THIRD PARTY ACCESS TO INFRASTRUCTURE HUBS AND THE FUTURE RECOVERY OF OIL AND GAS RESERVES IN THE UKCS

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Abstract

This paper explores how possible different ownership patterns (and access arrangements) might affect the economic viability of remaining resources in UKCS, by applying a mixed integer programming model to field data from the Northern North Sea. The model maximizes the net present value of regional production, determining the optimal set of new developments, tiebacks from fields to hubs, timings of hub and field shutdown, with the effects of the separation of infrastructure and field ownership captured by constraints which impose individual field and infrastructure viability conditions. The possible impact of a type of common carrier regime, where existing hub infrastructure might be unbundled from fields with average cost pricing based on throughput, is also modelled.

The results suggest that the separation of infrastructure and field ownership does reduce the overall potential area NPV. The cost of development delay is also relatively high, although in part this arises because potential production is postponed. In contrast, the version of the model where hubs are forced to charge fields a single price to cover average costs significantly reduces the reserves developed in the region.

Introduction

The importance of ensuring effective mechanisms to allow third-party access to infrastructure in the United Kingdom Continental Shelf (UKCS) has been understood since the early years of North Sea oil and gas exploitation, both in helping reduce the overall development costs of new fields and avoiding the proliferation of pipelines. In recent years, third-party use of the existing infrastructure has grown substantially. Because of the small size of the majority of the new fields in the UKCS, it is increasingly important in ensuring that that maximum economic recovery can be attained.

The UK government recognizes the potential negative effects of local monopoly power being used by infrastructure owners and has, within the 2011 Energy Act, taken some new powers to intervene. However, in contrast to other jurisdictions such as Norway, the approach taken in the UK remains voluntary. Here, the Industry's Infrastructure Code of Practice (ICOP) is meant to guide bilateral negotiations between existing infrastructure owners and potential third party users, with government intervention envisaged only when negotiations fail (UKOOA, 2004).

Despite the recent strengthening of DECC's powers, the current voluntary system is perceived to have a number of weaknesses for third party users of the existing infrastructure, particularly in terms of the typical delays involved in getting agreement between parties, with some suggesting that a much more regulated approach is required. For example, it has been argued that processing and transport should be entirely unbundled from field exploration and production using a common carrier system (OGIA, 2009; House of Commons, 2009; Rush, 2012).

By definition, potential third party access to infrastructure issues arise when patterns of ownership imply (at least a partial) separation of ownership between owners of infrastructure and those developing new fields (Kemp and Phimister, 2010). The aim of this paper is therefore to explore how possible different ownership patterns (and access arrangements) might affect the economic viability of exploiting remaining resources in UKCS. Specifically, using field data on current and estimated future potential recoverable resources, a mixed integer programming model is constructed which maximizes the net present value of regional production, by determining the optimal set of new developments, tiebacks (links) from fields to processing hubs (and on to the transportation network), and finally the timings of hub and field shutdowns. The potential effects of the separation of infrastructure and field ownership are captured by constraints which impose individual field and infrastructure viability conditions. The possible impact of a type of a common carrier regime, consistent with unbundling hub infrastructure from fields and average cost pricing, are also captured via constraints on the tariff charged by each hub for its processing services. This model is applied to a case study area namely the Northern North Sea region of the UKCS.

The Evolving Issues Relating to Access to Infrastructure in the UKCS

For many years negotiated contracts for access between asset-owner and potential asset-user have formed the basis for determining all the terms relating to third-party use of the infrastructure in the UKCS. The UK Department for Energy and Climate Change (DECC) and its predecessor bodies were generally involved on an informal basis and certainly made their views known. The appropriate balance between the objectives of avoiding the undue proliferation of pipelines and encouraging competition among pipeline systems was one of the perceived problems. In the late 1970's and early 1980's the Government became increasingly aware that third-party tariffing was becoming quite a profitable activity, and in 1983 it passed legislation which, amid some controversy, applied Petroleum Revenue Tax (PRT) as well as the existing corporation tax, to tariff incomes. In acknowledgement of the need to encourage the development of new fields via third-party use of existing infrastructure a substantial tariff receipts allowance (TRA) for PRT was introduced for each new tied-in field. In Budget 2003, in a change in thinking, PRT was abolished on tariff incomes from new contracts from January 2004 onwards, on the understanding that the benefits would be passed on to the payers in lower tariffs. With the increase in Supplementary Charge to 32% the tax rates currently payable on tariff incomes are 62% on non-PRT paying contracts and 81% on old, PRT-paying agreements.

The time taken to conclude negotiated agreements became a major issue and resulted in an Infrastructure Code of Practice being drawn up in 1996 by the industry and facilitated by Government. While this constituted an improvement, concern continued to be felt over the time taken to reach agreements and over their terms. This resulted in a revised and more substantial Infrastructure Code of Practice (ICOP) being developed. It was published in September 2004 under the auspices of PILOT, the joint Government-industry consultative body. The Code contains a number of principles. Key ones are that (1) the parties will follow a Commercial Code of Conduct, (2) the parties will provide meaningful information to each other during negotiations, (3) the parties support negotiated access in a timely manner, (4) parties undertake to ultimately settle continuing disputes with an automatic referral to the Secretary of State[1], (5) parties resolve conflicts of interest, (6) infrastructure owners provide transparent and non-discriminatory access, (7) infrastructure owners provide tariffs and terms for unbundled services where requested, (8) parties

[1] In principle, where negotiations between the two parties break down, DECC would arbitrate drawing on published guidance on how they would resolve disputes (DECC, 2009). However, in practice, because to date there have been only a limited number of referrals of disputes to Government, DECC has never issued a "determination" to resolve a dispute. This may change in the future as the recent Energy Act has enhanced provisions to allow DECC to intervene to resolve disputes.

seek to agree fair and reasonable terms where risks taken are reflected in rewards, and (9) parties publish key, agreed commercial provisions.

However, there have been continuing concerns over the operation of the Code in practice, particularly from those desiring access to infrastructure. For example, in the Oil and Gas Independents Association's 2009 submission to the House of Commons Energy and Climate Change Select Committee, they argued that the regime required significant change to "ensure that the owners of the infrastructure do not extract a disproportionate share of the value by creating delay or offering inappropriate tariffs and liabilities in relation to the risks they take". They also argued that "Legislation for guaranteed access terms or "common carrier" status should be seriously considered." (OGIA, 2009) Having reviewed the evidence, the House of Commons Energy and Climate Change Select Committee concluded in their report that the current voluntary ICOP code was not working effectively in enabling smaller companies to access the infrastructure they required to develop the smaller remaining fields in the region. They argued that if the Code could not be made to work, a common carrier system of regulated access might be appropriate. While the UK Government does not appear currently to accept the need for such radical change, some of the criticisms of the current Code have been acknowledged by the wider oil and gas industry in the UKCS. As a result the industry has embarked on a review of the voluntary code which will report in late 2012 to the joint Government-industry consultative body (PILOT, 2011).

Market Solutions and Failures

It is possible to argue that, in circumstances where both the asset owner and the potential user can benefit from third party use of the infrastructure, market forces will produce tariffs and other terms which result in an economically efficient solution to the problem and state intervention is not required. Stevens

(1996) has expressed sympathies with this view. It is then also arguable that, if the negotiated terms incorporate tariffs which transfer a significant proportion of the value generated as a result of a new field development to the asset owner from the field investor, there is no great cause for concern. The Government became aware of this issue in the early 1980's and the solution adopted was not to regulate the tariff but to impose PRT on tariff incomes.

It is clear that asset owners can readily take advantage of the bargaining power which ownership of infrastructure provides. Such bargaining power will be a function of the extent to which alternative processing and transportation facilities are available and the costs of accessing these by the potential user. Distance from the user field to the infrastructure is a key factor. For oil there may be an alternative of tanker transportation from the new field. For processing an FPSO development on the field may be a possibility. But in many cases in the UKCS at its present stage of development (personified by relatively small fields) a tie-in to existing infrastructure will be the most economic type of development. A stand-alone development would often be quite uneconomic.

Hence, in many places there is the potential for local natural monopolies to arise for processing and transportation services. As is well known where natural monopolies arise, it is most efficient for a product or service to be provided by a single producer, although in such cases market outcomes can embody other economic inefficiencies such as excessive pricing for access, under-provision of access etc. (Joskow, 2005).

As noted above disquiet has often been expressed at the length of time taken to effect negotiated agreements. There are several possible explanations for this. Thus the potential user is likely to be anxious to obtain a speedy agreement in order to permit field production to occur as early as possible. Returns to new field investment are highly sensitive to the attainment of production as soon as possible after development expenditure commences. On the other hand the asset owner may have other priorities, particularly the continuing equity production from his own field. The provision of new facilities for a third party on his platform may or may not be a priority, depending on the prospective size of the tariff income.

In contemplating the tariff to be requested the asset owner is likely to estimate the costs of the potential user in accessing other infrastructure. He may also estimate the expected returns which the potential user can expect from the new field development. The potential user will also calculate the costs of accessing other infrastructure and will certainly estimate his expected returns from the field development. But neither party will have the same knowledge base as the other. They are most unlikely to share all the knowledge relevant to a full understanding of the range of possible solutions to the problem. In particular, investors are very unlikely to share their knowledge of capital and operating costs. Knowledge is not symmetric. The result of all this is delays in reaching agreements. These can be very long. Sometimes negotiations are terminated. Long delays are clearly not in the national interest as revenues, including tax receipts, are all delayed. They are a manifestation of a market failure.

Theoretically a significant part of the delays and associated difficulties in reaching access agreements arise from the presence of asymmetric information. However even without such asymmetries, the presence of partial vertical integration, i.e. where the infrastructure owner is also one of the potential users, can lead to access pricing inefficiencies (Armstrong, Doyle and Vickers, 1996). In particular, where processing capacity and the installation of new capacity is limited on hubs, the delays and lack of priority placed on third part business might be partly interpreted as a displacement effect where infrastructure owners prioritize their own use of the processing facilities, excluding third party business even where this might increase overall economic welfare.

The demand and supply of oil and gas processing services by hubs also involves a range of significant indivisibilities. In particular, hub shutdown and where and when to activate a tie back from a new development to a hub are discrete choices which are associated with significant fixed costs (such as tie back set up costs, fixed hub operating expenses). These induce discontinuities in the net supply of processing services. As is well known, the non-convexities induced by the presence of fixed charges mean market solutions are not necessarily economically efficient (even in the presence of perfect information and many firms). In such cases, formally Pareto efficiency requires that a central planner determines the optimal structure of hubs and tie-backs (Ginsburgh and Keyzer, 1997).

Therefore, there is a range of possible economic rationales why market solutions may lead to inefficient exploitation of the remaining resources in the UKCS. While this does provide a basis of a case for intervention by Government, it is well understood that the ability of regulation to induce first best efficient outcomes is also limited by a range of factors (Train, 1992). For example, where fixed costs are high, enforcing marginal cost pricing cannot ensure economic viability for infrastructure owners. Simple regulatory prices such as uniform average cost (cost of service) prices may also lead to premature abandonment of higher cost fields (Kemp and Phimister, 2010). Although multi-part tariffs could reduce this impact, complex pricing rules are typically avoided by regulators. Finally, information asymmetry also affects regulators so that some rents are left with the regulated firm (Salanie, 1998; Laffont and Tirole, 1993).[2]

[2] In the UK the use of price caps in network utilities regulation attempted to allow for information asymmetries although in practice elements of cost of service pricing remained important within this system (Joskow, 2006)

From the above discussion, the impact of a number of potential market imperfections might be explored in economic modelling. However, as a key characteristic of the underlying production technology in terms of hub processing are the indivisibilities discussed above, we have chosen firstly to ensure these are captured in the model. The overall approach as described below is to characterize the first best solution for the case study area allowing for these indivisibilities and then consider the potential impact that different ownership structures, negotiating delays and the application of uniform average cost pricing might have on the exploitation of the remaining resources for our case study area. Therefore no attempt at this stage is made to model explicitly the impact of informational asymmetries, risk nor the bargaining between parties.

Northern North Sea Data

The model described below uses data on 70 fields both sanctioned and potential future developments in the Northern North Sea area (NNS). The NNS area is characterized by a number of mature fields nearing the end of their production life with associated large scale infrastructure. In addition there are a range of smaller possible developments of both existing fields and new (but smaller) fields which, for their economic viability, will rely on the processing facilities of the existing surface infrastructure in the area and the associated access to the oil and gas transportation system.

The data available includes 34 sanctioned fields and 36 future potential developments. For each existing or potential development, for the period 2010 to 2050 profiles on expected oil and gas production, real capital expenditure, operating and abandonment costs, and pre tax revenues[3] were available or constructed using data drawn from the Aberdeen University database as validated by the operators. Available data on tariffs was also used to impute costs for transportation costs for oil and gas outside the NNS region. Within the region, 12 hubs (and sub-hubs) were identified (see list in Table 1). The location of the hubs and the actual and potential field developments were made using GIS data available from DECC and CDA DEAL. The hubs were associated with the location of surface infrastructure, whereas for actual and future possible developments a number of assumptions were used. For existing developments, the location of the centroid of the field was used. For future developments which were developments of existing fields (incremental projects) the location of the existing field was used, while for other developments not associated with a field, the location of one of the wells associated with the development was used.

Using the GIS data, the network of tie backs between existing field developments and gas and oil transportation links within the Northern North Sea area was captured, i.e. between sub-hubs and hubs. The main transportation flows via pipelines from hubs in the region to the terminals at St Fergus and Sullom Voe were also accounted for. Distances between each hub and all existing and future developments were calculated, with future tiebacks (either from existing or future developments) assumed to be possible if the distance was less than 45km.[4]

Using the cost data for each year and development, the net present value of future abandonment costs was also calculated. For each hub, the fixed

[3] These are the values excluding tariff revenue. The assumed prices of oil and gas were \$90/bbl and 60p/therm (in real terms). The NGL price was \$79.52/bbl. Some of the sanctioned fields had a lower gas price based on historic contract prices.

[4] These assumptions draw on existing work by Hannon Westwood for Oil and Gas UK on the impact of loss of infrastructure on the UKCS. Existing tie-backs which were longer than 45km were not excluded. Under this assumption all future developments fell within this range.

operating costs per year which would be charged if the hub operated beyond the host field's production life was calculated as the average of actual operating costs. Costs of new tiebacks were calculated assuming a cost of £1m per km plus a fixed charge.

Model Structure and Simulations

The constructed model aims to capture the vulnerability of exploitation of resources in the NNS under different institutional settings. The role of the hubs and sub hubs is central to this with all field production assumed to be processed initially at a hub before it is transported via the oil and gas network to the relevant on shore terminal.

To do this a mixed integer programming model was constructed (see the appendix for detailed specification), which maximizes the 2010 post tax net present value of Northern North Sea production (at 10% discount rate), by determining the optimal set of new developments (out of the set of 36), tiebacks from fields to hubs, timings of hub and field shutdown.[5]

For example, for each potential new development, the model determines whether it should be developed, if so, to which hub the development should tieback (link) to, and for how many years the development should operate. If developed, capital expenditure and tie back costs are incurred. For existing and future developments (except hubs), when production stops the current PV of abandonment expenditure associated with the development is incurred.

In contrast, hubs can operate beyond the production life of their base field with the model determining the optimal shut down period for each hub. For each period of operation, a fixed operating charge is incurred. As for field

[5] A simplified version of the current UKCS tax regime is included in the modelling, with tax allowances for operating, capital tie back and decommissioning expenditure allowed for. 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.

developments when the hub is shut down, the current PV of abandonment costs is incurred.

In the basic model (*Base*), the only financial constraints at individual field level are that new developments should have a positive NPV. At hub level there are no specific financial constraints. This structure is used to approximate the optimal structure of future development and hub life in NNS as *if* the region was owned by a single actor. For example, in this case the continued operation of a hub may be cross-subsidized from anywhere in the region. Hence, a hub may continue operating even if its host field production has ceased so long as its contribution to the 2010 net present value of Northern North Sea is positive.

To attempt to capture the impact of the differing structures of ownership and operation in place across fields and hubs, in the second version of the model implemented (*Hubcfr*) the basic structure is augmented with a series of individual financial constraints. First, in each period for each hub net cash flow must be non-negative. This means that if a hub is to operate once the production of its base field has ceased, hub operating expenditure must be covered by income from the fields which tie back to this hub. To allow this, a set of cost shares are introduced in the model which capture the contribution of each operating field/development to their hub's operating expenditure. These cost shares reduce field level net cash flow. To ensure individual field viability in every period, a set of extra constraints for each field is introduced to restrict the net present value of net cash flow from the current period to the end of production to be non-negative. These individual viability constraints capture one basic implication of split ownership across hubs and fields in that individual elements of the system may be shut down if they are not "economically viable", even if their operation would add to NPV for the region as a whole. In this version of the model the cost shares determined are only restricted to be non-negative so that implicitly the model allows the fields contributing to a hub's operating costs to be treated in a discriminatory fashion. That is, on a per unit of production basis, the contribution of different fields to a specific hub may vary considerably.[6]

While these constraints capture basic individual viability requirements at field or hub level, they do not capture any strategic behaviour by operators/owners. For example, by implication, hub owners in this model operate passively and continue to operate the hub so long as operating costs are covered. New tie backs are negotiated at zero cost and are activated in a timely way. In contrast, at least part of the debate on the failings of the current arrangements for third party access to infrastructure in the UKCS concern the delay due to the protracted negotiations between potential partners. As a first approximation to capture some of the impact of potential negotiating delays, a second version of the model is also solved where the starting date of the 36 future potential developments is delayed by 3 years (*Hubcfr 3 year delay)*.

The final version of the model restricts the cost shares which hubs receive from the tie back fields so that user fields' contributions are identical on a per unit basis. Implicitly this defines a single non-discriminatory unit processing price for each hub. These can be interpreted as the prices charged if the hub ownership was unbundled and placed under an average cost pricing regulatory regime. The version of the model with unit hub pricing (*Unitpr)* imposes, as before, the constraint that each hub's operating expenditure must be covered by the cost shares from each tieback field.

[6] However, non-uniqueness of the solution in this case means that it is not possible to claim that outcomes of model determine a unique set of implicit discriminatory prices.

Results

Table 1 provides a summary of the model variants simulated and their characteristics. Table 2 reports some summary measures from the model outcomes. All programmes were solved using GAMS/CPLEX (GAMS Development Corp 2010).

Table 1 Summary of Models

Model Name	Description	Characteristics
Base	Determines optimal new developments, tiebacks, timings of hub and field shutdown to maximise 2010 NNS Net Present Value	Allows cross subsidies across fields and hubs to capture single ownership outcome.
Hubcfr	*Base* Model with individual field and hub financial viability restrictions.	Captures basic impact of split ownership structure across fields/hubs
Hubcfr 3 year delay	*Hubcfr* Model where the start date of all potential developments delayed by 3 years.	Basic exploration of potential costs of negotiation delays.
Unitpr	*Hubcfr* Model with restriction for each hub that each tie back field pays same unit price for processing to hub.	Captures non-discriminatory pricing with hubs potentially unbundled.

As expected, the NPV for the Northern North Sea is largest for the *Base* model, with the imposition of individual viability constraints in *Hubcfr* leading to a small NPV reduction. In contrast, the *Hubcfr 3 year delay* model leads to a more apparent reduction in regional NPV, while the imposition of unit hub pricing in *Unitpr* reduces the regional Post tax NPV very significantly.

As in the *Hubcfr* model, relative to the *Base* model the number of new development increases in the *Hubcfr 3 year delay* case (29-30=-1), as does the number of total production periods. In contrast, there is a significant reduction in both developments and total number of periods where production takes place in the *Unitpr* model (663-471=192), which implies that, in this model, a greater number of existing and new developments stop production earlier than in the other simulations. This arises because the single unit price at each hub increases the implied (unit) cost share for several of the fields such that their individual viability constraints are violated if they operate. In turn this affects the viability of several of the hubs.

In the *Base* and *Hubcfr models,* hub decommissioning times are (with a few exceptions) broadly similar, with the impact of the extra constraints within the *Hubcfr* model acting to extend hub life in a small number of cases, e.g. Cormorant. In contrast, the structure of the hub decommissioning results change for *Hubcfr 3 year delay*, with some hubs decommissioning early while the life of others is extended. In the *Unitpr* results there is a dramatic acceleration of decommissioning dates, with several of the hubs decommissioning immediately.

Table 2: Summary of Model Outcomes

	Base	*Hubcfr*	*Hubcfr 3 year delay*	*Unitpr*
Post Tax NNS NPV £m	7982.4	7889.8	6662.6	3261.4
Tax NPV £m	6861.1	7321.5	6776.0	5496.7
No New Developments (out of possible 36)	29	30	30	23
Total Number of Production Periods	663	682	676	471
Year Hub Decommissioned*				
Cormorant	2014	2020	2025	2017
Alwyn North	2031	2031	2031	2013
Brent	2022	2020	2011	2011
Eider	2016	2016	2011	2011
Dunlin	2042	2042	2045	2034
Tern	2023	2023	2023	2021
Dunbar	2027	2025	2025	2016
Thistle	2032	2031	2031	2031
Ninian	2034	2034	2033	2011
Heather	2038	2038	2041	2020
Magnus	2026	2026	2026	2013
Murchison	2017	2017	2017	2016

*Note these are simulated model outcomes only.

Figures 1 and 2 provide an illustration of the implied gas and oil production profiles for each of the models. Oil and gas production under the *Base* and *Hubcfr* cases is very similar, although for earlier years oil production in the *Hubcfr* model is actually above that implied for the *Base*, suggesting that the introduction of hub and field constraints slightly increase oil recovery. The results for *Hubcfr 3 year delay* suggest that moving potential field start dates typically delays, but do not stop, development of most potential oil production. However, overall gas production is slightly reduced in this case relative to the *Base* model. In contrast, the results for *Unitpr* show that the single hub prices have a significantly negative impact on both regional oil and gas production.

Figure 1 NNS Oil Production Thousand Barrels per Day (tb/d)

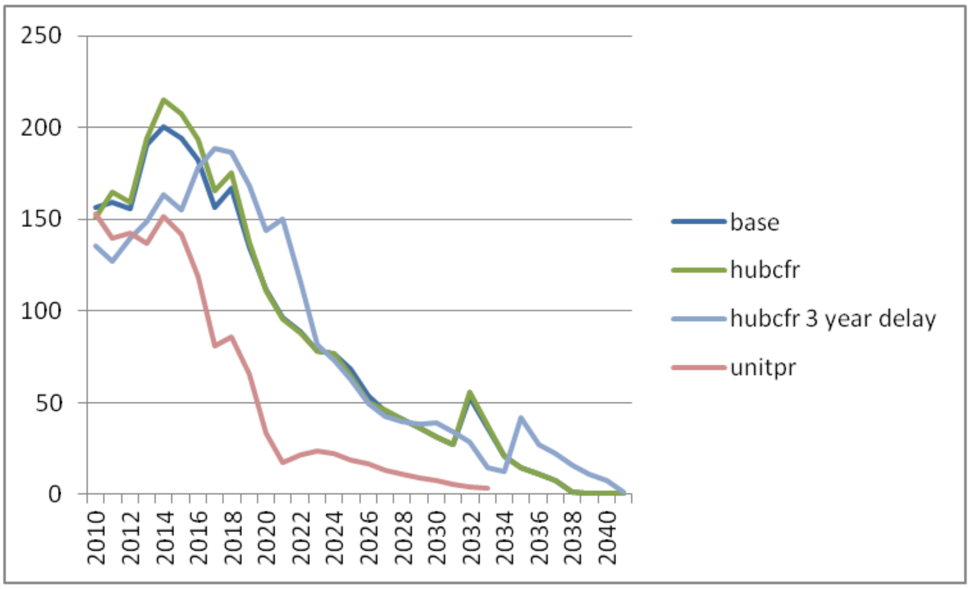
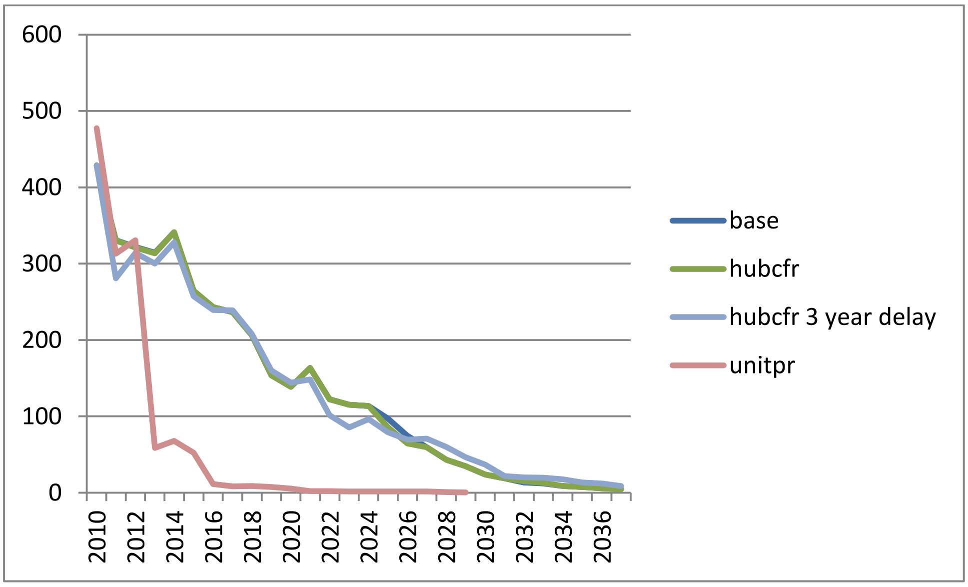


Figure 2: NNS Gas Production Million Cubic Feet per Day (mmcfd)



Figures 3 and 4 provide a picture of the implied Unit Hub Prices in the *Unitpr* model. Figure 3 provides an example of the cross section of the implied prices for 2011 for the hubs which were operating in that year. As can be seen, although at each hub all tieback production is charged at the same price, there are considerable differences in the unit price across hubs.

Figure 3 Non-Discriminatory Pricing Scenario (*Unitpr*): Unit Hub Prices 2011 £/boe

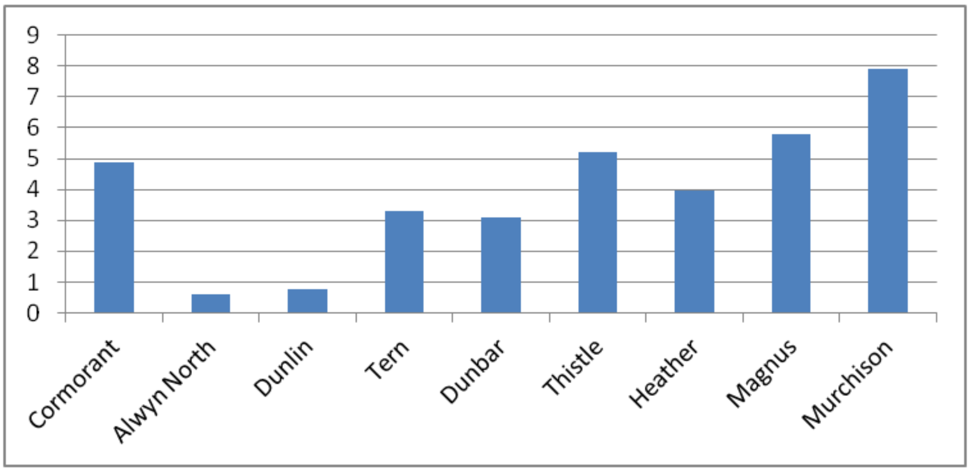
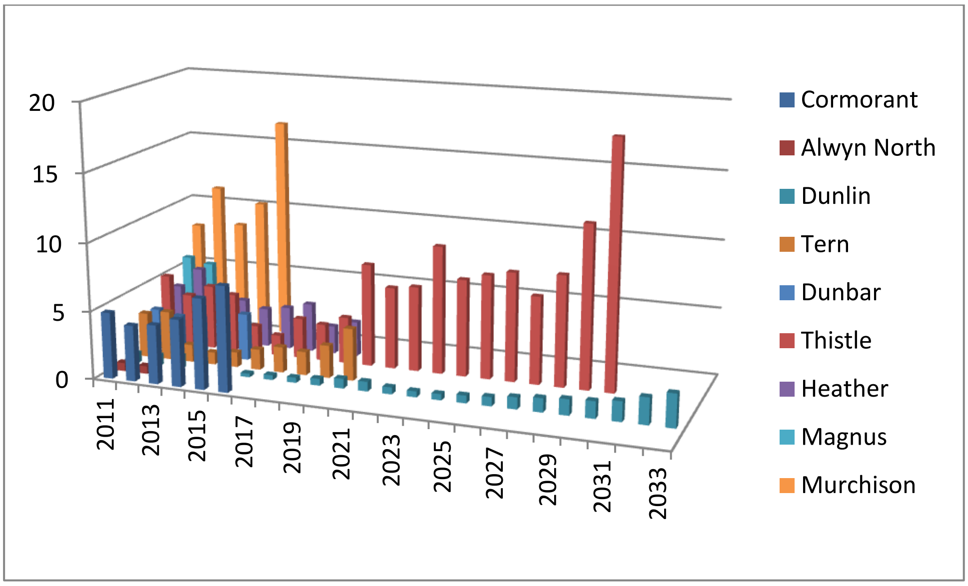


Figure 4 shows the variation in unit hub prices over time. Again there is considerable time variation with some evidence – as one would expect - that prices increase over time (at least for hubs which are operating over a long period).

Figure 4 Non-Discriminatory Pricing Scenario (Unitpr): Unit Hub Prices by Year £/boe



Summary and Conclusions

This paper has explored how possible different ownership patterns (and infrastructure hub access arrangements) might affect the economic viability of exploiting remaining resources in the UKCS by applying a mixed integer programming model to field data from the Northern North Sea. The model maximizes the post tax net present value of regional production, by determining the optimal set of new developments, tiebacks from fields to hubs, timings of hub and field shutdown, with the potential effects of the separation of infrastructure and field ownership captured by constraints which impose individual field and infrastructure viability conditions. The possible impact of a type of common carrier regime where existing hub infrastructure might be unbundled from fields and average cost pricing based on throughput applied, is also modelled.

A number of important caveats and limitations of the modelling exercise should be highlighted, which could form the basis for future work. First, it does not attempt to model the behaviour of individual firms in any detail. Rather it is assumed that as long as individual fields and hubs are viable they will be developed. Second no attempt is made to model the bargaining between parties or capture the (obviously) important role of risk and risk sharing in this process. Finally, as the set of potential fields developed used are given, it does not account for the impact of the differing structures for incentives for future exploration.

Nevertheless, the modelling results provide some interesting insights and suggest areas for future research. The results suggest that differences in ownership across fields do significantly reduce the overall NPV of future developments in the area. This occurs with the earlier shutdown of a number of hubs when individual hub viability constraints are imposed. However, any associated fall in the production of oil and gas is relatively limited. The cost of delay is also relatively high although in part this arises in the model because some potential production is postponed rather than not developed. In contrast, where hubs are forced to charge single average cost type prices to fields, the reserves developed in the region are significantly reduced. This emphasises the difficulty in applying a single, non-discriminatory pricing regime across fields with very different cost structures. Although not considered here, an obvious question is the extent to which either uniform multi-part tariffs or changes to the tax system might alleviate these negative effects. The paper obviously leaves unresolved at this stage whether the Government should seek to enhance the efficiency of negotiated settlements or instigate full regulation.

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Model Appendix[7]

Table A1: Model Sets, Parameters, and Variables

Symbol	***Explanation***
Indices & Sets	
$i \in D$	Fields/Developments
$j,k,h \in H\left(\subset D\right)$	Hubs
$i \in N\left(\subset D\right)$	Fields/Developments which are not Hubs
$i \in P\left(\subset D\right)$	Potential New Fields/Developments
$i \in S\left(\subset D\right)$	Sanctioned or Existing Fields/Developments
$t,\tau \in T$	Years (2010-2050)
$s_i, s \in T, i \in P$	First year of potential development expenditure for Potential New Fields
Parameters	
r	Discount factor
p_n	Per unit subsidy penalty
M	Arbitrary large value
boe	Gas Barrel of Oil Equivalent Conversion factor
Exogenous Variables	
$\overline{qo}_{it}$	Potential field/development oil production
$\overline{qg}_{it}$	Potential field/development gas production
$\overline{op}_{kht}$	Binary Variable = 1 if oil pipeline between hub *k* and *h* exists
$\overline{gp}_{kht}$	Binary Variable = 1 if gas pipeline between hub *k* and *h* exists
$\overline{mpto}_{hkt}$	Per unit oil transportation tariff from hub *h* to *k*.
$\overline{mptg}_{hkt}$	Per unit gas transportation tariff from hub *h* to *k*.
$\overline{pto}_{ht}$	Per unit oil transportation tariff to terminal if entry to pipeline system is hub *h*.
$\overline{ptg}_{ht}$	Per unit gas transportation tariff to terminal if entry to pipeline system is hub *h*.
$\overline{rev}_{it}$	Potential Pre-tax Gross revenue from oil and gas production
$\overline{opex}_{it}$	Potential Operating expenditure
$\overline{dev}_{it}$	Potential development expenditure (Capex + drilling)
$\overline{decm}_{it}$	Potential decommissioning expenditure if field/development operating in time *t*
$\overline{cdecm}_{it}$	NPV in time *t* of future decommissioning expenditure if field/development decommissions in *t*
$\overline{ctie}_{ih}$	Fixed cost of activating Tieback from *i* to *h*
$\overline{tiep}_{ih}$	Binary Variable =1 if tieback to *h* from *i* possible
Endogenous Continuous Variables	
yo_{ht}	Production Processed Oil hub *h*
yg_{ht}	Production Processed Gas hub *h*

[7] For brevity the version of the model shown here omits the tax modelling. The full set of model equations including these can be obtained from the authors on request.

to_{iht}	Fields/Development Oil Production Processed via Tieback to Hub *h*
tg_{iht}	Fields/Development Gas Production Processed via Tieback to Hub *h*
tso_{kht}	Transhipment Oil Between Hubs k and h
tsg_{kht}	Transhipment Gas Between Hubs k and h
ncf_{it}	Field/Development Net Cash Flow
npv_i	Field/Development Net Present Value
cs_{iht}	Cost Contribution of Field/Development to Hub Operating Costs
$NPVP$	Province NPV (Model Objective)
Unitp/Unitpr_hr Model Specific Variables	
uch_{iht}	Intermediate Variable – Unit Cost Contribution by Field/Development to Hub Operating Costs
$ucht_{iht}$	Intermediate Variable to capture product of $uch_{iht} * tb_{iht}$
up_{ht}	Unit Hub Processing Price
Endogenous Binary variables (0/1)	
f_{it}	=1 if Field/Development operating
$fdec_{it}$	=1 if Field/Development decommissions time *t*
fd_i	=1 if Potential New Field/Development activated
tb_{iht}	=1 if Tieback between Field/Development and Hub Active
tbs_{iht}	=1 if Tieback between Field/Development and Hub Activated period *t*
hb_{ht}	=1 if Hub operating
$hdec_{ht}$	=1 if Hub decommissioned in time *t*

Table A2: Equations

Base Model	
Hub Processed Production	
$yo_{ht} = \sum_{i \in D} \overline{tiep}_{ih} . to_{iht}$	$yg_{ht} = \sum_{i \in D} \overline{tiep}_{ih} . tg_{iht}$
Hub Transhipment Balances	
$\sum_{j \in H} \overline{op}_{jht} . tso_{jht} + yo_{ht} = \sum_{k \in H} \overline{op}_{kht} tso_{hkt}$	$\sum_{j \in H} \overline{gp}_{jht} . tsg_{jht} + yg_{ht} = \sum_{k \in H} \overline{gp}_{kht} . tsg_{hkt}$
Field/Development Tieback – Production Balance	
$\sum_{h \in H} \overline{tiep}_{ih} . to_{iht} = f_{it} . \overline{qo}_{it}$	$\sum_{h \in H} \overline{tiep}_{ih} . tg_{iht} = f_{it} . \overline{qg}_{it}$
Tieback Constraints: Tieback active	*Single Active Tieback*
$to_{iht} + tg_{iht} \le M . tb_{iht}$	$\sum_{h \in H} tb_{iht} \le 1$
Activate New Tieback	
$tbs_{iht} \ge tb_{iht} - tb_{iht-1} \quad t > 2010, i \in S, \ all \ t, i \in P$	

Field Constraints: Field Production Cessation	*Single Field Production Cessation*
$fdec_{it} \geq f_{it-1} - f_{it}$	$\sum_{t\in T} fdec_{it} \leq 1$
Activation Potential New Fields/Developments	*No Production after Production Cessation*
$fd_i \geq f_{it} \quad i \in P$	$f_{it} \leq 1 - \sum_{\tau=2010}^{t} fdec_{i\tau}$
New Fields/Developments Start Date	
$f_{is} \geq fd_i \quad s_i, s \in T, i \in P$	
Hub Decommissioning	*Single Hub Decommissioning*
$hdec_{ht} \geq hb_{ht-1} - hb_{ht} \quad t > 2010$	$\sum_{t\in T} hdec_{ht} \leq 1$
Fields/Developments which are not Hubs: Net Cash Flow & NPV	
$ncf_{it} = f_{it}.\left(\overline{rev}_{it} - \overline{opex}_{it} - \overline{decm}_{ht}\right) - .\sum_{h\in H}\overline{pto}_{ht}.\overline{tiep}_{ih}.to_{iht} - \sum_{h\in H}\overline{ptg}_{ht}.\overline{tiep}_{ih}.tg_{iht} - \sum_{h\in H} cs_{iht}$, $i \in N$	
$npv_i = \sum_{t\in T}\frac{1}{(1+r)^{t-t_0}}\left(f_{it}.\left(ncf_{it} - \overline{dev}_{it}\right) - \overline{cdecm}_{it}.fdec_{it} - \sum_{h\in H}\overline{ctie}_{ih}.tbs_{iht}\right),\ i \in N$	
Hubs: Net Cash Flow & NPV	
$ncf_{ht} = f_{ht}.\left(\overline{rev}_{ht} - \overline{decm}_{ht}\right) - \overline{pto}_{ht}.to_{hht} - \overline{ptg}_{ht}.tg_{hht} + \sum_{k\in H}\overline{pto}_{hkt}.tso_{hkt} + \sum_{k\in H}\overline{ptg}_{hkt}.tsg_{hkt}$ $- hb_{ht}.\overline{opex}_{ht} + \sum_{i\in N} cs_{iht}$	
$npv_h = \sum_{t\in T}\frac{1}{(1+r)^{t-t_0}}\left(f_{it}.\left(ncf_{ht} - \overline{dev}_{ht}\right) - \overline{cdecm}_{ht}.fdec_{ht}\right)$	
Model Objective Province Net Present Value	
$NPVP = \sum_{i\in D} npv_{it} - (1+pen).\sum_{t\in T}\frac{1}{(1+r)^{t-t_0}}.s_{ht}$	
Hubcfr &Unitpr Models: Additional Constraints	
Hub Cost Sharing Restriction	
$cs_{iht} \leq M.tb_{iht}$	
Financial viability: Field/ Development	*Hubs*
$\sum_{\tau\in T}\frac{1}{(1+r)^{\tau-t}}.ncf_{i\tau} \geq 0,\ i \in N$	$ncf_{ht} + s_{ht} = 0$
Additional Constraints Unitpr Models	
Field/Development – Unit Cost Definition & Restrictions (Unitpr Models)	
$cs_{iht} = uch_{iht}.\left(\overline{qo}_{it} + boe.\overline{qg}_{it}\right)$	$uch_{iht} \leq M.f_{it}$
$ucht_{iht} \leq M.tb_{iht}$	$uch_{iht} \geq ucht_{iht}$
$uch_{iht} \leq ucht_{iht} + M\left(1 - tb_{iht}\right)$	
Unit Hub Processing Price Restrictions	
$ucht_{iht} \leq up_{ht}$	$ucht_{iht} \geq up_{ht} - M\left(1 - tb_{iht}\right)$
$up_{ht} \leq M.hb_{ht}$	