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**Economic Principles and Determination of
Infrastructure Third Party Tariffs in the UK
Continental Shelf (UKCS)**

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DEPARTMENT OF ECONOMICS

NORTH SEA ECONOMICS

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

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

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy. The work on CO₂ Capture, EOR and storage was financed by a grant from the Natural Environmental Research Council (NERC) in the period 2005 – 2008.

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**Economic Principles and Determination of Infrastructure Third Party
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And
Professor Euan Phimister

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Economic Principles and Determination of Infrastructure Third Party Tariffs in the UK Continental Shelf (UKCS)

Professor Alex Kemp and Professor Euan Phimister

1. Introduction: History and Context

The notion of the desirability of third-party access to infrastructure in the UKCS was established in the early years of North Sea oil and gas exploitation. It was clearly understood that this could reduce the overall development costs of new fields. Another early consideration was the avoidance of the proliferation of pipelines which were possibly being encouraged by the very high rate of tax relief against Petroleum Revenue Tax (PRT) and corporation tax which included for PRT an uplift of 75% of the investment expenditure incurred.

It was also acknowledged that the ownership of pipelines and other infrastructure of processing platforms and terminals could confer substantial local bargaining powers on the asset-owners in the negotiation of tariffs with prospective third-party users. In recognition of this powers were taken by the UK Government in the Petroleum and Submarine Pipelines Act 1975 (PSPA 1975) which enabled the Secretary of State to determine such tariffs, but only if requested so to do by one of the parties.

Over the years third-party use of the growing infrastructure has grown very substantially. Where a new field investor required access to existing infrastructure this could be achieved by one of two mechanisms. The new field investor could purchase an equity share in the pipeline or other infrastructure and obtain access to the infrastructure as a consequence.

The second way was simply to pay tariffs to the existing asset-owner. Generally (but not always) asset-owners preferred the second method. There was a preference to receive tariffs from competitors rather than pay tariffs to them.

In the late 1970's and early 1980's the UK 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 PRT (as well as the existing corporation tax) to tariff income. 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.

Over the years the scale of the infrastructure in the UKCS has continued to grow and with it the amount of third-party use. The importance of such access is also much greater now because the small size of the majority of the new fields is such that a stand-alone development would often be uneconomic. Overall production of both oil and gas is falling at a steady pace and there is a clear national need to encourage more new developments to ensure that maximum economic recovery be attained.

Much of the existing infrastructure is now quite old and the need to maintain its integrity is a recurring issue. With production declining from the fields for which the infrastructure was originally constructed, incentives to prolong the life of the infrastructure can be provided by the development of new fields via tie-ins. In most of the large pipeline systems there is significant ullage available to receive more oil and gas from new fields. The basic context for many more third-party tie-ins is

thus positive, and much is to be gained nationally by a more extensive and intensive use of the infrastructure. Given the pace of decline of production the speedy conclusion of access terms are clearly desirable.

2. Recent and Current Arrangements for Third Party Access

For many years negotiated access between asset-owner and potential asset-user formed the basis for determining all the terms relating to third-party use of the infrastructure in the UKCS. The 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. 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 the DTI. While this constituted an improvement concern continued to be felt over the time taken to reach agreement and over the terms of agreements. 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, (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 seek to agree fair and reasonable terms where risks taken are reflected in rewards, and (9) parties publish key, agreed commercial provisions. The ICOP is maintained and its implementation regularly reviewed by OGUK. With respect to the question of what constitutes fair and reasonable terms Section 12.1 of the ICOP states that (1) these should reflect the risks taken, and (2) are best secured by open competition between different infrastructure systems. Section 2 of the ICOP states that the terms that could be determined by the Secretary of State are expected to be in line with those emanating from effective competition.

Since 2004 UKOOA/OGUK has devoted considerable effort to streamlining the negotiation process and has, for example, published several Guidance Notes dealing with subjects such as (1) the Automatic Referral Notice (to the Secretary of State), (2) Statement of Requirements for each party, (3) Typical Plan for negotiation (Template) and (4) Access Agreement Summary.

The DECC has also been active in this area and in April 2009 published Guidance on Disputes over Third Party Access to Upstream Oil and Gas Infrastructure. Of key importance in the present context is the section dealing with the principles which DECC would employ in settling tariffs when disputes were referred to it. This emphasises several points including (1) competitive prices, (2) the need for the payment to reflect the real costs, risks faced, and opportunities forgone. It was recognised that there was a tension between on the one hand (a) settling terms which rewarded past investment in infrastructure (thus making the overall investment environment in the UK more attractive), and on the other hand

(b) making the terms attractive enough to encourage further exploration and development.

The Guidance Notes see four distinct categories each of which may require different considerations in the determination of appropriate tariffs. The first relates to infrastructure built as part of an integrated field development project. Two sub-categories were distinguished. In the first spare capacity was available in infrastructure where provision had already been made for the capital costs to be recovered, including a reasonable return reflecting the costs and risks. In these circumstances the DECC disposition is to set terms which reflect the incremental costs and risks borne by the infrastructure owner. The second sub-category is where the field is near the end of its economic life. In this circumstance the DECC view is that tariffs may have to be set in excess of incremental costs to ensure that the infrastructure is maintained and is available for third-party users. The tariff terms should then provide for “appropriate” cost sharing.

The second category identified by DECC refers to infrastructure deliberately built oversized with a view to procuring third-party business. In this situation the tariff terms would provide for the recovery of the capital costs incurred in the expectation of such third-party business. The appropriate tariff would be that which was just sufficient to earn the asset-owner a reasonable return, taking into account the risks involved, on the costs incurred in the expectation of third-party business. It was noted that this tariff could be higher than that which the owner might offer if the potential asset-user had alternative infrastructure options (including the first category noted above).

The third category identified by DECC is where there is noteworthy competition among potential asset-user for a limited infrastructure capacity. In these circumstances the DECC view is that it would be unlikely to request the asset-owner to make the infrastructure available to a potential user who valued the capacity in question less than another potential user. A consequence of the above is that agreed tariffs could generate some economic rent to the asset-owner.

The fourth category identified by DECC is where the third-party business would result in the displacement of the asset-owner's own production or other contractual obligations. In this circumstance DECC would be unlikely to require third-party access. If this were to happen the terms would have reflect the cost to the asset-owner of backing off his own production or that of another party to which he was contracted. The economic concept of opportunity cost was relevant here.

In summary the DECC view in the Guidance Notes is that, in the majority of cases where a determination had to be made, the appropriate tariff is likely to be that which would be offered by an asset-owner when faced with effective competition from other infrastructure owners who also had adequate ullage available in their system.

3. Fundamentals of Third Party Tariff Determination

a) Conceptual Framework

Where natural (local) monopolies arise, it is most efficient for a product or service to be provided by a single producer rather than competing firms. These characteristics appear particularly in industries with high fixed investment costs and low marginal (or incremental) costs such as those where network infrastructure is

important, e.g. gas, electricity water. While production efficiency arguments suggest that network infrastructure should be provided by a single firm, it has long been understood that, left unregulated market outcomes can embody other economic inefficiencies such as excessive pricing for access, under-provision of access etc. While unregulated natural monopolies may lead to a range of undesirable outcomes, it is well recognized that the regulation in such cases is complicated by the need to ensure reinvestment in infrastructure (Joskow, 2005). The pricing of access to infrastructure and the efficiency of market outcomes may be further complicated when, as in many cases, there is also partial vertical integration, e.g. where the network infrastructure owner is also one of the potential users of the infrastructure (Armstrong, Doyle and Vickers, 1996).

This section analyzes a simplified model of common infrastructure assumed to be desirable for the exploitation of a number of oil fields. The model is a version of the general natural monopoly model adapted to capture particular aspects of the potential interaction between exploitation of oil fields and common infrastructure. This allows the conclusions from the general model to be seen more clearly in terms of the problem at hand. Specifically, when the market pricing of access to the infrastructure can lead to inefficient non-exploitation of high cost fields, why imposing marginal (incremental) cost pricing can lead to inefficient under-exploitation of resources, and how the interaction between vertical integration between the infrastructure and a field operator may affect regulation.

The model presented focuses on outcomes for a *given* level of infrastructure. Hence, the marginal costs discussed in the model cover short run incremental costs only. In the long run the overall capacity of infrastructure available is also clearly variable. How this changes the conclusions for the efficient pricing of access to infrastructure is also discussed.

Economic efficiency and therefore the government objectives are relatively easy to characterize in the context of oil which is a tradable commodity where it is realistic to assume the UK holds no market power. In such a case, outcomes will be efficient if the net present value (NPV) of all profits from the UKCS are maximised. Economic inefficiency will arise if different ownership patterns combined with market structure or regulation move the potential outcome away from the exploitation of resources implied by maximizing UKCS NPVs.

The basic model presented draws on the traditional literature on the theory of regulation (Crew and Kleindorfer, 1986), which assumes perfect information on costs and demand. Modern regulation theory emphasises the imperfect and asymmetric nature of the information held by regulators and other economic actors, particularly in terms of costs, and the impact of effort exerted by firms on costs (Laffont and Tirole, 1993). While no attempt will be made to formalize these aspects, the impact of imperfect information in the basic model predictions will be discussed.

b) Model

The initial model examines a situation where there are three potential user oil fields and a pipeline infrastructure with excess capacity is

available. The marginal cost of using the infrastructure is less than the average cost. The three fields have different unit costs. Consider three oil fields with potential output levels q_1, q_2, q_3 . The marginal (incremental) cost of oil from each field is given by fixed values c_1, c_2, c_3 where $c_1 < c_2 < c_3$. Output from each field could be transported to market via a single pipeline (which has capacity of at least $q_1 + q_2 + q_3$) and sold at an exogenously determined oil price, p_m .

Total costs for transporting oil are given by $TC_a = F + c_a q$ where q is the total output transported via the pipeline. The fixed cost F combined with the constant marginal cost c_a means that the provision of the infrastructure service is a natural monopoly with falling Average Costs $F/q + c_a$ which here always remain above marginal cost c_a . The fixed cost F should be interpreted as covering any cost which is effectively independent of the quantity of oil transported. Hence clearly the capital costs of original investment are included but also it may include certain short run costs which are required to maintain the capacity of the infrastructure.

First, to characterize the efficient outcome where overall profits would be maximized, consider the case where all three fields and infrastructure are operated by a single firm. If overall the fixed cost of the infrastructure is covered such that total revenues are at least as great as overall costs, the firm should operate any field where the marginal cost of transporting the oil c_a is less than the net revenue from producing the oil. The thresholds, $p_m - c_1$, $p_m - c_2$, $p_m - c_3$ are therefore the maximum pipeline costs at which Fields 1,2, and 3

would be viable, and represent the usage of infrastructure services at different costs .

Figure 1 illustrates an example case where the efficient solution is that all three oil fields would operate.

c) Potential Market Outcomes with No Regulation

To illustrate the potential for inefficiency associated with a local monopoly in this context consider now the case where the fields are licensed to three separate operators, firms 1,2 and 3, and the ownership of the infrastructure is held by a private local monopoly. Each field licensee is assumed to profit maximize and therefore will only choose to operate from each field if marginal revenue is at least as large as the marginal cost from producing and transporting oil. Hence, Field 1 will operate if $p_m \geq c_1 + p_a$, Field 2 if $p_m \geq c_2 + p_a$ and Field 3 if $p_m \geq c_3 + p_a$.

Setting these relations as equalities defines the maximum access price at which each field will operate. Hence, in Figure 1, demand (willingness to pay) for pipeline access is characterized by the step function line with thresholds, $p_m - c_1$, $p_m - c_2$, $p_m - c_3$.

If the infrastructure owner is constrained to charge a single access price p_a to the pipeline, the market solution may lead to an inefficient number of oil fields being exploited. In the example, to maximize profits the infrastructure owner would choose either $p_a = p_m - c_1$, or $p_a = p_m - c_2$, or $p_a = p_m - c_3$. Whether the latter efficient price is chosen depends on whether the loss in revenue from lowering the price for

existing fields is less than the gain in revenue from pricing to ensure that there is effective demand for access from higher cost fields.

In the example illustrated in Figure 1, the infrastructure owner would choose $p_m - c_2$ as the single access price, as the loss of profit from moving to the efficient price $p_m - c_3$ (Area D) is greater than the profit gain (Area G). Hence, in this case the market outcome would lead to the inefficient under-exploitation of the oil resources. .

As the local monopoly access price depends on the final market oil price p_m , where this market price is particularly volatile one would expect access contracts to be written with terms which vary explicitly with the final market price.

In this simple setting, the efficient solution can be obtained via the market by allowing the infrastructure owner to price discriminate and set individual access prices for each field. In this case with perfect information, the infrastructure owner could set access prices $p_m - c_1$, $p_m - c_2$, $p_m - c_3$ per unit transported for Fields 1, 2 and 3 respectively, and hence capturing all the rents from the three oil fields (but ensuring development of all fields). Alternatively, the infrastructure owner could set two-part tariffs, where each user pays an access fee (different across each user), and a separate charge equal to the marginal cost c_a for each unit transported.

In reality a number of factors undermine the ability of the price discriminating monopolist to generate the efficient solution via an unregulated market. Importantly, as the development of each oil field involves significant sunk costs, there is a potential hold-up problem

which will reduce the licence holders' incentives to invest. In principle field marginal costs c_1, c_2, c_3 would include elements to cover the opportunity cost for capital in field developments. However, once licence holders have sunk capital in developing fields, the infrastructure owner would, with sufficient information, be able to extract any surplus above the short run marginal production cost, meaning that the licence owner would be better off if he did not invest. On the other hand, asymmetric information means field licence owners will have significantly better information on costs than the infrastructure owner. As a result, the infrastructure owner may be unable to extract all rents from licence holders with lower costs (Salanie, 1998).

Partial vertical integration with a single firm being both infrastructure owner and operator of one of the fields can affect the market outcomes if there is a single access price for the other operators. Consider the case where the infrastructure owner also holds the licence to Field 1. Then, as before, the access price would be set at $p_m - c_2$ and Field 3 would not operate. However, if the infrastructure owner held the licence to the high cost Field 3, the access price would remain the same, but it would operate and transport the oil from Field 3 as the marginal cost of transport is below the marginal revenue from the field.

d) Regulation in Model Framework

The policy response to monopoly and in particular natural monopoly has been varied. For example, within UK utilities industries, the historic solution was to use vertically integrated state monopolies. More recently this approach has been replaced by the unbundling of

such industries into segments containing markets which are potentially competitive, e.g. wholesale electricity and private monopolies controlling the network infrastructure but which are subject to price and other regulation (Newbury, 1999).

In the simple local monopoly, if regulated prices can be set at marginal cost of transporting oil, regulation should in principle restore economic efficiency. However, decreasing average costs in the natural monopoly case mean that the infrastructure owner will make a loss at marginal cost prices and the regulator would have to provide a subsidy to ensure that the service is provided.

Figure 2 illustrates this with respect to the simple example model. Setting the regulated access price as $p_a^R = c_p$ then, as in the efficient solution, all three fields will operate. At this price and quantity, average cost is greater than average revenue and the infrastructure owner makes a loss of area B + D + G. In contrast, all three field operators make profits of (A+B), (C+D), and (E+G) for Firms 1, 2 and 3 respectively. Hence, to ensure that the infrastructure owner operates the pipeline facility, the regulator must provide a subsidy of B + D + G. Such subsidies are difficult to achieve politically and ignore the wider economic inefficiencies induced arising from raising taxes to finance them (Laffont and Tirole, 1993).

Partial vertical integration with a single firm being both infrastructure owner and operator of one of the fields, allows implicit profits from field operation to be set against the fixed cost of the common infrastructure. For example, if the infrastructure owner also holds the licence to Field 3, while the profit E+G remains above the fixed cost F ,

the infrastructure owner will operate both field and infrastructure. However, in the case where a single field operator bears the total fixed cost of the infrastructure, this will lead to premature (from an economic efficiency perspective) abandonment of the field and infrastructure. In Figure 2 this would occur if the infrastructure owner holds the licence to Field 3 where profit $E+G$ is less than the fixed cost, but the fixed cost is less than total profits across all fields $((A+B)+(C+D)+(E+G))$.

Where, as in the case of the UKCS, subsidy from the regulator is infeasible, the second best regulation prices are found by maximizing overall profit from the fields subject to the constraint that the infrastructure owner must not make a loss. In the case of a single homogenous service this leads to average cost or cost of service regulation, where the regulator sets the access price equal to the average cost of the operation of the infrastructure. In Figure 2 this implies $p_a^r = AC(q_1 + q_2 + q_3)$. At this price, by definition, the infrastructure average cost (which include opportunity costs of capital) and revenue are equal, and therefore the infrastructure will operate. A similar result holds under partial vertical integration where the infrastructure owner is also a user of the infrastructure operation (Armstrong, Cowan and Vickers, 1994).¹

It should be noted that second best average cost prices can lead to premature abandonment of higher cost fields. This would occur if average cost was sufficiently above marginal cost. For example, this

¹ Note this result does depend on the assumption that the product market is competitive. In other cases, the implications may be different. For example, if the product market is regulated the best pricing rule in the presence of vertical integration is the efficient component pricing rule which effectively states that the price of access should equal the incremental cost of access plus any opportunity cost in terms of lost profit (see for example, Armstrong, Doyle and Vickers, 1996).

would happen in Figure 2 if the average cost curve rose above $p_m - c_3$. The third field would not operate at average cost prices even if marginal cost was below this level.

The simple model presented underlies the traditional approach to regulation. However it assumes that the regulator is able to accurately assess the firm's costs and behaviour. Modern regulation theory emphasises the limitations of all pricing rules, including cost of service, due to the asymmetric nature of information between the regulator and the regulated firm. In particular, it explores the nature of the trade-off between preventing the regulated firm making excess profits and the firm's efficiency (Joskow, 2005).

The asymmetric information issues which arise can be simply illustrated using the cost of service/average cost pricing as an example. Assume the Regulator wishes to fix the price equal to average cost. Clearly the "correct" level depends on the regulated firm's costs, information which the firm holds but may be imperfectly available to the regulator. In this case the regulated firm (infrastructure owner) has incentives to convince the regulator that their costs are as high as possible. In part what is known as the adverse selection problem can be addressed via auditing, and an important part of regulation has been defining transparent, common accounting procedures which regulated firms have to follow. Auditing, therefore, does reduce the ability of regulated firms to gain excess profits. However, it has no impact on the so-called moral hazard problem. If it is assumed that the firm's costs (and therefore average costs) can be reduced by cost effort by the firm, e.g. via extra R&D, managerial effort, which cannot be perfectly

observed by the regulator, the effect of average cost pricing is to eliminate any incentive that the regulated firm has to reduce costs.

e) Long Run

The model presented above focuses on outcomes for a *given* level of infrastructure, where therefore marginal costs cover short run incremental costs only. Nevertheless, it is clear from the model that where a given level of new investment (reinvestment) is required, regulation which prices access to the infrastructure at the short run marginal cost may not provide sufficient incentive for (re)-investment ($p_a^R = c_p$ in Figure 2) for infrastructure owners and developers.

In long run decisions, the overall capacity of infrastructure available is also clearly variable. Decisions on overall capacity may arise either where new fields require new infrastructure or where reinvestment in existing capacity is needed due to depreciation of existing assets. In such circumstances, the efficient access prices would include the marginal costs of providing capacity. The difference in the access price required for short run and long run efficiency may be interpreted as analogous to the implications of peak load pricing (Joskow, 2005). In the short run, existing capacity does not constrain the outcome, and therefore if the infrastructure owner would operate at short run marginal cost prices, these are efficient. Where investment in capacity is required, (i.e. it does constrain the outcome), the access price must cover marginal investment costs in order to ensure an efficient level of infrastructure (re)investment.

f) Regulation in Practice and Cost of Service

Particularly in the US, average cost pricing or cost of service regulation has been the traditional method used by regulators to manage the trade off between trying to ensure private natural monopolies do not exploit their position while having sufficient incentive to provide the level of service demanded (Joskow, 2005).

In the UK the private monopolies created via the process of privatisation and deregulation in the utility industries in the 1980's and 1990s have been typically regulated via price caps (Newberry, 1999). This was an attempt to take more systematic account of the incentives which regulation gives to reduce costs (or not). In this system the regulator sets an initial Price p_o and x a target productivity factor and then prices for a fixed period are governed by a formula such as $p_t^r = p_o(1 + RPI - x)^t$. Hence, within the period the regulated firm gains any cost savings achieved. However, elements of cost of service pricing remain important within this system as the setting of initial price p_o depends in many cases on agreed profiles of capital and operating expenditure for regulated companies (see for example the regulation of UK Regional Electricity distribution companies RECs (Joskow, 2006; Pollit and Bialek, 2008).

The implementation of a cost of service type of approach to regulation can be characterized by two steps. First, there is a determination of the regulated firm's total allowable revenue or cost of service, and secondly the tariff structure. Total allowable revenue (or total revenue requirements) is estimated typically including allowance for "reasonable" operating expenditure, depreciation, an allowable rate of

return on some defined capital base (regulatory asset value) plus other costs (Joskow, 2005). The tariff structure is then set so that the discounted value of predicted total revenue of the regulated firm's activities covers this value. For example, in the regulation of UK Regional Electricity distribution companies, the values of x and p_0 are chosen so that the present value of total predicted revenue for each firm equals the present value of total allowable revenue (Joskow, 2006; Pollit and Bialek, 2008).

When regulated, access to network infrastructure does typically include cost of service elements. In the UK as discussed above access charges to the regional distribution electricity networks includes cost of service elements in setting initial prices for each regulator period. Similarly, although rather ad-hoc, the method of setting electricity transmission charges by National Grid aims to partially cover infrastructure cost (Pollit and Bialek, 2008). Although currently not regulated in the UK, in the US pipeline rates for interstate transport of oil have been controlled since the Hepburn Act in 1906. The methodology used here to set rates includes a cost of service element covering operating and capital expenditure or a market based rate where the pipeline operator can evidence sufficient competition (FERC, 2010).

4. DECC Guidance and Access Tariff Determination

As noted above the current DECC guidance on dispute resolution over Third Party Access to Oil and Gas Infrastructure (DECC, 2009) set out a number of principles which the Secretary of State will use to set access tariffs including supporting the principle of non-discriminatory access,

which would appear to preclude price discrimination by infrastructure owners. The ICOP also states that tariffs should be non-discriminatory. Further, the principles of pricing access in the DECC Guidance (DECC, 2009, page 13) are discussed with reference to a number of different scenarios, which may be interpreted with respect to different cases in the simple model set out above.

Firstly, for “infrastructure built as a part of an integrated field development”, terms would normally reflect incremental costs except where the field is near the end of its economic life in which case “third party access may need to be set above incremental costs to ensure it is maintained”. When this becomes insufficient due to the depletion of the field(s) owned by the operator, the fixed costs/access price will then be set at a cost of service level covering operating expenditure (DECC,2009, p13). In this scenario, the fixed costs F discussed in the model only cover operating expenditure with the initial investment cost deemed to be sufficiently depreciated to be discounted. Hence, referring to Figure 2, this may be interpreted as implying that regulation would initially set the access price equal to marginal cost relying on partial vertical integration of infrastructure ownership with field operation to ensure that the fixed costs of the infrastructure are covered. When sufficient field depletion has occurred in the field licensed by the infrastructure owner, the access tariff would then have to be reset to a cost of service level.

In the second DECC scenario, where infrastructure operators can make a case that infrastructure was built or “maintained with a view to taking third party business”, a cost of service access price would be set covering both operating expenditure and return on capital. In terms of the model, this suggests that fixed costs F cover both operating and capital costs in

this case due to the fact that this involves significant new or recent investment by infrastructure owners.

While consistent with the traditional model of regulation (and the simple model presented above) i.e. assuming perfect information, the varying principles for access price setting suggested for different situations will pose challenges for the regulator when information is less than perfect. It is of course important to recognize, as modern regulation theory suggests, that it is not possible to ensure efficiency and extract all possible excess profit from regulated firms. However, the different principles provided by DECC may provide potential perverse incentives for infrastructure owners. For example in certain circumstances, it may be in their interests to bring forward plans for the shutdown of its field(s) in order to ensure a move to cost of service access pricing. Similarly the distinction between infrastructure maintained (or not) for third part business would appear to provide some incentive to overinvest in infrastructure maintenance in order to move to a pricing regime which covers capital costs.

5. Taxation and Regulated Tariffs

The prospect of the introduction of cost-related tariff determination in the UKCS raises the question of the appropriate tax treatment of tariff incomes. The historic situation was described in Section One above. This, of course, applied to a situation where the tariffs were determined purely by negotiation between the infrastructure owner and field developer. The abolition of PRT on tariff incomes relating to new contracts was introduced to enhance the competitiveness of the UKCS generally including the ability to contract for gas imports from Norway through infrastructure located in the UKCS. There was implicit

recognition that the size of the tariff was influenced by the taxation applied to the related income.

In the situation where tariffs are determined on a cost-related basis there has to be recognition of the tax payable on the income and the tax relief given for expenditures incurred in providing infrastructure service to third parties. Currently the tariff income is taxed at 50% (corporation tax (CT) at 30% and Supplementary Charge (SC) 20%) and the associated expenditures are relieved at the same rates. In general in a situation of infrastructure regulation the requirement to pay income taxes is taken into account by regulators in tariff determination. The size of the tax payments is a relevant consideration.

The present situation in the UKCS should be seen in this context. There can be no doubt that corporation tax should apply to tariff incomes along with all other sources of corporate income, and that this should be acknowledged in tariff determination. But the application of SC to tariff incomes and its inclusion in cost-related tariff determination is very questionable. It could mean that tariffs are higher than they otherwise would be and result in economic recovery of oil and gas from potential user fields being reduced. The increased operating costs for user fields could accelerate the economic cut-off from such fields or even cause the non-development of marginal fields.

In the above circumstances there is a case on economic efficiency grounds for removing the SC on tariff incomes where the tariff is determined on a cost-related basis. It is arguably inconsistent to determine tariffs in this manner while levying SC on the income in question. Given that tariff determination on a cost-related basis is just

starting the appropriate mechanism could be to remove SC from new third party contracts from a specified date. This should help to incentivise third party infrastructure agreements and encourage maximum economic recovery from the UKCS.

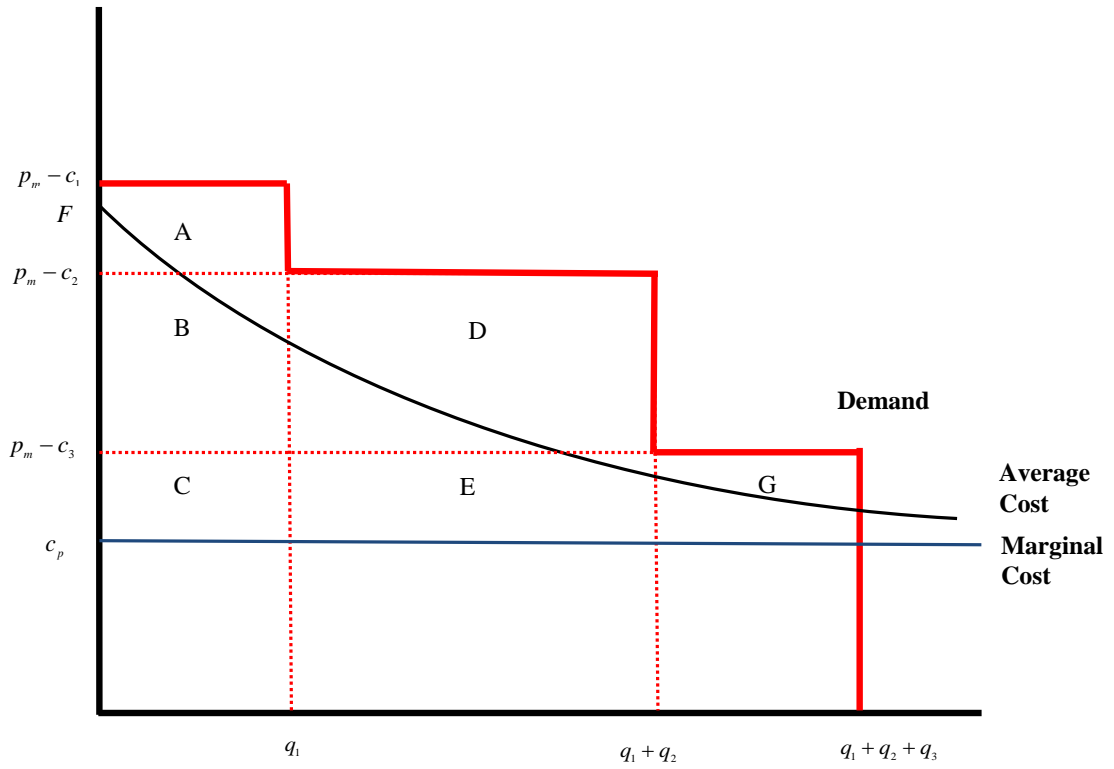
6. *Conclusions*

In this paper an economic model has been developed to show the potential effects of third party tariffing of new oil/gas fields with an infrastructure owner who has some local monopoly powers. It has been demonstrated that, in the absence of any regulation at all, negotiations between the parties may not always lead to an economically efficient solution (which is the maximisation of economic recovery from the UKCS). An efficient solution could be procured by a scheme of discriminatory tariffs based on the willingness to pay of the users. This could ensure that even marginally attractive fields are developed. But this outcome depends on full knowledge by the infrastructure owner of the field owners' costs. Further, if price discrimination by the infrastructure owner is not permitted (as is the case with the ICOP and DECC Guidance) the result can be that the costs of infrastructure operation are not covered. Non-discriminatory marginal cost tariff determination in a typical situation where the marginal cost of providing infrastructure services is below the average cost can be non-optimal and could lead to the premature closure of the infrastructure, and thus incomplete economic recovery. In these circumstances tariff determination by a regulator can lead to an economically more efficient solution with enhanced oil and gas recovery. Average cost pricing ensures that all the infrastructure costs are covered. It should be recognised, however, that this is a second best solution and the resulting

tariffs could still render a field uneconomic compared to marginal cost pricing. But in the absence of discriminatory pricing or subsidies this second best solution is the best that can be obtained. In the longer term where further investment in the infrastructure is required to maintain or enhance its integrity for use by third parties the necessary costs need to be reflected in the tariffs. In a situation where tariffs are determined on a cost-related basis the requirement to pay corporation tax on tariff income has to be acknowledged. But the payment of Supplementary Charge on tariff incomes and the associated reflection of that in tariffs charged is inconsistent and non-optimal, and could lead to incomplete economic recovery from the UKCS. There is thus a case for abolishing the application of SC to new third party tariff contracts in the UKCS.

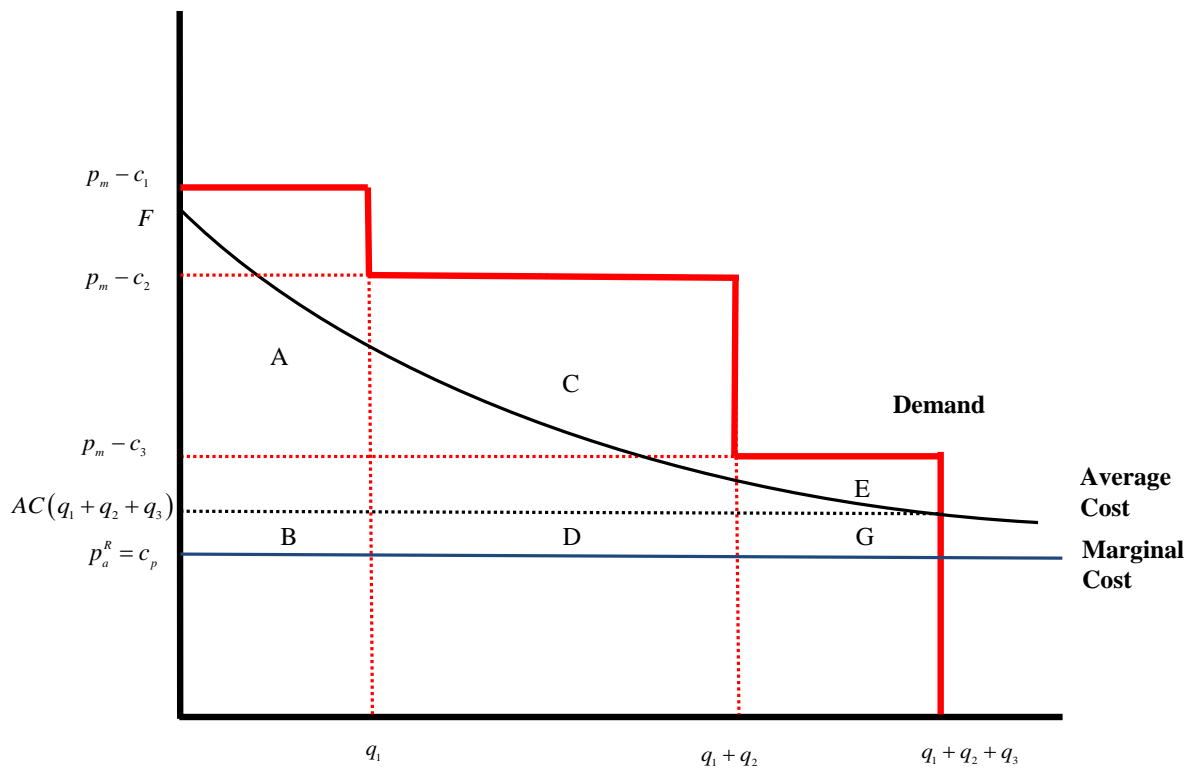
MC/AC,
Access Price

Figure 1



MC/AC,
Access Price

Figure 2



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