An optimisation model for incentivising the development of marginal oil and gas fields amidst increasingly complex ownership patterns: UKCS case study

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Abstract

Many recent discoveries in the UKCS have been economically marginal and comparatively small such that they cannot support standalone field development. Nevertheless, there is a proliferation of production facilities and transport infrastructure that can, on accepting a tariff, process hydrocarbons from these smaller-sized oil and gas fields, thereby contributing to the UK Government's strategy of maximising economic recovery (MER). However, the empirical dimensions of cost-sharing arrangements between a field owner (host field or hub) and tie-in (satellite) fields are not well examined in the literature although they influence long-term economics in matured oil provinces. In this paper, we develop a mixed integer programming optimisation model to analyse how these third-party access to infrastructure issues impact MER in the UKCS. The first-best situation with only one regional operator is empirically compared with the actual situation of multiple ownership. We then assess the impact of different infrastructure unbundling provisions via pipeline tariff choices and their interaction with the fiscal regime on the net present value (NPV) and other metrics such as timings of hub and field shutdowns. We find that differences in field ownership, tariff choice and changes to the fiscal regime impact the overall NPV of field developments. Our results also show that having a progressive fiscal regime in a mature basin such as the UKCS is important to support continued operations under low oil prices while increasing the government's take at high prices. The cost-sharing effect shows that imposing strict cost-sharing rules does not change overall project valuations, even in a low oil price scenario. An additional contribution to the extant literature is that tariff determination could be based on cost-sharing rules that enjoin each field tieback to a hub to pay a split tariff, comprised of a fixed cost of service (access charge) and variable (marginal) costs.

Keywords: *Marginal fields; petroleum economics; mathematical modelling; oil and gas; MER; UKCS*

Highlights

- Presents MIP model for analysing economic dependencies of infrastructure assets.
- Ownership style, choice of tariffs, and fiscal regime impact overall field value.
- Reducing marginal tax rates improves profitability, reflecting neutrality and progressivity.
- Tariffs are decisive as to whether satellite or user fields are developed.
- Tariff determination to maximise MER should be based on two-part cost-sharing.

1 Introduction

The United Kingdom Continental Shelf (UKCS) is a mature region with around 43 billion barrels of oil equivalent (bn boe) produced since the late 1960s. There is potential for further remaining recoverable hydrocarbon resources in the range of 10 to 20 billion barrels of oil equivalent to be produced (Wood Review, 2014; Oil and Gas Authority, 2018). Most of the remaining median estimate of 15 billion barrels of oil equivalent resources lies in more technical and marginally challenging areas (Paterson and Gordon, 2013; Kemp and Stephen 2019 & 2020). Many recent discoveries have been comparatively small and are not large enough to support their separate infrastructure. As noted by Rouillard et al. (2020), the average commercial discovery size since 2010 has been about 27 million barrels of oil equivalent (mmboe) recoverable, and only 10% of discoveries have been bigger than 43 mmboe recoverable.

To produce the remaining reserves in the UKCS, access to existing infrastructure, such as subsea tiebacks or standalone development options (for example, via Floating production storage and offloading: FPSOs) for new development projects, remain key to the future of UKCS. It is estimated that about 60% of all new fields in the UKCS are subsea tiebacks to existing infrastructure; there is an increasing interdependence for both production facilities and transportation infrastructure (Oil and Gas UK, 2012).

A greater majority of the estimated resources lie within a 25-kilometre (km) sweep of existing infrastructure facilities, and this might be the harbinger to catalyse their development in a timely, fair and integrated manner with the ultimate objective of maximising reserve recovery (Rush, 2012; Acheampong et al., 2015). This is imperative as some of the host facilities on which these new smaller mature field accumulations lie and are likely to be developed are bound to be decommissioned earlier than planned, stranding several potential recoverable reserves with consequential losses in jobs and tax proceeds to The Treasury. According to the industry regulator, the Oil and Gas Authority (OGA), the UKCS has over 300 oil and gas "small pools" or discoveries with accumulations under 50 mmboe that are not being pursued by licence holders (Oil and Gas Authority, 2020a).

Third-party access to infrastructure forms one of the critical components of the UK's maximising economic recovery (MER) strategy to "ensure the development of UKCS resources on a regional, rather than solely a field basis (Wood, 2014; p16)." Though maximising economic recovery (MER) has no detailed definition in the Wood Review of 2014, the concept represents, in essence, "…a holistic approach in regulating exploration, development and production" (Wood, 2014; p.15). It has a legal obligation that would be included in all existing and future UKCS production licences required to facilitate higher production based on a regional development strategy on a field-wide and area-wide basis (Gordon et al., 2018).

MER from a mature province such as the UKCS with an existing ageing infrastructure network is a significant challenge for all industry stakeholders. The scale of the problem is captured by The Wood Review report, which posits: "the UKCS operating environment has changed very significantly in the last 20 years… increasingly interdependent for both production facilities and infrastructure…consistent with this and the increasing need to tie back smaller and more marginal discoveries into existing – and often ageing - infrastructure, licence holders, should make their infrastructure and process facilities available, subject to their own capacity requirements and technical compatibility, at fair and economic commercial terms and rates to potential third party users." (Wood, 2014; p.15)

In the UKCS, most oil and gas produced are through offshore hubs, subsea pipelines, and onshore processing terminals with sometimes different owners (Willigers et al., 2010). The companies that produce the hydrocarbons within the upstream value chain are, more often than not, different from those that own the processing infrastructure. Hence, to get oil and gas production operations running smoothly, contracts in the form of commercial agreements that cover the provision of transportation, processing, and operating services (TPOSAs) create intra-asset economic dependencies between infrastructure owners and hydrocarbon producers. These so-called third-party access (TPA) arrangements have implications for field development decisions, especially for cost recovery and decommissioning activities in a mature basin such as the UKCS. With this, the UK Government, since the early years of production from the North Sea, understood the importance of ensuring that adequate mechanisms are put in place to allow TPA to infrastructure to reduce overall field development costs and avoid the proliferation of pipelines (Kemp and Phimister, 2010).

TPA has become more critical now, given that the majority of the new fields in the UKCS are relatively small to support standalone development options. There is thus the need for proactive steps to be taken by all stakeholders to ensure MER (Kemp and Phimister, 2010). Many infrastructure owners made substantial investments into their processing hubs and pipeline networks in the early operational years to primarily take advantage of their production with the low unit operating costs driven by higher production volumes. Minimal ullage or capacity existed at the time in those transportation and processing networks (Willigers et al., 2010). However, with declining production and with many of the existing infrastructure currently old (requiring substantial maintenance investments to prolong their design life), there is spare ullage to process oil and gas from these new field developments. Despite ullage, many smaller oil companies (third-party companies) have reported difficulties accessing existing infrastructure such as pipelines and processing FPSO hubs (usually owned by the large integrated oil and gas companies) to produce their petroleum reserves. This is due in part to infrastructure owners demanding cost-prohibitive tariffs, making these third party projects uneconomic.

Access arrangements have become essential to the extent that standalone developments are often cost-prohibitive and uneconomic because of their lower production volumes negating any economies of scale. Hence, tie-ins of these third-party fields to existing infrastructure are critical to the basin's future (Kemp and Phimister, 2010 & 2012). As such, the question that arises is: what are the fiscal, commercial and regulatory tools which field owners, hub operators and upstream regulators can adopt to enhance economic outcomes such as reducing unit operating costs, thereby improving MER? There is a dearth of empirical research on third-party access to infrastructure and its impact on the recovery of hydrocarbon resources in mature oil provinces. Thus, this work examines how possible different ownership structures (and access arrangements) together with taxation in a mature basin might affect the economic viability of remaining UKCS reserves. To that extent, we investigate how the separation or unbundling of infrastructure and field ownership affects economic recovery in a mature oil basin through the following: (1) assess the effect of the oil and gas tax regime on long-term economics of oil production hubs and their satellite or user fields; (2) assess the impact of cost-sharing arrangements on long-term economics of hubs and their user fields; and (3) discuss what these complexities mean for decision-making on maximising economic recovery in matured oil provinces.

Several studies have been conducted on oil and gas fiscal regimes and how they influence oil and gas investments (Daniel et al., 2016; Nakhle, 2007; Daniel et al., 2008; Blake & Roberts, 2006; Kemp & Kasim, 2006; Noreng, 1997). However, until the past ten years, little work was being specifically done to assess how changes to the fiscal regime impact long-term project economics vis-à-vis province maturity indicted by declining discoveries and production (Kemp & Stephen, 2018; Abd Manaf et al., 2014; Deloitte, 2014; Kemp, 2013; Abdo, 2010). Furthermore, works specifically assessing third party issues associated with petroleum hubs and their user fields, which, as we indicated, is a growing problem in matured oil provinces, are starting to gain traction albeit at a slow pace (Abdul-Salam et al., 2021; Acheampong et al., 2015; Willigers & Hausken, 2013; Rush, 2012; Willigers et al., 2010a and 2010b). However, the exact empirical dimensions through which cost-sharing arrangements between a field owner (host field or hub) and tie-in (satellite) fields influences long-term economics in matured provinces are not well examined in the literature. Some of these gaps further motivate our work, and it bridges a core empirical research gap in a nascent area in the upstream oil and gas industry. Hence, this paper, which is among the first of its kind, plugs this gap by providing a detailed empirical analysis of how tariffing and cost-sharing decisions could be used to support MER. The findings have broader applicability for mature oil provinces in the North Sea (Norway, Denmark, Netherlands and UK) and other basins such as the Gulf of Mexico and the Pacific, such as Indonesia.

The rest of the paper is structured as follows: Section 2 reviews access to infrastructure issues in the UKCS, namely the regulatory framework for access and related legislations. It leads to developing a conceptual framework and model based on which we make extractions to characterise potential market outcomes. In Section 3, the mathematical formulation, which utilises the mixed integer programming (MIP) model, is discussed and data sources. The 'Baseline Model', 'Tax Model' and the 'Cost Sharing plus Tax Model', including the structure and simulated results with underlying assumptions, are presented in Section 4 and discussed. Section 5 concludes this paper with policy recommendations.

2 Literature Review

2.1 The concept of third-party access to infrastructure: economic and technical drivers

Upstream infrastructure facilities used in the processing and transportation of hydrocarbons are usually owned by the field owner or different parties in a joint venture (JV) arrangement (Figure 1). Constructing these facilities, which is symptomatic of industries where network infrastructure is vital such as utilities (gas, water, sewerage and electricity), comes with high fixed and sunk costs. This includes tieback costs, fixed hub operating expenses, joint costs and processing costs, among others. This often gives rise to natural (local) monopolies, and thus it is most efficient for a product or service to be provided by a single producer rather than several competing firms (de Palma & Monardo, 2019; Kemp and Phimister, 2010; Joskow, 2007; Gordon et al., 2003; Train, 1991).

Third-party access to infrastructure involves a party other than the infrastructure owner or JV partners gaining access to and using excess capacity (ullage) in the natural monopoly infrastructure of the infrastructure owner on fair and reasonable commercial terms (Johnstone, 2003). For example, the EU Gas Directives envisage third-party access rights based on open and non-discriminatory access to upstream petroleum pipelines, explicitly excluding host facilities as a key element of opening the energy markets to competition (Rush, 2012). The EU energy market is based on three pillars of 'third party access, unbundling and strong regulators (Hauteclocque, 2011).

The access regime typically involves a set of procedures that allow third party use (rent) of part of the monopolised asset capacity to provide services to downstream consumers on fair terms (Johnstone, 2003; Cross et al., 1994). In the UKCS, the purpose of access to infrastructure is to promote MER by offering a range of field development options to reduce costs and to avoid the proliferation of pipelines (Oil and Gas Authority, 2020b). Ullage or spare capacity is commonly available and may be used by third parties subject to the successful negotiation of a tariff and access arrangements (Abul-Failat, 2014). The use of such spare capacity can benefit both the field owner (host field or hub) and the tie-in (satellite) field by reducing unit operating costs and overall field profitability (Santoro et al., 2017; Willigers et al., 2010a; Cross et al. 1994). Besides, the host field or hub can earn additional revenues (tariff income) from the satellite producers, thus contributing to maximising economic recovery by deferring abandonment (Santoro et al., 2017; Pedroso et al., 2012; Willigers et al., 2010a; Antia, 1994)

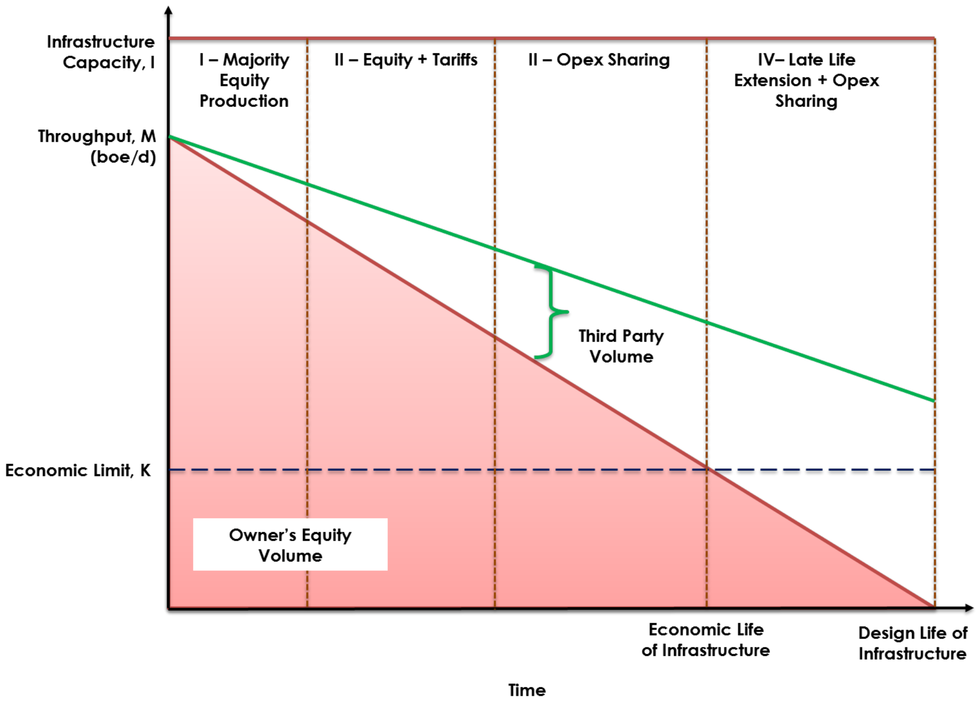

Figure 1 - Generic life of an infrastructure

Source: Adapted from PILOT (2005)

2.2 Infrastructure network development and use in the UKCS

As Figure 2 indicates, many of the larger fields in the early years of the UKCS, such as Brent, Forties and Ninian, were developed as integrated or cluster developments partly to reduce the overall field development costs (Acheampong et al., 2015; Kemp, 2013a & 2013b; Kemp and Phimister, 2010). The value chain was 100% owned by the consortia of international oil companies (IOCs). The 1980s and 1990s saw different companies with varied interests enter the UKCS. As a result, discoveries such as Scott and Brae had their own pipelines and offshore host facilities to process the hydrocarbons locally. These were, however, tied into the pipeline transportation systems earlier developed by the IOCs in the 1970s to deliver the hydrocarbons to the onshore downstream processing facilities such as the Sullom Voe terminal located in the Shetland Islands (Kemp, 2013a & 2013b). With the increasing amount of third-party utilisation of existing infrastructure due to increased ullage in the transportation systems, access arrangements have become important.

Regulating access arrangements for markets and industries that are inherently monopolistic in nature remains a challenge (Joskow, 2007; Gordon et al., 2003; Train, 1991). Consensus on the correct way of regulating, either through legislation, policy, codes of practice and regulations are non-existent (Abul-Failat, 2014). For many years in the UKCS, the regulatory approach has remained "light-touch regulation", whereby less and yet significant government intervention through the application of competition law is used to regulate natural monopolies (Rush, 2012). The basis for determining terms related to third party infrastructure use in the UKCS has been negotiated access between the asset-owner and potential asset-user with DECC (now OGA), the regulatory authority playing a more informal role (Kemp and Phimister, 2010).[1]

[1] The following regulatory frameworks and laws apply regarding third party access to infrastructure in the UKCS: Infrastructure Code of Practice (ICOP), DECC (now OGA) Guidance; The Energy Act 2008, 2011 and 2016, The Infrastructure Act 2015 and Maximising Economic Recovery Strategy.

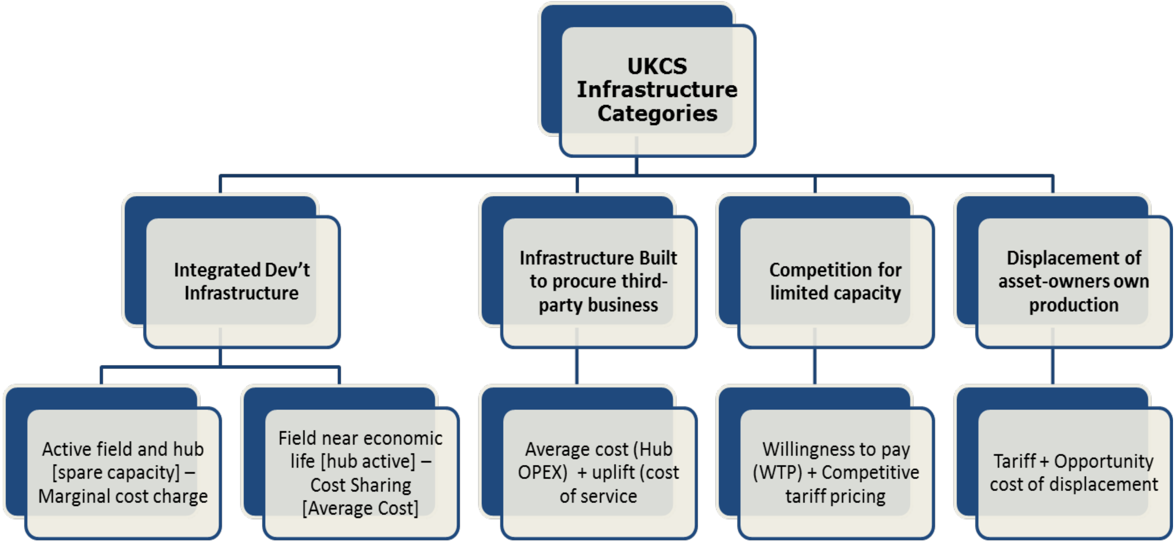

Figure 2 - Infrastructure asset sharing categories in the UKCS

Source: Acheampong et al. (2015)

During the negotiation process, conduct is regulated under the industry's *'Infrastructure Code of Practice'* (ICoP) backstopped with rights given to the Secretary of State within the petroleum legislation to set terms where agreement cannot be reached between parties.[2] The UKCS offshore upstream pipeline transportation system is neither in public ownership nor falls under a common carrier controller tasked with operating the pipeline system as an integrated system. As such, conflicting situations are bound to arise (Paterson and Gordon, 2013). This regulatory approach relied on the process of private bargaining of the parties to achieve efficient market outcomes with little direct intervention by way of specific legislation due to the threat of regulation possibly inducing the asset-owner to be cautious about charging high prices and thus achieving some of the desirable outcomes of actual regulation without the attendant costs (Rush, 2012).

Despite extensive infrastructure network, namely platforms, pipelines and onshore processing plants and terminals, many new developments remain constrained and are sometimes not developed. This is due to the "inability of third parties to negotiate appropriate technical and commercial terms to achieve access to existing infrastructure", thus, making these developments sub-optimal due to the value lost in delayed time (Wood, 2014: p45). At the heart of this is the lack of incentives resulting from a misalignment of technical and commercial interests between two parties - the potential third party and the operator of the hub platform. Juxtaposed against the extensive bargaining powers that infrastructure owners wield due to their natural monopoly characterisation, new entrants are challenged to access infrastructure on "fair and reasonable terms"," affecting project viability (Vass, 2011).

On a principal level, fields are also not developed despite this immense potentially mutually beneficial economic potential for all parties due to several reasons. One of these is coordination failure due to information asymmetries and associated transaction costs. Clustering between a field owner and the satellite field typically requires coordination between two or more licenses with different owners or interests and unbalanced ownership (Medema, 2020; Ayres et al., 2018; Libecap & Smith, 2001, Hannesson, 2000; Libecap & Wiggins,1985). For example, a review of the literature on unitization shows that unitization is often difficult to achieve between two parties due to the parties' entrenched beliefs about the non-homogeneity of the geological structure as well as effects

[2] See https://www.ogauthority.co.uk/media/3088/commercial-code-of-practice-2016.pdf and https://www.ogauthority.co.uk/media/2712/oga_guidance_disputes-over-third-party-acccess-to-upstream-infrastructure.pdf

of the regulatory environment (Hannesson, 2000; Libecap, 1989). Most of the players are likely to have "conflicted production incentives" within such a setup, as Libecap & Smith (2001) aptly frame it.

At the policy level, the OGA, the UK's industry regulator, is aware of some of these issues and has powers to encourage the asset transactions to procure alignment of the interest to enhance cluster development. If a licensee is reluctant to engage in beneficial asset transactions, the OGA has powers to require the licensee to market his asset or even relinquish it. These powers are all specified within the OGA Dispute Settlement Guidelines.[3] OGA has exercised such powers in several third party infrastructure access disputes, most recently in February 2020 (OGA, 2021a & 2021b). However, such regulatory interventions as forcing two parties to agree on tariff terms to improve access to common-pool resources could also harm the parties despite being socially optimum. As Libecap & Smith (2001; 2002) argue in the case of compulsory field unitisation, which can be helpful by reducing the deadweight cost of bargaining, such an approach can also be seen as forcing on the parties a harmful "solution".

Nevertheless, the OGA in the UK's case has also been pushing for joint or cluster developments to maximise economic recovery — the broader public interest or socially optimum solution. Abdul-Salam et al. (2021) demonstrate the advantage of clustering fields regarding the economies of scale they bring. They find that clustering offers a unique opportunity to unlock marginal fields by unlocking up to 8.70 times the value from standalone developments based on a post-tax net present value (NPV) estimation. Likewise, Kemp and Stephens (2019) investigated the extent to which cluster developments can enhance economic recovery in the UKCS, considering technical and economic feasibilities. They find that cluster developments can significantly enhance economic recovery from the UKCS, albeit not considering the complexities of third party tariffing regime. The potential of cluster developments is evidenced in other studies such as Kemp and Kasim (2012) and Kemp and Stephens (1995).

3 Optimisation model

This section presents our formulation of the mathematical model describing the regional production optimisation problem within the context of third-party access to infrastructure in the UKCS (Figure 3). An introduction to various aspects of the model is followed by the assumptions and underlying philosophical paradigms made during modelling. The mathematical model and justification for the mixed-integer linear programme (MILP) are presented. Kemp and Phimister (2012) first developed a MIP model to explore how possible different ownership patterns (and access arrangements) might affect the economic viability of remaining resources in UKCS using field data from the Northern North Sea (NNS).

3.1 Problem Statement

We adopt and extend the Kemp and Phimister (2012) model with two significant additions, namely: (1) the inclusion of marginal processing costs incurred by each field tied to a processing hub, and (2) the impact of various tax changes on hub economics. The former allows us to capture a level of granularity within the model to identify the intricacies and the effects of different processing costs and cost-sharing recovery mechanisms on regional field economics. The latter is interesting because studying the tax effects allow us to explore how the various fiscal changes over the past years have impacted field and hub economics and, ultimately, the attainment of maximum economic recovery objective.

[3] See OGA (n,d). Guidance on Disputes over Third Party Access to Upstream Oil and Gas Infrastructure. Available at: https://www.ogauthority.co.uk/media/2712/oga_guidance_disputes-over-third-party-acccess-to-upstream-infrastructure.pdf (Accessed: 28 May 2021).

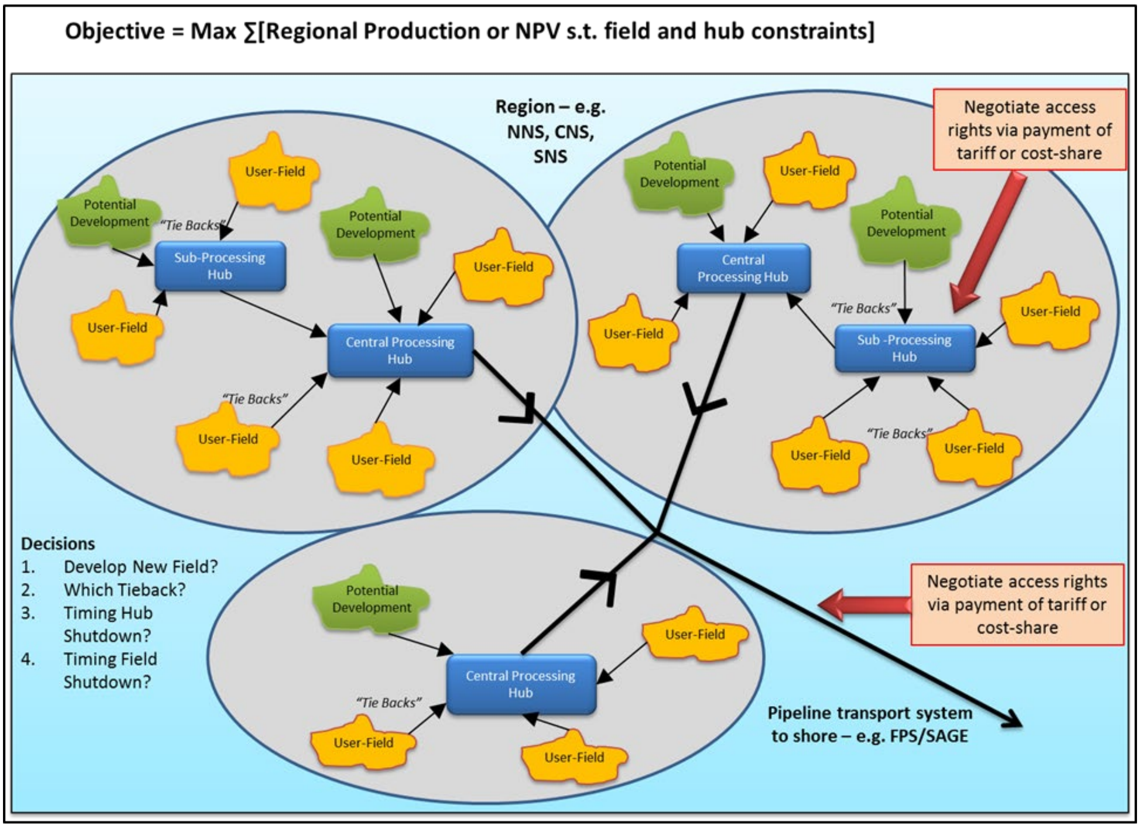

Figure 3 - Example infrastructure network

Source: Authors' Construct

The model was coded using the General Algebraic Modelling System (GAMS) software package with the CPLEX solver (GAMS, 2020a; GAMS, 2020b). The MIP approach provides us with the flexibility to allow some of the decision variables to be integer constrained (that is, whole numbers such as -1, 0, 1, 2, ...) at the optimal solution point (Williams, 2013; Redutskiy, 2017; Wang et al., 2018).

This allows us to expand significantly the scope of useful optimisation problems that we define and solve, and the integrality constraints of the MIP models provide us with a unique ability to capture the discrete nature of some decisions (Calderón and Pekney, 2020; Li et al., 2020; Carvalho and Pinto, 2006). For example, timing decisions for switching on and decommissioning hubs and fields take on discrete (binary) values restricted to 0 or 1 (Carvalho and Pinto, 2006). Also, continuous variables are used for some decisions along the project lifetime, such as costs and oil prices. A regional field valuation model is considered to attain these objectives:

(1) a cash flow model is formulated as a mixed-integer programme in which the overall net present value expressed as a function of costs and revenues subject to various financial and economic participation constraints;
(2) solution procedure of the model is developed; and
(3) to maximise the NPV, optimal field tiebacks, production and decommissioning times are determined.

3.2 Optimisation model formulation

We illustrate the cost elements of the objective function and the model constraint categories in Table 1 below. To reiterate our framing, we formally define an oil and gas hub network as comprised of a central processing hub or sub-processing hubs to which various oilfields are connected so their fluids can be safely processed and then transported to the terminal points or loaded offshore. The fields connected to these hubs have different production profiles and compositional characteristics (Figure 4). The lower-case letters (q, c) represent indexes for the field type whereas the upper-case letters (D, M_H) represent their corresponding sets for the fields and hubs. We employ the generic expressions '*flow*' *and* '*open*' for binary variables $(0,1)$ to represent the opening or closing of a field and transportation flow routing from the field to the processing hub and the terminal, our exit point in the model. The model performs an iterative process to choose which fields to produce from within the network to maximise value by way of NPV.

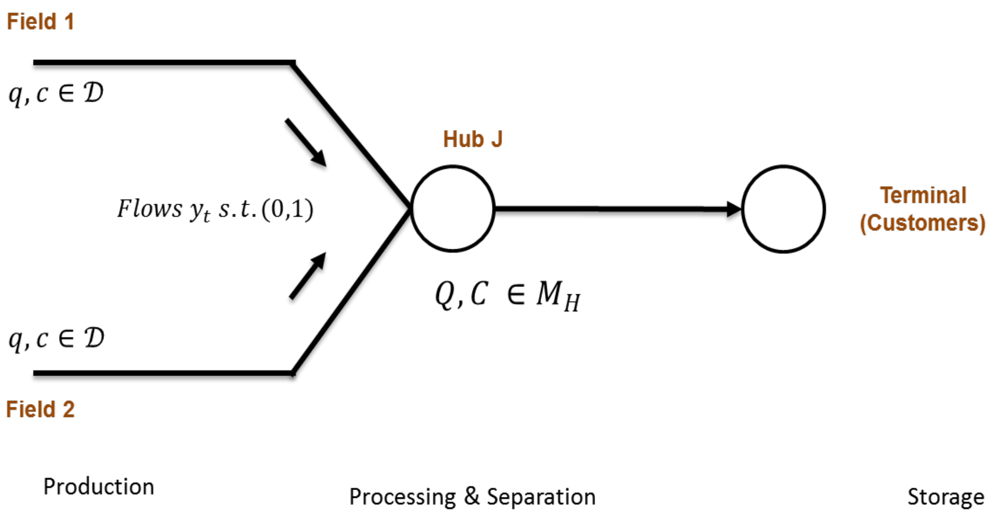

Figure 4 - Representation of potential networks for the production decision

Source: Authors' Construct

3.3 Objective function and model constraints

In this section, we present a static MIP model for optimising the NPV decision in the network of oilfields and hubs. To facilitate the presentation, we first summarise our notation below.

Notation and Definitions

Sets

$\mathcal{D}$	The set of all fields, developments and hubs in the UKCS region.
$\mathcal{I}(d)$	Field names based on DEAL & DECC names
$f(d)$	Development (actual or potential future)
$\mathcal{H}(d)$	Developments which are entry points to the transport system
$\mathcal{E}(d)$	Oil/gas terminal or exit points - either landfall or FPSO, others.
$\mathcal{N}(d)$	set of entities in NNS - a dynamic set
$\mathcal{P}(d)$	Sanctioned projects
$\mathcal{Q}(d)$	Incremental projects
$\mathcal{R}(d)$	Future projects
$\mathcal{S}(d)$	Technical reserves
$\mathcal{T}$	The set of time periods included in the model.

Indexes

d	Used for fields and hubs in general, $d \in \mathcal{D}$. When more indexes are needed, i, j, k,... will be used.
t	Time period $t \in \mathcal{T}$

Constants

$mmcf\_mmboe$	Gas Barrel of Oil Equivalent Conversion factor
$disc\_fact$	Discount factor
ER_USD_UKS	Dollars per £
$base\_oilprice$	Oil price, USD per barrel
$base\_nglprice$	NGL price, USD per barrel

Parameters and Variables

$BigM$	Constant coefficient representing a defined upper bound for total transhipment oil and gas
f_{it}	Binary variable (0/1) that captures whether a field is operating at a particular period
f_{ht}	Binary variable (0/1) that captures whether a hub is operating at a particular period
$fdec_{ht}$	Binary variable (0/1) that captures hub decommissions time t
$fdec_{it}$	Binary variable (0/1) that captures field/development decommissions time t
$\overline{tiep}_{ih}$	Binary variable (0/1) equal to 1 if tieback from field i to hub h is possible
$PipeOil_{hkt}$ $PipeGas_{hkt}$	Indicator variables showing that pipeline between two connecting hubs h and k is active
$tiebackact_{iht}$	Binary indicator variable equal to one when tieback is active
$tiebackstart_{iht}$	Binary indicator variable capturing when a tieback is active.
$hubactive_{ht}$	Binary indicator variable equal to one when a hub is active
$hubdecom_{ht}$	Indicator variable for when hubs are decommissioned
pto_{iht} ; $\overline{ptg}_{iht}$	The per unit oil and gas transportation tariff to the terminal if entry to pipeline system is hub h
to_{iht} ; tg_{iht}	Oil and gas production processed via tieback to hub h respectively
tso_{hkt} ; tsg_{hkt}	Transhipment oil and gas between hubs k and h
$\overline{pto}_{hkt}$; $\overline{ptg}_{hkt}$	The per unit oil and gas transportation tariff between if connection exists between hubs k and h.
pt_{ht}	The per unit transportation tariff to the terminal if entry to pipeline system is hub h
$\overline{rev}_{it}$	The potential pre-tax gross revenues from oil and gas production from field i
$\overline{dev}_{it}$	The capital and drilling expenditure associated with field i
$\overline{opex}_{it}$	The potential operating expenditure
$\overline{decm}_{it}$	The potential decommissioning expenditure if field/development operating in time t
$\overline{transpcost}_{it}$	The potential transportation charges a field/development pays to the pipeline and terminal operator
$\overline{ctie}_{ih}$	The potential one-time fixed cost incurred by activating a tieback from field $i \in D$ to hub $h \in H\ (\subset \mathcal{D})$
$\overline{cshare}_{iht}$	The potential cost contribution of a field/development to hub operating costs
$\overline{cdecm}_{it}$	The NPV in time t of future decommissioning expenditure if field/development decommissions in t
$\overline{rev}_{ht}$	The pre-tax hub gross revenues from oil and gas transportation
$\overline{dev}_{ht}$	The capital expenditure associated with hub h
$\overline{fopex}_{ht}$	Fixed operating expenditure associated with running the hub in time t
$\overline{vopex}_{ht}$	The variable hub operating expenditure in time t
$\overline{decm}_{it}$	The potential decommissioning expenditure hub is operating in time t
$\overline{cdecm}_{ht}$	The NPV in time t of future decommissioning expenditure if hub decommissions in t;

$allowance_{it}$	The field specific tax allowance
$taxrate_{it}$	Marginal rate of tax

Objective function and constraints:

<table>
<tr><td>Objective Function</td><td>

The objective to be maximised is the net present value (NPV) of regional production subject to various cost-sharing and financial viability constraints in addition to fiscal regime (tax) changes. The objective is summarised below as:

$$Max\ NPV_{region} = \frac{1}{(1+r)^t}\left(NCF_{hubs} + NCF_{fields}\right) \qquad [3.1]$$

$$s.t\ \ cost\ sharing, financial\ viability\ constraints\ plus\ and\ taxation\ changes$$

We can define the net cash flow (NCF) and net present value (NPV) for the different revenue streams as follows:

Fields/Developments

$$NCF_{it} = f_{it} \cdot \begin{bmatrix} \overline{rev}_{it} - \overline{dev}_{it} - \overline{opex}_{it} - \overline{decm}_{it} \\ - \overline{transpcost}_{it} - \overline{ctie}_{ih} - \overline{cshare}_{iht} \end{bmatrix} \forall\ i \in \mathcal{D} \qquad [3.2]$$

$$Max\ Z = NPV_i = \sum_{t \in T} \frac{1}{(1+r)^t} \cdot \left[NCF_{it} - \overline{cdecm}_{it} . fdec_{it}\right] \forall\ i\ \in \mathcal{D} \qquad [3.3]$$

Hubs

$$NCF_{ht} = \begin{bmatrix} f_{ht} \times (\overline{rev}_{ht} - \overline{dev}_{ht} - \overline{fopex}_{ht} - \overline{vopex}_{ht}) \\ - \overline{decm}_{ht} + \overline{cshare}_{iht} \end{bmatrix} \forall\ i\ \in \mathcal{D} \qquad [3.4]$$

$$Max\ Z = NPV_h = \sum_{t \in T} \frac{1}{(1+r)^t} \cdot \left[NCF_{ht} - \overline{cdecm}_{ht} . fdec_{ht}\right]\ \forall\ i\ \in \mathcal{D} \qquad [3.5]$$

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<tr><td>Physical flows of gas and oil</td><td>

The physical flows of oil and gas through the hub and pipeline transportation network are those which initiate the model. We define ten constraints that force the pipeline indicator variable positive. A pipeline integer constraint is foremost defined to ensure that transhipment oil and gas is only possible once there is a connection between hubs.

$$Active\ Pipeline\ Oil\text{:}\quad tso_{hkt} \le BigM.PipeOil_{hkt} \qquad [3.6]$$

$$Active\ Pipeline\ Gas\text{:}\quad tsg_{hkt} \le BigM.PipeGas_{hkt} \qquad [3.7]$$

The total oil processed at a hub is given by the sum of all the oil and gas tieback to a hub conditional on the existence of possible tiebacks allowable within the maximum possible distance between a development and hub. This is given as:

$$yhub\_oil_{ht} = \sum_{i\ |\ tiepos_{ih}} tieback\_oil_{iht}\ \forall\ i, h\ \in \mathcal{D} \qquad [3.8]$$

$$yhub\_gas_{ht} = \sum_{i\ |\ tiepos_{ih}} tieback\_gas_{iht}\ \forall\ i, h\ \in \mathcal{D} \qquad [3.9]$$

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	We further define a flow balance constraint that ensures that oil and gas inflows at any potential transportation node j plus the hub processed oil and gas equal to the outflow given by: $$oilflowbalance\colon \sum_{\alpha}(tso_{\alpha\delta t} + yhub\_oil_{\delta t}) = \sum_{\beta} tso_{\delta\beta t} \qquad [3.10]$$ $$gasflowbalance\colon \sum_{\alpha}(tsg_{\alpha\delta t} + yhub\_gas_{\delta t}) = \sum_{\beta} tsg_{\delta\beta t} \qquad [3.11]$$ Next, we define the constraint that captures the total tieback production equal to the total production by: $$\sum_{h \mid tiepos_{ih}} tieback\_oil_{iht} = f_{it}.(oilprod_{it} + NGLprod_{it}) \qquad [3.12]$$ $$\sum_{h \mid tiepos_{ih}} tieback\_gas_{iht} = f_{it}.(gasprod_{it}) \qquad [3.13]$$ Finally, we define the total production at the terminal for a given time t as the sum of all transhipment oil and gas conditional on the potential transportation nodes and given as: $$terminal\ oil\ prod\colon\ \ yterm\_oil_t = \sum_{\alpha,\varphi(\in\mathcal{D})} tso_{\alpha\varphi t} \qquad [3.14]$$ $$terminal\ gas\ prod\colon\ \ yterm\_gas_t = \sum_{\alpha,\varphi(\in\mathcal{D})} tsg_{\alpha\varphi t} \qquad [3.15]$$
Physical infrastructure constraints	Capturing the underlying dynamic oil and gas flows to a hub implies the activation of a tieback; we define these four physical infrastructure constraints given by: (1) constraints which force tieback indicator variable positive if either positive gas or oil flows; (2) constraints which force tie back start-up indicator positive for new developments; and (3) constraints which force hub indicator variable positive if either positive gas or oil flows. $$tieback\_oil_{iht} + tieback\_gas_{iht} \le BigM.tiebackact_{iht} \qquad [3.16]$$ To ensure unidirectional flow, we impose another constraint that ensures that only one tieback is allowed. This is given by: $$\sum_{h\in H} tiebackact_{iht} \le 1 \qquad [3.17]$$ (2) Constraints which force the tie back start-up indicator positive for new developments and starts up the costs that may be incurred conditional on the existence of possible tie backs within max possible distance is given by: $$tiebackstart_{iht} \ge tiebackact_{iht} - tiebackact_{iht-1} \qquad [3.18]$$ (3) Constraints which force hub indicator variable positive if either positive gas or oil flows is given by: $$yhub\_oil_{ht} + yhub\_gas_{ht} \le BigM.hubactive_{ht} \qquad [3.19]$$
Field start up and shut down constraints	We define a common variable which captures if new development developed $$fact_i \ \ge\ f_{it} \qquad [3.20]$$ Also, we constrain new developments to start on the correct date by defining a constraint that captures the fact that if a new development is developed then it must have entire devex profile and this starts in first year where devex incurred.

	$$fact_{i\,\vert\,\emptyset} \geq f_{it} \quad [3.21]$$ where ∅ is the year first development expenditure is set. The field decommissioning constraint $fdecom_{it}$ is given by: $$fdecom_{it} \geq f_{it-1} - f_{it} \quad [3.22]$$ A further constraint to ensure one field decommissions is given by $$\sum_t fdecom_{it} \leq 1 \quad [3.23]$$
Hub shutdown constraints	The hub shutdown constraints force the hub decommissioning indicator positive when a hub infrastructure shuts down $$hubdecom_{ht} \geq hubactive_{h,t-1} - hubactive_t \quad [3.24]$$ A further constraint to ensure one hub decommissions and to ensure once decommissioned it cannot be restarted (initially all hubs open) is given by the two equations below respectively. $$\sum_t hubdecom_{ht} \leq 1 \quad [3.25]$$ $$hubactive_t \leq hubactive_{h,t-1} \quad [3.26]$$
Economic constraints (participation constraints)	Two economic participation constraints are defined: (1) a minimum NPV requirement that ensures that the post-tax NPV of new developments is positive and (2) and economic shutdown limit for fields (and hubs)[4] when future post-tax NCF is less than zero. The two are given by the equations below: *Minimum NPV requirement - Post Tax NPV new developments positive* $$npv\_dev(newdev) - npv\_tax(newdev) \geq 0 \quad [3.27]$$ *Economic Shut Down when NPV of future NCF <0* $$Fields: \quad \sum_t dfact_t\,(NCF_{it} - TAX_{it}) \geq 0 \quad [3.28]$$ $$Hubs: \quad \sum_t dfact_t\,(NCF_{ht} - TAX_{ht}) \geq 0 \quad [3.29]$$ With regard to cost sharing, cost shares are activated once a tieback is activated and also field commences operation. This is defined as $$costshare_{iht} \leq BigM2 \times tiebackact_{iht} \quad [3.30]$$ $$costshare_{iht} \leq BigM2 \times f_{it} \quad [3.31]$$
Cost Sharing	The hub opex is apportioned to the respective fields in a number of ways so as to ensure effective cost recovery. **(i) Split the tariff into two components:** Assuming the hub opex as the basis for cost-sharing (i.e $opex_{ht} = \sum_i costshare_{it}$), then the tariff applicable to a field will consist of a fixed cost of service (access charge) and the operating costs, which is based on throughput and assumed to capture the marginal cost of processing.

[4] We subsequently relax this hard rule for hubs to ensure they remain operational even if future NCF is zero.

$$\sum_i costshare_{it} = \mu + p_{it} \sum_i \Theta_{it} = \psi\left(\frac{opex_{ht}}{\sum_i N}\right) + p_{it} \sum_i \Theta_{it} \qquad [3.32]$$

$\mu = fixed\ cost\ component\ to\ cover\ access\ charge$

$p_{it} = marginal\ cost\ of\ processing\ and\ \ \Theta_{it} = field\ throughput$

(ii) Single throughput cost: Potential developments pay the hub a processing cost $p(i)$ is based on a nominal charge without disaggregating the costs so far as it enough to cover the yearly hub opex. A nominal per unit tariff (marginal cost) is levied on all the developments to cover the hub costs. Again, assuming $opex_{ht} = \sum_i costshare_{it}$, we can compute the break-even tariff that ensures that a hub is kept operational in any given period as:

$$\sum_i costshare_{it} = p_{it} \sum_i \Theta_{it} \qquad [3.33]$$

Tax Computations

Considering the oil and gas tax regime that applies to the UKCS, we define the following equations that incorporate the different elements, namely the marginal tax rates and allowances that can be offset against corporate taxation.

Total tax allowable for fields/ developments: this is equal to the total unused allowances from previous year plus devex and other capex and is defined as:

$$tallow\_un_{it} = \begin{array}{c} tallow\_un_{i,t-1} - allow\_use_{i,t-1} + f_{it}.\overline{dev}_{it} \\ + \sum_h tiefixc_{ih}.\Gamma_{iht} + allowance_{it} \end{array} \qquad [3.34]$$

Total paid by fields/ developments: this is given as the tax adjusted net cash flow of a development (revenues minus operating expenditure, transportation costs, tieback costs, development and decommissioning costs) plus the development expenditure which is added back in as it is included in allowances (and can be carried over) minus any allowances utilised. This is given by the equation below as:

$$tax_{it} \geq \Omega(taxrate_{it} \times NCF_{it}) + f_{it}\overline{dev}_{it} - allow\_use_{it} \qquad [3.35]$$

Total tax allowable for hubs: this is equal to the total unused allowances from the previous year plus devex and other capex and is defined as:

$$tallow\_un_{ht} = \begin{array}{c} tallow\_un_{ht-1} - allow\_use_{ht-1} \\ + f_{ht}.\overline{dev}_{ht} + allowance_{ht} \end{array} \qquad [3.36]$$

Total paid by hubs: this is given as the tax-adjusted net cash flow of a hub plus the development expenditure which is added back in as it is included in allowances (and can be carried over) minus any allowances utilised. This is given by the equation below as:

$$tax_{ht} \geq \Omega(taxrate_{ht} \times NCF_{ht}) + f_{ht}\overline{dev}_{ht} - allow\_use_{ht} \qquad [3.37]$$

Finally, we define two additional tax equations that ensure that usage of allowances is common across developments and hubs and also that operators can offset their final decommissioning expenditures against tax elsewhere from within the region. These are given by:

$$allow\_use_{it} \leq tallow\_un_{it} \qquad [3.38]$$

where the index i is the combined set of potential active developments and hubs.

$$npv\_tax_i = \sum_t [\ (dfact_t.tax_{it}) - (taxrate_{it}.DecomNPV_{it}.fdec_{it})\ ] \qquad [3.39]$$

3.4 Simulated models

An overview of the model variants simulated, and their characteristics are provided in Table 2 below. Three scenarios are modelled, namely a base case, the impact of tax changes and cost-sharing rules on field economics which are then analysed in terms of the effects on field economics and maximising economic recovery. The *Base Model* captures the basic impact of split ownership structure across fields/hubs. It does not include the imposition of cost-sharing rules and also any fiscal regime impact by way of taxes is removed. The *Tax Model* captures the tax changes resulting from the impact of split ownership structure across fields/hubs whereas the *Cost Sharing plus Tax Model* combines both cost-sharing and tax changes to estimate their combined impact on field economics.

Name	Description
Baseline Model	Captures basic impact of split ownership structure across fields/hubs. Based on the cost sharing model without any imposition of cost sharing rules and the removal of any fiscal regime impact by way of taxation. Cost-sharing model based on restrictions that each tieback field pays different processing charges to hubs. To identify the impact of different market arrangements on third party access to infrastructure, we need to have a reference point, which is our cost sharing model without any imposition of cost sharing rules and the removal of any fiscal regime impact by way of taxation. The benchmark model defines the economic size of the prize at stake in terms of the maximum amount of oil and gas resources that can be recovered subject to constraints of a minimum NPV requirement for all fields and an economic shutdown limit for fields (and hubs) when future post-tax NCF is less than zero. It also allows us to benchmark how various additional rules such as cost sharing and taxation deviate from this ideal. To have this numeric reference point, we run the model maximising the NPV as our objective model outcome and as the basis of the valuation methodology based on the following points: (1) the NPV approach properly accounts for all the relevant cash flow streams and costs; (2) takes into account the time value of these cash flows; and (3) it is a direct measure of wealth in terms of both the government and investor takes.
Tax Model	Captures the tax changes resulting from the impact of split ownership structure across fields/hubs. This is based on Cost-sharing model without any imposition of strict cost sharing rules and also incorporates the fiscal regime changes in the UKCS from Budget 2015 to 2016. The tax model allows us to capture the extent of recent fiscal regime changes on field and hub economics. Three tax regime elements are considered namely: (1) Budget 2015 where the marginal tax rate on old fields and hubs is 67.5% and 50% for new fields and hubs; (2) Budget 2016 where the marginal tax rate is 40% for both old fields and new fields; and (3) a special case where the hubs are assumed to be taxed at only the existing ring fence corporation tax of 30% but fields pay a marginal tax rate of 40%. The special case where the hubs are taxed at an assumed ring fence corporation tax of 30% approximates the situation of allowing independent ownership of midstream infrastructure such as pipelines and processing hubs to encourage the development of infrastructure tariff income business. The tax model is centred on the *Base Model* with individual field and hub financial viability restrictions and includes the imposition of various fiscal regime elements. This allows us to capture the tax changes resulting from the impact of split ownership structure across fields/hubs. We reiterate here again that explicit cost sharing rules are not considered in the tax model as we are interested in observing the direct taxation impacts by incorporating fiscal regime changes in the UKCS from Budget 2015 to 2016. Again, we run the model maximising the NPV as our objective model outcome. The basis of the valuation methodology based on the following

	points: (1) the NPV approach properly accounts for all the relevant cash flow streams and costs; (2) it takes into account the time value of these cash flows; and (3) it is a direct measure of wealth in terms of both the government and investor takes.
Cost Sharing plus Tax Model	This combines both the cost-sharing and tax changes to estimate the combined impact of the two on field economics. Captures how different cost-sharing rules combined with split ownership structure across fields/hubs affects profitability. This is based on Cost-sharing model with imposition of different cost-sharing rules and tax imposed. Here, we model how different cost sharing rules combined with split ownership structure across fields and hubs affect profitability. Unlike the baseline model where we place no imposition of strict cost-sharing rules, we impose different cost sharing rules as well as the three tax scenarios described earlier. We place restrictions for each hub such that each tieback field pays different processing charges to hubs. That is, we split the tariff into two components namely a fixed cost (access charge) and variable (marginal) costs, which is based on throughput and assumed to capture the marginal cost of processing. The sum of the fixed and variable cost must cover the yearly hub opex and capex. Two fiscal scenarios are considered here, namely Budget 2015 and Budget 2016.

Table 2 - Summary of the simulated models

Tax Regime Modelling

The modelled changes are shown in Table 3 below. We employ a simplified version of the current UKCS fiscal regime in our model. This includes tax-deductible capital allowances for capital, tieback and decommissioning expenditure. The key here is to show the extent to which the fiscal regime plays in maximising economic recovery. However, the government's position is that tax changes will not solve every challenge facing the UKCS (HM Treasury, 2014). The tax treatment of capital expenditure is a key element of the UKCS fiscal regime. First-year capital allowances of 100% are available for virtually all capital expenditure, with relief also available for expenditure incurred when decommissioning infrastructure after production has ceased. The effect on investment incentives also depends on reliefs for investment. The investment relief for non-PRT fields are 62.5% and 46.25% under the 2015 and 2016 terms, respectively. For PRT paying fields, this translates to 75.62% and 46.25% under the 2015 and 2016 terms. The cost shares paid by fields to hubs to cover operating expenditure are tax-deductible, but cost shares received by hubs are liable for tax.

	Tax Regime	Budget 2015	Budget 2016	Special Case*
Fields	Marginal tax rate of old PRT Fields	67.5%	40%	40%
	Marginal tax rate of new Fields	50.0%	40%	40%
Hubs	Marginal tax rate of the old Hubs	67.5%	40%	30%
	Marginal tax rate of new hubs (Post 1993)	50.0%	40%	30%

Special Case: The special case represents that of non-licensee investors such as the new pipeline and terminal owners. Non-licensees pay the non-North Sea tax which at 20% rate with capital allowances for plant and machinery at 18% declining balance. We model the case where they pay Ring Fence Corporation Tax (RFCT) at 30%. The special case tax terms which are modelled are for comparative purposes only.*

Table 3 - Modelled tax changes

3.5 Case study data

Our model uses various public and private data from the Northern North Sea (NNS) region of the UKCS to simulate the interactions between hub infrastructure owners and third-party fields. The Northern North Sea area of the UKCS is bounded by Quadrants 1 to 9 and 207 to 217. NNS fields are defined within X coordinate greater than -1.5 (Shetland), and Y coordinates greater than 59.24 (just south of Gryphon/Harding but North of Devenick). The area is typically characterised by several mature fields nearing the end of their production life and new (but smaller) fields with associated large-scale infrastructure. Examples are Cormorant, Ninian, Magnus and Dunbar fields (Kemp and Phimister, 2012). GIS data available from OGA was used to map the location of the hubs and potential developments. Tiebacks either from existing or future developments are assumed possible if they lie within a radius of up to 45 km to the nearest hub– that is, hub economic distance constraint. We also factor into this calculation whether the potential development is within the hub economic distance, the hub's capacity limits, and subsequent analysis, the alignment of ownership, which determines preference criteria of the owners for each development. Our base model set consisted of the following sets:

- 150 developments (actual or potential)
- 19 associated with hubs and 131 Developments that have no associated hubs
- 50 Sanctioned, 24 Incremental, 14 Future and 31 Technical developments
- 19 Hubs

4 Results and discussion

4.1 Benchmark model

A comparison of the regional production and NPVs for the base case is presented below. From Table 4, the NPV using a base case oil price of $60 per barrel and $50 per barrel for NGLs was £5,286 million (no constraints in place, no cost-sharing rules or taxes imposed) and £4,412 million (individual field and hub financial viability constraints but no cost-sharing rules or taxes imposed). We argue the case without economic constraints as that which corresponds to a single ownership scenario. That is, we approximate the regional production as though a single operator owned all the hubs and fields, and therefore, cross-subsidization from fields to hubs and vice versa is possible so long as this contributes positively to overall value creation.[5]

The case with economic constraints, on the other hand, represents multiple ownership patterns where different operators of the fields and hubs act out to maximise individual field cash flow and profitability (NPV). In line with our *ex-ante* expectations, the results confirm the case that imposing economic constraints that capture the different ownership patterns in the UKCS does impact overall regional economic maximisation objectives as different ownership does considerably decrease the total NPV of developments. However, this outcome is not surprising in the sense that the comparative case without economic constraints can be interpreted as the theoretically maximum value (upper limit) that can be extracted from the region under a single owner and operator. That is the maximum economic size of the prize.

Parameter	Without Economic Constraints @$60/bbl	With Economic Constraints $60/bbl
NPV, £m	5,286	4,412
Number of Developments	30	23
Years' Operating	427	368

Table 4 - Base case NPV results

With regard to the number of developments and their total operational years, relative to the case without economic constraints, 23 developments remain on-stream throughout till 2050 at $60/bbl compared to 30 developments without economic constraints at the same oil price. The cumulative years of the developments decrease by 16% from 427 years in the case without economic constraints to 368 years when economic constraints are imposed at $60/bbl in all cases, implying reduced activity levels which are to be expected. The effect of imposing the two economic constraints defined as (1) a minimum NPV requirement that ensures that the post-tax NPV of new developments is positive, and (2) economic shutdown limit for fields (and hubs) when future post-tax NCF is less than zero is that it increases the average operational years from 14 to 16 years per development. This is because although the number of operating years reduces by 59 with the imposition of these two constraints, only a comparatively smaller number (namely seven developments) fail to stay online throughout the period.

4.2 Tax model

Table 5 shows the base case tax results represented by Budget 2015, where the marginal tax rate on old fields and hubs is 67.5% and 50% for new fields and hubs. At oil prices of $60 per barrel and $50 per barrel for NGLs, the optimally computed pre-tax NPV for the region imposing individual

[5] Similar arguments advanced by Kemp and Phimister (2012)

field and hub financial viability constraints is £3,985 million. This translates into a post-tax investor take of £1,550 million (39% of the pre-tax value) compared with a government take of £2,435 million (61% of the pre-tax value). Utilising the same set of assumptions, Budget 2016 parameters representing a 12.5% and 10% reduction in the marginal tax rate for old and new fields as well as hubs respectively, results in an increment in the pre-tax NPV to £4,848 million.

This translates to a post-tax investor NPV of £1,994 million (41% of pre-tax NPV) and government NPV of £2,854 million (59% of pre-tax NPV). Concerning the special case tax scenario where the hubs are taxed at only the existing ring fence corporation tax with fields paying the existing marginal tax rate, the model generates a pre-tax NPV of £4,937 million, translating into a post-tax investor NPV of £2,024 million (41% of pre-tax NPV) and government NPV of £2,912 million (59% of pre-tax NPV). The notable difference in pre-tax values at different budget conditions is due to the effect of the different tariffing arrangements with regard to the way cost-share attributions are made. The optimisation works such that relatively higher amounts of cost shares are moved between developments and hubs in order to prevent early shut down of the hubs as the tax rate increases. That is, the model automatically computes various sets of cost-shares without any restrictions placed on them which are then moved between fields and hubs in a way that maximises the overall NPV. Hence, the pre-tax values at certain points for the same oil price are likely to be different due to the way these cost-share attributions are made.[6]

Scenario	Post-Tax NPV	Tax NPV
Budget 2015: NPV, £mm @$60/bbl	1,550	2,435
Budget 2016: NPV, £mm @$60/bbl	1,994	2,854
Special Case: NPV, £mm @$60/bbl	2,024	2,912

Table 5 - Base case tax results

The results above confirm our *ex-ante* expectation that reducing the marginal tax rate does improve overall regional profitability. In all three cases, the project values increase with decreasing marginal tax rates, although we do not observe noticeable changes in the profit-sharing scheme at $60 per barrel irrespective of the tax rate imposed. The investor's share of the profit lies between 39%-41% of the overall project value compared to the government's take of between 59%-61%. We argue this result reflects both a relative degree of neutrality and progressiveness of the regime to the extent that lowering the tax rate, although increases the absolute project value, also results in a marginal 3% improvement in the investor take. It has been argued in the literature that the overall effect of a petroleum fiscal regime should encompass good fiscal principles of neutrality – that is, does not distort investment decisions - and progressivity in responding to field profitability indicators such as variations in oil prices and development costs (Blake & Roberts, 2006; Nakhle, 2007).

The implied oil and gas production and operating years associated with the three tax scenarios are presented in Table 6. Oil and gas production in Budget 2015, Budget 2016 and the Special Case remain similar at a cumulative 335 mmboe at $40 per barrel despite marginal differences across some years. The implied oil and gas production at $60 per barrel for both Budget 2016 and the Special Case is estimated at 825 mmboe and 803 mmboe with Budget 2015 parameters. This increases to 1,378 mmboe at $80 per barrel under all three tax scenarios. Although the different tax treatments result in different value shares in terms of investor and government take, the implied overall production that can be maximised economically does not change much across different fiscal

[6] The scenario where additional restrictions are placed on the cost shares is captured in *the Cost Sharing plus Tax Model*

parameters. This is because the objective function in our model formulation is to maximise value NPV. These results would have been different were we to have chosen the maximisation of overall production volumes as compared to the value (NPV) as our objective.

Tax Model (no strict cost sharing rules)									
Fiscal Regime	**Budget 2015**			**Budget 2016**			**Special Case**		
Oil Price Scenario	$40/ bbl	$60/ bbl	$80/ bbl	$40/ bbl	$60/ bbl	$80/ bbl	$40/ bbl	$60/ bbl	$80/ bbl
Total Regional Production, mmboe	335	803	1,378	335	825	1,378	335	825	1,378
No of devts	7	17	33	7	16	34	7	16	34
Operating years	89	265	541	89	252	525	89	252	525

Table 6 - Tax model comparative statistics

Table 7 shows the response of the various changes to oil price changes. It can be observed that overall project profitability increases as oil prices increase and the fiscal terms captured by the marginal rate of tax also decrease. The pre-tax NPV under all the various tax scenarios increase with increasing oil prices, but the split in terms of the investor and government take are not necessarily proportionate to the size of the increment. These results confirm our *prior* expectations based on the literature on oilfield economic modelling that the key revenue determinant remains oil prices - they fundamentally drive asset values. Thus, high prices imply higher asset values and vice-versa. High oil prices, coupled with a reduction in the tax burden, imply greater field NPV and therefore bigger share for all stakeholders, both government and investor alike.

Scenario	Pre-Tax NPV	Post-Tax NPV	Tax NPV
Budget 2015: NPV, £mm @$40/bbl	345	180	166
Budget 2015: NPV, £mm @$60/bbl	3,985	1,550	2,435
Budget 2015: NPV, £mm @$80/bbl	15,495	7,174	8,321
Budget 2016: NPV, £mm @$40/bbl	527	257	270
Budget 2016: NPV, £mm @$60/bbl	4,848	1,994	2,854
Budget 2016: NPV, £mm @$80/bbl	17,758	8,668	9,090
Special Case: NPV, £mm @$40/bbl	527	266	262
Special Case: NPV, £mm @$60/bbl	4,937	2,024	2,912
Special Case: NPV, £mm @$80/bbl	18,001	8,686	9,315

Table 7 - Tax regime changes and oil price sensitivity

4.3 Cost Sharing plus tax model

The results of the cost-sharing and tax model are presented in Table 8 below. At $60 per barrel for oil and $50 per barrel for NGLs, the pre-tax NPV for the region based on the imposition of cost-sharing rules as well as individual field and hub financial viability constraints was estimated at £2,649 million for Budget 2015 fiscal terms. This translates into a post-tax investor take of £1,110 million (42% of the pre-tax value) compared with a government take of £1,539 million (58% of the pre-tax value). Utilising the same set of assumptions, Budget 2016 parameters resulted in a near-doubling of the pre-tax NPV to £5,197 million as a result of non-tax factors. This translates to an investor post-tax NPV of £1,995 million (38% of pre-tax NPV) and government NPV of £3,202 million (62% of pre-tax NPV).

Scenario	Budget 2015: NPV, £mm @$60/bbl	Budget 2016: NPV, £mm @$60/bbl
Pre-tax NPV	2,649	5,197
Post-Tax NPV	1,110	1,995
Tax NPV	1,539	3,202

Table 8 Tax and cost-sharing model results

The difference in the pre-tax value while maintaining the same oil price can be attributed to the combined effect of the stricter cost-sharing rule (non-tax factors) and the tax adjustments. That is, imposing a much stricter cost share requirement such that cross-subsidisation of fields and hubs virtually becomes impossible, while at the same time, increasing the higher tax rate reduces the overall profitability. This is, however, different from the similar set of stricter cost share requirement but with a reduction in the tax rate. Here, we see the tax reduction producing a much bigger effect on the overall NPV maximisation. Even though overall field profitability increases under the combined effect of the stricter cost sharing rule together with the various fiscal treatments and financial viability constraints, the split in terms of the various takes is marginally in favour of the government. With regard to the tax treatment, we observe that at $60 per barrel, there is a proportionate 4% value shift from the investor to the government as is shown in Figure 5. We argue that lowering the tax rate while imposing a stricter cost sharing rule effectively increases overall project value as it allows hitherto unprofitable fields and developments that may never have been developed to do so and also prolongs the tail effect of the production. That is, the lower tax rate produces a tail effect by extending overall regional production profiles and thus allowing additional recovery of oil and gas in later years of production.

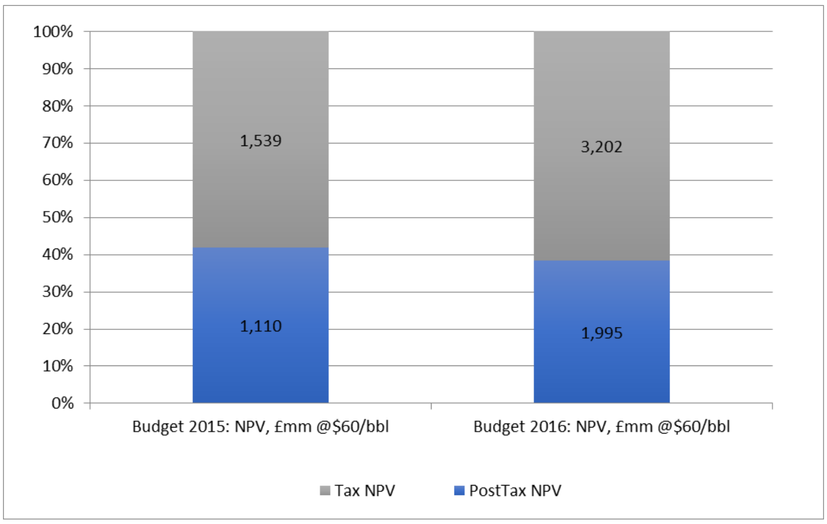

Figure 5 - Tax comparison of takes

Source: Authors' Construct

Figure 6 shows the oil price effect under the cost sharing plus tax model. We observe that the fiscal regime retains the general price progressivity principle whereby the government share of the overall project value increases with increasing oil price. The government share moves from 48% of the project value at $40 per barrel through to 58% of overall project value at $60 per barrel and marginally down to 57% of project value at $80 per barrel. Oil price progressivity in fiscal systems is mainly aimed at capturing windfall profits at high prices, whereas maintaining a relatively low government take under low prices (Nakhle 2007). Although it may be rare to find price progressivity over the entire oil price range, our results here show that having a progressive fiscal regime in a mature basin such as the UKCS is important to support continued operations under low oil prices while creating extra benefits for the government under high prices. The cost sharing effect is computed by comparing the results from the tax model in which no strict cost sharing rules were enforced to the results under the cost sharing plus tax model with the imposition of strict cost sharing rules. We compare results under the different oil price assumptions while keeping the fiscal measures constant – that is, Budget 2015 in this case.

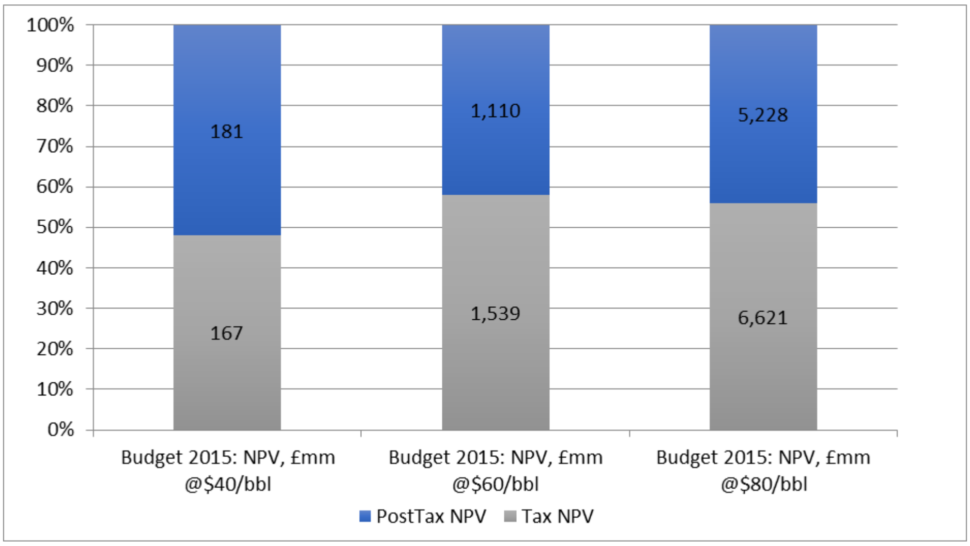

Figure 6 - Revenue shares at different oil prices

Source: Authors' Construct

Figure 7 provides the comparison of the value split between the investor and government with regard to the tax and cost sharing plus tax models. At low oil prices of $40 per barrel, the share of the value between the investor and government remains broadly unchanged and marginally in favour of the investor with a combined 53% take compared to the government's 47% take. This suggests that the imposition of the strict cost-sharing rule does very little to change the overall project valuation in the low oil price scenario. The value split begins to change with increasing oil prices at $60 and $80 per barrel, respectively, although the total project value decreases across the board. For example, at $60 per barrel, the 61%:39% split between the government and investor in the tax model reduces to 58%:42% in the cost sharing plus tax model despite a reduction in the overall value from £3,985 million to £2,649 million. At $80 per barrel, there is a reversal in value shares from 54%:46% government and investor take in the tax model to 56%:44% under the cost sharing plus tax model. Based on the above results, we argue that the enforcement of the strict cost sharing rules in the cost sharing plus tax model does reduce overall value across the board although this does not necessarily result in an equitable distribution of value that reflects the risks undertaken by the investor.

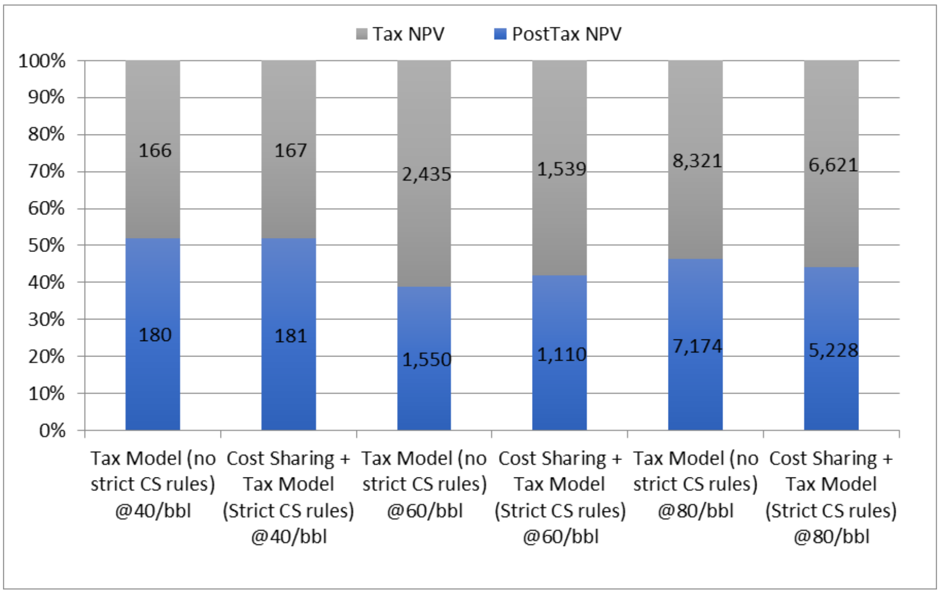

Figure 7 - Comparison between tax and cost sharing + tax models

Source: Authors' Construct

The implied oil and gas production and operating years associated with the two tax scenarios are presented in Table 9. Oil and gas production in Budget 2015 and Budget 2016 remain similar at a cumulative 335 mmboe at $40 per barrel. The implied oil and gas production at $60 per barrel increases by 36% to 782 mmboe for Budget 2016 compared with 576 mmboe for Budget 2015. This increases to 1,367 mmboe at $80 per barrel under Budget 2016 compared with 1,288 mmboe for Budget 2015. The number of developments and operating years follow this trend as well with an average increment of four operating years between changes in oil prices under the same tax terms. Compared to the tax model, the tax and cost-sharing treatment results in varied value shares for the investor and government as well as different implied overall production across the fiscal parameters.

Model Type	Cost Sharing + Tax Model (Strict Cost Share rules)					
Fiscal Regime	**Budget 2015**			**Budget 2016**		
Oil Price Scenario	$40/ bbl	$60/ bbl	$80/ bbl	$40/ bbl	$60/ bbl	$80/ Bbl
Total Regional Production, mmboe	335	576	1,288	335	782	1,367
No of developments	8	14	34	8	17	34
Operating years	72	146	448	72	224	506

Table 9 - Comparative statistics – cost sharing plus tax model

5 Conclusions

We have presented a MIP model for analysing economic dependencies of infrastructure assets in the UKCS and compared the results from our model with a benchmark model without any imposition of strict cost sharing rules and removing any fiscal regime changes. The results of this analysis using data from the Northern North Sea region support the conclusion that differences in field ownership, the choice of tariffs, and changes to the tax system impact the overall value of developments in the UKCS.

Results from the *Benchmark Model* examines the impact of ownership patterns using cases with and without economic constraints to confirm our ex-ante expectation that imposing economic constraints that capture the different ownership patterns in the UKCS impacts overall regional economic maximisation objectives. Different ownership patterns as proxied by financial viability constraints do considerably decrease the overall NPV of developments. That is from £4,412 million versus £5,286 million at $60 per barrel. We interpret the comparative case without economic constraints as the theoretical upper-value band extracted from the region under a single owner and operator. The implied production associated with the respective oil prices also confirms the trend of more value being unlocked in terms of oil and gas extracted under the theoretical single regional owner-operator than imposing economic constraints.

We then considered a *Tax Model* to capture fiscal regime changes resulting from split ownership structure across fields and hubs. To reiterate, we did not consider explicit cost sharing rules in the tax model, as we are interested in observing fiscal regime changes in the UKCS from Budget 2015, 2016 and a Special Case. The results from the tax model show that reducing the marginal tax rate does improve overall profitability. In all three cases, the project values increase with decreasing marginal tax rates, although we observe minor changes in the profit-sharing scheme irrespective of the tax rate imposed. The investor's share of the profit lies between 39%-41% of the overall project value compared to the government's take of between 59%-61%. We argue this result reflects both a relative degree of neutrality and progressiveness of the regime to the extent that lowering the tax rate, although it increases the absolute project value, also results in a marginal 3% improvement in the investor take.

The *Cost Sharing plus Tax Model* explored how different cost-sharing rules combined with split ownership structure across fields and hubs affect profitability. We imposed different cost sharing rules and the two tax terms, namely Budget 2015 and 2016. Even though overall field profitability increases under the combined effect of the stricter cost-sharing rule and the various fiscal treatments and financial viability constraints, the split regarding the various takes is marginally titled for the government. Regarding the tax effect, we observe that at $60 per barrel, there is a proportionate 4% value shift from the investor to the government. We argue that lowering the tax rate while imposing stricter cost-sharing rules increases overall project value as it allows hitherto unprofitable fields and developments to come onstream. Furthermore, the lower tax rate produces a tail effect by extending overall regional production profiles and allowing additional oil and gas recovery in later years of production.

On the oil price effect under the cost-sharing plus tax model, we observe that the fiscal regime retains the general price progressivity principle whereby the government share of the overall project value increases with increasing oil price. The government share moves from 48% of the project value at $40 per barrel to 52% of the overall project value at $60 per barrel and 62% of the project value at $80 per barrel. We estimate the cost sharing effect by comparing the results from the tax model in which no strict cost-sharing rules to the results under the cost sharing plus tax model with the imposition of strict cost sharing rules. The results suggest that the imposition of the strict cost-sharing rules does very little to change the overall project valuation in the low oil price scenario.

However, the value split begins to change with increasing oil prices, although the total project value decreases across the board. For example, at $60 per barrel, the 61%-39% split between the government and investor in the tax model reduces to 58%:42% in the cost-sharing plus tax model despite reducing the overall value from £3,985 million to £2,649 million. Based on the above results, we argue that the enforcement of the strict cost-sharing rules in the cost-sharing plus tax model does reduce overall value across the board. However, this does not necessarily result in an equitable distribution of value that reflects the risks undertaken by the investor. Overall, we argue that modelling third party access to infrastructure in oil and gas networks, taking into account firm decision making in terms of financial constraints and the fiscal regime effects, remains an important aspect of upstream decision making and economic analysis of issues surrounding third party access to infrastructure, particularly in matured regions such as the UKCS.

The study makes the following policy recommendations on third-party access to infrastructure in the UKCS. A first major policy implication is that the regulatory agency in settling disputes over third party access arrangements and tariffs needs to understand the region's economics in terms of the relationship between fields and hub infrastructure owners. The regulator needs to establish a baseline scenario corresponding to a single ownership model. This, therefore, allows benchmarking the extent by which multiple ownership patterns where different operators of the fields and hubs act out to maximise individual field cash flow and profitability deviate from this norm through protracted disputes over tariff and access terms.

Secondly, regarding the impact of taxation on the long-term economics of hubs and their user fields, we recommend that tax policies that enhance project profitability should be continued as they remain fundamental to the region's future in terms of sustaining production from hitherto marginal oilfield developments. For example, the study found that reducing the marginal tax rate improves overall regional profitability with minor impacts on the profit-sharing scheme between the investor and the government. The tax system remains progressive and largely neutral.

Finally, we recommend that tariff determination should be based on cost-share rules that enjoin each field tieback to a hub pays the split tariff made up of two components, namely a fixed cost of service (access charge) and variable (marginal) costs, which are based on throughput and capture the marginal cost of processing. Where processing capacity is not an issue, we observe that optimal third party tariff, in this case, should reflect: (1) the standard monopoly mark-up given by a third party firm's elasticity of demand for oil and gas processing and transportation; and (2) the willingness to pay for capacity (the shadow price) in the case of a congested transportation network. This could be regulated or negotiated access; the latter, whereby parties seek consensus on tariffs acceptable to both the owner and the user. Hence, in line with Chaton et al. (2012), Sannarnes (2007a and 2007b), Cremer et al. (2003) and Cremer & Laffont (2002), we argue that the efficient transportation and processing charge when pipeline capacity is fixed and or constrained must equal the marginal cost of transportation adjusted by a mark-up factor. However, this could vary according to the specificities of processing facility configurations rather than a universal or postage stamp rate. Such a pricing approach is also adopted in other North Sea jurisdictions such as Norway. Tariffs vary from facility to facility, and there is no fixed tariff despite having two public-private monopolies (Gassco and Gassled) owning and operating all gas pipeline networks (Grondalen & Lower, 2016; Bannet 2012).

Furthermore, such a pricing approach will also be in line with competition principles —that is, essential facilities doctrine in competition law — and the broader resource management objective of MER. Applying a flat cost-share structure has the disincentive of punishing more cost-efficient fields by transferring value from the field owner to the hub infrastructure operator because a single throughput charge subsidises other fields. Tariffs are ultimately decisive as to whether the satellite or user field will be developed or not, thereby contributing to MER.

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CRediT authorship contribution statement

Theophilus Acheampong: Conceptualization, Methodology, Formal analysis, Writing – original draft, Writing – review & editing. **Euan Phimister:** Conceptualization, Supervision, Writing – review & editing. **Alexander Kemp:** Conceptualization, Supervision, Writing – review & editing.

Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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