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OPTIMIZING OIL AND GAS DEPLETION IN THE MATURING NORTH SEA WITH GROWING IMPORT DEPENDENCE

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Hydrocarbon production from the UK Continental Shelf has now passed its peak. Net gas import requirements started in 2004 and increase substantially. The remaining reserves of both oil and gas are substantial, but are distributed largely in relatively small fields. Historically, depletion policy has generally been determined by market forces with the need for early revenues being the major consideration. Currently, policy is concentrating on enhancing development and depletion by removing perceived barriers. It is possible to construct a case for reducing the depletion rate. This involves significant risks and costs, and it is concluded that optimization is more likely to be achieved by minimizing the resource costs of extraction. This entails the encouragement of both new field developments and incremental investments. Current licensing and regulatory arrangements generally recognize the need to enhance activity on fallow blocks/discoveries and to remove barriers facing entrants. These policies should be pursued with vigour.

I. INTRODUCTION

The discovery and exploitation of oil and gas from the UK Continental Shelf (UKCS) has arguably been one of the most important events in post-war British economic history. Oil and gas production have not only transformed the energy sector but have had a major impact on the whole national economy, particularly the balance of payments and, for some years, on tax and royalty receipts. The direct and indirect effects of the rapid growth of the sector from both energy policy and macroeconomic perspectives have been analysed at length. While differences of view on the appropriate mix of policies remain, there is broad agreement on how the energy economy and macroeconomy have been affected by indigenous oil and gas.

The new millennium ushered in a new energy era as well. Oil and gas production in aggregate peaked in

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2000 at around 4.6m barrels of oil equivalent per day (mmboe/d) after which decline set in, resulting in output of around 3.8 mmboe/d in 2004. The evidence put forward in this paper is that this trend will not be reversed. Depletion policy has to be seen in this context. Depletion policy has also to be viewed in the context of the recent world oil-price increase and the reappraisal of likely medium-term price levels. It has also been argued that, in the context of security of supply, further relevant considerations are the government's commitments to fostering renewable energy and major reductions in greenhouse-gas emissions, the fast decline of indigenous coal production, and the prospect of some nuclear power stations approaching the end of their lives.

This paper briefly examines the historic framework within which UK oil and gas depletion policy evolved. After examining the basic principles involved, the study then models the likely future depletion rates of oil and gas from the UKCS on the basis of current government policies. It then considers the plausible alternatives, and suggests what might be optimal in prospective UK conditions.

II. HISTORICAL DEVELOPMENT OF UK DEPLETION POLICY

Following first licensing in 1964, prolific gas discoveries were made in the southern North Sea in 1965 and 1966. Policy was to introduce North Sea gas into the energy market as soon as possible. Rapidly increasing gas utilization was desired, based on the perceived benefits of a relatively cheap indigenous fuel substituting for imported naphtha, in particular. The government and the Gas Council were both very anxious to ensure that this new fuel was available from the North Sea as cheaply as the needs to encourage exploration and development permitted. The resulting negotiations with the producers were prolonged and caused some delays to production. But production commenced in 1967 and grew at a fast pace until the early 1970s.

In the 1970s a combination of low prices on offer from British Gas, the monopsony buyer, the greater attractions of oil exploration and development in the Central and Northern North Seas, plus the signing of the huge Frigg contracts, led to a major reduction in exploration in the Southern North Sea. Production from the UKCS reached a plateau and imports from Norway soared. By the beginning of the 1980s British Gas became concerned about the long-term adequacy of gas reserves for the growing UK market and offered very much higher prices for new supplies from the UKCS. Exploration interest revived. The proposed huge Sleipner import contract then created considerable controversy and uncertainty. Its cancellation led to further increases in exploration and development in southern, central, and northern waters of the UKCS.

The result was a dramatic increase in production. Between 1990 and 2000 (the peak year) it grew by 138 per cent. Associated gas from fields in central and northern waters became increasingly important. The swing factors for these fields were much less than in those for the dry gas in the southern North Sea, where they had averaged 1.67. The rapid expansion in the 1990s coincided with the liberalization of the UK market by the government. This contributed to the growth in output. When British Gas effectively supplied all the UK gas market, it planned its gas purchases to be consistent with its estimates of gas market demand. When liberalization came along, competition in supplying consumers gradually developed. This produced a more competitive market at the upstream part of the gas chain. The end result was such a large increase in output that the evolving wholesale spot prices fell dramatically in 1995 (from around 18 pence per therm to around 10 pence). This had major consequences for the long-term contracts between producers and British Gas. They had to be renegotiated with painful consequences for British Gas. The opening of the Interconnector between Bacton and Zeebrugge in late 1998 enabled exports to take place which led to the end of the gas bubble. Thereafter, the UK and continental markets became linked.

Oil production commenced in 1975 and grew at a quite remarkable rate (even by world standards) to reach a peak in 1985 of 2.6m barrels of oil per day (mmb/d). This was primarily the consequence of the discovery of several giant fields, particularly Forties, Brent, Ninian, and Piper. They were all developed within a fairly short time of each other and accounted for a very high proportion of the aggregate.

Government depletion policy was again to give priority to early production particularly to alleviate the continuing balance-of-payments problem and to procure security of supply. This coincided with the interests of the oil companies. The pace of development around the mid-1970s was somewhat frantic, leading to substantial cost escalation. In real terms, expenditure on field investment in the UKCS reached its all-time maximum in this period.

The incoming Labour government in 1974 soon introduced an increased taxation package. Although this excited much attention at the time, the new petroleum revenue tax (PRT) had several substantial allowances which ensured that field developments and exploration could proceed unimpaired. The Labour government also took powers to regulate depletion rates and established the British National Oil Company (BNOC) with an accompanying state participation policy which included existing as well as new licences. All these measures provoked great controversy with the industry. The debate did not adversely affect development plans for the first generation of oil fields. The Varley Assurances with respect to limitations on production cuts and development delays gave some comfort to investors but still left uncertainties. The field development approval procedure, whereby production approvals were given only for part of the life of a field, with the remainder subject to later consent, also created uncertainties and controversies. Thus, on the Forties field, the performance of the reservoir exceeded expectations, and the operator sought an upward revision to its agreed production profile in 1980. This was eventually approved, but only after much debate relating to the diverging arguments for more early tax revenue and slower depletion.

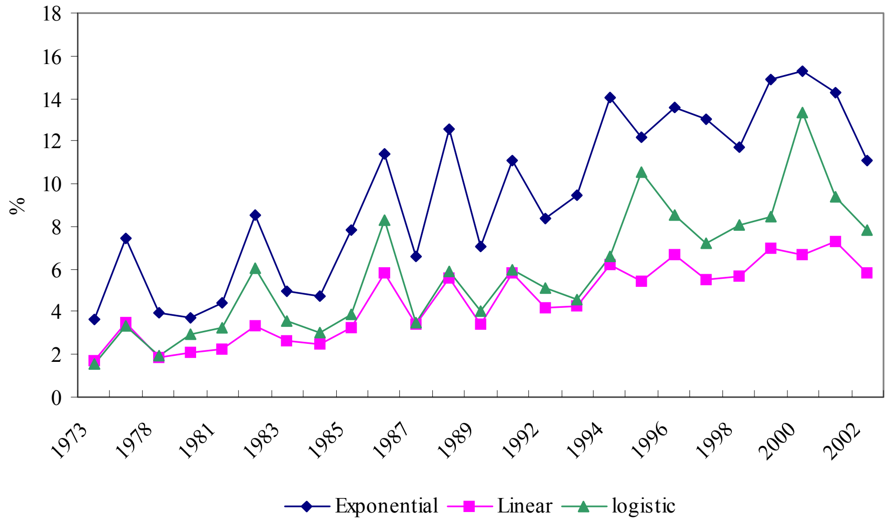
The debate and negotiations relating to state participation occupied much time and effort but did not hold back production from the early generation of fields. Broadly speaking, and despite the many debates and comprehensive powers taken to control depletion, a permissive policy was adopted. The only overt intervention was the 2-year delay imposed on the development of the Clyde field. The effect of this on overall depletion was negligible, though, as BNOC was a substantial partner, it did improve the short-term public-sector borrowing requirement (PSBR).

It had become clear by the later 1970s that, on existing trends, oil production would reach a peak in the mid-1980s and then fall at a quite noticeable pace. The depletion policy debate related primarily to the pros and cons of smoothing the hump to prolong approximate self-sufficiency and enhance security of supply in the later 1980s and 1990s. A further ingredient in the debate was the notion that the prospect of rising real oil prices meant that investment in oil in the ground was a serious consideration. Yet another element was the idea that rising oil revenues would push up the sterling exchange rate to undesirably high levels and, thus, lower depletion rates would be beneficial to the macroeconomy. In the event, by the early 1980s when major decisions had to be taken on whether field development delays and production cuts consistent with the Varley assurances should be made, a combination of the perceived needs for a repletion policy for the late 1980s and beyond, plus the short-term tax revenue needs determined the outcome. The near-term revenue requirements, in particular, determined that there would be no production cuts. Taxation policies were not designed to influence depletion policy. The many changes introduced in the later 1970s and early 1980s were certainly controversial. The introduction of the supplementary petroleum duty (SPD) in 1981 and 1982, as a fourth tier of government's take, possibly contributed to some field development delays. The major relaxations made in 1983 certainly incentivized both exploration and the development of smaller fields.

The collapse of oil prices in 1986 had a major negative effect on the pace of new field developments. Two years later came the Piper Alpha tragedy, resulting in 167 deaths. Priority was then given to investment in safety enhancement. Production continued to fall to 1990. Even as late as 1989 some reputable oil production forecasts were indicating continuous decline. The major upturn which took place in the 1990s was the combined result of a number of substantial discoveries, technological progress, and a cost-reducing initiative.

The achievement of a major increase in oil production to a record high of over 2.8 mmb/d in 1999 was remarkable because of the decline in the average size of new field. From a peak of around 600 mmboe in the first half of the 1970s, the average size fell to

Figure 1
UKCS: Annual Mean Production Decline Rates by Year of Decline Commencement



Source: Kemp and Kasim (2005).

a little over 30 mmboe by the year 2000. The increase in output in the 1990s was thus achieved by the development of large numbers of fields. From the mid-1990s onwards the average annual number of new field developments has been around 20.

Over the last few years, oil and gas production have become increasingly dependent on fields of more recent vintage. This is an inevitable consequence of the depletion of the older fields. There is a worrying implication, however. Decline rates in fields of more recent vintage are generally substantially higher than in those of older vintage. This is indicated in Figure 1, which shows the average decline rate for all currently sanctioned fields by year of decline commencement.

The implication of the above is that, if the overall depletion rate of oil and gas is to be moderated, a large number of fields will have to be regularly developed and/or a major increase achieved in the recovery factor from existing fields.

III. LESSONS FROM PRINCIPLES RELATING TO OPTIMAL DEPLETION

The considerations which have determined UK oil and gas depletion policy historically were briefly noted in section II above. The conventional principles of optimal natural-resource depletion played only a minor role in determining the outcome. It is pertinent to consider how these principles can inform depletion policy in the current situation. The conventional starting point is the Hotelling model, based on the proposition that the optimal depletion rate is that which produces the maximization of returns through time. This involves the equalization of the present values of returns in each time period (Hotelling, 1931). The model emphasizes the influence of growing scarcity from the exploitation of a non-renewable resource, with the optimal solution being where the resource rent (or royalty, or user cost, or depletion premium) grows through time at the rate of interest. The production volumes are adjusted in each time period to produce this result.

On this analysis, the key to the optimal depletion rate is, thus, how it is priced through time. In any period the price should reflect its marginal social costs (including the depletion premium which is a real resource cost). The model's findings depend on a number of restrictive assumptions, particularly the existence of competitive markets (including the efficient functioning of futures markets), and information on the size of the petroleum reserves. From a national policy viewpoint, the social discount rate is the relevant interest rate in the calculation.

The petroleum industry historically has been characterized by new discoveries sufficiently large to affect significantly total recoverable reserves and thus the supply curve and efficient price path. Similarly, technological progress has been such that the industry supply curve has been moved substantially to the right, and with it the efficient price path. Thus in the UKCS the combined cost of exploration, development, and production of new oil fields (including return on investment) in the first half of the 1980s was estimated by the Department of Trade and Industry (DTI) to be around £16 per barrel whereas for the present vintage of new fields the corresponding figure is around £7 per barrel. The existence of the Organization of Petroleum Exporting Countries (OPEC) cartel in the petroleum market constitutes a major departure from the competitive model and greatly influences the efficient price path.

The application of the Hotelling model to the petroleum industry has been subjected to much examination, with the general finding being that, at least to date, it has not provided much illumination.[2] The depletion premium has generally been found to be fairly insignificant. Given the major market imperfections, it can be argued that, within the umbrella of the Hotelling framework, the efficient price should equal the marginal production cost, plus depletion premium, plus economic rent owing to supply restraints (whether from OPEC quotas or other investment restrictions).[3] This can, in principle, indicate the efficient price path (and thus production volumes) consistent with estimates of current production costs and size of depletion and other premia. Some insights into current perspectives of oil and gas price expectations, and thus implications for depletion policy, can be obtained. There is a high probability, however, that changes to investment restrictions within OPEC and elsewhere will occur. Technological progress to an extent not currently foreseen may also take place. Demand changes (not considered in the Hotelling model) may also occur to an extent not currently foreseen. The result of any or all of these could be significant changes to the efficient price path and thus the optimal depletion rate.

These possibilities indicate the difficulties of formulating a consistent and stable long-term depletion policy. Views have to be taken of the behaviour of actors over which the UK government has little or no influence. Further, on past experience the behaviour of these actors is liable to vary in unpredictable ways, which will significantly affect the current level and future trajectory of efficient prices. The implication is that policy should be flexible in recognition of the likelihood of exogenous shocks substantially altering both current and prospective future prices.

The important elements in petroleum exploitation policies relate to licensing and taxation. A key choice lies between the awards of licences based on competitive cash auctions or on work programme bids and other criteria relating to the prospective contribution of the investment to the economy. The bonus bidding system is widely employed in the USA and in Alberta, Canada, but not elsewhere. The main advantages claimed for the scheme are that, given effective competition among investors, it should collect the expected economic rents to the state at low compliance costs. It is also argued that it does not distort the size of the work programmes. Proponents of the auction scheme argue that the use of work programme as the bid variable introduces a distortion to the allocation of resources, and, in particular, can lead to unnecessary drilling being undertaken.

The proponents of the discretionary system are concerned that bonus bidding can only collect expected economic rents. Realized economic rents may be very different owing to factors, such as field sizes and oil/gas prices, varying substantially from the expected. A discretionary system of taxation is, thus, necessary to ensure that the nation receives an appropriate share of the realized rents. The free-market view is that the investor takes the risks at the time of the initial licence award and the returns should reflect the risks seen at that time. It is also argued that the bonus bid system reduces the exploration budget available for drilling and other work. In a mature province such as the UKCS, where the numbers of commitment wells in recent licence rounds have been very low, it is arguable that the likelihood of 'excessive' work programmes being bid is quite remote, and that, where the priority is to

[2] For illuminating discussions see Watkins (1992) and Adelman (1993).

[3] This is the general approach adopted by Newbery (1985) in estimating the efficient price for gas in the UK within constrained market conditions.

mitigate the fall in reserves, the emphasis should be given to work programmes. It is, of course, possible to combine an auction system with a discretionary royalty/tax system.

The optimal tax system for collecting realized rents has been the subject of much discussion, particularly since the 1970s.[4] The economic inefficiencies of conventional royalties and the merits of special taxes targeted on the economic rent have been highlighted. Essentially, the resource rent tax permits the investor to recover his costs plus a threshold rate of return, after which tax relating to his cash flow is levied. A recent variant proposed by Lund (2002) provides that the threshold rate of return be given over a depreciation period rather than as soon as income from the project permits. This device ensures that taxation payments occur earlier.

The UK adopted the PRT, a complex variant of the resource rent tax, in 1975, but, oddly, abolished it for all new fields in 1993. The current system for all new fields is essentially a cash-flow tax as far as existing, tax-paying players are concerned. This scheme was proposed as long ago as 1948[5] but never adopted until recently. A key feature of this tax is that the post-tax internal rate of return continues to equal the pre-tax rate (excluding debt capital issues). Thus a positive pre-tax return is never turned into a negative one by the tax. From the viewpoint of incentives it ensures that *all* investment risks are fully and immediately shared by government to the extent of the tax rate. (It is for this reason that governments have generally been reluctant to adopt it.) It can be claimed for the cash-flow tax that, other things being equal, it provides maximum investment incentives and even reduces the downside risks. The only issue concerns the tax rate. Returns expressed in net present values are obviously reduced by the tax, and the only possible disincentive can arise when a high rate reduces these to unacceptably low levels.

A licensing issue which is relevant to depletion policy relates to the relinquishment conditions. These determine how speedily licensees undertake work programmes on their blocks. An extreme view is that, as the investor is the best judge of the optimal timing of his investment, there should be no relinquishment obligations. No government in its capacity as landlord has accepted this view. Host governments throughout the world attempt to ensure that speedy exploration and development occur, while investors argue for longer periods before relinquishment obligations ensue. The supposition is that, at least in many instances, governments have higher discount rates. Investors will generally have a portfolio of assets and opportunities, and optimization of a worldwide portfolio could produce a different time pattern of investment in particular countries. In countries where depletion rates exceed discovery of new reserves, the need to reduce or eliminate the presence of fallow acreage becomes more pressing. This may also be the situation where the perceived exploration opportunities to investors are less exciting than those available elsewhere.

IV. CURRENT GOVERNMENT POLICIES

Current policies in the areas of licensing and taxation are directed to enhancing and accelerating activity in the UKCS through the removal of perceived barriers, while ensuring that the state receives a substantial share of the economic rents. A series of licensing measures involving more frequent rounds, with large numbers of blocks being offered, and more interventionist initiatives designed to reduce the numbers of fallow blocks and discoveries, are the main elements, along with a tax system which is designed to incentivize investment. The context is the continued fall in hydrocarbon production since 2000 and the decline in discovered reserves of both oil and gas since the mid-1990s.

A further consideration in current policy is the view that the total remaining potential is still very substantial. Proven oil reserves are officially (DTI, 2004*b*) estimated at 571m tonnes, proven plus probable at 857m tonnes, and proven plus probable plus possible at 1,267m tonnes. The respective reserves: production (R:P) ratios are 5.4, 8.1 and 12. These figures are quite low by the standards of major producing countries. Potential additional reserves are 95m (low), 247m (central), and 496m tonnes (high). Undiscovered resources are estimated at 323m (low), 782m (central) and 1,826 (high) million tonnes.

[4] See, for example, Garnaut and Clunies Ross (1983), Kemp (1988), and Lund (2002).

[5] See Brown (1948).

Cumulative production to the end of 2003 was 2,910m tonnes. Thus the remaining potential is 34 per cent (low), 65 per cent (central), or 123 per cent (high) of the total depletion to date. The frequently employed colloquial statement that the glass is still half full is thus based on optimistic views about future discoveries.

For natural gas, proven reserves are estimated at 590 billion cubic metres, proven plus probable at 805 billion cubic metres, and proven plus probable plus possible at 1,241 billion cubic metres. The respective R:P ratios are 5.8, 8.9, and 12.2, all relatively low for a major producing country. The ratios have also been falling in recent years with the rapid growth of production in the 1990s. Potential additional gas reserves are estimated at 74 billion cubic metres (low) estimate, 153 billion cubic metres (central), and 276 billion cubic metres (high). Undiscovered resources are estimated at 279 (low), 492 (central), and 1,259 (high) billion cubic metres. With cumulative production at 1,828 billion cubic metres, the remaining potential is 52 per cent (low), 85 per cent (central), or 152 per cent (high) of total depletion to date. The potential is thus relatively more favourable for gas than for oil, though the R:P ratios are similar.

It may be asked how current depletion policy relates to the Energy White Paper (DTI, 2003*a*). This initiated very ambitious targets for the reduction of greenhouse-gas emissions and for the rapid development of renewable energy. Other things being equal, this would involve reduced use of oil and gas. The current policy stance of maximizing the economic recovery of hydrocarbons is consistent with the White Paper in the context of the UK's imminent net import position for both gas and oil on the assumption that the real resource cost of meeting demand from domestic production is less than from imports.

Another consideration relates to security of supply. It is often argued that domestic production is more secure than imports. This is frequently an assertion, rather than a scientifically tested proposition. In general it is arguable that greater diversity adds to security of supply, irrespective of whether these sources are indigenous or imports. A highly concentrated domestic source may involve substantial security-of-supply risks. With respect to the North Sea, there are currently over 270 producing fields, including over 100 gas-producing ones. This diversity contributes significantly to security of supply. In fact, significant risks are more likely to emanate from the infrastructure, which is more concentrated. The discovery and development of new fields will contribute to security of supply by enhancing or maintaining diversity, though it should be acknowledged that the interdependence of production from fields through reliance on common infrastructure is increasing both offshore and onshore.

A major current policy initiative concerns fallow acreage. The problem relates principally to blocks awarded in early licence rounds where the relinquishment terms typically required the surrender of 50 per cent of the acreage after 6 years and allowed retention of the remainder for 40 years without the specification of further work obligations. The annual licence fees are also quite low (especially at today's values). These represent the holding costs of the licences. The issue was of less consequence when considerable prospective acreage was available for licensing to new and existing players. In recent years little 'new' prospective acreage has been available, particularly in the mature North Sea, and most of the blocks put on offer have been relinquished from previous rounds. Potential new investors have complained that enough interesting acreage has not been available to them.

The issue was raised forcibly as long ago as 1988 by BRINDEX and since then the government has been trying to enhance the utilization of mature acreage. A multi-pronged PILOT initiative was launched in early 2002. With respect to fallow blocks/discoveries, where there has been inactivity for 4 years after the initial term has expired (the 'official' definition of fallow), the licensee has to discuss his plans for the asset. If an acceptable work programme is produced, the block or discovery can be retained, but the DTI continues to monitor the situation. Where an acceptable work programme is not in place, the licensee has to consider and report on whether and how activity could be enhanced. This would involve consideration of partner misalignment, reassignments, and market testing, including putting the assets on LIFT (licence information for trading). For fallow blocks, a total time of 1 year is allowed, after which the asset has to be divested, reassigned, or relinquished. For fallow discoveries, a total time period of 2 years is allowed.

A further initiative relates to pre-emption rights of partners in licence groups when one participant seeks to assign his interest. These rights have hindered transactions and inhibited new players from pursuing them. The PILOT agreement stated that pre-emption rights cannot be included in future joint-operating agreements among co-licensees. For existing licences they may remain, but in a standardized form which would become generally known to potential purchasers.

The 20th round in 2002 ushered in significant changes in licensing policies. Blocks were awarded for an initial term of 4 years, after which 50 per cent of the acreage had to be surrendered. After a further 4 years, the remainder also had to be surrendered unless a development was under way or in prospect. In that event, the relevant part of the block could be held for a further 18 years. These changes were designed to accelerate the exploration of acreage and to ensure that unworked acreage was not held for a long time.

Another innovation in the 21st round in 2003 was the introduction of 'promote licences'. These are designed to encourage companies, including very small ones, to acquire data, work up prospects, and, where appropriate, seek resource commitment, over an initial 2-year period when the licence fees are reduced by 90 per cent. In the second 2-year period significant work has to be undertaken. No fewer than 34 companies acquired promote licences in the 21st round. Around 60 per cent are seismic contractors or small consultants/new independents.

In the 22nd round 163 blocks were awarded in September 2004, the largest number since the 4th round in 1971–2. It should be noted, however, that the majority of the blocks were in the promote licence category, where the initial work commitments are generally much less than with traditional licences. A further noteworthy feature of the 22nd round was the substantial presence of new players. Of the 58 companies offered licences, 15 are newcomers.

An issue which had been examined several times in the 1990s relates to terms and conditions for access to infrastructure. These have been negotiated between asset-owners and users. The legislation established in 1975 gave the government powers to determine tariffs, but only if requested to do so by one of the relevant parties. No official requests have been made, but negotiations over terms have often been very protracted. In a free-market situation the asset owner can attempt to set tariffs at levels which are just less than the costs of alternative transport (or other services). It was this phenomenon which led the government to levy PRT on tariff incomes in 1983. There was then a concern that the economic rents from a field's production were being diverted into high tariffs.

The government investigated the sluggish operation of the tariff market in the 1990s and a voluntary code of practice was implemented, whereby asset owners agreed to publish indicative tariffs for their transportation and processing services and to provide them on a non-discriminatory basis. The market continued to function in a sluggish manner, however. Potential new entrants expressed their concerns over the issue. The DTI led another initiative on the matter, which culminated in a revised code of practice being agreed with the industry under the PILOT umbrella in September 2004. Key features of the agreement are that tariff terms will be non-discriminatory and details of actual agreements will be published. The most important element from an economic viewpoint relates to the determination of tariffs. The agreement states that the parties shall negotiate in good faith for up to 6 months. If after that time no agreement has been reached, the DTI can intervene and determine tariffs in accordance with competitive market conditions. Thus local monopoly elements in tariff levels would be excluded, but elements reflecting costs and risks would be included.

In the Finance Act 2003 the Chancellor introduced a measure also dealing with tariffs. Up to then, where a host asset (such as a platform and/or pipeline) was subject to PRT, tariff income received was subject to PRT and corporation tax, producing a marginal rate of 70 per cent. Where the host asset was not subject to PRT, the tariff income received was not subject to PRT and the marginal rate of tax was 40 per cent. This situation produced a non-level playing field in the evolving tariff market and was arguably anomalous. There was a further oddity. Where the producing user field was itself subject to PRT, the host asset received a tariff receipts allowance (TRA) per tied-in field. But where the producing user field was not subject to PRT, no TRA was available to the host asset. In the Finance Act, 2003 PRT was removed from tariffs relating to new contracts. There was an understanding with the industry that the net economic benefits from this removal of PRT would be passed on to the user. This is not straightforward. The net economic benefit to the asset owner of the PRT removal depends on the combined effect of the reduced tax payable on the income and the reduced tax relief on the expenditures incurred in producing that income. Host assets are now commonly employed to receive some hydrocarbons where the tariffs are subject to PRT (old contracts), and some where the tariffs are free of PRT. The relevant costs have to be allocated between the two categories. This has to be done on a just and reasonable basis according to the PRT legislation. The practical interpretation of this is not always clear, and is the subject of debate between the United Kingdom Offshore Operators Association (UKOOA) and the Inland Revenue. A further consequence is that the extent to which tariffs should be reduced as a consequence of the PRT relief is still subject to debate.

The most important recent tax changes occurred in 2002. A package of measures was introduced. A supplementary charge of 10 per cent was added to corporation tax, capital allowances for field investment were increased from 25 per cent declining balance to 100 per cent first year, and royalties were abolished from January 2003. Thus, for existing taxpayers, there is effectively a cash-flow tax for all their operations in the UKCS. Despite its manifest attractions in facilitating investment through its inherent sharing features, the package was received with dismay by the industry. For fields developed from March 1993, the marginal rate was increased from 30 to 40 per cent. For those developed prior to April 1982, the top marginal rate was increased slightly from 69.37 to 70 per cent, and for those developed between April 1982, and March 1993, the increase was from 65 to 70 per cent.

V. MODELLING PROSPECTIVE DEPLETION UNDER CURRENT POLICIES

The consequences of the current licensing and tax policies for prospective depletion were estimated using financial simulation modelling (including the Monte Carlo technique for exploration risk analysis) and a large field database validated by the operators. It consists of key data relating to production, investment, operating, and decommissioning costs on sanctioned fields (270), incremental projects on these fields (135), probable fields (43), and possible fields (40). A second database is composed of 199 technical reserve fields which have been given production and investment profiles based on known summary reserve data and block locations and the use of the Monte Carlo technique. These technical reserve fields are not currently being examined for potential development by the operators.

The Monte Carlo technique was used to model new discoveries up to 2030. For this, assumptions based on recent trends regarding exploration effort, success rates, size and type (oil, gas, condensate) were made. Five-year moving averages of these variables were calculated for six areas of the UKCS (southern North Sea (SNS), central North Sea (CNS), Moray Firth (MF), northern North Sea (NNS), west of Scotland (WOS), and the Irish Sea (IS)), and used as the base assumptions in the Monte Carlo analysis. Because of the lack of adequate recent data for WOS and IS in the last 5 years, judgemental assumptions on success rates and average size of discoveries were used for the modelling.

Exploration effort is taken to depend primarily on (i) the expected success rate, (ii) the likely size of discovery, and (iii) oil and gas prices. As stated, 5-year moving averages were used to ascertain success rates and discovery size in each of the basins considered and three future oil/gas price scenarios were used as shown in Table 1.

Table 1
Future Oil and Gas Price Scenarios

	Oil price (real) \$/bbl	Gas price (real) pence/therm
High	25	24
Medium	20	18
Low	15	14

The postulated number of annual exploration wells for the whole UKCS are as shown in Table 2.

Table 2
Exploration Wells

	2004	2018	2028
High	35	23	15
Medium	25	16	10
Low	15	9	5

The annual numbers are modelled to decline in a generally linear fashion over the period to 2030.

Success rates are taken to depend on (i) recent experience, and (ii) size of effort. Higher effort is associated with more discoveries, but with lower success rates compared to reduced effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects and, therefore, higher effort involves the acceptance of higher risk. For the UKCS as a whole three success rates were postulated as shown in Table 3.

Table 3
Success Rates (%)

Medium effort/medium success rate	25
High effort /low success rate	20
Low effort/high success rate	30

It is assumed that technical progress will maintain these success rates.

The mean sizes of discoveries made in the period 1997–2003 inclusive for each of the six regions were calculated. It was then assumed that the mean size of discovery would decrease in line with historic experience. Such decline rates are quite modest. For 2004 the average size of discovery for the whole of the UKCS is 34 mmboe. For purposes of the Monte Carlo modelling of new discoveries the standard deviation (SD) was set at 50 per cent of the mean value. In line with historic experience the size distribution of discoveries was taken to be lognormal.

Using the above information the Monte Carlo technique was employed to project discoveries in the six regions to 2028. For the period the total numbers of discoveries for the whole of the UKCS were as shown in Table 4.

Table 4
Total Number of Discoveries to 2028

High effort/low success rate	133
Medium effort/medium success rate	115
Low effort/high success rate	77

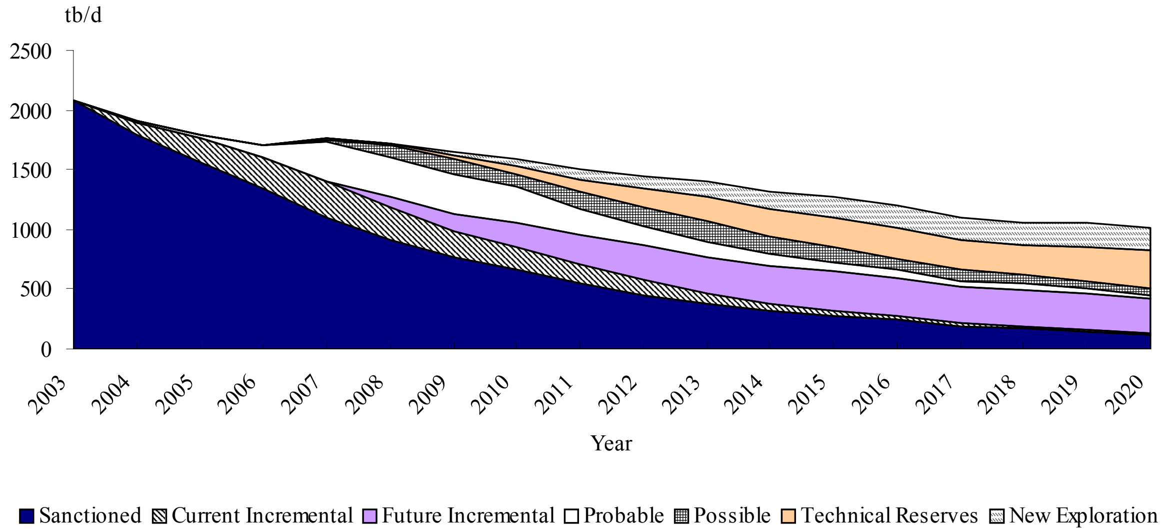
For each region the average development costs (per boe) of fields sanctioned since the later 1990s and those in the probable and possible categories were calculated. Using these as the mean values, the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with an SD equal to 20 per cent of the mean value was employed. For the whole of the UKCS the average development cost on this basis was \$4.33/boe. Annual operating costs were modelled as a percentage of accumulated development costs. This percentage was taken to increase as the size of field was reduced, reflecting economies of scale.

With respect to fields in the technical reserves category, it was recognized that many have remained undeveloped for a long time. Accordingly, it was assumed that their development costs would be \$1/boe higher than for new discoveries for each of the regions. For purposes of Monte Carlo modelling, a lognormal distribution of recoverable reserves for each technical reserve field with an SD equal to 50 per cent of the mean was assumed. With respect to development costs, the distribution was assumed to be normal with an SD equal to 20 per cent of the mean value.

The annual numbers of new field developments were assumed to be constrained by the capacity of the industry. The ceilings were assumed to be linked to the oil/gas price scenarios, with maxima of 25, 20, and 15, respectively, under the high, medium, and low price cases. These constraints do *not* apply to incremental projects which are additional to new field developments.

A noteworthy feature of the 135 incremental projects in the database validated by operators is the expectation that the great majority will be executed over the 3 years from 2004 if they pass the economic hurdle rate. It is virtually certain that in the medium

Figure 2
Potential Oil Production, $20/bbl and 18p/therm (hurdle rate 10%)



and longer term many further incremental projects will be designed and executed. They are just not yet at the serious planning stage. Such projects can be expected not only on currently sanctioned fields but *also* on those currently classified as in the categories of probable, possible, technical reserves, and new discoveries.

Accordingly, estimates were made of the potential extra incremental projects from all these sources. Examination of the numbers of such projects and their key characteristics (reserves and costs) being examined by operators over the past 4 years indicated a decline rate in the aggregate volumes from these projects. On the basis of this, and from a base of the information of the key characteristics of the 135 projects in the database, it was felt that, with a decline rate reflecting historic experience, further portfolios of incremental projects could reasonably be expected. As noted above, such future projects would be spread over *all* categories of host fields.

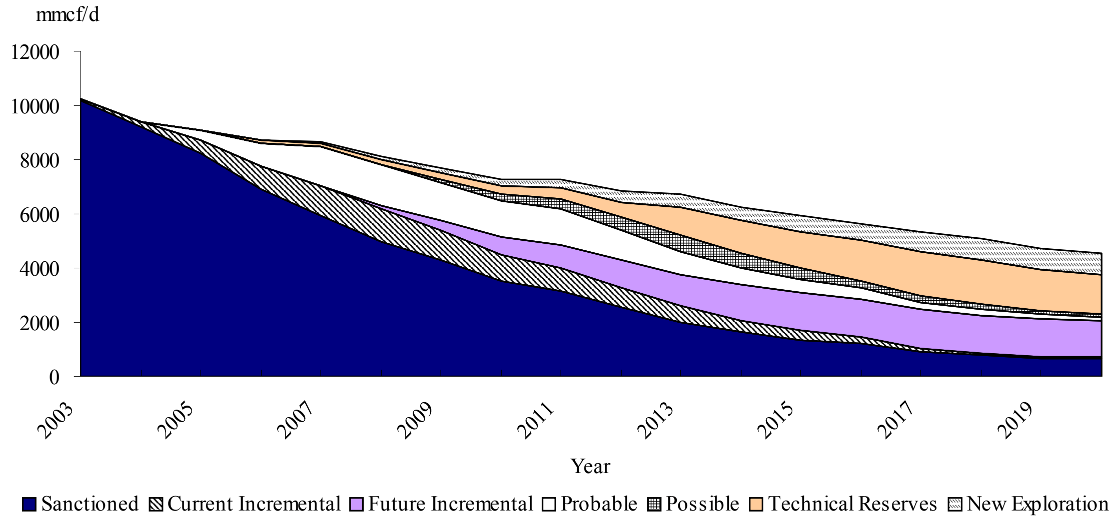
The economic modelling of the incremental projects involved, first, the calculation of the production, revenues, and costs of the host field plus the incremental project, and second, the production, revenues, and costs of the host field alone. The host field's results are then deducted from those of the results for the host plus increment to give the production, revenues, and costs for the incremental project. This procedure permits the capture of any change in the host field's production and costs that arises from the introduction of an incremental project, including any postponement in decommissioning. The procedure also ensures that on PRT-paying fields the correct tax liability on the incremental project is calculated.

The financial modelling incorporates a threshold or hurdle rate, field economic cut-off, and the full details of the petroleum tax system. Different discount rates are employed, but there is emphasis on 10 per cent post-tax in real terms. An important assumption in the modelling is that adequate infrastructure will be available to facilitate the development of the future incremental projects.

Potential oil production (excluding natural gas liquids (NGLs)) under the $20/18p scenario is shown in Figure 2. A key feature is the fairly fast decline from sanctioned fields, especially over the period to 2010. In the later part of the period, the pace of decline moderates, but the level in 2020 from this category of field is just 100,000 b/d. Incremental projects currently being examined make a substantial contribution to the moderation of the decline rate over the next few years. Fields in the probable category dramatically change the whole profile for a few years from 2007 onwards. A very substantial contribution comes from one field, Buzzard, which, at the time of the database construction, was still in the probable category.

Other features of the results are the major long-term contributions made by fields in the technical reserves category and by future incremental projects

Figure 3
Potential Gas Production, $20/bbl and 18p/therm (hurdle rate 10%)



(related to all categories of fields). Total production in 2020 is around 1 mmb/d, of which technical reserves contribute around 350,000 b/d. Their combined contribution is substantially greater than that from new discoveries (excluding incremental projects on these). The contribution from this category of field is fairly modest owing to a combination of the relatively small number of discoveries and their modest average size.

In Figure 3 prospective production of natural gas (excluding NGLs) is shown. The decline rate in total output is broadly similar to that for oil. Production from the sanctioned fields falls at a fairly brisk pace. Up to 2010 this category of field accounts for 50 per cent or more of total output. Currently planned incremental projects substantially moderate the decline rate in the period 2006–10. The development of probable fields makes an even bigger contribution in the period 2006–12. Beyond 2012, production becomes increasingly dependent on the development of technical reserves and further incremental projects. By 2020, each of these categories accounts for over 35 per cent of output. The contribution of new discoveries remains moderate, reflecting the modest numbers of finds and their relatively small size.

In Figure 4 prospective total hydrocarbon production (including NGLs) is shown under the $20/18p scenario. The decline rate is seen to be fairly brisk until 2006, after which it is moderated for a few years. The large Buzzard field plays a significant role here. In 2010, the PILOT target of 3 mmboe/d is just achieved. It is noteworthy, however, that this is dependent on a significant contribution from future incremental projects, and smaller contributions from both new discoveries and the development of some fields in the technical reserves category. By 2020 total production is around 1.9 mmboe/d, at which date technical reserves and future incremental projects constitute a high proportion of the total. In that year each of these categories provides more output than new discoveries.

The price sensitivity of production is now examined. Oil production (excluding NGLs) is shown under the $25 price. In the early years there is little difference in the profiles. Many of the current incremental projects go ahead under the lower price, as do the most important probable fields and some of the possible ones. More new discoveries are made and developed. By 2020 total production is around 1.2 mmb/d under the $25 case.

Potential gas production (excluding NGLs) under the $25/24p case is shown in Figure 5. The price sensitivity is broadly similar to that for oil. In the later part of the period, production from technical reserves is very much greater under the high price case, as is output from new discoveries. Total production in 2020 is 5.5 billion cubic feet per day (bcf/d).

Figure 4
Potential Total Hydrocarbon Production, $20/bbl and 18p/therm (hurdle rate 10%)

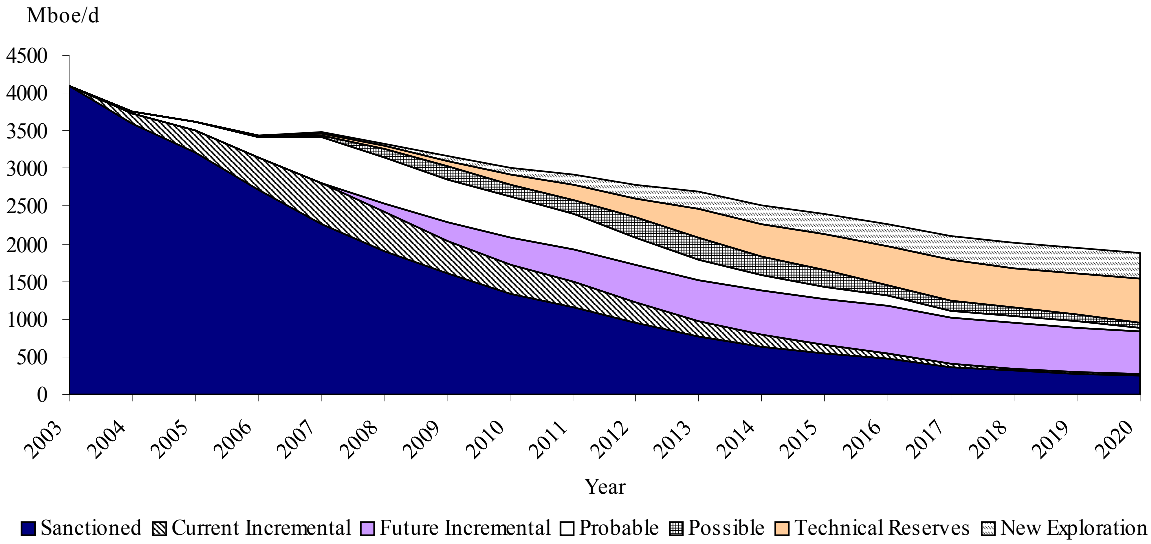
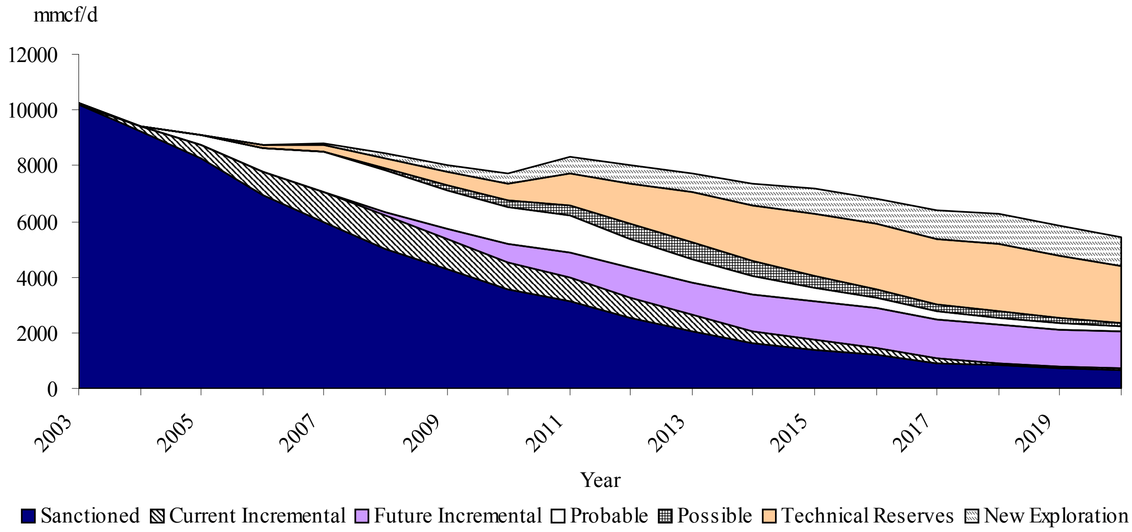


Figure 5
Potential Gas Production, $25/bbl and 24p/therm (hurdle rate 10%)



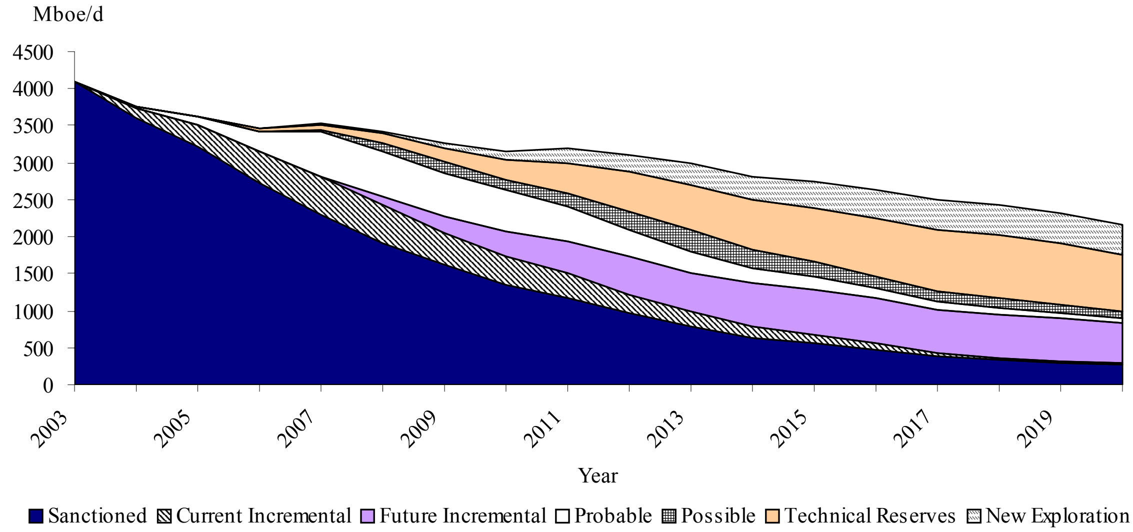
In Figure 6 total hydrocarbon production (including NGLs) is shown under the $25/24p scenario. Output is around 3.2 mmboe/d in 2010 and 2.2 mmboe/d in 2020. Greater production from technical reserves and new discoveries account for the bulk of the difference compared to the $20/18p case.

The above results are the consequence of current investor views of prospectivity and the impact of present licensing and taxation policies. The medium-term results reflect the success of the current licensing initiatives. Failure of these policies, or the requirements of higher minimum returns by investors, would result in faster decline rates.

VI. PROSPECTIVE GAS SUPPLY AND DEMAND

With declining oil and gas production, the UK faces the prospect of becoming a net importer of both. This will have obvious repercussions on the balance of payments. From an energy viewpoint, the gas situation offers more challenges. Oil trading on a worldwide basis is long established and relatively straightforward. Gas trading, while well established, involves more complexities relating to contracts and infrastructure requirements. In the UK, there is also the issue of peak demand requirements. Gas has also become the most important energy source,

Figure 6
Potential Total Hydrocarbon Production, $25/bbl and 24p/therm (hurdle rate 10%)



accounting for around 40 per cent of total primary energy demand. Nearly 40 per cent of UK electricity is generated from gas. There is, thus, a particular interest in the prospects for the gas supply/demand balance.

Gas demand projections are regularly made by Transco, the DTI, and others. Transco has obligations to meet annual average and peak winter demand. Prospective annual average demand in relation to UK production is shown under two price scenarios in Figures 7 and 8. The UK became a net importer in 2004. Under the $20/18p scenario, production accounts for 55–72 per cent of the UK's needs and by 2020, 30–38 per cent, depending on the demand projection. Under the $25/24p scenario indigenous production accounts for 46–61 per cent of UK demand in 2012 and 22–28 per cent by 2020, depending on the demand estimate.

A considerable number of import schemes, both by pipeline and liquefied natural gas (LNG), are currently being seriously examined. In addition, several storage schemes are also being planned. There is some uncertainty regarding the timing of the projects and the capacity likely to become available from them. Announcements and estimates have been made public by both project promoters and other analysts/commentators. There is much agreement that by 2012 most proposals could come to fruition.

Table 5 shows a snapshot of the potential import and storage volumes in 2012. The data were obtained from a variety of sources. A range is shown to reflect the different views on what the potential capacity/volumes may be. A high proportion of the volumes in the 'low' case have either already been contracted or are highly likely to occur. The 'high' case shows a current view of the *capacity* that may be available and the 'base' case shows the volumes thought most likely to be available. The base volumes from storage and LNG show the current view of gas deliverability from the facilities.

Of the potential imports to the UK there is a relatively wide range given for the Langeled pipeline from the Ormen Lange field, and the BBL pipeline from Holland. Further gas will also come to the UK from Norway via established pipelines. There is a large range in the estimates namely from 350 mmcf/d to 1,200 mmcf/d. There is also a wide range of estimates for the potential from future potential LNG projects.

In Table 6 estimates are shown of the deliverability and capacities of the storage projects. A range is indicated, reflecting differing estimates. For current storage, significant LNG is available but the deliverability is very short.

Figure 9 shows expected annual average demand plus exports to Ireland and Holland alongside potential production and base estimates of net imports at the $20/bbl and 18p/therm price. Net IUK is the Bacton to Zeebrugge Interconnector at capacity, which increases over the time period. The modelling

Figure 7
Potential Production and Estimated Gas Demand, £20/bbl and 18p/therm (hurdle rate 10%)

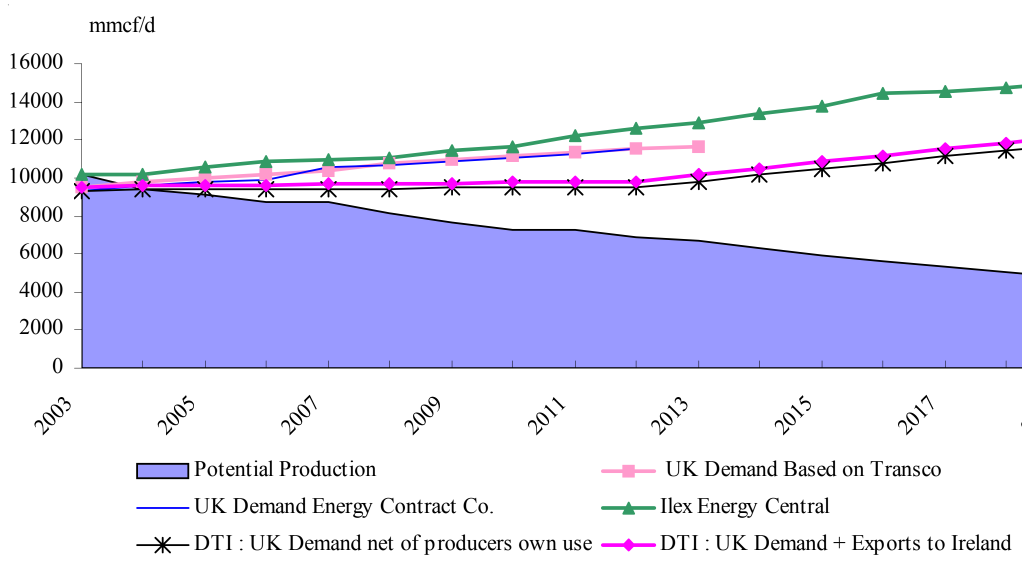
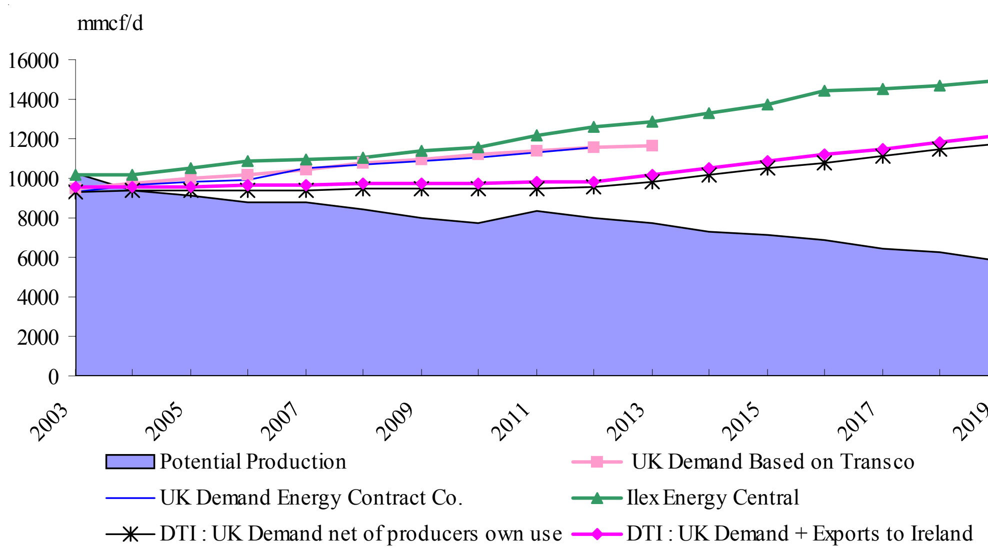


Figure 8
Potential Production and Estimated Gas Demand, £25/bbl and 24p/therm (hurdle rate 10%)



of the Interconnector UK position is conservative as it shows the net position, taking into account contracted exports.

It is seen that the market situation in 2004 has been quite tight. The prospect for 2005 is that it will be even tighter. From 2006 onwards, however, the development of the new import projects offers the prospect of an increasingly amply supplied market.

Figure 10 shows annual expected demand plus exports to Ireland and Holland alongside potential production and base level net imports at the $25/bbl and 24p/therm price. In the near term, the supply/demand position with the high price is almost the same as with the medium price. In the longer term, the potential for supply surplus is greater. From 2007 onwards, the potential surplus becomes quite large.

A potentially more pressing problem is whether or not gas supply, storage, and demand management (through the use of interruptible contracts) will be adequate to meet peak demand. Historically, much of UK peak demand was provided for through the

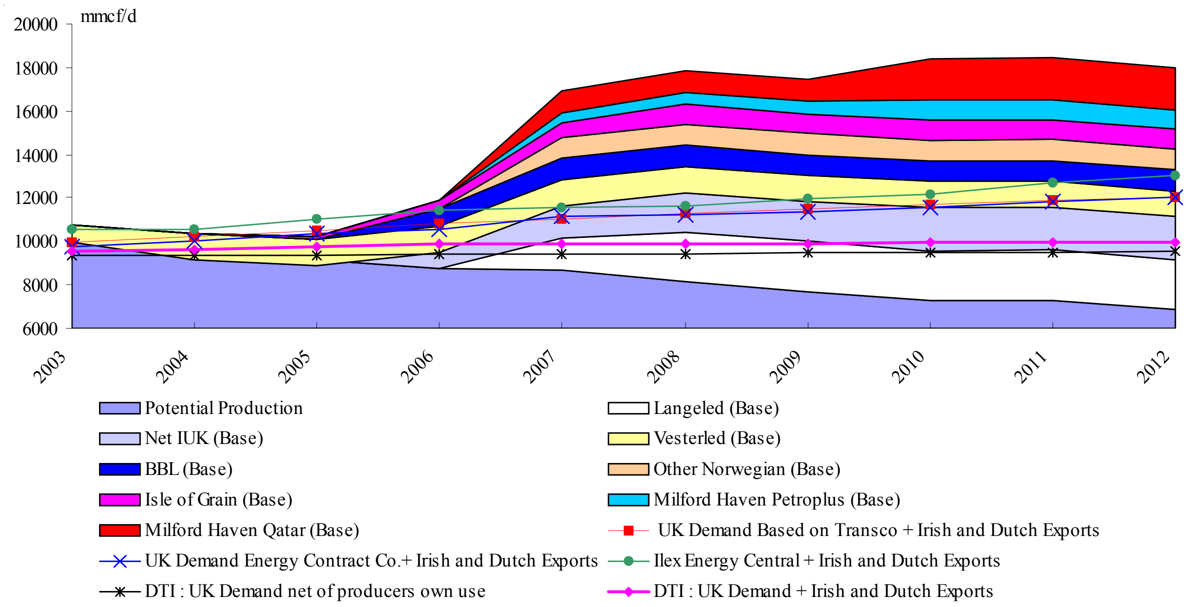
Table 5
Potential Import and Storage in 2012 (mmcf/d)

	Low	Base	High
Potential imports			
Langeled	1,117	2,300	2,471
Interconnector UK	2,273	2,418	2,420
Vesterled	1,200	1,200	1,200
BBL Line	774	970	1,451
Other Norwegian	967	967	1,059
Potential LNG			
Isle of Grain	430	919	1,290
Milford Haven Petroplus	600	900	1,161
Milford Haven Qatar	800	1,934	2,100
Potential storage (deliverability)			
Aldbrough Scottish & Southern/ Statoil	1,407	1,412	1,412
Cheshire/ Scottish Power/ Byley	588	702	1,036
Humbly Grove/ Vitol	264	265	265
Welton/ Star Energy	297	300	300
Lancs/Fleetwood /Canatxx	1,407	1,412	1,412
Current storage (deliverability)			
Rough	1,497	1,521	1,521
Hornsea	652	652	652
LNG	1,768	2,570	2,570
Hole House	98	100	100
Hatfield Moor	83	184	184

Table 6
Potential Storage Capacity and Deliverability in 2012

	Deliverability (mmcf/d)	Number of days	Capacity (mmcf)
Current storage			
Rough	1,521	67	101,404
Hornsea	652	18	11,680
LNG	2,570	5	12,853
Hole House	100	10	1,003
Hatfield Moor	184	23	4,211
Potential storage			
Aldbrough Scottish & Southern/ Statoil	1,412	11	14,794
Cheshire/ Scottish Power/ Byley	1,036	10–15	10,567
Humbly Grove/ Vitol	265	37	9,862
Welton/ Star Energy	300	34	10,213
Lancs/Fleetwood /Canatxx	1,412	14	20,078

Figure 9
Potential Production, Imports, and Estimated Gas Demand, £20/bbl and 18p/therm (hurdle rate 10%)



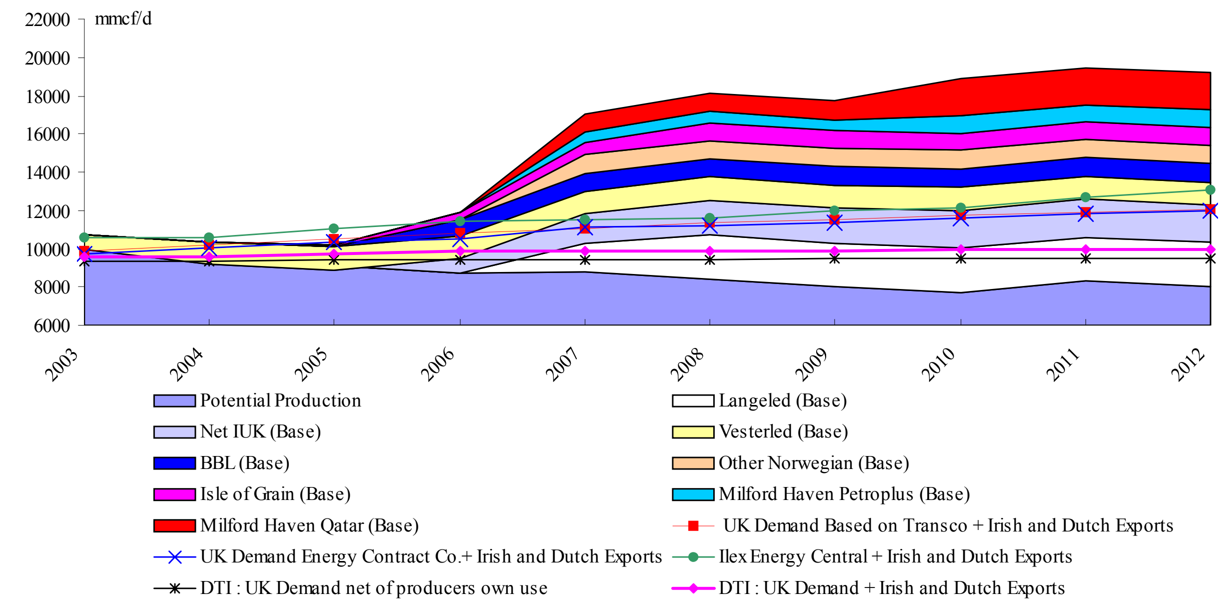
swing factor from SNS fields. However, because of the changing nature of contracts and the depletion of the older fields, some of this swing availability has gone. Newer contracts tend not to have the same provisions for swing gas, and a large proportion of UKCS gas is now extracted as associated gas, where the pace of oil extraction determines the rate of gas supplied. Given that the gas price is much higher in periods of peak demand, there is some incentive for producers to attempt to increase their swing potential. If higher winter production cannot be obtained because of capacity constraints, swing could be procured by reducing non-peak production and producing at capacity in times of peak demand if the gas is non-associated. The Transco view of peak demand shown is undiversified demand for 1 in 20 winter conditions. This means that the 1 in 20 peak demand occurs *simultaneously* in all parts of the UK. This could exceed expected or diversified demand by around 10 per cent. Transco is obliged to use undiversified demand in the planning of its network since any element of the system has to accommodate 1 in 20 conditions. Gas customers with the ability to switch to alternative fuel sources may do so when the gas price rises. Transco estimates that this potential to switch may reduce demand by 10 per cent. Indeed, these are the main reasons for the substantial revisions to Transco's peak demand in 2003. Both milder than expected winter weather and some consumers switching to alternative fuel sources occurred.

The situation with production, imports, and storage compared to peak UK demand is now considered. Figure 11 shows potential peak supply with a high swing factor (1.4), based on historic averages, and demand under the $20/18p price scenario with current and potential (base case) storage and (base case) imports. Following recent experience, where UK winter gas prices have substantially exceeded those on the Continent, it is assumed that the Interconnector can operate at up to full reverse flow capacity. Commitments for export contracts on the Continent are assumed to be met by purchasing gas there.

With respect to the Transco 1 in 20 winter demand, there is no supply shortfall, but the balance is very tight in 2004, 2005, and 2006. With the $25/24p price scenario, the supply is sufficient to meet Transco's estimate of peak 1 in 20 winter demand. This is shown in Figure 12. Again it is emphasized that the Transco peak demand refers to undiversified demand and does not take into account fuel switching at higher gas prices.

Figures 13 and 14 shows potential peak supply with a low swing factor (1.16) based on new contracts,

Figure 10
Potential Production, Imports, and Estimated Gas Demand, £25/bbl and 24p/therm (hurdle rate 10%)



and demand under the two scenarios with current and potential (base case) storage and (base case) imports. With respect to the Transco 1 in 20 winter peak demand, there is a supply shortfall in 2004, 2005, and in 2006. The comparisons highlight the importance of the swing factors in meeting peak demand over the next few winters. Given the large differential between winter prices and those prevailing at other times of the year, there is an incentive on producers to have a significant swing factor in their sales agreements.

If severe winters do materialize in 2005 and 2006 there may be a need to interrupt customers on interruptible contracts. If alternative fuels are available to these customers, such as in power generation, the peak demand problem should be manageable without the need to interrupt customers with firm contracts.

The other feature of the findings is the likelihood of ample supplies emerging in the medium term. It is clear that market forces are working in this complex market, involving heavy investment in infrastructure as well as field developments, LNG transportation, and regasification plants. The contracts between producers and customers have to accommodate the uncertainties of the liberalized UK market. The gas price in the UK is linked to Continental gas prices, and the contracts have to accommodate the uncertainties regarding the pace at which deregulation and competition will emerge there. Currently Continental gas prices are heavily linked to oil product prices. Whether this will remain the case in the longer term depends on the extent to which deregulation produces gas-to-gas competition.

The above findings indicate a surplus of gas capacity availability in the medium term. Supply always equals demand, and the prospect of this surplus capacity could have several consequences. Some of the projects might be deferred or scaled down. Exports could resume through the Interconnector. Some of the prospective LNG volumes could be diverted to other markets. In recent years the flexibility of LNG with respect to taking advantage of geographic differentials in market opportunities has become very apparent. In any case there should be downward pressure on prices from 2007.

From the viewpoint of UK security of supply, the findings offer comfort. Not only are the prospective volumes adequate but the diversity of sources is striking. Currently UK gas production is well

Figure 11
Potential Peak Supply/Demand, £20/bbl and 18p/therm (hurdle rate 10%)

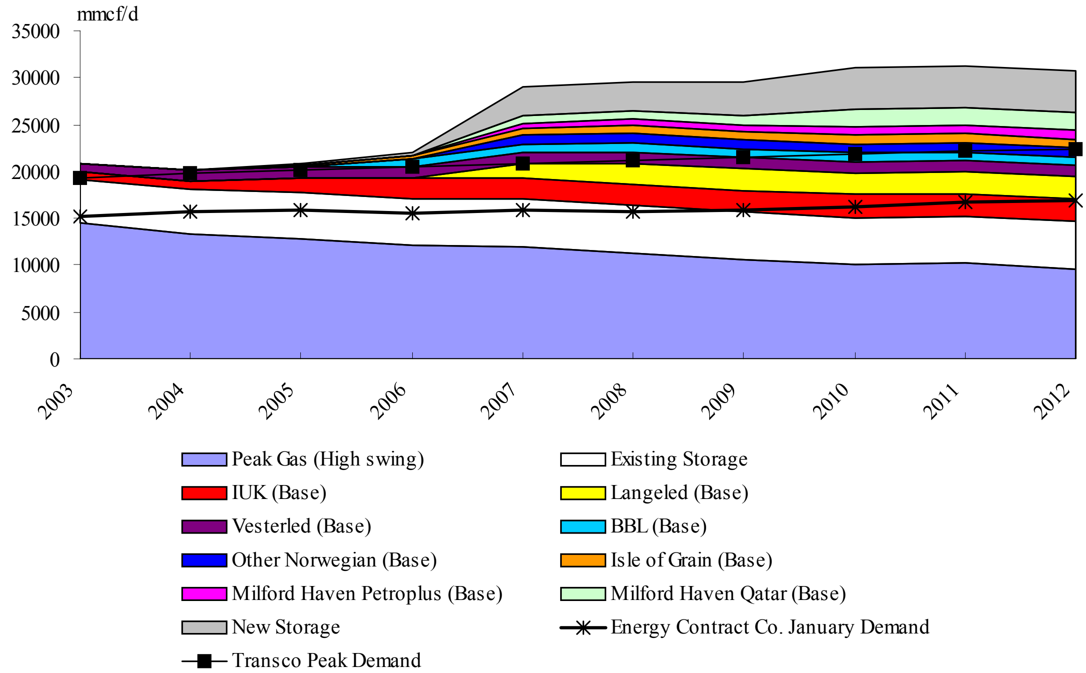
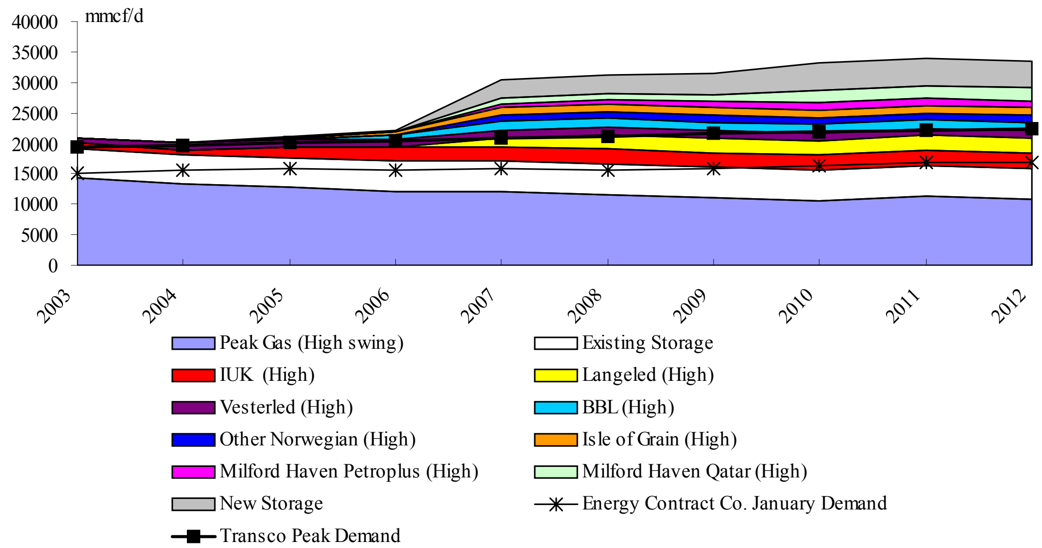


Figure 12
Potential Peak Supply/Demand, £25/bbl and 24p/therm (hurdle rate 10%)



diversified, coming from over 100 fields. There is more concentration with respect to pipelines. With respect to terminals it is noteworthy that key ones, such as Bacton and St Fergus, each have several independent sub-terminals. The proposed import projects offer considerable diversity as they come to different (including new) terminals. Terminal capacity also becomes more diversified.

VII. IMPLICATIONS OF RECENT OIL-PRICE INCREASE

The recent large increase in the oil price and the related increase in gas prices have implications for future activity in the UKCS. Cash flows have increased very substantially. Investment decisions are generally made on the basis of long-term price

Figure 13
Potential Peak Supply/Demand, £20/bbl and 18p/therm (hurdle rate 10%)

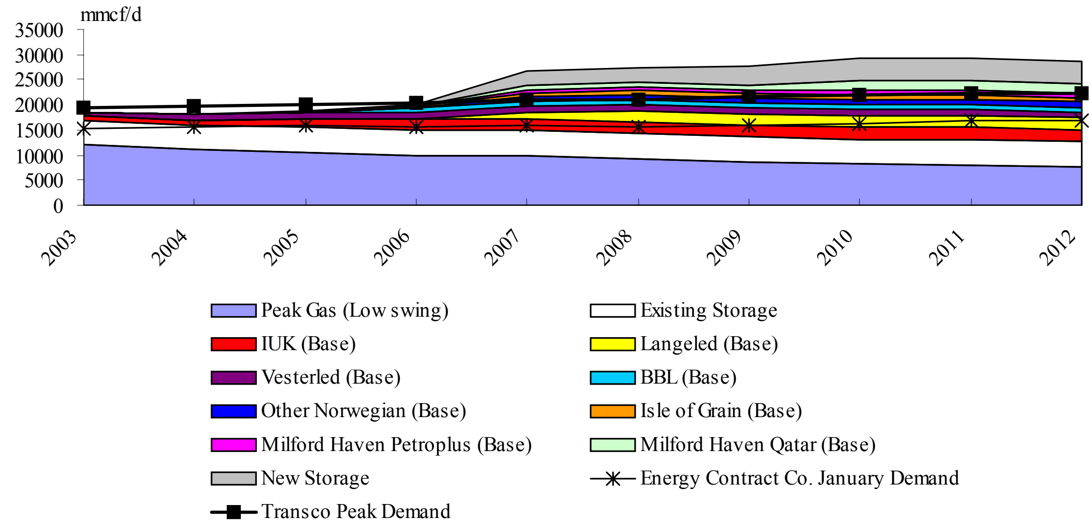
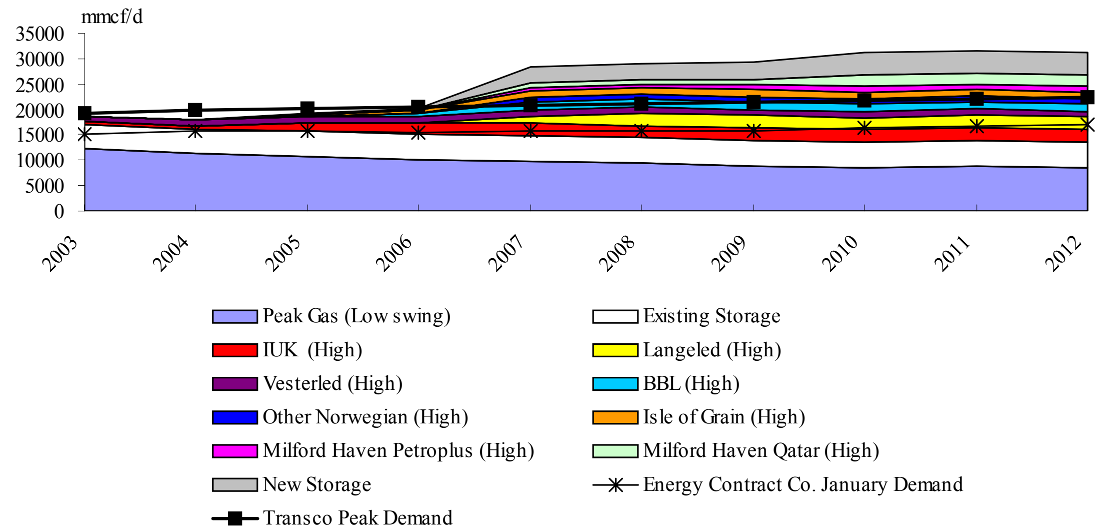


Figure 14
Potential Peak Supply/Demand, £25/bbl and 24p/therm (hurdle rate 10%)



expectations. Oil companies tend to take cautious views on this subject. Given this, it is not surprising that, in 2004, only a modest increase in exploration activity was experienced. Production continued to decline. If oil prices are expected to remain at levels of over $30 per barrel for some years (which forward prices and the pronouncements of analysts certainly indicate), more incremental projects and fields in the technical reserves category would pass conventional economic hurdles. For relatively short-lived incremental projects, and production from at least some part of the life of a new field, it is currently possible to contract to sell on the forward market at very high prices. There is thus an incentive to bring forward in time more projects. Further, the increased cash flows from current operations facilitate the financing of more projects.

On this basis, there could be some acceleration in development projects. On the other hand, however, there are physical constraints limiting the flexibility in the timing of projects. The current focus on reserves replacement by many oil companies could also mean that, given the relatively small size of many of the remaining prospects, additional investment is concentrated in other petroleum provinces where larger reserves are in prospect. In this context it is noteworthy that the mean size of field in the technical reserves category is only 20 mmboe and the most likely size considerably less (given the lognormal distribution). On a world basis these are quite low for investors with an international perspective. Hence the importance of the tax rate in maintaining the competitiveness of the UKCS.

So far as new exploration is concerned, there is evidence that the expected full-cycle returns are sensitive to oil- and gas-price behaviour. On the other hand, there is also evidence that the main determinants of the exploration and appraisal effort are more strongly correlated to geological prospectivity, including expected size of discovery and full-cycle costs, than to oil/gas prices.[6] The experience of the last few years is consistent with this view. On balance, the likelihood is that the major increase in prices will result in a moderate absolute increase in the exploration and development effort. In the present circumstances, even a modest acceleration in the development of new fields and incremental projects could bring a double benefit. They could help to prolong the lives of the existing infrastructure. Accelerated developments would also be likely to have a longer life because the supporting infrastructure would be available for a longer period. It is arguable that accelerating developments, and thus depletion rates, will increase the overall recovery factors because marginal projects proceed on the basis of infrastructure availability. If the infrastructure is decommissioned, some incremental projects may not be viable.

VIII. POLICY IMPLICATIONS

The analysis of this paper has pointed to the advantages of enhancing and accelerating the pace of new developments. This would be optimal in the sense that it is consistent with (i) minimizing the resource costs of extracting the oil and gas, and (ii) maximizing the ultimate recovery of hydrocarbons from the UKCS. Deferral of the decommissioning of platforms and other infrastructure is also accomplished by enhancement of the level of activity.

The analysis has indicated that security of gas supplies in the medium term, when the UK becomes a substantial net importer, should not be a significant problem. Reducing import dependence when the resource costs of domestic production are less than the import costs is clearly optimal. Oil and gas imports will become a major item in the UK balance of trade. This has deteriorated substantially in recent years, and further deterioration may start to cause problems.

From an overall energy-policy viewpoint, enhancing domestic production over the next few years enlarges the breathing space required to develop other (domestic) sources of energy, particularly for electricity generation. The continued availability of offshore infrastructure and producing facilities can also contribute to lower emissions in another way. Thus carbon dioxide (CO_2) from major sources of emissions such as power stations can be captured, transported out to the North Sea fields, and injected into the reservoirs for sequestration there and/or for use to enhance oil recovery. If this were achieved, conventional power stations could continue in operation with reduced emissions.

As discussed above, the government now has in place a number of licensing and regulatory measures designed to enhance activity. The fallow block/discovery initiative is now starting to bear worthwhile fruit. Some existing players and potential new entrants express concern that the assets being made available are not of great interest, and that many more blocks which existing licensees are allowed to keep are not being worked very fully, although they have passed the DTI's scrutiny. What constitutes an appropriate minimum work programme must involve some judgement, but it is arguable that it should be seen in the context of the need to display good stewardship of the acreage awarded. It is arguable that this concept should be extended to currently producing assets as well as fallow ones.

Enhancing the pace of depletion is generally consistent with past UK policies, particularly for oil. Despite the plethora of powers taken by the government in the 1970s to moderate depletion rates, the maximization of short-term revenues was generally given top priority. The Varley assurances ensured

[6] For a fuller discussion of this subject see Kemp and Kasim (2003).

that no restrictions occurred in the 1970s, principally for macroeconomic reasons relating to the balance of payments. Gas developments were delayed in the 1970s, but this was not due to a systematic depletion policy but as a consequence of the low prices offered by British Gas to producers and the very large Frigg contract. In the early 1980s, when the Varley assurances would have permitted field development delays and production cuts, the maximization of short-tern tax revenues for purposes of reducing the PSBR was the decisive influence. The introduction of SPD was the key instrument to achieve higher near-term revenues. The major reductions in taxation in 1983 were geared towards enhancing new investment and production and maintained short-term tax revenues reasonably effectively.

Looking ahead it is possible to construct an argument for slowing down depletion rates. Thus, if longer-term future oil and gas supplies are to become more expensive and less secure, husbanding the remaining reserves might constitute a worthwhile national investment. Currently, there is a vociferous group which argues that peak world oil production is nigh, to be followed by decreases at a fairly sharp pace.[7] The conventional view is that world oil production can increase to 2030 or so.[8] With respect to gas this study has shown clearly that very substantial imports from diversified sources are in prospect in the medium term. For the longer term, however, further contracts become necessary as supplies from the ones in prospect will start falling at around 2015. It is thus possible to construct a scenario whereby, on energy policy grounds alone, slower depletion could be justified. The costs and risks of such a policy are substantial, however, and pursuing current policies may produce higher overall economic recovery.

The 2004 Infrastructure Code of Practice has the potential substantially to increase the efficiency of the operation of the offshore infrastructure market. Its success depends on goodwill being exhibited by the parties involved and, in the event that they fail to agree, the skill of the DTI in the practical determination of market rates for tariffs taking into account the costs and risks involved. The alternative of direct regulation of tariffs by the state was chosen in Norway. This approach can always be held in reserve if the new scheme does not operate efficiently.

There is widespread agreement that activity can be boosted by the ready trading of assets. Every investor has his own perceived range of worldwide opportunities and priorities, and also his own interpretation of the remaining prospects in the UKCS. The inevitable differences can readily lead to misalignment of partner interests within a licence group. This can hold back developments—the partner-drag phenomenon. Potential new entrants are, of course, anxious to secure acquisitions in a timely manner. There are several perceived potential or real barriers to asset transactions. Those relating to the third party use of infrastructure and the fallow block/discovery phenomenon have already been discussed. There is a market in mature fields with some licensees (often operators) willing to sell and others willing to buy. A problem can arise with respect to financial liability for decommissioning. There is joint and several liability for this in the UK. This was imposed by the government in order to protect the state's interests against a default. The effect is to encourage licensees to take steps to protect themselves against the possibility of default by their partners. On the occasion of a proposed asset transfer, the DTI decides whether in its opinion the prospective new licence group can satisfactorily meet the decommissioning obligation. If there is a concern, the prospective group has to establish a financial security agreement (FSA) to which the DTI can become a party. A key issue is the security required for an acceptable FSA. This should normally sum to at least 100 per cent of the likely cost. Acceptable security includes cash, letters of credit from a reputable bank, and performance bonds from such a bank. These forms of security can be quite expensive and, particularly for smaller companies, can have a material effect on their borrowing capacity. For these parent company guarantees may not be acceptable.

In the early 1990s the concept of a Decommissioning Fund was discussed between the government and the industry. Under this scheme, contributions would

[7] See Campbell (2003) for statements of recent views and estimates.

[8] See for example, IEA (2004).

be made into an alienated fund during the life of a field by all licensees. These would sum to the amount required for decommissioning when that event arrived. The concept produces financial security for all parties. The stumbling block was the refusal of the government to permit the provisions to be tax deductible on the grounds that (i) tax relief was generally not given for an expenditure until it was actually incurred, and (ii) it would encourage overprovision by investors. The scheme is now employed in a number of countries including the Netherlands, Angola, and Azerbaijan, where steps are taken to ensure that abuse does not occur, for example by subjecting overprovisions fully to tax, and by requiring independent estimates of the likely costs of decommissioning during the part of field life when provisions are being made. Another possibility is insurance-based schemes. These have recently been promoted, but again the stumbling block is tax relief under the schemes. Given the importance of incremental recovery from mature fields and the willingness of parties to trade these assets, there is a sound case for the provision of tax relief for such schemes, which offer to provide security for the abandonment liability at relatively low cost. There is a potentially significant positive effect on the number of desirable transactions and subsequent extra recovery from the fields.

The cash-flow taxation system generally applicable to the UKCS has highly attractive features in the context of encouraging investment. For existing players, all risks are immediately shared to the extent of 40 per cent for exploration and new developments, and on older PRT-paying fields to the extent of 70 per cent for incremental projects. The downside risks are reduced and the upside returns shared to the extent of the tax rate. While the internal rates of return remain at their pre-tax levels, the net present values at typical discount rates are reduced. In the context of small UK fields and capital-rationing on a worldwide basis, this may reduce the attractiveness of some investments. Judgement on the appropriate tax rate is always required and should be seen in the context of capital rationing and international opportunities. For new players for whom tax relief is not available, the current interest rate on exploration and appraisal cost allowances carried forward (6 per cent) does not produce a level playing field. There is a case for increasing it to reflect better the cost of capital. The cost to government would be negligible. If the exploration were unsuccessful, the new investor bears the full cost. Relief for the expenditures would only become available against future discoveries. A more radical alternative has just been introduced in Norway. This involves the cash reimbursement by the government of a share of the exploration costs at the overall marginal tax rate for investors who do not have tax cover.

The various initiatives taken recently by the DTI are generally commendable. If they are to produce substantial benefits they need to be pursued with vigour. Slow implementation and a slow response from the industry would mean that the production profile would fall quite briskly over the next few years. The attainment of the production levels indicated in Figure 6 depends on a vigorous response to rigorously implemented initiatives.

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