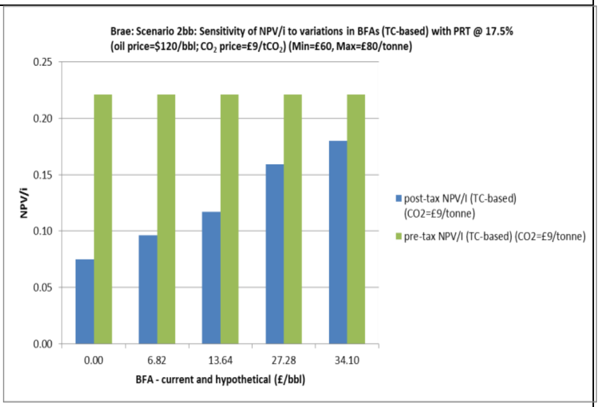
The conclusions that can be reached from the analysis are that when either the BFA or investment uplift is based on the project's CAPEX (1) the combined commercial and fiscal incentives are potentially more effective in encouraging CO_2-EOR investments and, (2) the combined package incorporating the investment uplift is much more likely to encourage investment compared to the package incorporating BFAs at the various rates of allowance considered.

The potential efficacy of BFAs to incentivise CO_2-EOR (Total cost-basis) (partial OPEX)

The next step in the analysis was an investigation of the relative efficacy of the incentives when the basis of the allowance is the project's total cost rather than capital cost. The total-cost-with-partial OPEX (TCWPO) is considered at this stage. The maximum allowance is available at £10.91/bbl. (£80/tonne)[5] of incremental reserves. But, where necessary, the existing cap on the maximum available total allowance for a PRT field (£500 million) is lifted.

[5] See Fig.1.

Table 4: Brae: Sensitivity of NPV/i to variations in PRT, given BFAs (Total cost-based) and captured CO_2 prices.

<table>
<tr><td>Current and hypothetical BFAs with captured CO_2 price=£0/tCO_2</td><td>Current and hypothetical BFAs with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig.4.1a: Base scenario: PRT @ 50%</td><td>Fig. 4.2a: Base scenario: PRT @ 50%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 4.1b: PRT @ 25%</td><td>Fig. 4.2b: PRT @ 25%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 4.1c: PRT @ 17.5%</td><td>Fig. 4.2c: PRT @ 17.5%</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

Comparing the results summarised in Fig. 4.1a with those in Fig. 2.1a, it is seen that the application of the current BFA using the TCWPO basis resulted in a 7% improvement in the NPV/I index over the CAPEX-basis

(0.112 v. 0.105). The total amount of BFA used up increased by 54% but remains less than the maximum available of £500 million. The application of five times the current unit BFA resulted in NPV/I = 0.196, which is an improvement of 23% over the corresponding CAPEX-based allowance. However, the total amount of BFA used increases to 2.2 times the current maximum available.

Comparing Figs. 4.2a and 2.2a indicates the same pattern in the relationship between the profitability indices of the CAPEX- and TCWPO-based allowances. As before, the induced BFA-only profitability indices in Fig. 4.2a are generally lower than the corresponding combined incentives package shown in Fig. 4.2a. Indeed the highest NPV/I at 0.141 is only 72% of the combined incentives case.

Adding to the combined incentives in Fig. 4.1a (base case), the further incentive of the PRT rate reduction to 25%, the results in Fig. 4.1b show a general improvement in the profitability indices. Thus, when the current unit BFA is applied, the NPV/I improves by 45% (from 0.112 to 0.162. However, the maximum NPV/I = 0.246 in this scenario, even though higher than the base case by 26%, is still below the minimum threshold.

The results summarised in Fig. 4.2b can be compared with those in Fig. 4.1b in the case of the fiscal-incentives-only regime. The combined incentives case along with the PRT reduction to 25% in this scenario generally improves the profitability indices but not so robustly. Thus, unlike the 45% increase in profitability in the initial combined incentivisation scheme, the corresponding increase in this scenario is only 37% (NPV/I = 0.078 v. NPV/I = 0.057). In this scenario's best case, the profitability index reaches 0.162, which, at 15% above the base case, represents a relatively weak improvement compared to the combined incentives case.

Fig. 4.1c summarises the results when the base case of the combined incentive scheme (in Fig. 4.1a) is enhanced by reducing the PRT rate to 17.5%. Applying the current unit BFA improves the profitability index (over the base case) by 80% (0.202 v. 0.112). The index improves by 42% to 0.286 if the current unit BFA is multiplied five times. While not shown in Fig. 4.1c, the hurdle rate is marginally surpassed (NPV/I = 0.307) if the current unit BFA was multiplied six times (to £40.91/bbl.).

Fig 4.2c summarises the base case of the fiscal-incentives-only regime being further incentivised by reducing the PRT rate to 17.5%. Applying the current unit BFA improves the NPV/I by 68% (again, less strongly than the corresponding combined incentives case) to 0.096. Increasing the current unit BFA five times improves the profitability index by 88% to 0.180. When the current unit BFA was multiplied six times it yielded NPV/I = 0.201. Generally, as in the previous cases, the profitability indices of this scenario are significantly lower than in the corresponding combined incentives package.

The potential efficacy of uplifts to incentivise CO2-EOR (Total cost-basis) (partial OPEX)

Table 5: Brae: Sensitivity of NPV/i to variations in PRT, given uplifts (Total cost-based) and captured CO_2 prices

Current and hypothetical investment uplifts (Total cost-based) with captured CO_2 price=£0/tCO_2	Current and hypothetical investment uplifts (Total cost-based) with captured CO_2 price=£9/tCO_2
Fig.5.1a: Base scenario: PRT @ 50%	Fig. 5.2a: Base scenario: PRT @ 50%

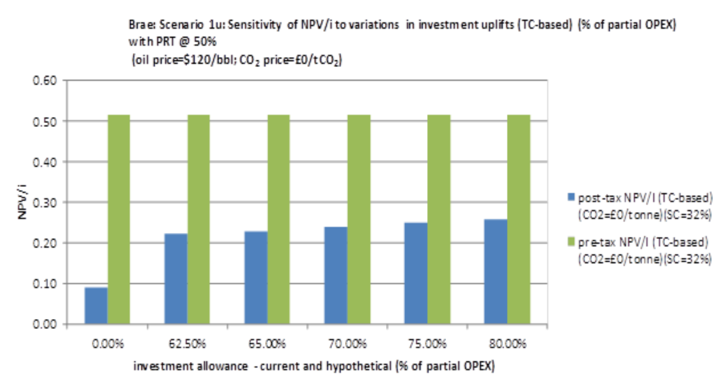
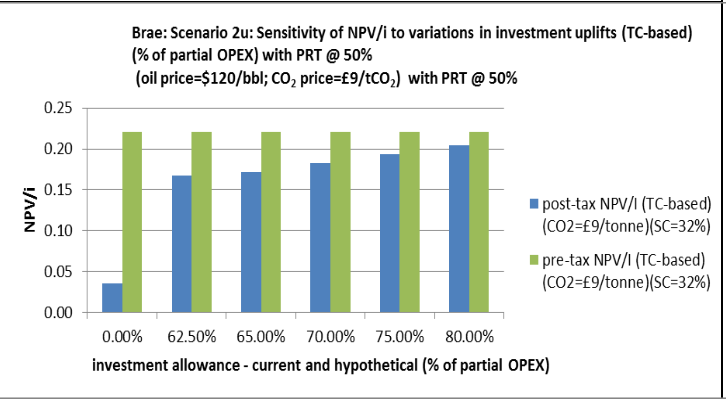

	

Fig. 5.1b: PRT @ 25%	Fig. 5.2b: PRT @ 25%

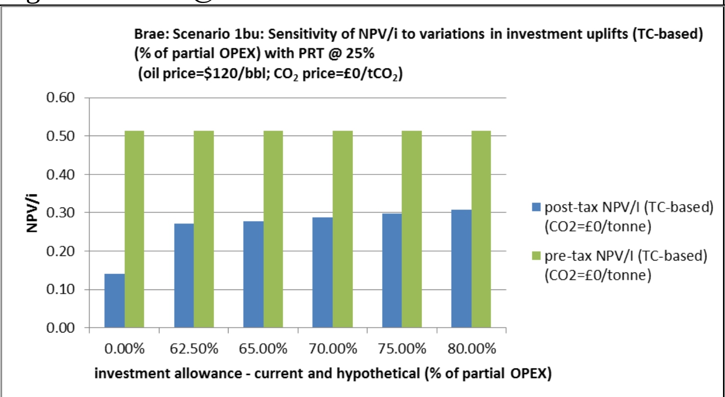
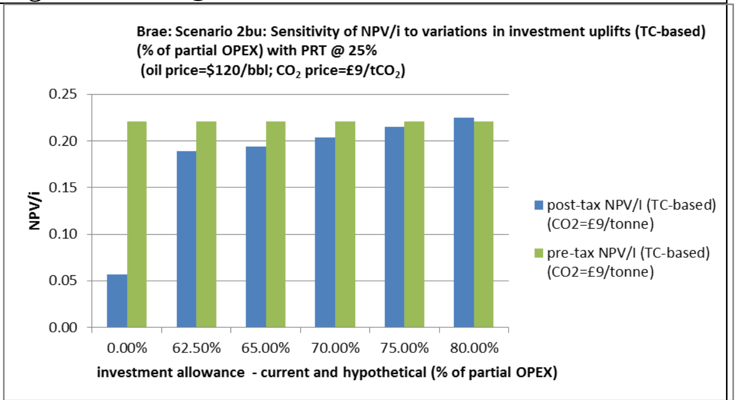
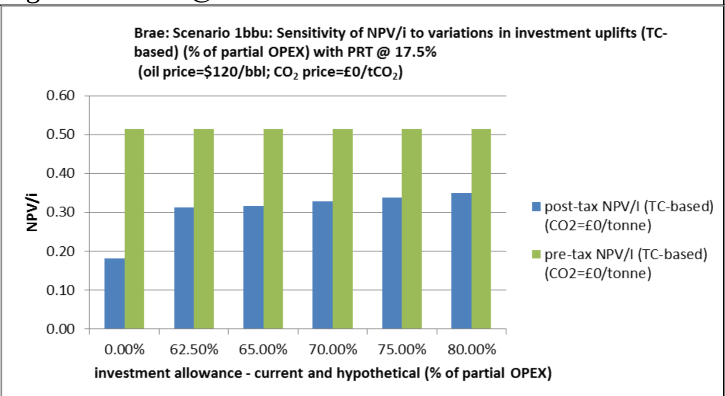
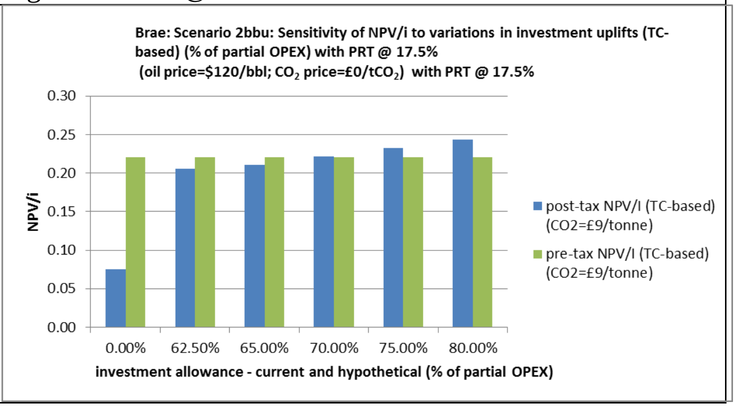

	

Fig. 5.1c: PRT @ 17.5%	Fig. 5.2c: PRT @ 17.5%
	

In Fig. 5.1a, applying the uplift at the 62.5% rate on the TCWPO basis as part of the combined incentives package generated NPV/I = 0.223. This is 8% higher than the corresponding CAPEX-based allowance (in Fig. 3.1a). Increasing the allowance rate to 80% improves the NPV/I to 0.259.

In Fig. 5.2a, NPV/I = 0.167 when the 62.5% allowance rate is applied in the fiscal-incentives-only case on TCWPO-basis. This is 11% higher than the corresponding CAPEX-based allowance (in Fig. 3.2a). The stronger improvement in profitability in this scenario compared to the corresponding combined incentives case in Fig. 5.1a is noteworthy. Increasing the allowance to 80% improves the profitability index to 0.204 which is still 11% above the CAPEX-based allowance, but 21% lower than the corresponding combined incentive scheme.

Further incentivising the combined incentives package by reducing the PRT rate to 25% produced the results summarised in Fig. 5.1b. The reduction improves the profitability index over the base case (Fig. 5.1a) by 22% (0.272 v. 0.223) when the 62.5% allowance rate is applied. By raising the allowance rate to 75% there is a 10% improvement in project profitability with NPV/I = 0.298. An increase in the allowance rate to 80% generates a 14% higher NPV/I = 0.309. These results are interesting because they show that, compared to the corresponding CAPEX-based case (where the hurdle rate was not met), an adoption of the TCWPO can lead to the realisation of the hurdle rate with PRT reduced to 25%.

In Fig. 5.2b, applying the 62.5% allowance rate and the 25% PRT rate from the fiscal-incentives-only base case (Fig. 5.2a) generates a 13% increase in the profitability index to 0.189 (from 0.167). Increasing the allowance rate to 80% improves the NPV/I to 0.225.

Fig. 5.1c summarises the results of reducing the PRT rate in Fig. 5.1a to 17.5%. At the 62.5% allowance rate, the profitability index improves by 40% to NPV/I = 0.312 (from 0.223). This satisfies the assumed hurdle rate. Compared to the results in Fig. 5.1b, the results of this scenario suggest that the 62.5% allowance when combined with a lower PRT (17.5%) and the joint incentives may encourage CO_2-EOR investment. Increasing the allowance rate to 80% improves the profitability index to 0.349.

Fig. 5.2c shows the fiscal-incentives-only scenario corresponding to Fig. 5.1c. At 62.5% allowance rate, the PRT reduction to 17.5% generates a 23% profitability improvement to NPV/I = 0.206. While increasing the allowance rate to 80% raises the profitability index to NPV/I = 0.243 this is still below the hurdle rate.

In sum, within the current and hypothetical ranges of the BFA and uplift allowances chosen in the study only a few instances of the combined incentives package delivered results that could incentivise CO_2-EOR investment. None of the fiscal-incentives-only regimes yielded outcomes that passed the investment hurdle. One contributory explanation of the generally poor investment returns is the assumed commencement of the EOR project relatively late in field life, with low levels of remaining reserves and high water cut.

Buzzard

The potential efficacy of BFAs to incentivise CO_2-EOR (CAPEX-basis)

The results of the experiments investigating the possible effectiveness of an extension of BFAs alongside commercial incentives to encourage

CO_2-EOR at Buzzard are presented in Table 6. The project hurdle remains at NPV/I of 0.3 in this and all other cases. The basis of the BFA allowance is the project's CAPEX.

Table 6: Buzzard: Sensitivity of NPV/I to variations in captured CO_2 prices, given BFAs (CAPEX-based)

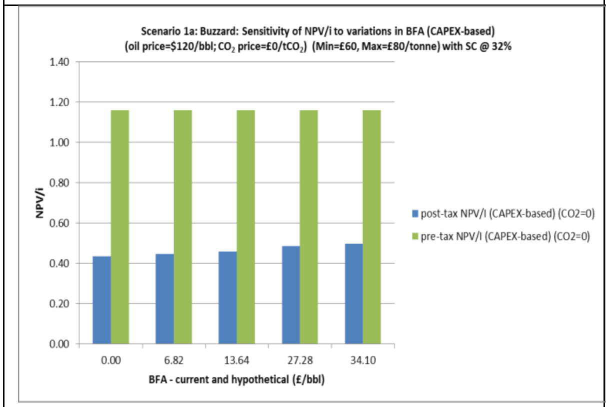
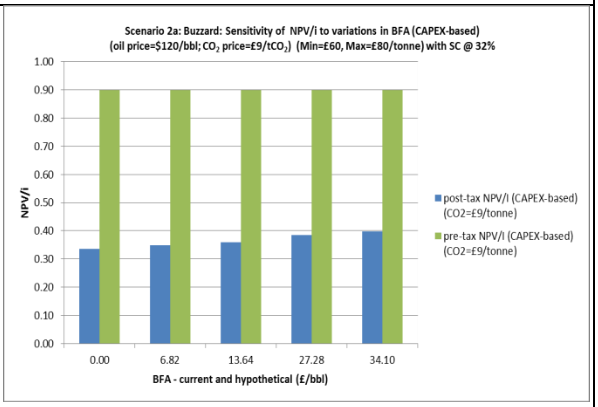
Current and hypothetical BFAs (CAPEX-based)	**Current and hypothetical BFAs (CAPEX-based)**
Fig.6.1a: Base scenario: captured CO_2 price=£0/tCO_2	Fig. 6.1b: Alternative scenario: captured CO_2 price=£9/tCO_2
	

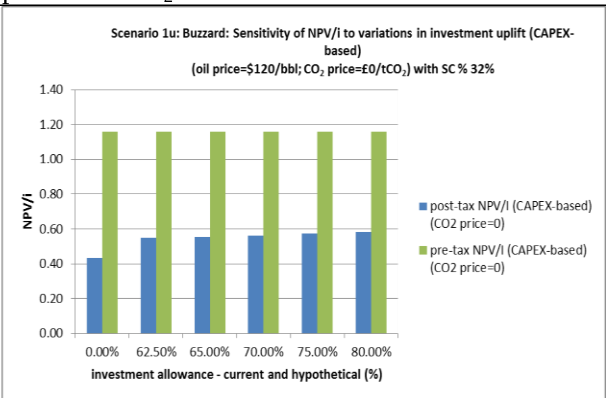
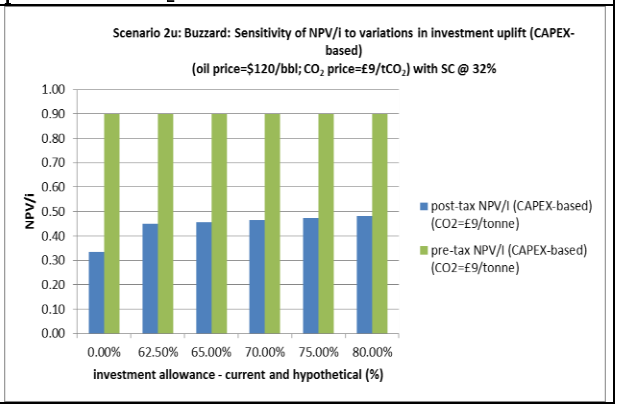
Fig 6.1a shows a summary of the results when the combined incentives package is applied to the Buzzard field. At zero BFA but with zero price paid for CO2, the profitability index at NPV/I = 0.434 exceeds the hurdle rate. Applying the current BFA of £6.82/barrel improves the profitability index marginally by 5% to NPV/I = 0.447. Increasing the unit allowance to £34.1/bbl. improves the profitability index to NPV/I = 0.497.

The results of the corresponding fiscal-incentives-only case are summarised in Fig. 6.1b. Without the BFA profitability is slightly above the hurdle rate at NPV/I = 0.335. Applying the current BFA improves the profitability by 3% to NPV/I = 0.348. Increasing the unit BFA allowance to the maximum assumed in the study resulted in an 18% increase in the NPV/I to 0.398.

The foregoing results suggest that CO_2-EOR investment at Buzzard is potentially promising. This is due in part to the relatively larger volume of remaining reserves and comparatively low water cut at the commencement of CO_2-EOR operations. Being relatively close to the onshore CO_2 hub and the backbone pipeline produces savings in transport costs.

Given the field's relative profitability with moderate incentives, further incentivisation schemes were deeded unnecessary. However, by way of comparison the relative impact of the investment uplift allowance is shown in Table 7.

Table 7: Buzzard: Sensitivity of NPV/i to variations in captured CO_2 prices, with uplifts for SC

Current and hypothetical uplifts (CAPEX-based)	**Current and hypothetical uplifts (CAPEX-based)**
Fig.7.1a: Base scenario: captured CO_2 price=£0/tCO_2	Fig. 7.1b: Alternative scenario: captured CO_2 price=£9/tCO_2
	

The results in Table 7 compared to those in Table 6 show that the investment uplift offers higher returns to CO2-EOR investments. Thus, in Fig. 7.1a at the 62.5% rate, the NPV/I = 0.549 which is 23% higher than the corresponding initial BFA's profitability index (NPV/I = 0.447).

The same conclusion is reached in the fiscal-incentives-only case summarised in Fig. 7.1b. At the initial investment uplift rate of 62.5% and the BFA at £6.82/bbl., the former's profitability index at NPV/I = 0.450, is 29% higher than with the BFA scheme.

CLAYMORE

The potential efficacy of BFAs to incentivise CO_2-EOR (CAPEX-basis)

The results of the experiments investigating the possible effectiveness of an extension of BFAs alongside commercial incentives to encourage CO_2-EOR at Claymore are presented in Table 8. The project investment hurdle remains a minimum NPV/I = 0.3 in this and all other cases. The basis of the current and hypothetical allowances is the project's CAPEX.

Table 8: Claymore: Sensitivity of NPV/i to variations in PRT, given BFAs (CAPEX-based) and CO_2 prices.

Current and hypothetical BFAs with CO_2 price=£0/tCO_2	**Current and hypothetical BFAs with CO_2 price=£9/tCO_2**
Fig.8.1a: Base scenario: PRT @ 50%	Fig. 8.2a: Base scenario: PRT @ 50%

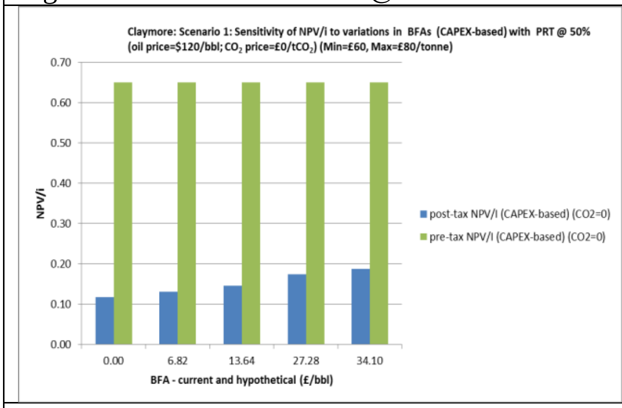
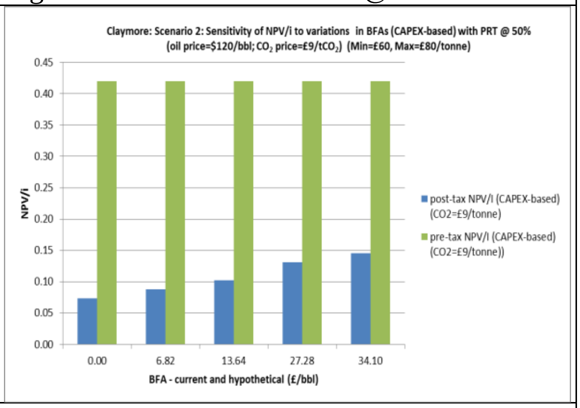

	

Fig. 8.1b: PRT @ 25%	Fig. 8.2b: PRT @ 25%

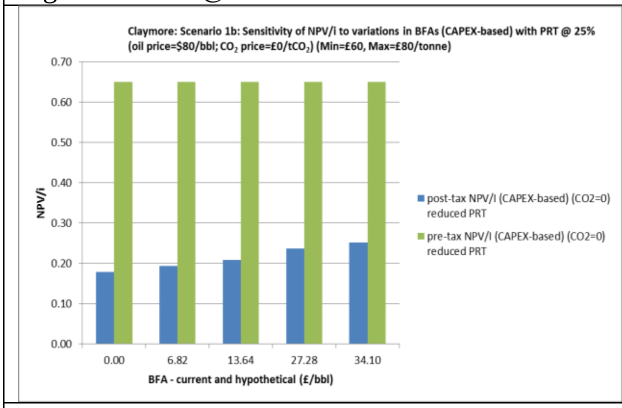
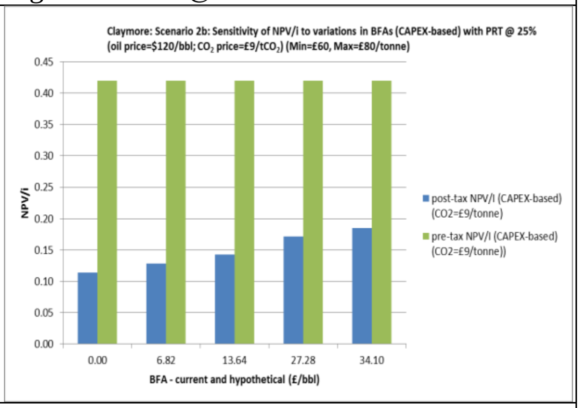
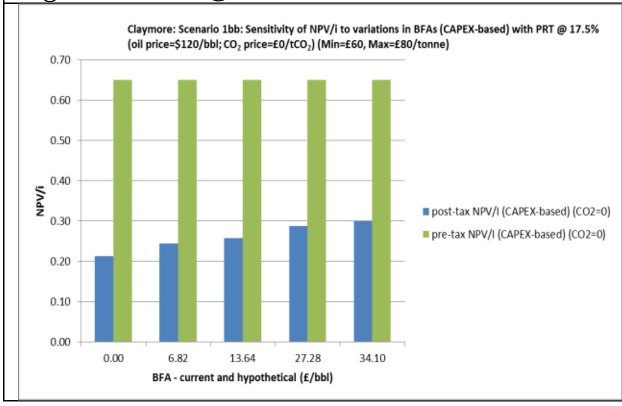
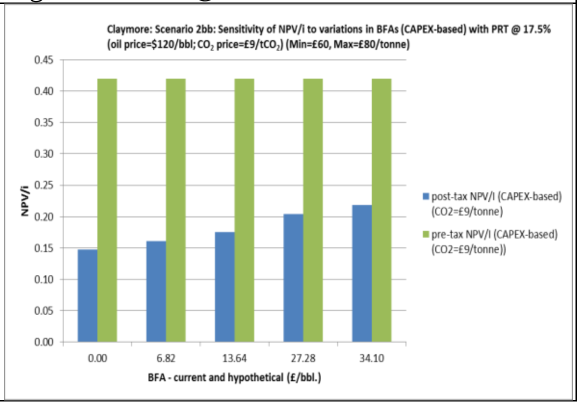

	

Fig. 8.1c: PRT @ 17.5%	Fig. 8.2c: PRT @ 17.5%
	

The results of the base case scenario of the application of the combined commercial and fiscal incentives package are summarised in Fig. 8.1a. The project is seen to be clearly viable before tax with NPV/I of 0.64. When only the commercial incentive was available NPV/I = 0.117. When the BFA was added at the current unit rate of £6.82/bbl., the profitability index improved by 12% to 0.131. Applying the study's maximum hypothetical BFA of £34.1 per barrel further improved the profitability index to 0.188 which is still below the hurdle rate.

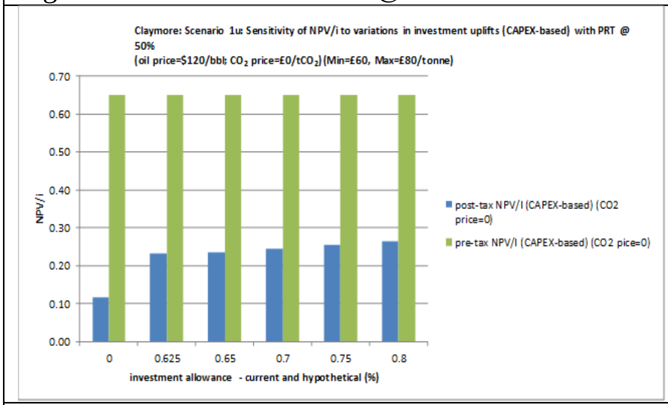
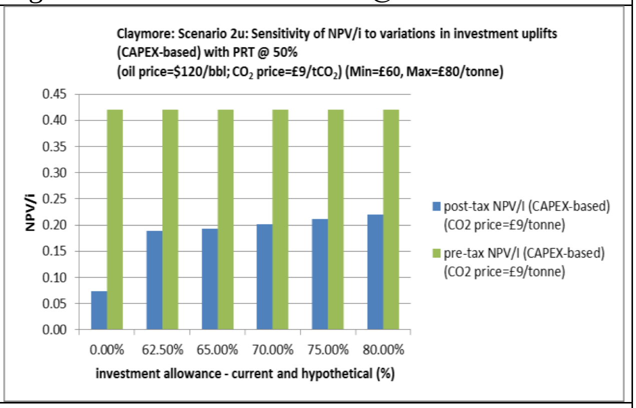
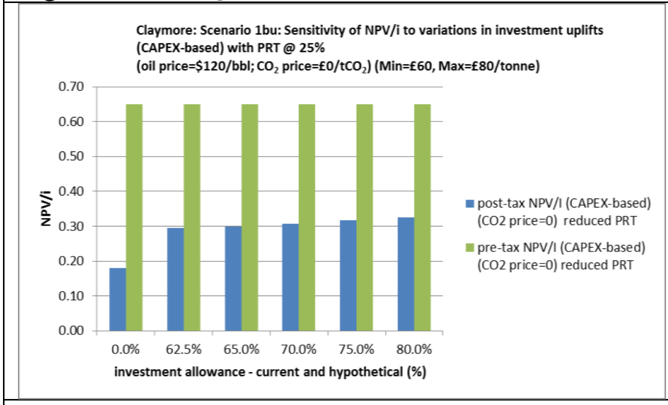
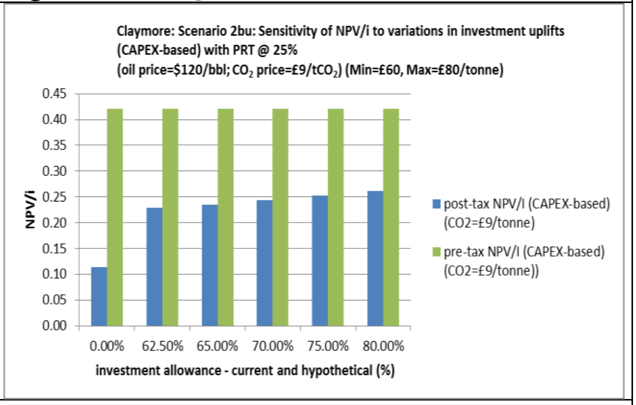
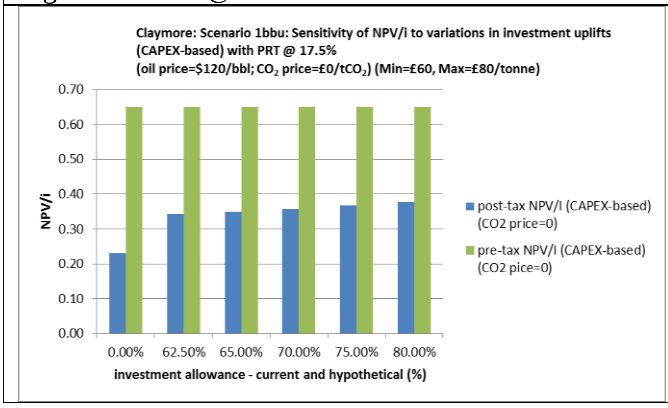
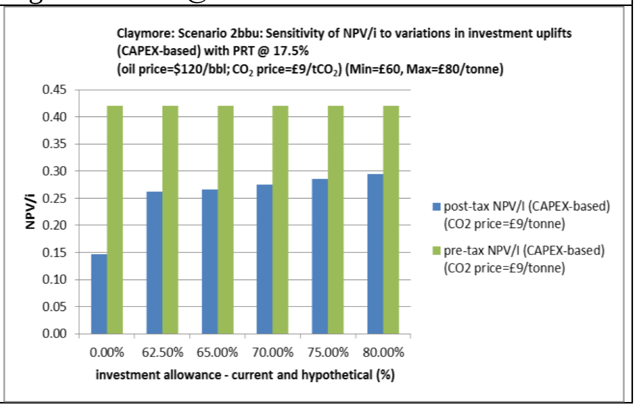
In Fig. 8.2a the results of the corresponding (base case) fiscal-incentives-only scenario indicate that the project remains viable before tax with NPV/I = 0.42. After the current tax NPV/I = 0.073 which is 38% lower than the corresponding case with-commercial incentive. When the BFA at the rate of £6.82/bbl is applied, the NPV/I improves by 21% to 0.088. Increasing the BFA rate to the study's maximum improves the profitability index to 0.145 which is 30% lower than the corresponding combined incentives case.

Figs. 8.1b and 8.2b show summaries of further incentivisation by reducing the PRT rate to 25%. The post-tax results remain below the investment threshold. However, as can be seen in Fig. 8.1c the combined incentives scenario with PRT reduced to 17.5% plus BFA at the extremely high level of £34.1 per barrel produces NPV/I = 0.3. At lower BFA levels the threshold is not reached. With a CO_2 price of £9 per tonne the hurdle is never passed. The difference between the pre- and post-tax NPV/I ratios remains large.

The potential efficacy of investment uplifts to incentivise CO_2-EOR (CAPEX-basis)

The results of the experimental runs with investment uplifts (CAPEX-basis) are summarised in Table 9.

Table 9: Claymore: Sensitivity of NPV/I to variations in PRT, assuming various uplifts (CAPEX-based) and CO_2 prices

<table>
<tr><td>Current and hypothetical investment uplifts (CAPEX-based) with captured CO_2 price=£0/tCO_2</td><td>Current and hypothetical u-HPHT uplifts (CAPEX-based) with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig.9.1a: Base scenario: PRT @ 50%</td><td>Fig. 9.2a: Base scenario: PRT @ 50%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 9.1b: PRT @ 25%</td><td>Fig. 9.2b: PRT @ 25%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 9.1c: PRT @ 17.5%</td><td>Fig. 9.2c: PRT @ 17.5%</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

The initial conditions in Fig. 9.1a summarising the combined incentives results are the same as those in Fig. 8.1a (BFA incentives case) and, therefore, require no further elaboration. However, when the 62.5% uplift rate was applied the difference in the relative performance of the two allowances is apparent. In this scenario the application of the rate of 62.5% led to a 98% improvement in the profitability index (0.232 v.

0.117), while the initial improvement in the BFA case was only 12% (0.131 v. 0.117). Increasing the uplift allowance to 80% improves the profitability index to 0.264.

In Fig. 9.2a which summarises the results of the fiscal-incentives-only scenario corresponding to the combined incentives case in Fig. 9.1a, it can be seen that the profitability indices are generally lower and none meet the investment hurdle.

In Fig. 9.1b it can be seen that even before applying the uplift allowance the reduction in the PRT rate to 25% by itself improves the profitability index by 53% over the base case in Fig. 9.1a. Another feature of the results in this chart is that NPV/I = 0.299 and the threshold rate virtually attained at the 65% uplift rate. At 70%, the NPV/I = 0.308. Clearly, compared to the BFA, the threshold rate is reached with a smaller reduction in the required PRT rate (25% v. 17.5%).

The investment hurdle is still not satisfied in Fig. 9.2b in the corresponding fiscal-incentives-only case, even with a very high uplift.

In Fig. 9.1c complementing the combined commercial and fiscal incentives with PRT rate reduction to 17.5% greatly enhances profitability. Thus, applying the 62.5% rate, NPV/I = 0.344.

The main feature of Fig. 9.2c summarising the corresponding[6] fiscal-incentives-only is the near satisfaction of the investment hurdle. NPV/I = 0.294 with the very high 80% uplift rate.

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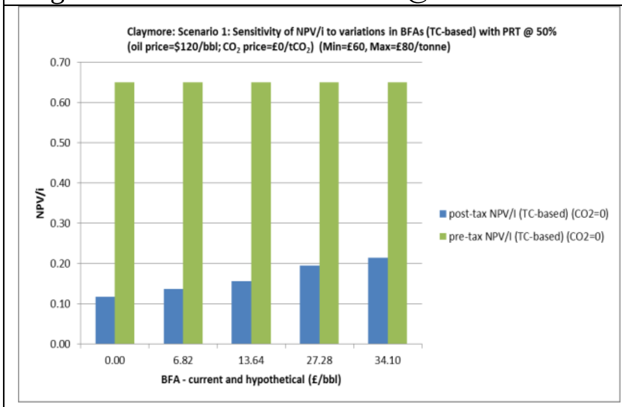
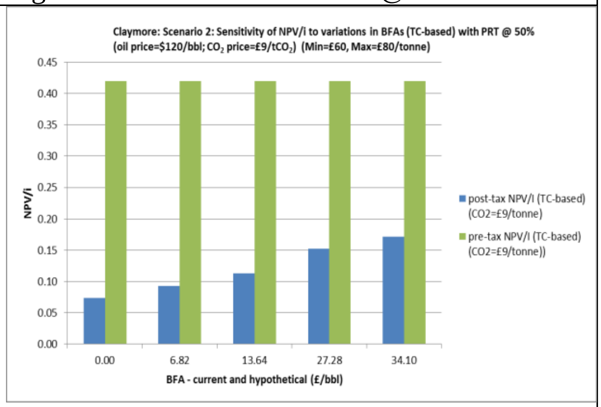
[6] To Fig. 9.1c.

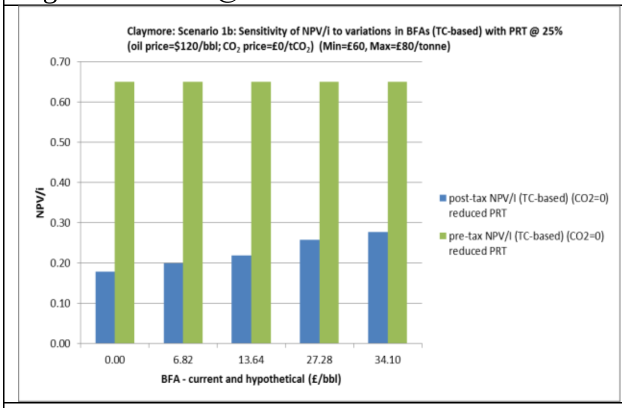
The potential efficacy of BFAs to incentivise CO_2-EOR (Total cost-basis)

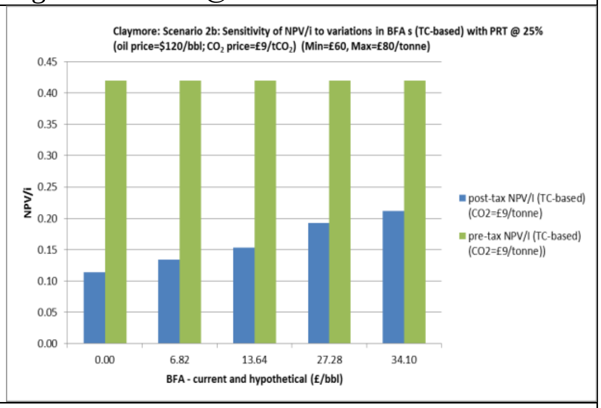
Table 10 summarises the results of the various experimental runs designed to assess the efficacy of BFAs based on total cost.

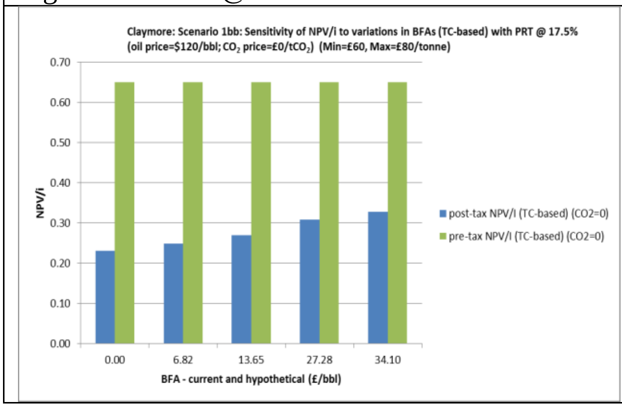
Table 10: Claymore: Sensitivity of NPV/i to variations in PRT, assuming various BFAs (Total cost-based) and captured CO_2 prices.

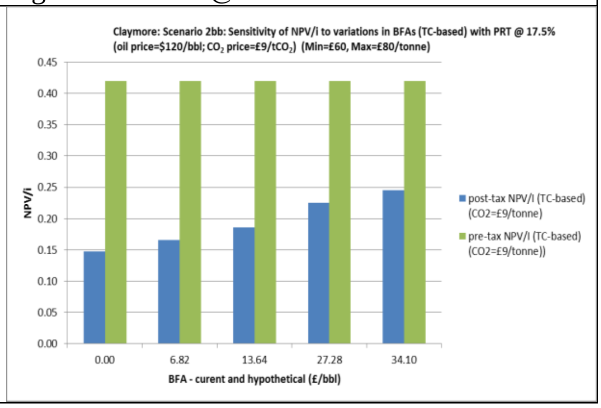
<table>
<tr><td>Current and hypothetical BFAs with captured CO_2 price=£0/tCO_2</td><td>Current and hypothetical BFAs with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig. 10.1a: Base scenario: PRT @ 50%</td><td>Fig. 10.2a: Base scenario: PRT @ 50%</td></tr>
<tr><td>


</td><td>


</td></tr>
<tr><td>Fig. 10.1b: PRT @ 25%</td><td>Fig. 10.2b: PRT @ 25%</td></tr>
<tr><td>


</td><td>


</td></tr>
<tr><td>Fig. 10.1c: PRT @ 17.5%</td><td>Fig. 10.2c: PRT @ 17.5%</td></tr>
<tr><td>


</td><td>


</td></tr>
</table>

Fig. 10.1a shows that when the initial BFA of £6.82/bbl is applied on the total-cost basis the profitability index is, at NPV/I = 0.137, 5% higher than the corresponding CAPEX-basis one. Increasing the BFA to the maximum in the study improved the NPV/I to 0.215 which is 14% higher that achieved with the equivalent CAPEX-basis.

The fiscal-incentives-only results summarised in Fig. 10.2a, as in previous cases, fared worse than those in Fig. 10.1a with profitability well below the hurdle.

Fig. 10.1b shows the summary results of supplementing the combined incentives package with a reduction in the PRT rate to 25%. The best outcome from the investor's perspective is an NPV/I = 0.277 with a very high BFA. In the corresponding fiscal-incentives-only results summarised in Fig. 10.2b the best outcome is NPV/I = 0.212 with a very high BFA.

More encouraging results can be seen in Fig. 10.1c which summarises the case of supplementing the combined incentives with a reduction in the PRT rate to 17.5%. Applying a BFA rate of £27.28/bbl., the profitability index improves to 0.308. In the corresponding fiscal-incentives-only case summarised in Fig. 10.2c, the best outcome is NPV/I = 0.245 with the highest rate of BFA.

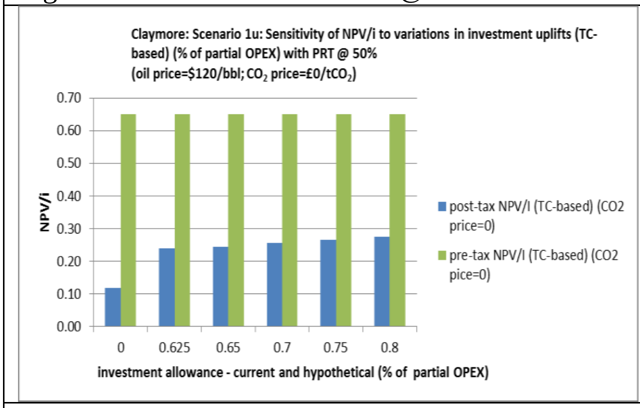
The potential efficacy of investment uplifts to incentivise CO_2-EOR (Total cost-basis with commercial incentive)

Tables 11 and 12 summarise the results of the various experimental runs designed to assess the efficacy of the investment uplift allowances on a total cost-basis. Table 11 presents the combined-incentives results while Table 12 presents the fiscal-incentives-only results.

The focus here is on an assessment of the relative impact on the project's profitability of using the total-cost-with-the-full OPEX basis or with-partial-OPEX basis. The total cost-with-the-partial OPEX summary results are on the LHS panels of the table while the total-cost-with-full-OPEX basis is on the RHS.

Table 11: Claymore: Sensitivity of NPV/i to variations in PRT, assuming various investment uplifts (alternative Total cost-bases) and captured CO_2 prices

Current and hypothetical investment uplifts (Total cost -based) (% of partial OPEX) with captured CO_2 price=£0/tCO_2	Current and hypothetical investment uplifts (Total cost-based) (% of full OPEX) with captured CO_2 price=£0/tCO_2
Fig. 11.1a: Base scenario: PRT @ 50%	Fig. 11.2a: Base scenario: PRT @ 50%



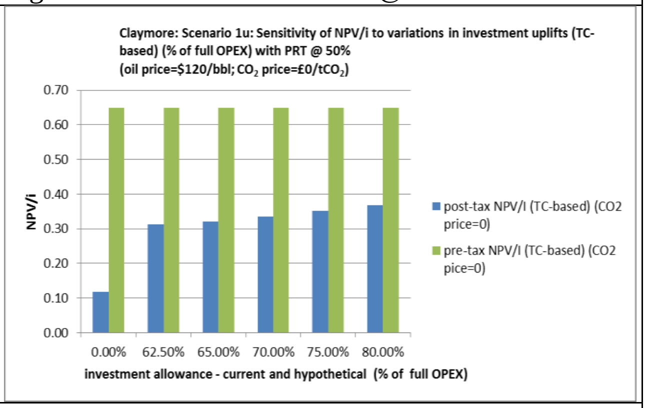
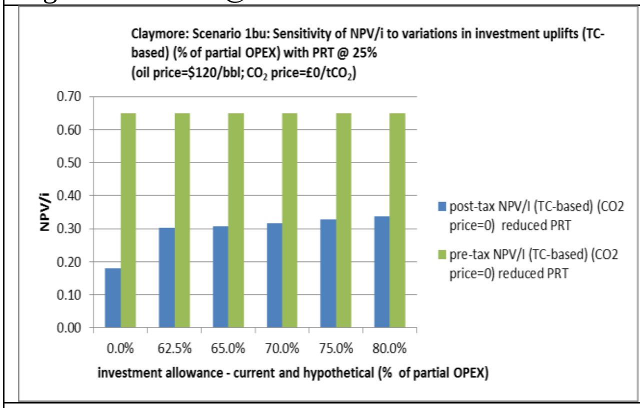


Fig. 11.1b: PRT @ 25%	Fig. 11.2b: PRT @ 25%



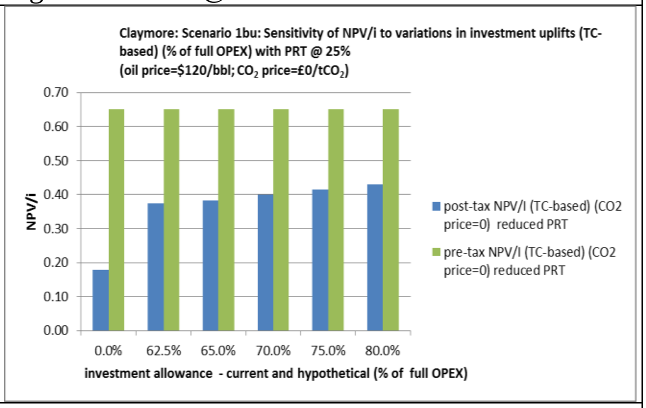
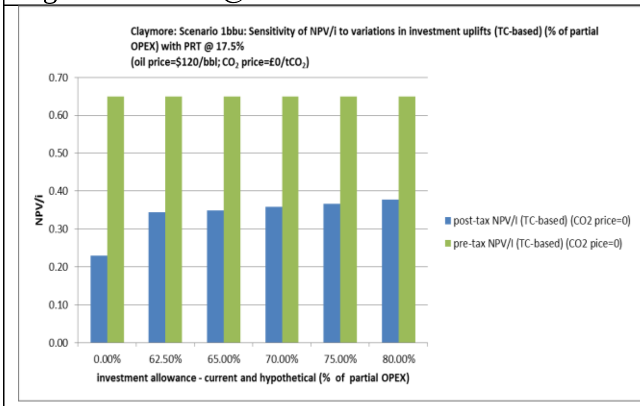
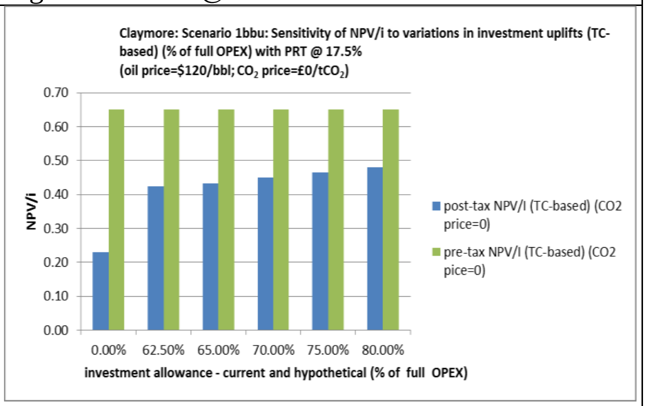


Fig. 11.1c: PRT @ 17.5%	Fig. 11.2c: PRT @ 17.5%





In comparing the summary results in Figs. 11.1a and 11.2a, it is seen that the latter set of results exhibit higher investment returns. Thus, at the 62.5% rate, the NPV/i = 0.313 in the full OPEX case. This not only satisfies the investment hurdle but is 30% higher than the partial OPEX case (NPV/I = 0.240). Increasing the allowance rate to 80% magnifies the differences. The full OPEX-basis case is now 34% higher (0.368 v. 0.275).

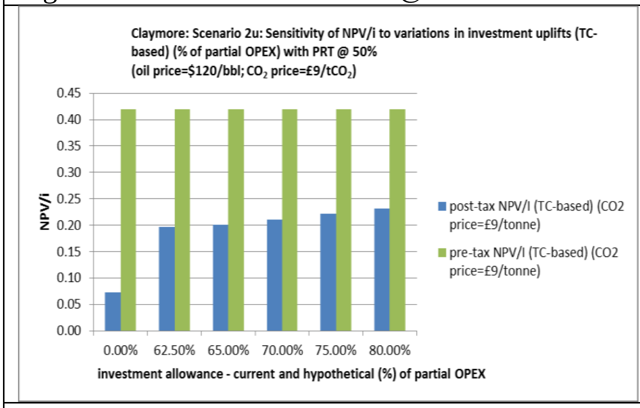
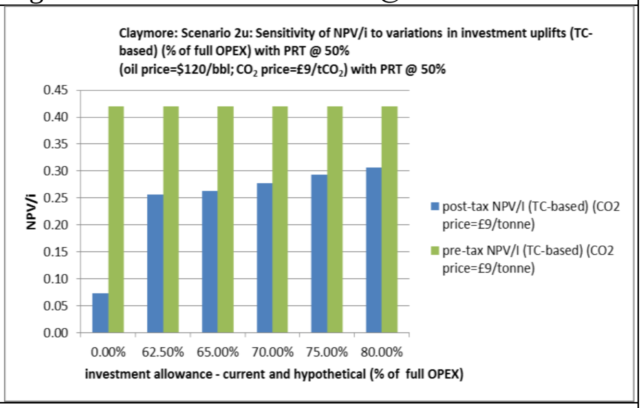
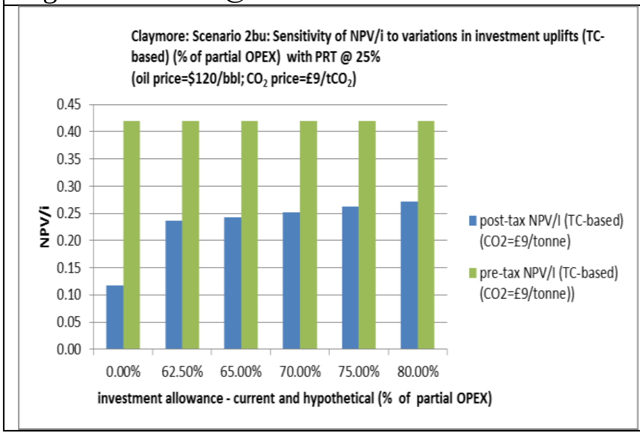
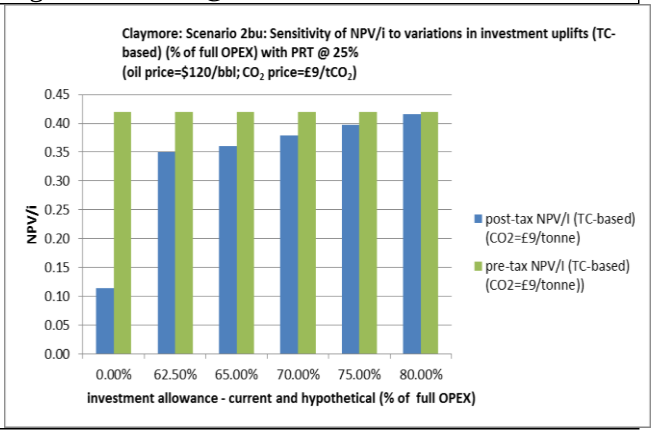
The results in Fig. 11.2a suggest that the full OPEX-basis case requires no further incentivisation through PRT reductions. But the partial OPEX basis requires further incentivisation. In Fig. 11.1b and 11.2b the combined-incentives package (in Figs. 11.1a and 11.1b) is supplemented with a reduction of the PRT rate to 25%. At the 62.5% rate the partial OPEX basis passes the hurdle (NPV/I = 0.375 v. NPV/I = 0.303). At the assumed top rate of 80%, the full OPEX basis produces a profitability index of 0.430 which is 28% higher than the partial OPEX one (0.337).

The results of further incentivisation by reducing the PRT rate to 17.5% are summarised in Figs. 11.1c and 11.2c. At the 62.5% uplift rate, the improvement in profitability from the full OPEX-basis over that of the partial-OPEX one reduces to 20% (0.425 v. 0.353).

The potential efficacy of investment uplifts to incentivise CO_2-EOR (Total cost-basis without commercial incentive)

Table 12 presents summaries of the fiscal-incentives-only results.

Table 12: Claymore: Sensitivity of NPV/i to variations in PRT, assuming various investment uplifts (alternative Total cost-bases) and captured CO_2 prices

<table>
<tr><td>Current and hypothetical investment uplifts (Total cost -based) (% of partial OPEX) with captured CO_2 price=£9/tCO_2</td><td>Current and hypothetical investment uplifts (Total cost-based) (% of full OPEX) with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig. 12.1a: Base scenario: PRT @ 50%</td><td>Fig. 12.2a: Base scenario: PRT @ 50%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 12.1b: PRT @ 25%</td><td>Fig. 12.2b: PRT @ 25%</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

Comparing the results in Figs. 12.1a and 12.2a, it can be seen that the relative superiority of the full-OPEX basis remains at 30% as in the combined incentives case, but both profitability indices (that is, of the full-and partial-OPEX bases) fall short of the hurdle rate (at 0.256 and 0.197 respectively). At the top rate of allowance considered the investment performance increases to 33% (NPV/I = 0.307 v. NPV/I = 0.231). The full-OPEX basis satisfies the investment selection criterion while the partial-OPEX basis does not.

The summaries of the results when the fiscal-only incentives are supplemented with a reduction in the PRT rate to 25% are presented in

Figs. 12.1b and 12.2b. At the 62.5% rate, the full-OPEX basis passes the investment hurdle, and is 48% higher than the partial-OPEX one (NPV/I = 0.350 v. NPV/I = 0.237). At the assumed 80% top rate, the profitability index of the full-OPEX basis improves to 0.416 which is 53% higher than the partial-OPEX basis (0.272). The pre- and post-tax NPV/I ratios of the full-OPEX basis are virtually equal at the top rate of allowance.

Though not shown graphically, the OPEX-basis scheme eventually (with NPV/I = 0.304) passes the hurdle rate when the fiscal-incentives are supplemented by a reduction of the PRT rate to 17.5% and the allowance rate set at the extremely high level of 80%.

Miller

The potential efficacy of BFAs to incentivise CO_2-EOR (CAPEX-basis)

The results of the experiments investigating the possible effectiveness of an extension of BFAs alongside commercial incentives to encourage CO_2-EOR at a reopened Miller field are presented in Table 13. The project hurdle remains a minimum NPV/I of 0.3 in this and all other cases. The allowance is CAPEX-based. Further incentivisation accomplished through reduction in the Supplementary Charge from the current 32% rate to 25% is also examined.

Table 13: Miller: Sensitivity of NPV/I to variations in CO_2 prices, given BFAs (CAPEX-based)

Current and hypothetical BFAs (CAPEX-based)	**Current and hypothetical BFAs (CAPEX-based)**
Fig. 13.1a: Base scenario: captured CO_2 price=£0/tCO_2 and SC = 32%	Fig. 13.2a: Alternative base case scenario: captured CO_2 price=£9/tCO_2 and SC = 32%

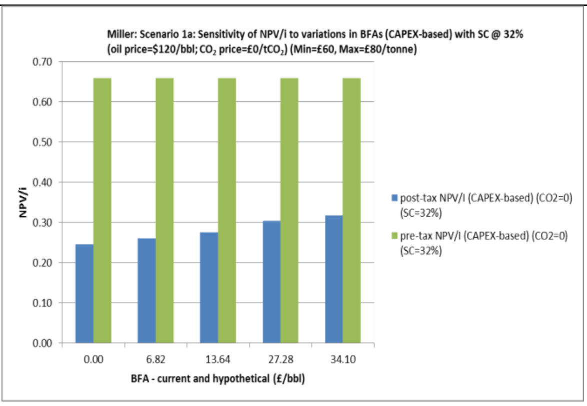
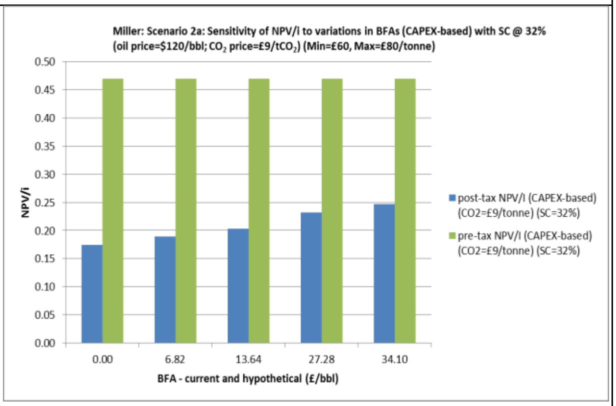
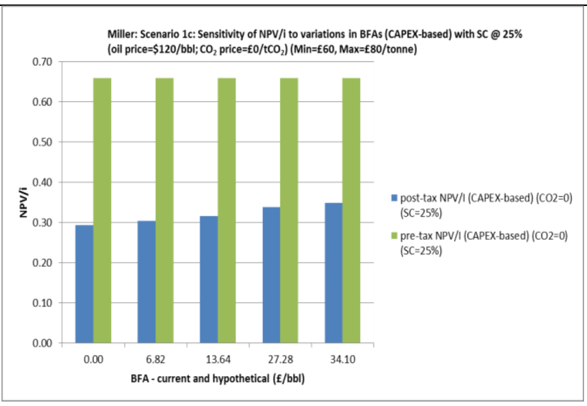
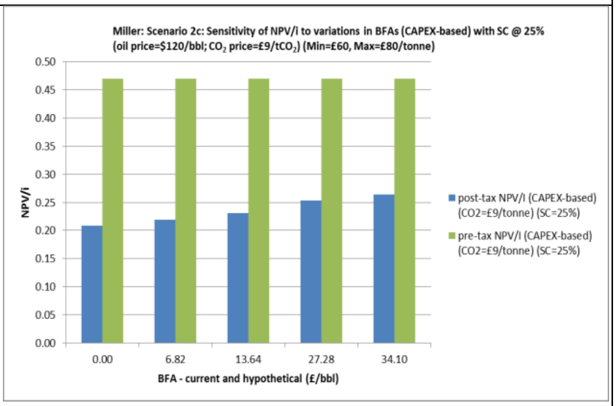

	

Fig. 13.1b: Base scenario: captured CO_2 price=£0/tCO_2 and SC = 25%	Fig. 13.2b: Alternative base case scenario: captured CO_2 price=£9/tCO_2 and SC = 32%
	

It can be seen in Fig. 13.1a that, with zero CO_2 price, the pre-tax NPV/I ratio exceeds 0.5. Without any BFA the post-tax NPV/I index is 0.246. If BFA was introduced at £6.82/bbl., the index improves by 6% to NPV/I = 0.261. Increasing the BFA four-fold to £27.28/bbl. produces an index that just passes the hurdle (NPV/I = 0.304). A further increase to £34.10/bbl. improves the index to NPV/I = 0.318.

The results of the corresponding fiscal-incentives-only scenario summarised in Fig. 13.2a show that without the commercial incentive the pre-tax NPV/I ratio exceeds 0.46. Post-tax, before any BFA and commercial incentive apply, the profitability index is 29% worse off (0.174 v. 0.246). Applying the maximum BFA rate of £34.10/bbl. improves the profitability index to 0.247 which is still below the hurdle rate.

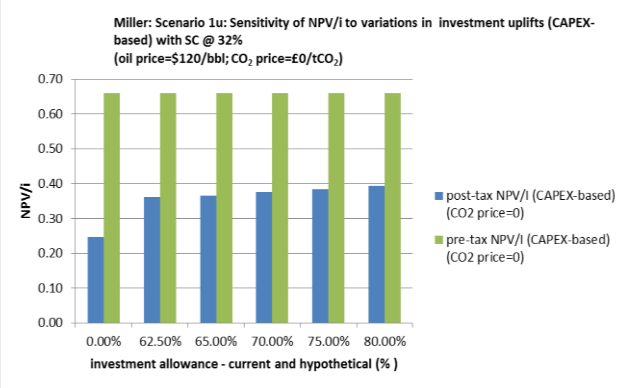
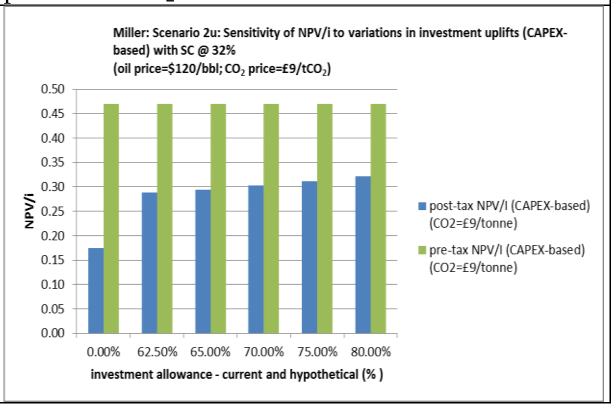
Fig. 13.1b shows a summary of the results when the combined incentives scheme is supplemented with a reduction in the SC rate to 25%. With these the profitability index improves by 19% to 0.293 (compared to 0.246 in Fig. 13.1a). Unlike in the SC=32% case, supplementing the combined incentives package with the initial BFA (=£6.82/bbl.) satisfies the hurdle rate, with the NPV/I = 0.304 (16% improvement over the corresponding SC=32% case).

In Fig. 13.2b, supplementing the fiscal-incentives-only package with the reduction in the SC rate to 25% failed to satisfy the investment hurdle. The profitability index attained with BFA = £34.10/bbl. is NPV/I = 0.264.

The potential efficacy of investment uplifts to incentivise CO_2-EOR (CAPEX-basis)

The results through the introduction of CAPEX-based investment uplifts are summarised in Table 14.

Table 14: Miller: Sensitivity of NPV/I to variations in CO_2 prices, given uplifts

<table>
<tr><th>Current and hypothetical investment uplifts (CAPEX-based)</th><th>Current and hypothetical investment uplifts (CAPEX-based)</th></tr>
<tr><td>Fig. 14.1a: Base scenario: captured CO_2 price=£0/tCO_2</td><td>Fig. 14.2a: Alternative scenario: captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

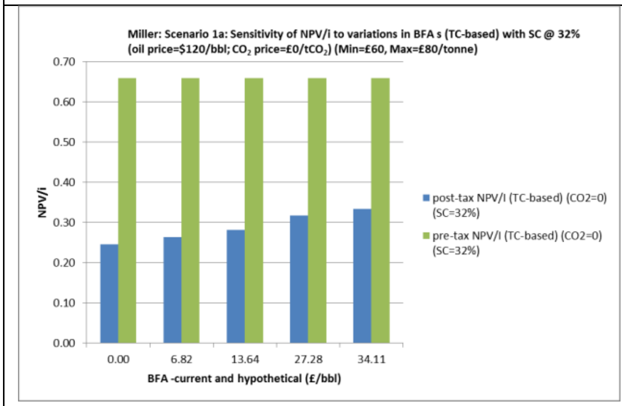
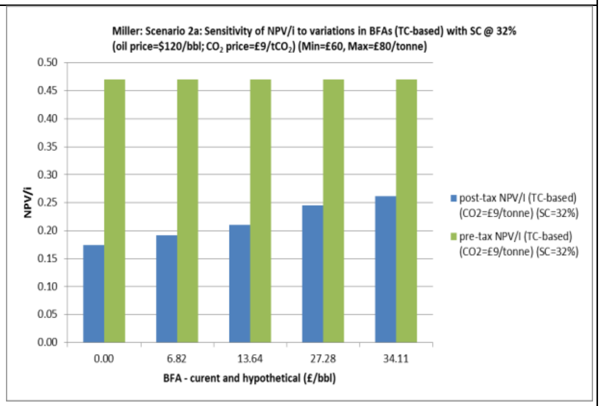
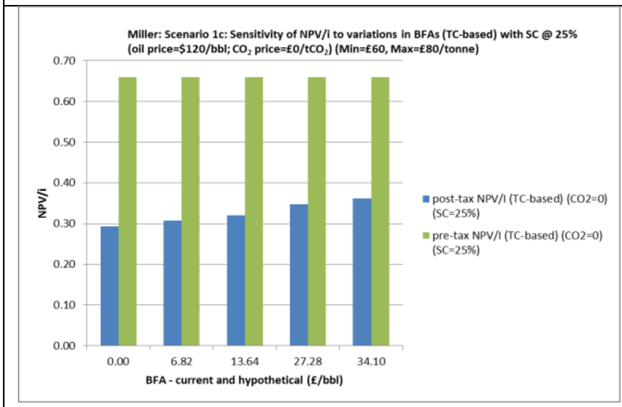
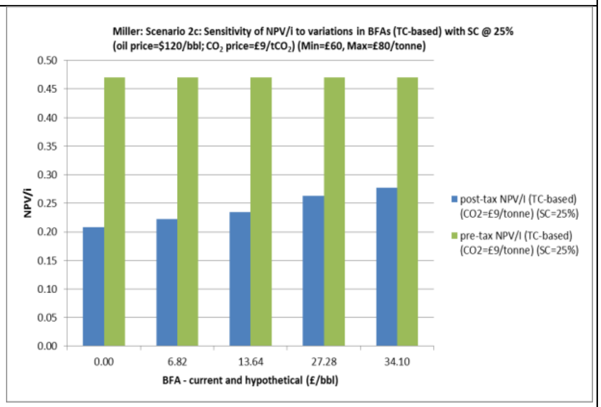
The pre-allowance NPV/I indices in this scenario (Fig. 14.1a) and the corresponding BFA case (Fig. 13.1a) are the same at NPV/i =0.246. However, the application of the 62.5% investment uplift produces a strong improvement in the profitability index by 47% to NPV/I = 0.361. Further increases in the rate of the uplift allowance to 80% enhanced the profitability index to 0.393.

In the corresponding fiscal-incentives-only results summarised in Fig. 14.2a, the hurdle rate is just passed when the allowance is set at 70%, with the index being 0.303.

The potential efficacy of BFAs to incentivise CO_2-EOR (Total cost-basis)

The results of the experimental runs with BFA on total cost-basis are summarised in Table 15.

Table 15: Miller: Sensitivity of NPV/I to variations in CO_2 prices, given BFAs (Total cost-based)

<table>
<tr><th>Current and hypothetical BFAs (TC-based)</th><th>Current and hypothetical BFAs (TC-based)</th></tr>
<tr><td>Fig. 15.1a: Base scenario: captured CO_2 price=£0/tCO_2 with SC @ 32%</td><td>Fig. 15.1b: Alternative scenario: captured CO_2 price=£9/tCO_2 with SC @ 32%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 15.1b: Base scenario: captured CO_2 price=£0/tCO_2 with SC @ 25%</td><td>Fig. 15.2b: Alternative scenario: captured CO_2 price=£9/tCO_2 with SC @ 25%</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

Comparing the results in Figs. 13.1a and 15.1a shows that the profitability indices in the latter are slightly higher. Thus, at the initial BFA of £6.82/bbl., the total cost-based index in Fig. 15.1a is only 1% higher than the CAPEX-based one in Fig 13.1a. At the very high BFA rate of £34.10/bbl., the difference in the profitability indices increases to 5% (NPV/I = 0.334 v. NPV/I = 0.318).

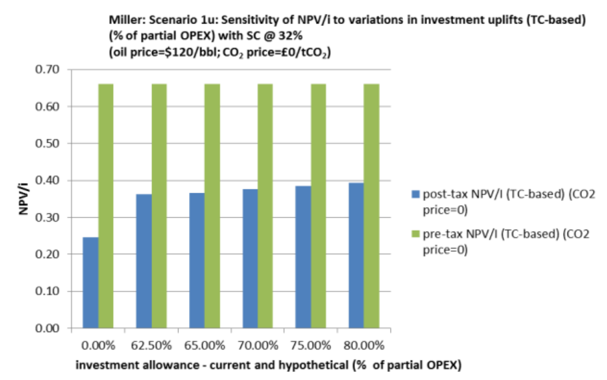
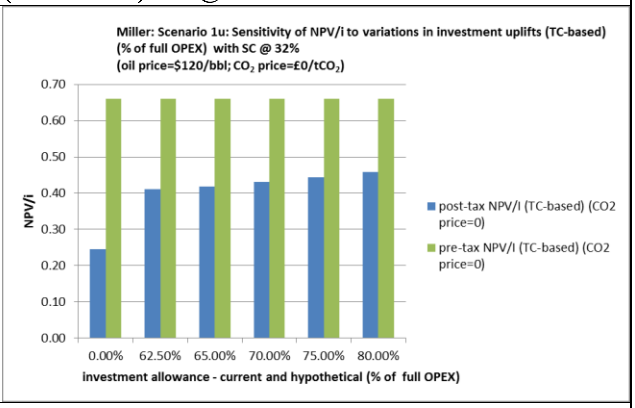
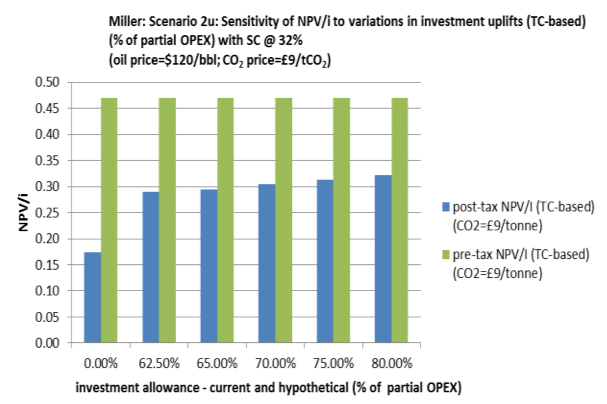
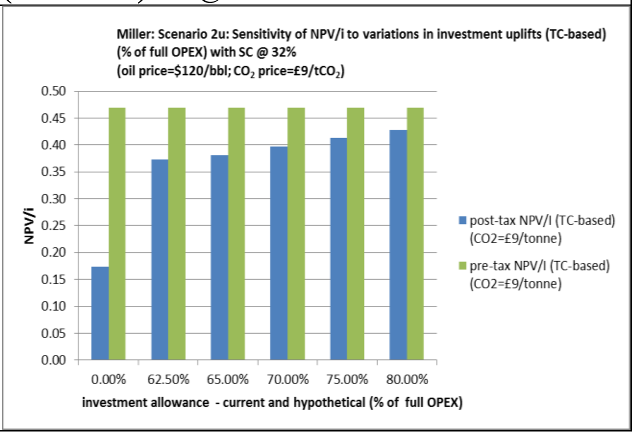
The foregoing pattern is repeated when Figs. 13.2a and 15.2a summarising the corresponding fiscal-incentives-only cases are compared. But the hurdle rate is not satisfied in either set of these results.

The results when the combined-incentives package is supplemented with a reduction in the SC to 25% are summarised in Fig. 15.1b. By itself, the reduction in SC leads to an improvement of 19% in the profitability index to 0.293 (from 0.246, with SC at 32%). Once the initial BFA at £6.82/bbl. is added, the profitability index improves to 0.307. It is noteworthy that with SC at 32% this condition was not satisfied until the BFA was raised to £27.28/bbl.

The potential efficacy of investment uplifts to incentivise CO_2-EOR (Total cost-basis)

Table 16 shows the summary comparisons of the results of the investment uplift allowances based on the project's total cost with partial- or full-OPEX.

Table 16: Miller: Sensitivity of NPV/I to variations in PRT, assuming various uplifts (alternative Total cost-bases) and captured CO_2 prices

<table>
<tr><td>Current and hypothetical investment uplifts (Total cost -based) (% of partial OPEX) with captured CO_2 price=£9/tCO_2</td><td>Current and hypothetical investment uplifts (Total cost-based) (% of full OPEX) with captured CO_2 price=£9/tCO_2</td></tr>
<tr><td>Fig.16.1a: Combined incentives on total cost basis (partial OPEX) SC @ 32%</td><td>Fig.16.2a: Combined incentives on total cost basis (full OPEX) SC @ 32%</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Fig. 16.1b: : Fiscal-incentives-only on total cost basis (partial OPEX) SC @ 32%</td><td>Fig. 16.2b: Fiscal-incentives-only on total cost basis (full OPEX) SC @ 32%</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

In Figs. 16.1a and 16.2a the project is viable with 62.5% uplift whether the basis of the allowance is partial OPEX (TCWPO) or total cost with full OPEX (TCWFO). The allowance based on the latter results in a profitability index that is 14% higher than the former-based one (NPV/I = 0.411 v. NPV/I = 0.362) Increasing the allowance rate to 80% improves the relative efficiency of TCWFO. The gap in the resulting profitability indices widens to 16% (NPV/I = 0.458 v. NPV/I = 0.394).

Comparing the corresponding fiscal-incentives-only results in Figs. 16.1b and 16.2b reveals that the scenario with TCWFO passes the hurdle rate, but with TCWPO it does not (NPV/I = 0.373 v. NPV/I = 0.290). When compared with the 14% advantage in the corresponding combined-incentives case, the 29% advantage in the profitability of the TCWFO-based allowance suggests its importance to marginal projects. As in the combined-incentives case, increasing the allowance rate to 80% widens the relative efficiency of TCWFO. The resulting profitability index is 33% higher than the TCWPO-based one (NPV/I = 0.428 v. NPV/I = 0.322).

7. Conclusions

In this paper the case for tax incentives to encourage the activity of CO_2 EOR in the UKCS has been examined within the context of a possible CCS cluster in the Central North Sea/Moray Firth region. Four fields with recognised CO_2 EOR potential were examined with detailed financial simulation modelling which recognised the physical constraints on the CO_2 EOR activity in the fields. In most, but not all, cases the pre-tax returns were acceptable at an oil price of \$120 per barrel. This price reflects the start date of the investments in 2020. Cases of CO_2 purchase prices of £0 and £9 per tonne of CO_2 were examined to highlight the effects of non-tax costs/incentives on the prospective returns. The moderate price of £9/tonne was found to significantly affect the returns.

Many experiments were conducted involving application of the BFA for SC to CO_2 EOR at many different rates. Further experiments involved the introduction of the investment uplift allowance for SC at several different rates. Experiments were also conducted on the effects of including operating costs (all or part) in the base for the BFA and uplift allowances. Yet further experiments were undertaken with reduced rates of PRT and SC.

The effectiveness of the various schemes in incentivising investment in CO_2 EOR was found to vary greatly. In general the uplift allowance performed moderately well, but, where the CO_2 had to be purchased at £9/tonne, the inclusion of at least part of the operating costs in the eligible base was found to be necessary to make the scheme effective. In some cases the rate of the allowance had to be very high to produce the necessary incentive. This could raise question of cost-consciousness. Rate reductions in the PRT and/or SC rate could produce the desired level of incentive, and could do so with more moderate levels of uplift allowance. To some extent there is a trade-off between size of uplift and tax rates.

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