Energy Transition in the UKCS – Modelling the Effects of Carbon Emission Charges on Upstream Petroleum Operations

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Abstract

The UK has ambitious decarbonisation, climate change mitigation and energy transition goals. The upstream petroleum sector in the UK shares in these goals, as evidenced by its North Sea Transition Deal and as set out in its sector 'Roadmap 2035' for emissions reduction. Participation in an emissions trading scheme as a mechanism for achieving these goals is a key strategy identified in the sector roadmap. Currently, only qualifying installations in the UK Continental Shelf (UKCS) are charged for their emissions. Notwithstanding, prudent non-qualifying operators are also now incorporating these charges in their financial models for asset valuation purposes. This paper uses a recently updated database of 21 new UKCS fields to examine the effects of carbon emission charges on upstream petroleum operations in the province. We find that emission charges increase operating expenditures, which results (1) an acceleration of the timing of the economic limit of fields, leading to significantly lower petroleum production and carbon emissions; and (2) a reduction in the economic value of petroleum fields hence diminishing the competitiveness of the UKCS. These outcomes advance the energy transition cause of the UK. However, they give rise to major implications for the UK, including energy security, jobs, risk of exposure to a carbon leakage situation, and so on. We advocate a 'just transition' approach to energy transition, where petroleum production in the UKCS progresses but with a carbon footprint that is reduced and consistent with an economic optimum.

Keywords: Carbon; Emissions; Net zero; Petroleum; Energy Transition; UKCS

1 Introduction

Many countries impose different types and levels of carbon emission charges on selected, typically carbon intensive industries. Over 60 such carbon emission charge regimes exist across the world, at international, national and sub-national levels (Wood Mackenzie, 2021). The upstream petroleum sector (which includes prospecting, exploration, development, production, processing, storage and transportation) emits significant levels of carbon through activities such as oil and/or gas fuelled power generation, oil and/or gas combustion in connection with well testing and well maintenance, intermittent and/or routine gas flaring and venting, fugitive emission occurrences, and so on (i.e. Scope 1 emissions; see US EPA, 2021). However, globally these emissions have been largely un-charged at meaningful rates (i.e. above \$20/tCO_2e; see Wood Mackenzie, 2021).[1]

In recent years, there has been a significant shifting in the global political economy of the upstream petroleum sector away from policies that provide fiscal support to the sector, to rather, the imposition of new carbon charges and/or the expansion in the level and/or scope of pre-existing such charges on the sector. Three reasons account for this shift. First, more countries are adopting these charges as a way of facilitating the drive towards decarbonisation, climate change mitigation and energy transition, which are all topical issues in the contemporary energy landscape (see e.g. Papadis and Tsatsaronis, 2020; Tagliapietra et al., 2019; Tvinnereim and Mehling, 2018; Welsby et al., 2021).[2] The recent IEA (2021) and IPCC (2021) reports on the roadmap to net-zero by 2050 for example highlight the urgency for radical reductions in the investment, development and/or production of oil and gas resources globally. Welsby et al. (2021) find that up to 60% of global oil and gas resources must remain unextracted in order to keep within the 1.5 ^{o}C carbon budget.[3] Second, there is a growing global acceptance of the 'polluter pays principle' as a way of correcting emission externalities from carbon intensive industries (Ambec and Ehlers, 2016; Nash, 2000). Third, countries may introduce and/or expand carbon emission charges with a goal to restore and supplement government budgets that have been ravaged by the COVID-19 pandemic (Mackenze, 2021; Burke and Bowen, 2020; Helm, 2020; Mintz-Woo et al., 2020). There is evidence of national and/or local government tendencies to introduce such charges in periods of high budget deficits (Ramseur, Leggett, and Sherlock, 2012), such as is the case in the current global economy.

The UK has significant ambitions for decarbonisation, climate change mitigation and energy transition. It is the first major economy to set a world-leading net-zero target (OIES, 2020),[4] with a goal to reach 100% reduction in emissions by 2050, compared to 1990 levels. The upstream petroleum sector in the UK shares in these goals, being one of the first sectors to declare so, as evidenced by its North Sea Transition Deal with the UK Government (see OGUK.a, 2021). The sector accounts for about 4% of UK emissions. It has produced a 'Roadmap 2035' strategy (OGUK.b, 2021) by which it aims for absolute reductions in production emissions of 10% in 2025, 25% in 2027, and 50% in 2030 on the pathway to net-zero by 2050. The UK Government and the upstream petroleum sector recognise that internalising emission externalities by way of carbon emission charges is a critical element of the strategy towards the realisation of the overall national and sector goal of decarbonising petroleum production through emissions reduction.[5] The challenge facing the government and sector is to achieve these goals alongside other equally pertinent goals, such as the goal of

[1] The exceptions to the global status quo are Norway, the Canadian federal government, and the Canadian provinces of Alberta and British Columbia. In the case of Norway, carbon charges have been levied on upstream petroleum emissions since 1991, and in the case of Canada, since 2007.
[2] The Norwegian Government for example recently announced a significant hike on upstream carbon emission charges for this reason. Specifically, a carbon charge of \$250/tCO_2e by 2030 was announced, which effectively quadrupled the pre-existing level of only \$58/tCO_2e. The Canadian federal government has also announced a steep rise in emissions charges, with a target of \$135/tCO_2e by 2030.
[3] It must be pointed out though that there is significant uncertainty regarding these estimates.
[4] In June 2019, the UK parliament passed legislation requiring the UK Government to reduce the country's net emissions of greenhouse gases by 100% relative to 1990 levels, by 2050.
[5] Other means of decarbonising upstream petroleum production include carbon capture, utilisation and storage (CCUS) and electrification.

maximising economic recovery (MER) (OGA, 2016) from the province, in a manner that is consistent with the ethos of each goal.

There are two ways in which countries levy carbon emission charges. The first is through the imposition of a carbon tax whilst the second is through an Emissions Trading Scheme (ETS), also known as a cap-and-trade scheme. The EU ETS is the most advanced and active ETS market in the world. The relative merits and nuances of carbon taxes and ETS schemes have been extensively discussed in the literature (see e.g. Coria and Jaraite, 2015; Crals and Vereeck, 2005; Marron and Toder, 2014; Pope and Owen, 2009; Robert, 1995; Avi-Jonah et al., 2009; Goulder and Parry, 2020; Shapiro and Walker, 2020).

Following BREXIT, the UK has introduced a new UK ETS market to replace the EU ETS (UK Government, 2021a). As part of the key actions of the UK oil and gas sector 'Roadmap 2035' strategy, the sector supported the development of the UK ETS, and aims to promote full and enhanced participation in the scheme as a way of facilitating the decarbonisation of petroleum production in the UKCS province (OGUK, 2021.b). The ETS approach is the preferred option for levying carbon emission charges in the UK although a carbon tax introduced to complement it cannot be ruled out, as is currently the case in Norway.

Currently, just over 100 qualifying installations[6] in the UKCS province are charged for carbon emissions through the UK ETS.[7] Qualifying installations are mandated to account for their emissions through surrendering of emission allowances annually. These may be free allowances, or allowances bought via the ETS market. Free allowances, equivalent to 100% of the relevant sector benchmark[8] are awarded to sectors on the carbon leakage list.[9] These are sectors considered to be at the highest risk of relocating investment and production to jurisdictions outside the UKCS. Oil is currently on the carbon leakage list, and therefore subject to allowances equivalent to 100% of the sector benchmark for free. Gas on the other hand is no longer on the carbon leakage list and therefore subject to phased out reduction in free allowances from the current 30% to 0% after 2026. The intention is to reduce and eventually eliminate allowances for both oil and gas. Notwithstanding the current rules on qualifying installations and free allowances, prudent oil and gas operators are now incorporating carbon emission charges in their financial models for asset valuation purposes (Wood Mackenzie, 2021; OGUK.a, 2021; Thorne and Mittal, 2019). They are in part doing so in response to shareholder and public demand for greater accountability in reducing the carbon footprints of upstream petroleum operations and the carbon intensity of petroleum products (Thorne and Mittal, 2019).

This paper uses a recently updated database of 21 new UKCS fields to examine the effects of carbon emission charges on upstream petroleum operations in the province. Specifically, we

[6] Qualifying installations are those producing petroleum with a rated thermal input greater than 20MW and emitting more than 25000 tCO_2e annually or had a net thermal input below 35MW in 2008 – 2010.
[7] The first phase of the UK ETS has been aligned with Phase IV of the EU ETS for the period 2021 – 2030. This means that the UK ETS will use the same mechanisms and definitions of the EU ETS for that period.
[8] The relevant benchmark is based on the emission intensity of the most efficient 10% of installations in a sector. Only the most efficient installations in each sector receive enough free allowances to cover all their emissions.
[9] Carbon leakage refers to the prospect of an increase in global emissions when production or investment is moved from one jurisdiction where significant carbon charges are observed, to another, where carbon charges are not imposed at all, or at less meaningful levels. The shift in production or investment from the high carbon cost jurisdiction is typically because of the inability of firms in that jurisdiction to pass on the cost of the carbon charge to consumers.

construct a mathematical optimisation model and use the database of new fields as input to the model to examine the effects of carbon charges on such fields. The constructed model fully captures the existing UK taxation regime for upstream petroleum operations in the UKCS. In particular, we incorporate in our model the Ring Fence Corporation Tax (RFCT) (UK Government, 2021.b), which is currently levied at 30% of field taxable income; and the Supplementary Charge (UK Government, 2021.c), which is currently levied at 10% of field taxable income after Investment Allowance deductions. Also, tax allowances under the current UK taxation regime are incorporated in our model. Specifically, we incorporate the Capital Allowances for capital expenditures; and the Investment Allowance for the Supplementary Charge, which is currently set at 62.5% of capital expenditures (UK Government, 2021.d).[10]

Within the peer-reviewed literature, there have been numerous examinations of the economic effects of carbon emission charges, including on industry (Floros and Vlachou, 2005; Morgenstern et al., 2004), household electricity use (Ghaith and Epplin, 2017), consumption and welfare (Bretschger et al., 2011), economy-wide effects (Guo et al., 2014; Kamat et al., 1999; Kemfert and Welsch, 2000; Meng et al., 2013; Wissema and Dellink, 2007) and international effects (Whalley and Wigle, 1991; Whalley, 1992). A comprehensive examination of the literature shows however that there have been no previous peer-reviewed publications on the effects of carbon emission charges on upstream petroleum operations anywhere in the world. The present paper therefore makes a significant and pioneering contribution in that regard. It is close in its purpose to the reports by Wood Mackenzie (2021) and Kemp and Stephen (2010).

We find that emission charges increase upstream operating expenditures and affect upstream petroleum operations through a number of channels. First, the increased operating expenditures accelerate the timing of the economic limit of fields which results early cessation of production, leading to decreased production in the province. Across the 21 new UKCS fields, up to 59.98 million barrels of oil equivalent (mmboe) in petroleum resource is unextracted as a result of the imposition of carbon charges. Associated with the reduced production are 3.45 million tCO_2e reduction in production emissions. This is equivalent to taking about 1.73 million cars off UK roads for a year.[11] Second, the increased operating expenditures erode the economic value of petroleum fields, making them less attractive investment propositions. On average, there is a 28.17% reduction in the value of a field due to the imposition of carbon emission charges. Up to $2.14 billion in economic value is eroded across the 21 new fields as a result of the imposition of the charges. In a capital rationing investment climate, such as is the case in the UKCS and globally (see e.g. Osmundsen et al., 2022), this has significant implications for the economics of fields at the margin of investment feasibility. We find that 4 additional fields are rendered economically unviable as a result of the imposition of carbon emission charges. More broadly, the reduction in the economic value of fields diminishes the competitiveness of the UKCS province as a major hub and destination for global upstream petroleum investments. These outcomes facilitate the decarbonisation, climate change mitigation and energy transition goals of the UK.

However, the reduced petroleum production and the diminished competitiveness of the UKCS province have significant energy security implications for the UK. It has the potential to for

[10] Investors have access and/or eligibility for the Investment Allowance for Supplementary Charge element of taxation, or the Ring Fence Expenditure Supplement (RFES) element (UK Government, 2021e), but not both.
[11] Per OGA (2021.b) estimates, a standard car emits about 1.986 tCO_2e a year.

example increase the country's import dependency on petroleum products. This subjects it to risk of exposure to a carbon leakage situation, where the UK would be deemed to be effectively 'offshoring' emissions to other provinces due to foregone domestic petroleum production and increased importation. Appendix I provides an overview of the UK's net-zero consistent petroleum demand, production and import dependency outlook, showing that projected demand far outstrips domestic production over the next several decades, therefore implying that further reductions in domestic production would increase UK import dependency. There are also tax revenue implications for the UK Government. Our results show that about 16.80% less tax (about $1.48 billion) is accrued to the UK government due to the imposition of these charges. There are also wider implications for the UK economy, including for example the loss in good, high-skill and high-paying jobs in an extensive value chain linked to the upstream petroleum sector. It is estimated for example that the upstream UKCS petroleum sector supports over 250,000 direct, indirect and induced jobs in the UK prior to the COVID-19 pandemic (OGUK, 2021.c),[12] hence underscoring the significant importance of the sector to the wider UK economy.

The rest of the paper is organised as follows; Section 2 introduces our methodology, with a description of our model and its underlying assumptions. Section 3 introduces our data whilst Section 4 presents our results and discussion. Section 5 concludes the paper.

2 Methodology

2.1 Model setting and assumptions

Several factors are considered when modelling the effects of carbon emission charges on energy intensive industries. First is the relative effect of the charges in the short run before industry adjustments are possible, and the long run, when changes in capital and technology occur in response to the charge (Morgenstern et al., 2004). The financial modelling approach adopted in this paper does not account for industry responses to carbon emission charges over the long run. A general equilibrium model framework is required to examine long-run effects (Sanstad and Greening, 1998). Second is the organisational structure of the industry. Monopolistic and oligopolistic industries may react differently to the charges compared to competitive industries. This is due to disparities in the exercise of cost pass-through and pricing powers (Orlov and Grethe, 2012). We consider the case of a competitive upstream petroleum industry, where oil and gas prices are exogenously observed by UKCS operators. This to a large extent reflects the reality of upstream UKCS oil and gas economics whilst also avoiding the complexity of modelling monopolistic or oligopolistic market structures. Third is the international trade environment, where a carbon-leakage scenario may occur due to domestic and international petroleum production cost and price differences occasioned by the imposition of domestic carbon charges (Bruvoll and Fæhn, 2004; Kemp and Stephen, 2010). We do not consider this scenario as it is best modelled in a framework where international climate change

[12] Direct jobs relate to employment 'directly involved in the production of oil and gas in the UK'. Indirect jobs relate to 'employment supported in companies from across the wider supply chain who supply goods and services in support of oil and gas production in the UK'. Induced jobs relate to 'employment supported by the expenditure of income from the oil and gas sector e.g. accommodation, services, etc.' (OGUK, 2021.c).

agreements are explicitly considered and factored (Morgenstern et al., 2004; Sanstad and Greening, 1998; Whalley and Wigle, 1991).

Additionally, the UK Government makes a distinction between different types of upstream petroleum investors[13] for tax application purposes. This has important implications for the economics of oil and gas developments and operations in the UKCS province. As a result, modelling oil and gas economics in the province requires explicit assumptions about the type of investors being considered, namely whether the investors have existing and sufficient tax paying positions to the extent that they are eligible for substantive first-year capital investment tax reliefs, or not. In the present UKCS environment, modelling of new petroleum developments with the assumption that investors have existing and sufficient tax paying positions to the extent that they can obtain full and first-year tax reliefs is unrealistic. The net cash flow of the whole UKCS sector is currently negative and will likely remain so for the near future. We therefore assume the case of investors with no existing, or alternatively, insufficient tax paying positions so that they are unable to benefit full and immediate first-year tax reliefs.

Finally, the financial modelling approach adopted in this paper uses a Net Present Value (NPV) investment hurdle criterion for determining optimality in the development and operation of the modelled UKCS fields. The NPV criterion is consistent with the UK Government and the UK Oil and Gas Authority's (OGA) stated UKCS MER strategy (OGA, 2016)[14] and has been severally used to assess the economics of oil and gas operations in the province (see e.g. Abdul-Salam et al., 2021).

2.2 Model structure

Our model is formulated and applied for oil and/or gas fields in the data. For purposes of exposition and the preservation of space in this paper however, we present here the formulation and application of the model for oil fields only.

2.2.1 Equations defining capital and investment tax allowances

Following the above model setting and assumptions, let i represent an oil field and t represent time. For field i, let CE_i^{total} ($ million) represent an exogenous positive variable indicating the total field capital expenditure. For new fields, this includes drilling and completion expenditures of production and completion wells as well as the expenditures accompanying the installation of associated infrastructure (e.g. pipelines, manifold, processing hub, etc.). Also for field i, let x_{it} (million barrels; mmbbl) represent an endogenous positive variable indicating the optimal production in period t, and let φ_i represent an endogenous binary variable indicating field development status (i.e. whether a field is developed or not), such that;

[13] Where appropriate, we use the term 'investor' and 'operator' interchangeably.

[14] The OGA regulates the upstream oil and gas sector in the UK. OGA (2016) define economically recoverable reserves as 'those resources which could be recovered at an expected (pre-tax) market value greater than the expected (pre-tax) resource cost of their extraction, where costs include both capital and operating expenditures but exclude sunk costs and costs (such as interest charges) which do not reflect current use of resources. In bringing costs and revenues to a common point for comparative purposes a 10% real discount rate will be used'.

$$\sum_t x_{it} - BigM \cdot \varphi_i \leq 0 \ \forall \ \ i \tag{1}$$

where $BigM$ is an exogenous large positive number.[15] Equation (1) captures the development status of a field such that the binary variable φ_i takes a value of 1 if development and/or production of field i is endogenously determined to be optimal (i.e. when $\sum_t x_{it} > 0$), and 0 otherwise. Consequently, the total field i capital and investment allowances for tax relief purposes in any period, per the existing UK taxation regime, can be determined and constrained in the model as follows;

$$CA_{i,t=1}^{total} = CE_i^{total} \cdot \varphi_i \ \forall \ i, t = 1 \tag{2}$$

$$IA_{i,t=1}^{total} = ia \cdot CE_i^{total} \cdot \varphi_i \ \forall \ i, t = 1 \tag{3}$$

$$CA_{i,t+1}^{total} = (CA_{it}^{total} - CA_{it}^{annual}) \cdot \varphi_i \ \ \forall \ i, t = 2, \dots, T \tag{4}$$

$$IA_{i,t+1}^{total} = \left(IA_{it}^{total} - IA_{it}^{annual}\right) \cdot \varphi_i \ \forall \ i, t = 2, \dots, T \tag{5}$$

$$CA_{it}^{annual} \leq CA_{it}^{total} \ \forall \ i, t \tag{6}$$

$$IA_{it}^{annual} \leq IA_{it}^{total} \ \forall \ i, t \tag{7}$$

where

Variable	Description
CA_{it}^{total}	Endogenous total capital allowance for field i in period t ($ million)
IA_{it}^{total}	Endogenous total investment allowance for field i in period t ($ million)
CA_{it}^{annual}	Endogenous capital allowance applied for tax relief purposes for field i in period t ($ million)
IA_{it}^{annual}	Endogenous investment allowance applied for tax relief purposes for field i in period t ($ million)
Parameter	**Description**
ia	Exogenous investment allowance rate (%)

Equations (2 – 3) define field total capital and investment allowances as determined in the first-year, as is the case in the current upstream UK taxation regime for offshore petroleum developments. Equations (4 – 5) define field remaining capital and investment allowances in subsequent periods. This involves deduction of the allowances allocated and applied in the previous period. Allowances are only applicable for fields that are endogenously developed and producing, as shown in the accounting of the binary variable φ_i in Equations (2 – 5). Equations (6 – 7) ensure that the total capital and investment allowances applied for tax relief purposes in any period do not exceed the total available for that period.

[15] Use of the large positive number $BigM$ in equation (1) is an integer programming formulation trick that forces the associated binary variable to take a value of 1 when field production is nonzero.

2.2.2 Equations controlling field production

Petroleum reservoirs are naturally three-dimensional and can be modelled as such in specialised applications. The computational demand of such models however hampers their usefulness in generalised applications such as is being modelled in this paper. We therefore adopt a zero-dimensional tank model, which has been shown to reflect the structural form of the reservoir production profile of a typical petroleum field (Lund, 2000; Lund, 1997; Nystad, 1985). The zero-dimensional tank model has been widely applied in the literature for modelling petroleum provinces around the world (Aronofsky and Williams, 1962; Beale, 1983; Frair and Devine, 1975; Lund, 2000; McFarland et al., 1984). Consequently, using the zero-dimensional tank model for field i, the optimal field production in time t, x_{it}, is given as follows;

$$x_{it} = \min\{[N_{it} \cdot WR_i];\ [PC_i];\ [q_{it}]\}\ \ \forall\ i,t \tag{8}$$

$$N_{it} \leq N_{max}\ \ \forall\ i,t \tag{9}$$

$$q_{it} = N_{it} \cdot WR_i \cdot \frac{V_{it}}{V_i^{init}}\ \ \forall\ i,t \tag{10}$$

$$V_{it} = V_{i,t-1} - x_{i,t-1}\ \ \forall\ i,t \tag{11}$$

$$\sum_t x_{it} \leq V_i^{init} \tag{12}$$

where

Variable	Description
N_{it}	Exogenous number of production wells for field i in period t
N_{max}	Exogenous maximum number of production wells for any field
WR_i	Exogenous well rate for field i. This is the production capacity of any single well (mmbbl)
PC_i	Exogenous platform capacity of field i (mmbbl)
q_{it}	Endogenous maximum reservoir depletion rate for field i in period t (mmbbl)
V_i^{init}	Exogenous initial reservoir volume (mmbbl)
V_{it}	Endogenous remaining reservoir volume for field i in period t (mmbbl)

Equation (8) encapsulates the zero-dimensional tank model which yields the typical production profile illustrated in Figure 1. The field optimal production in any period x_{it} is the minimum of three terms capturing (1) an initially rising production phase, corresponding with the term $N_{it} \cdot WR_i$; then (2) a plateaued production phase, corresponding with the term PC_i; and subsequently (3) an exponentially declining production phase, corresponding with the term q_{it}. The number of production wells for field i annually increases to an exogenously imposed maximum N_{max}, as shown in Equation (9). The platform production capacity of a field includes its combined production, processing and storage capacities. It represents the maximum well stream that can be handled by the field platform at any one time. The maximum reservoir depletion rate, as defined in Equation (10), captures the productivity of the field reservoir in each period. Equation (11) updates intertemporal reservoir volumes whilst Equation (12) ensures that total cumulative production does not exceed the initial reservoir volume.

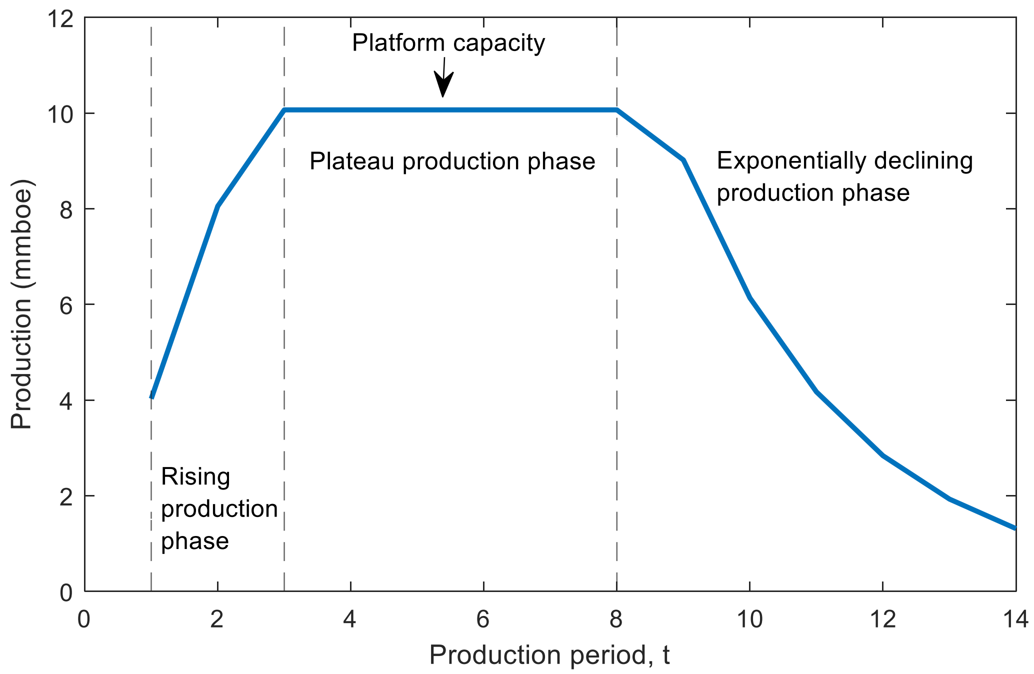


Figure 1: An illustration of the zero-dimensional tank model production profile, showing the structural form of a typical petroleum field production profile

2.2.3 Equations defining carbon emission levels and charges

Let P^{crbn} (\$/tCO_2e) represent the exogenous unit price of carbon. For field i in period t, let E_{it} (tCO_2e/bbl) represent an exogenous variable indicating its unit level of carbon emissions and let EC_{it} (\$ million) represent an endogenous variable indicating the total emissions charge. Available data from Wood Mackenzie (2021) and OGA (2021.b) suggest that unit emissions from upstream petroleum operations increase approximately linearly in intensity over time. The reason for this observation is that as fields progressively mature, reservoir pressure declines hence more energy is required for extraction (i.e. increased pressure support, higher water cuts, etc.), leading to greater unit emission levels (Banet, 2017; Thorne and Mittal, 2019). We assume total internalisation of emissions costs (i.e. no free carbon emissions allowances). Consequently, we model unit emission levels and total emissions charges for field i in period t as follows;

$$E_{it} = \alpha + \beta \cdot t \;\; \forall \;\; i, t = 1, \dots, T \tag{13}$$

$$EC_{it} = P^{crbn} \cdot E_{it} \cdot x_{it} \;\;\; \forall \;\; i, t \tag{14}$$

where α (tCO_2e/bbl) and β (tCO_2e/bbl) are the intercept and slope respectively of the linear unit emissions function. The intercept α is effectively the unit emission level for the initial year of production, whilst β is the annual marginal increment in unit emission levels.

2.2.4 Equations defining revenues and cashflows

The following equations outline definitions and constraints capturing the income statement of field i in each operational period t;

$$R_{it} = P^{oil} \cdot x_{it} \; \forall \; i,t \tag{15}$$

$$PTP_{it} = R_{it} - OE_i - EC_{it} \; \forall \; i,t \tag{16}$$

$$TI_{it} = PTP_{it} - CA_{it}^{annual} \; \forall \; i,t \tag{17}$$

$$TICT_{it} = TI_{it} \; \forall \; i,t \tag{18}$$

$$TISC_{it} = TI_{it} - IA_{it}^{annual} \; \forall \; i,t \tag{19}$$

$$tax_{it} = \max\,[0, rfct \cdot TICT_{it} + sc \cdot TISC_{it}] \; \forall \; i,t \tag{20}$$

$$CF_{it} = PTP_{it} - tax_{it} \; \forall \; i,t \tag{21}$$

where

Variable	**Description**
R_{it}	Endogenous total revenues of field i in period t ($ million)
PTP_{it}	Endogenous pre-tax profit of field i in period t ($ million)
EC_{it}	Endogenous emissions charge for field i in period t ($ million)
TI_{it}	Endogenous taxable income of field i in period t ($ million)
$TICT_{it}$	Endogenous taxable income for Ring Fence Corporation Tax for field i in period t ($ million)
$TISC_{it}$	Endogenous taxable income for Supplementary Charge for field i in period t ($ million)
tax_{it}	Endogenous tax paid by field i in period t ($ million)
CF_{it}	Endogenous cashflow of field i in period t ($ million)
Parameter	**Description**
P^{oil}	Exogenous real price of oil ($/bbl)
OE_i	Exogenous operating expenditure of field i ($ million)
$rfct$	Exogenous ring fence corporation tax (%)
sc	Exogenous supplementary charge (%)

Equation (15) defines annual revenues which are a function of the real price of oil. Equation (16) defines pre-tax profits. We use average operating expenditures which are non-variant over time, consistent with the cost structures of petroleum operations in the UKCS province (Abdul-Salam et al., 2021). Equation (17) defines the overall taxable income, which involves deduction of capital allowances to provide tax reliefs to investors. Equation (18) defines taxable income for Ring Fence Corporation Tax. Equation (19) defines taxable income for Supplementary Charge, which involves further deduction of investment allowances to provide additional tax reliefs to investors. Minimum tax paid in each period is 0, but maximum is levied as shown in equation (20). Equation (21) captures cashflows for each field in each operational period. These cashflows are used in the determination of the overall objective of maximising NPV for a field, as shown next.

2.2.5 Objective function

The objective of the investor is to maximise the NPV ($ million) of field i as follows;

$$\text{maximise} \quad NPV_i = -CE_i^{total} \cdot \varphi_i + \sum_t \frac{CF_{it}}{(1+r)^{t-1}} \;\; \forall \; i \tag{22}$$

where r is the discount rate. Other important but more nuanced definitions and constraints are imposed in the model to better reflect the reality of upstream petroleum operations and economics in the UKCS. For example, following Kemp and Stephen (2010), a constraint is imposed in the model to allow only developments of new fields for which the ratio of the NPV to capital expenditure is greater than 0.3, as follows;

$$\frac{NPV_i}{CE_i^{total} \cdot \varphi_i} \geq 0.3 \;\; \forall \;\; \varphi_i \neq 0 \tag{23}$$

This constraint reflects the reality of capital rationing in the current environment for petroleum field developments in the UKCS (see e.g. Osmundsen et al., 2022). Also, we impose constraints to allow only sequential production of fields, so that a start-stop-start production sequence is disallowed (Abdul-Salam et al., 2021). By this constraint, we have implicitly assumed that the cost of stopping and restarting a field is prohibitive, so that once cessation of production occurs, restart is not permitted. Additionally, we impose constraints to prevent implicit subsidies by way of improper allocation of capital and/or investment allowances for tax relief purposes. To preserve space, further of such definitions and constraints are not presented here. However, the full model detailing all equations and constraints is available from the authors upon request.

2.3 Model implementation

The above model is formulated in the General Algebraic Modelling System (GAMS) software and language as a Mixed Integer Non-Linear Programming (MINLP) problem. The model is solved using the LINDOGLOBAL solver in GAMS. This solver ensures globally optimal solutions are obtained for each modelled field.

3 Data

We source a recently updated UK OGA database for 402 UKCS fields, of which there are 368 sanctioned fields and 34 probable and possible fields. Sanctioned fields are defined as presently developed and producing fields. Probable fields are new fields for which there is over 50% likelihood of being developed by the holding licensees; whilst possible fields are new fields for which there is a less than 50% likelihood of being developed by the holding licensees. Retrieved relevant data for our modelling purposes include projected field oil, gas, natural gas liquids (NGL) and condensate reserve levels, as well as field capital expenditures ($ million) and operating expenditures ($ million). Data on the emission intensities of fields is not available in the database.

We focus on new fields only for two reasons. First, as data on the emission intensities of fields are unavailable in the database, assumptions about the emission intensities of individual fields are required. As previously noted however, emission intensities increase as fields mature which implies that knowledge of individual field vintages is essential for proper determination of individual field emission intensity levels. Unfortunately, data on the individual field vintages for sanctioned fields is also not available in the source database. By limiting our focus to new fields only (i.e. fields of equal vintage, notionally 0 years), we reduce the uncertainty regarding our assumptions of field emission intensities. All new fields, as they are of equal vintage, may be assumed to have the same initial year emission intensity estimates. Second, we consider new fields only as they relate to modelling over the entire spectrum of the zero-dimensional tank model discussed in Section 2 (see Figure 1).

After data processing and cleaning, we resulted 21 new (i.e. probable and possible) fields for which we have the full complement of data. The overall reserve volume of the 21 fields is 880.60 mmboe, with an aggregated 733.43 mmbbl of oil, NGL and condensate reserves; and 832.87 billion cubic feet of natural gas reserves. Table 1 summarises the number and volumes of the fields across the various regions of the UKCS province. The West of Shetland (WoS) and the Central North Sea (CNS) regions have the largest oil reserves, whilst the Southern North Sea (SNS) region has the largest natural gas reserves. Figure 2 shows the size distribution of the 21 fields. Median field size is 17.58 mmboe, although there are two large fields of more than 170 mmboe, both of which are in the WoS region of the province.

Table 1: Number of fields and reserve levels by UKCS region (Source: Data obtained from the offices of the OGA, 2021)

UKCS region	Number of fields	Reserves				
		Oil (mmbbl)	Gas (billion scf)	NGL (mmbbl)	Condensate (mmbbl)	Total (mmboe)
CNS	9	170.35	289.87	17.19	-	238.76
NNS	5	57.02	41.79	-	-	64.41
SNS	4	-	354.31	-	1.70	64.31
WoS	2	487.17	83.48	-	-	501.92
Other	1	-	63.43	-	-	11.21
Total	21	714.54	832.87	17.19	1.70	880.60

Figure 2: Distribution of field sizes (Source: Data obtained from the offices of the OGA, 2021)

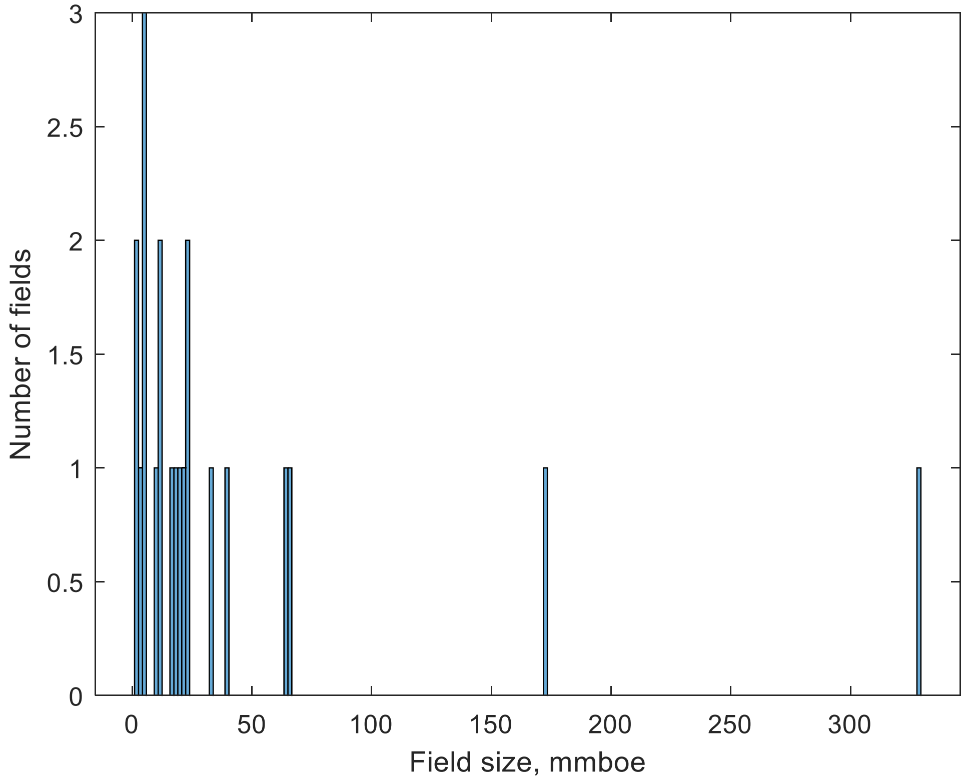
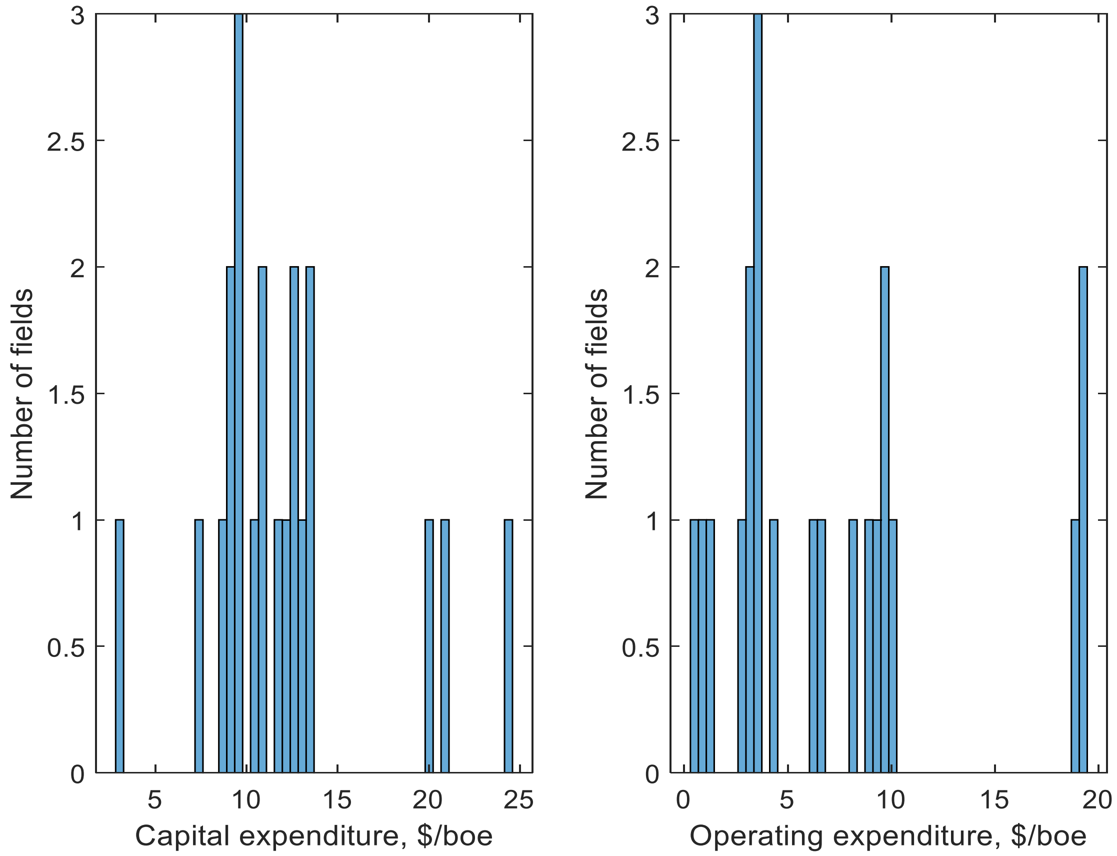


Figure 3 summarises the unit capital and operating expenditures of the 21 fields. Average capital and operating expenditures are $12.03/boe and $7.28/boe respectively. The three fields with the highest unit capital expenditures of about $20/boe and above; and the two fields with the highest unit operating expenditures of about $19/boe are all located in the NNS and CNS regions of the province.

Figure 3: Distribution of unit capital and operating expenditures, \$/boe (Source: Data obtained from the offices of the OGA, 2021)



Regarding emission sources, we assume upstream emissions resulting from activities such as burning of oil and/or gas for power generation, well maintenance and testing purposes; the intermittent and/or routine flaring and venting of natural gas; fugitive emission occurrences; the discharge of carbon dioxide (CO_2) separated from petroleum, etc.[16] Three greenhouse gas (GHG) emissions are dominant in the upstream petroleum sector. These are CO_2, methane (CH_4) and nitrous oxide (N_2O). Other GHG emissions include carbon monoxide (CO), nitrogen oxides (NO_x), sulphur dioxide (SO_2) and volatile organic compounds. Upstream emission estimates and intensities are determined as the aggregate emissions across these sources based on their global warming potentials and expressed in CO_2 equivalents (CO_2e).

Regarding operations coverage, we assume upstream emissions associated with oil and gas activities performed on offshore UKCS installations that are used for the production, processing, storage and transportation of petroleum. These together constitute Scope 1 emissions. As noted earlier, Scope 1 emission estimates are unavailable in our data and are either unavailable or difficult to ascertain from other data sources for the 21 fields in question. However, OGA (2021.b) and Rystad Energy (2021) provide upstream emission estimates as ranging from 5 kgCO_2e/boe to levels well over 100 kgCO_2e/boe, with an average of about 17 kgCO_2e/boe. Wood Mackenzie (2021) also provide UKCS data suggesting that the annual increment in emission intensity is about 7.2 kgCO_2e/boe, with an initial year emission level

[16] Power generation and flaring accounted for 64% and 26% respectively of all UKCS upstream emissions in 2017 (EEMS, 2019)

below 28 $kgCO_2e$/boe. With these estimates, we are able to make base assumptions about emission levels in order to calibrate the linear emissions function in our model (see Equation (13)). This equation is fundamental to the determination of the effects of emission charges in the UKCS province. Recognising the uncertainty with the initial year emission estimate of the 21 new fields, we conduct sensitivity analyses to determine the responsiveness of our results to a range of initial year emission estimate levels. Table 2 summarises further model data.

Table 2: Model base and sensitivity parameter values

Parameters	**Base case values**	**Sensitivity values**	**Source**
Oil price (real, long run), $/bbl	70	-	Within range of US EIA (2021.a) short term Brent crude price forecast and the UK OBR (2020) estimates.
Gas price (real, long run), $/ MMBtu	3.42	-	BP (2021), based on the Heren NBP natural gas price index.
Carbon price (real, long run), $/t$CO_2$e	120	Min: 0 Max: 200	Within range of Wood Mackenzie (2021) price assumptions, and the 2030 carbon price target for Norway. See also Abdul-Salam (2022)
Intercept: Linear emissions function, see Equation (10), tCO_2e/boe	17×10^{-3}	Min: 5×10^{-3}; Max: 20×10^{-3}	Within range of reported data by OGA (2021.b), Wood Mackenzie (2021) and Rystad Energy (2021).
Slope: Linear emissions function, see Equation (10), tCO_2e/boe	7.2×10^{-3}	-	Author calculation derived from data provided by Wood Mackenzie (2021).
Ring Fence Corporation Tax, %	30	-	UK Government (2021.b).
Supplementary Charge, %	10	-	UK Government (2021.c).
Investment Allowance for Supplementary Charge, %	62.5	-	UK Government, (2021.d).
Real discount rate, %	10	-	Abdul-Salam et al. (2021).

Maximum number of production wells for any field, N_{max}	6	-	Lund (1999).
Well rate as percentage of field size, %	4	-	Lund (1999).
Platform capacity (mmboe)	Various	-	Taken as the maximum production capacity of a field in our database.
Realisable production horizon, T (years)	Up to 40	-	Typical production horizon of petroleum fields of comparable sizes of fields in our database.

4 Results and Discussion

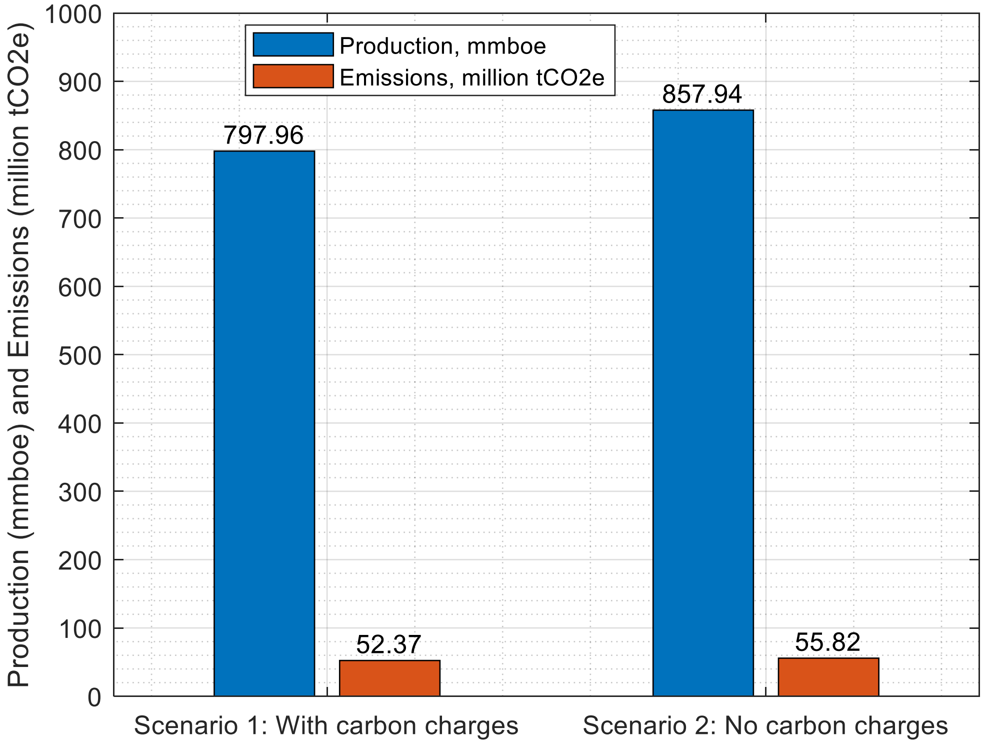
Below, we first discuss our base scenario results. This relates to the results arising from our base case model assumptions and application. We then discuss the sensitivity of these results to market conditions, specifically carbon emission prices and the assumption about the initial year field unit emission level. Two scenarios are discussed in each case; the carbon charge (CC) scenario in which carbon emission charges are imposed on field emissions; and the no carbon charge (NCC) scenario in which emission charges are not imposed.

4.1 Base scenario results

4.1.1 Production and Emissions levels

Figure *4* shows the petroleum production and carbon emission levels under both the CC and NCC scenarios aggregated over the 21 modelled UKCS fields. Due to the additional operating expenditure effect of the carbon emission charge, the timing of the economic limit of fields under the CC scenario is accelerated, leading to lower cumulative production under the CC scenario compared to the NCC scenario. Overall, cumulative production under the CC scenario is 59.98 mmboe lower (i.e. about 7.24% lower) than the NCC scenario. The resulting effect of lower aggregate production under the CC scenario is also that the aggregate emission level under the CC scenario is lower. Cumulative emission under the CC scenario is 3.45 million tCO_2e lower (i.e. about 6.38% lower) than under the NCC scenario.

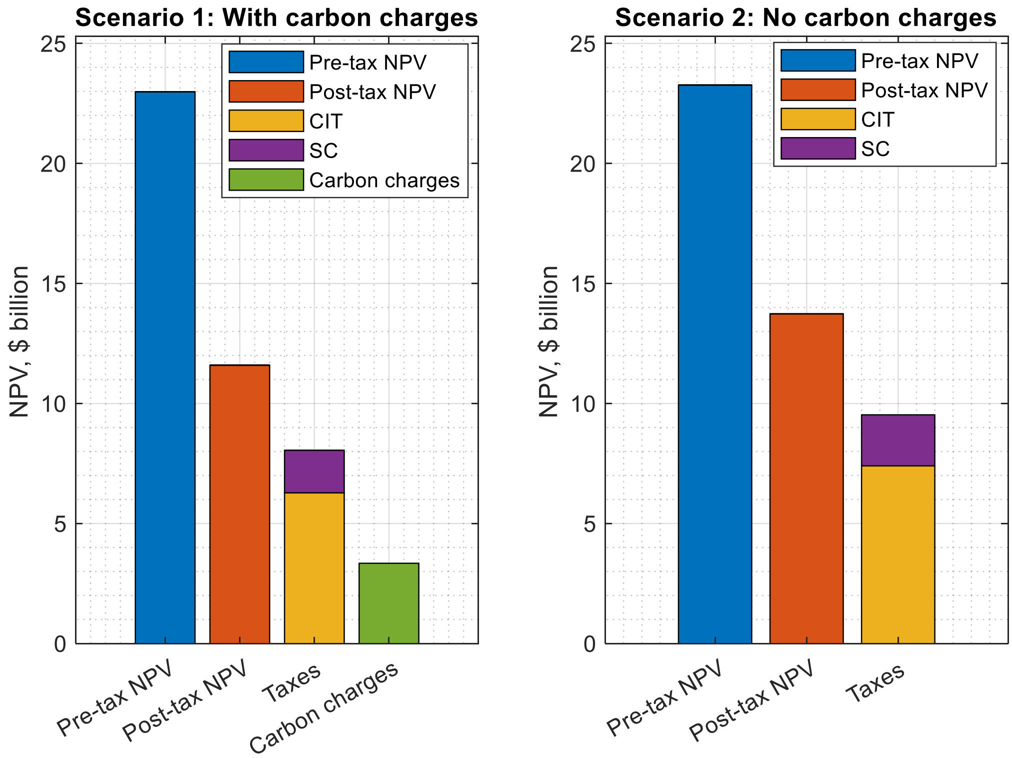
Figure 4: Aggregate production and emission levels, by carbon emission charge scenario



4.1.2 Field asset values

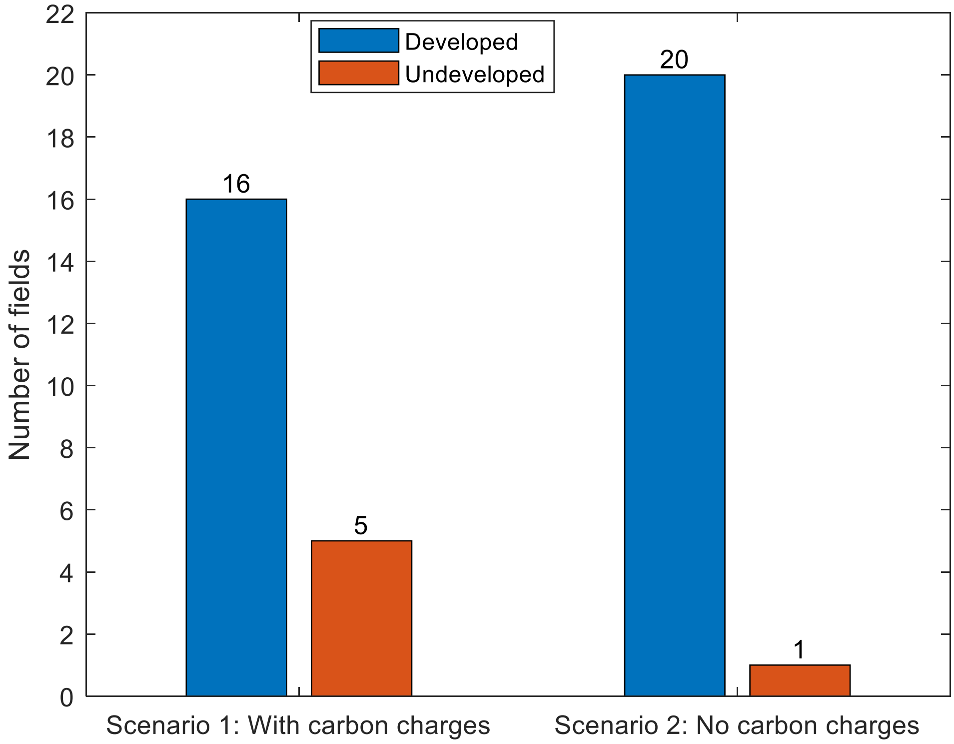
Figure 5 shows the aggregate investor pre-tax NPV, post-tax NPV and tax payment under both the CC and NCC scenarios. For the CC scenario, the aggregated carbon emission charges is also shown. The aggregated post-tax NPV of the 21 fields for the CC and NCC scenarios are \$11.60 billion and \$13.74 billion respectively. The imposition of carbon emission charges therefore reduced the aggregate post-tax asset value of the 21 new fields by \$2.14 billion under the CC scenario. This represents about 18.45% of the post-tax value of fields under that scenario. This shows, as expected, that the imposition of carbon emission charges reduces UKCS asset values significantly.

Figure 5: Aggregate asset values and emission charges, by carbon emission charge scenario



The reduction in asset values under the CC scenario is further evidenced in Figure 6 which shows the number of economically viable fields under both scenarios. Under the CC scenario, 4 less fields are economically viable compared to the NCC scenario. To the extent that more fields under the NCC scenario are developed than under the CC scenario, this implies that new economically marginal fields in the UKCS would be further marginalised by the imposition of carbon emission charges than otherwise. Of the subset of fields that were developed under both the CC and NCC scenarios, field value under the CC scenario is on average about 28.17% lower than field value under the NCC scenario.

Figure 6: Number of developed and undeveloped fields, by carbon charge scenario



4.1.3 Summary

As previously discussed, the imposition of the carbon emission charges has the effect of an additional operating expenditure for UKCS operators. For the CC scenario, the aggregate carbon emission charges over the 21 new fields is about \$3.34 billion (see Figure 5, scenario 1). This represents the aggregate marginal increase in operating expenditure under that scenario. The aggregate production under that scenario is 797.96 mmboe. The increase in operating expenditure per barrel of produced petroleum under the CC scenario is therefore \$4.19/boe. This represents the unit marginal increase in operating expenditure under that scenario.

The increase in operating expenditures resulted the decreased production under the CC scenario, owing to an acceleration of the timing of the economic limit of fields under that scenario. This also accounts for the reduced emissions under that scenario. Aggregate reduction in emissions and aggregate emission charges are 3.45 million tCO_2e and \$3.34 billion respectively under the CC scenario, implying that the average abatement level is about 1.03 $kgCO_2e$/\$ of emissions charge. This provides a measure of the effectiveness of carbon emission charges in decarbonising emissions towards the realisation of the climate change mitigation and energy transition agenda in the UKCS province.

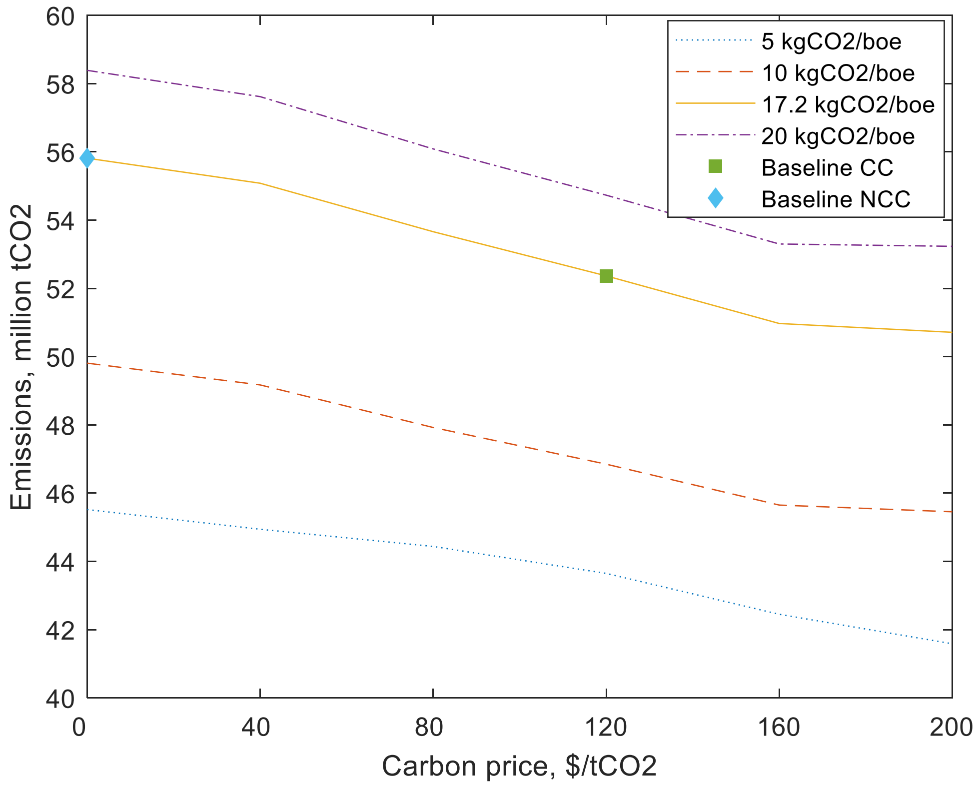
The increase in operating expenditures also resulted the decrease in field asset values under the CC scenario. The aggregate loss in post-tax field asset value under the CC scenario is $2.14 billion and the aggregate production under that scenario is 797.96 mmboe meaning that the post-tax reduction in asset values per barrel of produced petroleum is about $2.68/boe. The reduction in asset values rendered some marginal fields economically unviable. The results provide a measure of the effectiveness of carbon emission charges in reducing the competitiveness of petroleum field assets and the UKCS province as a whole, which facilitates the UK's goal of decarbonisation, climate change mitigation and energy transition.

4.2 Sensitivity analysis

We examine the sensitivity of our results to carbon prices and the initial unit emission level of fields. These variables have particular relevance to how the internalisation of emission costs channel to decarbonisation of petroleum production. Carbon emission prices are selected within range of Wood Mackenzie (2021) estimates and the carbon emission charge and/or tax targets for major net-zero-pledged countries such as Norway. The initial unit emission levels are selected within range of OGA (2021.b), Rystad Energy (2021) and Wood Mackenzie (2021) estimates. All other variables (e.g. taxation, operating costs, etc.) are maintained at their base case values.

Figure 7 shows our sensitivity analysis results for the effect of carbon prices on aggregate emissions under various initial year unit emission level assumptions. The results show, as expected, that the price of carbon is a significant driver of aggregate emissions. For example, under the base case initial unit emission level of 17 kgCO_2e/boe, aggregate emission is 49.76 million tCO_2e in an aggressive carbon price regime of $200/t$CO_2$e. This represents a 6.06 million tCO_2e reduction in emissions from the baseline NCC scenario. The initial year emission level is also a significant driver of aggregate emissions. Under an assumption of only 5 kgCO_2e/boe initial year unit emission level for example, aggregate emission under the base case CC price scenario is only 43.65 million tCO_2e. In contrast however, under an assumption of up to 20 kgCO_2e/boe initial year unit emission level, aggregate emission under the same base case CC price scenario is up to 54.73 million tCO_2e, representing a 11.08 million tCO_2e difference in emissions.

Figure 7: Sensitivity analysis showing the effect of carbon prices on aggregate emissions under various initial year unit emission levels.



* Baseline CC: Baseline 'Carbon Charge' scenario, where carbon price is $120/tCO_2e$ and initial year unit emission level is 17 $kgCO_2e$/boe
* Baseline NCC: Baseline 'No Carbon Charge' scenario, where carbon price is $0/tCO_2e$ and initial year unit emission level is 17 $kgCO_2e$/boe

5 Conclusion

The UK Government has ambitious energy transition goals, being the first major world economy to have set a net-zero target by 2050. The upstream petroleum sector in the UK has an important role to play towards the realisation of this goal. Operators and allied institutions in the sector broadly share in the UK Government's goals and have determined that the internalisation of carbon emission costs by way of full engagement in the development, operationalisation and participation in a UK ETS scheme is an efficient means of facilitating the achievement of this goal. Internalising emission costs ensures economically optimal and efficient production of petroleum in a manner that is consistent with the decarbonisation, climate change mitigation and energy transition agenda. This study examined the effects of carbon emission charges on petroleum operations in the UKCS, linking how these effects relate to the energy transition goal of the UK Government and upstream petroleum sector.

Our base results confirm the supposition that carbon emission charges have the effect of an additional operating expenditure, leading to an acceleration in the timing of the economic limit of fields. This results in lower cumulative petroleum production and ultimately lower cumulative carbon emission levels. In our base scenario, up to 59.98 mmboe in petroleum resource is unextracted across the 21 new UKCS fields as a consequence of the imposition of carbon charges. Associated with the reduced petroleum production is 3.45 million tCO_2e reduction in emission levels. Although this pales in comparison with global emission levels and targets, it represents a significant reduction in the context of the narrow and specific setting that is the UKCS. The reduced emission level is the equivalent of taking up to 1.73 million cars off UK roads for a year. These results highlight the effectiveness of carbon emission charges as a means of decarbonising petroleum production and facilitating climate change mitigation and energy transition in the UKCS. Our base results also show that the additional operating expenditure effect of the carbon emission charges (1) reduce the asset values of petroleum fields, hence making them less attractive investment propositions; and (2) renders marginal fields economically unviable. Emission charges therefore reduce the competitiveness of upstream UKCS assets along with the competitiveness of the entire province as a major hub and destination for upstream petroleum investments. This increases the risk of capital flight and stranded assets in the province, particularly so given the capital rationing climate that currently characterises the global upstream petroleum sector. It also indirectly enhances the competitiveness of alternative clean energy sources relative to petroleum. These findings further highlight the effectiveness of carbon emission charges in advancing the transition from petroleum production to clean modern renewable energy production in the UK. Sensitivity analyses show that the extent of the effects of carbon emission charges is sensitive to assumptions about the level of carbon prices as well as the initial field unit emission levels.

The combined effect of the loss in production due to accelerated timing of the economic limit of fields and the increase in the likelihood of stranded assets and capital flight from the UKCS may however have energy security implications for the UK. It is therefore not sufficient to accelerate energy transition by way of disincentivising petroleum (and more widely, fossil fuels) production alone. To ensure energy security in the long term, commensurate investment in clean energy production is required to ensure that displaced petroleum is adequately replaced by clean energy sources. In the short term however, a possible implication from stranded assets and the loss of UK petroleum production may be that the UK reliance on petroleum imports may increase. This raises the carbon leakage problem which arises when such petroleum imports are from countries where no meaningful attempts are being made at decarbonising petroleum production. In this case, the UK would be deemed to be effectively ‘offshoring’ emissions to other parts of the world, which then undermines the UK’s contributions to global emissions reduction targets. Also, the reduction in the competitiveness of the UKCS province as a destination for upstream petroleum investments has implications for the wider UK economy including for example loss in good, high-skill and high-paying jobs which are extensively linked to the UKCS province. The upstream petroleum UKCS sector currently sustains about 0.6% – 0.7% of all jobs in the UK (OGUK, 2021.c), underscoring its importance to the wider UK economy. There is also loss in petroleum tax revenue from the foregone production. Our base results for example show that 16.80% less tax (about $1.48 billion) is accrued to the UK Government due to the imposition of these charges.

In recent years, the political economy of petroleum production in the UKCS has taken a divisive turn, with environmental groups and political parties with green-energy inclinations advocating for a complete and immediate cessation of the development of new fields in the UKCS. This 'cliff-edge' energy transition stance is however opposed by parties who advocate a more nuanced approach to energy transition, consistent with the 'just-transition' approach. This debate has sharply centred on the Cambo field in the UKCS, which is one of the 21 new fields modelled in this paper. Our paper has shown that it is possible to significantly decarbonise petroleum production for new fields in the UKCS by internalising the economic costs of carbon emissions. A complete and immediate cessation of all investments and development of new fields in the UKCS province, as advocated by some, would not be economically ideal and/or optimal. Norway which has a long history of charging carbon emissions on upstream petroleum operations at meaningful rates has also shown that it is possible to significantly decarbonise these operations, and to gradually facilitate energy transition; without a complete and immediate decimation of the sector.

Further, the recent IPCC (2021) and IEA (2021) reports suggest that for the world as a whole, plans for investments, development and production of new petroleum fields would need to be curtailed if the world is to meet its 2050 net-zero target. Whilst this rule may apply to many countries, it may not apply to a petroleum net-import country such as the UK. Data provided by the OGA (2021.a) and the UK Committee on Climate Change (UK CCC, 2021) for example show that the UK's net-zero-consistent oil and gas demand far outstrips UK baseline production targets over the next several decades (see Appendix I, Figure 8). From the UK Government perspective therefore, we advocate maintenance of the competitiveness of the UKCS province as an upstream petroleum investment and production hub. This would enhance UK energy security, reduce petroleum import dependency and minimise the risk of carbon leakage to jurisdictions with less stringent and less meaningful decarbonisation goals and enforcements. The imposition of carbon charges ensures that the produced petroleum has a carbon footprint that is reduced and consistent with an economic optimum. This approach is consistent with the climate change mitigation and energy transition goal as well as the MER goal of the UK Government and upstream petroleum sector. The current energy crisis has also shown the importance of UK domestic natural gas production in supplementing renewable energy generation, highlighting the need to consider natural gas as a complement to renewable energy sources in the drive towards energy transition. In addition, the OGA, which is the UK Government petroleum regulator, have the power to mandate oil and gas operators to submit emission reduction plans before approving petroleum operations. Recent encouraging indications are that the OGA is taking a more proactive stance to enforcing these powers to ensure that the UKCS remains a low carbon petroleum production and investment hub.

Credit Author Statement

Yakubu Abdul-Salam: Conceptualization; Methodology; Writing - Original draft preparation, Reviewing and Editing; Software: Modelling; Data curation; Validation. **Alex Kemp:** Data curation; Validation; Reviewing and Editing. **Euan Phimister:** Data curation; Validation; Reviewing and Editing.

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Appendix I: UK petroleum production, net-zero-consistent demand and import dependency

Figure 8 shows the UK petroleum production and demand projections for the period 2022 – 2050. The demand projections are for the net-zero pathway (see UK CCC, 2021). The graph shows that over the next few decades, UK net-zero-consistent oil and gas demand outstrips projected production, with UK petroleum import dependency remaining at about 50% in that period. As demand outstrips production (supply), a complete and immediate cessation of all UKCS investments and developments, as advocated by some, would exacerbate the UK's import dependency. It would also lead to a potential carbon leakage situation.

Figure 8: UK oil and gas production, net-zero-consistent demand and import dependency (source: OGA, 2021.a)