

# **How can the North Sea Oil and Gas Industry be Revitalised?**

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## **Abstract:**

The UK offshore oil and gas industry exhibits all the signs of a mature petroleum province, with long term declining production, exploration, and size of new discoveries, plus very high unit costs. These symptoms were disguised in the period 2009-2014 due to the high oil prices and an investment boom. But the remaining physical potential is substantial. Tax concessions can have a positive effect on incentives. The overall impact can be quite complex. Further cost reductions and technological progress are both necessary to enhance investment in the many undeveloped discoveries. The life of the province could then extend beyond 2050.

## **1. Context**

Activity in the UK Continental Shelf is currently exhibiting the signs of advancing maturity. Thus production peaked at 4.55 mmboe/d in 1999 and declined briskly thereafter despite the rising oil prices to 1.49 mmboe/d in 2014. However, it has increased over the last year to reach 1.64 mmboe/d. The exploration effort has also fallen dramatically this century even before the collapse in the oil price. Only 14 exploration wells were drilled in 2014 and 13 in 2015. By comparison 75 were drilled in 1986, 74 in 1987 and 93 in 1988. These were all years following a price collapse. The peak years for exploration effort were in 1990 when 157 wells were drilled and in 1991 when 103 were drilled, though it should be recognised that there were special circumstances in these years, namely the execution of work programme promises made by BP relating to its takeover bid for Britoil.

Another manifestation of the maturity of the province is the decline in the average size of discovery and development. Currently the average size of discovery is around 20 mmboe. The most likely size is less than this given the lognormal distribution of sizes of discoveries. In the first half of the 1970's the average exceeded 320 mmboe.

The number of significant discoveries has also fallen significantly in recent years. Using the DECC/OGA definition they numbered 4 in 2013 and 1 in 2014. By comparison they were 14 in 1986, and 20 in 1987. Both were years of low oil prices. There were 79 in 1989.

Another indicator of maturity is the number of field development approvals. There were only 8 in 2014 and 5 in 2015, far below the average for the long period 1970 – 2015.

Another feature consistent with maturity is the steep rise in unit costs. Field investment costs averaged \$20.40 per boe in 2014 and \$17.30 per boe in 2015. Unit operating costs averaged \$29.30 in 2014 and \$20.95 in 2015<sup>1</sup>. These figures relate to a very wide range. Thus on very mature fields where production is now very low from large, old platforms operating costs per barrel can be very high indeed. The general dramatic degree of cost inflation in the industry across the world, on top of the ageing platform structures, along with declining production, have produced these extremely high average figures.

## **2. Interpretation of Recent Experience**

The above observations appear straightforward but further analysis is needed to enhance understanding of the recent behaviour of the sector. The subject of production decline rates in the oil and gas sector has probably received insufficient attention. There is the frequently accepted view that field decline rates are exponential in character. Kemp and Kasim (2005) found that the logistic curve produced the best fit across fields for the UKCS in the period up to the early years of this century, with incremental investments moderating the rates of decrease in the more mature years of field life. Since that study was undertaken many further new field developments have occurred. Reflecting the maturity of the province they are generally much smaller in terms of reserves. In addition their decline rates are noticeably faster than those exhibited by the earlier generation of generally much larger fields.

In Charts 1 and 2 the behaviour of oil and gas depletion by field is shown, stratified according to the vintage of first production. It is clearly seen that the decline rates in fields of more recent vintage are significantly faster than those of earlier ones. This has contributed to the brisk rate of overall decline in the UKCS

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<sup>1</sup> See OGUK (2016) Activity Survey, p.58

this century. It is likely that the rate of decline from the newer generation of generally smaller fields is inherently faster than from the larger older ones. But aggregate production is also a function of other factors. These include the numbers of new fields coming on stream and the production efficiency achieved across all fields. Production efficiency is the ratio of actual production to that at the maximum efficient rate. DECC has calculated that the ratio has fallen from 80% in 2004 to 60% in 2012. This has made a significant contribution to the fast decline rate. A main cause has been the substantial unplanned shutdowns relating to technical problems on the producing facilities. The increased interdependence of fields with the infrastructure of processing hubs and pipelines has sometimes caused major knock-on effects. When a major processing hub platform has to shut down the fields which feed into it will also have to shut down.

Chart 1

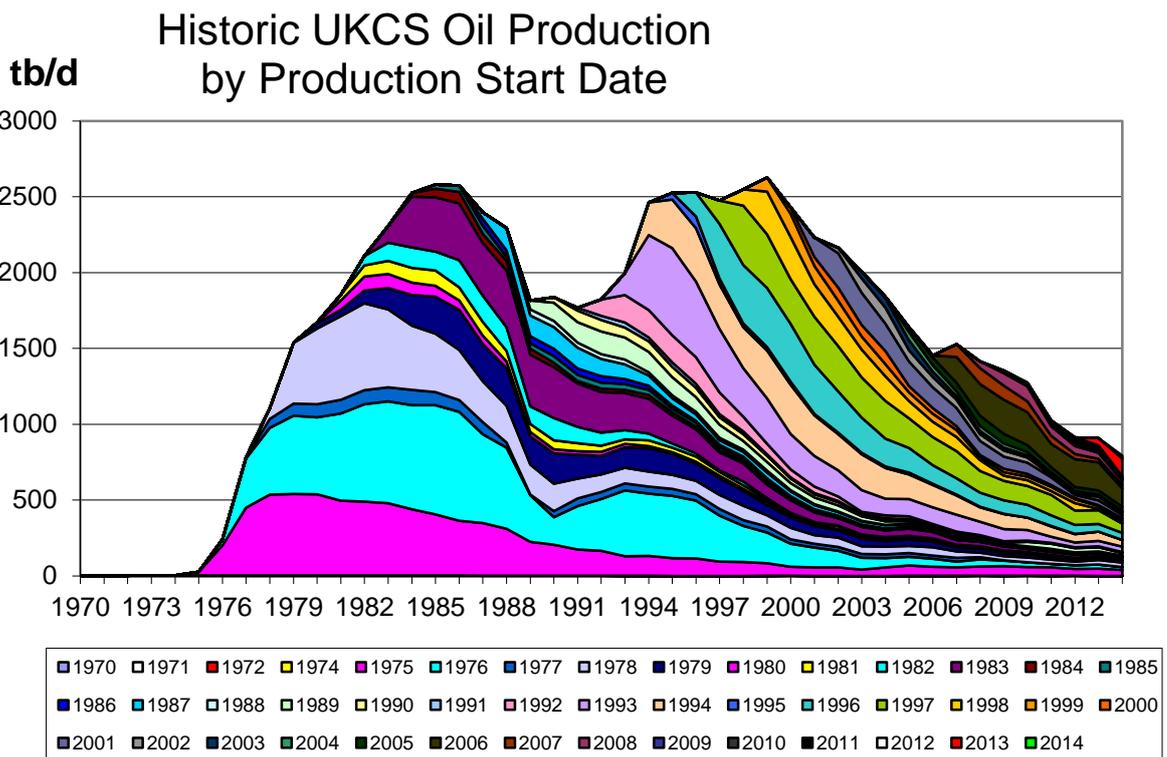
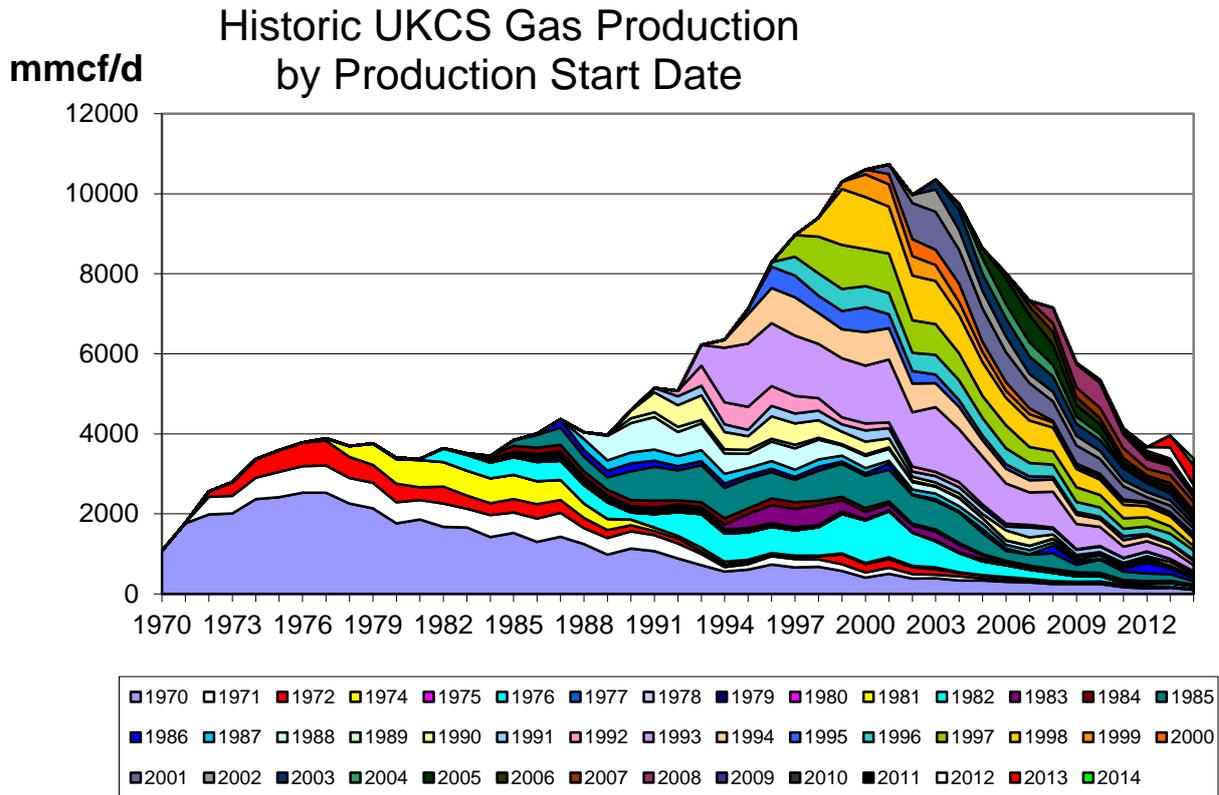


Chart 2

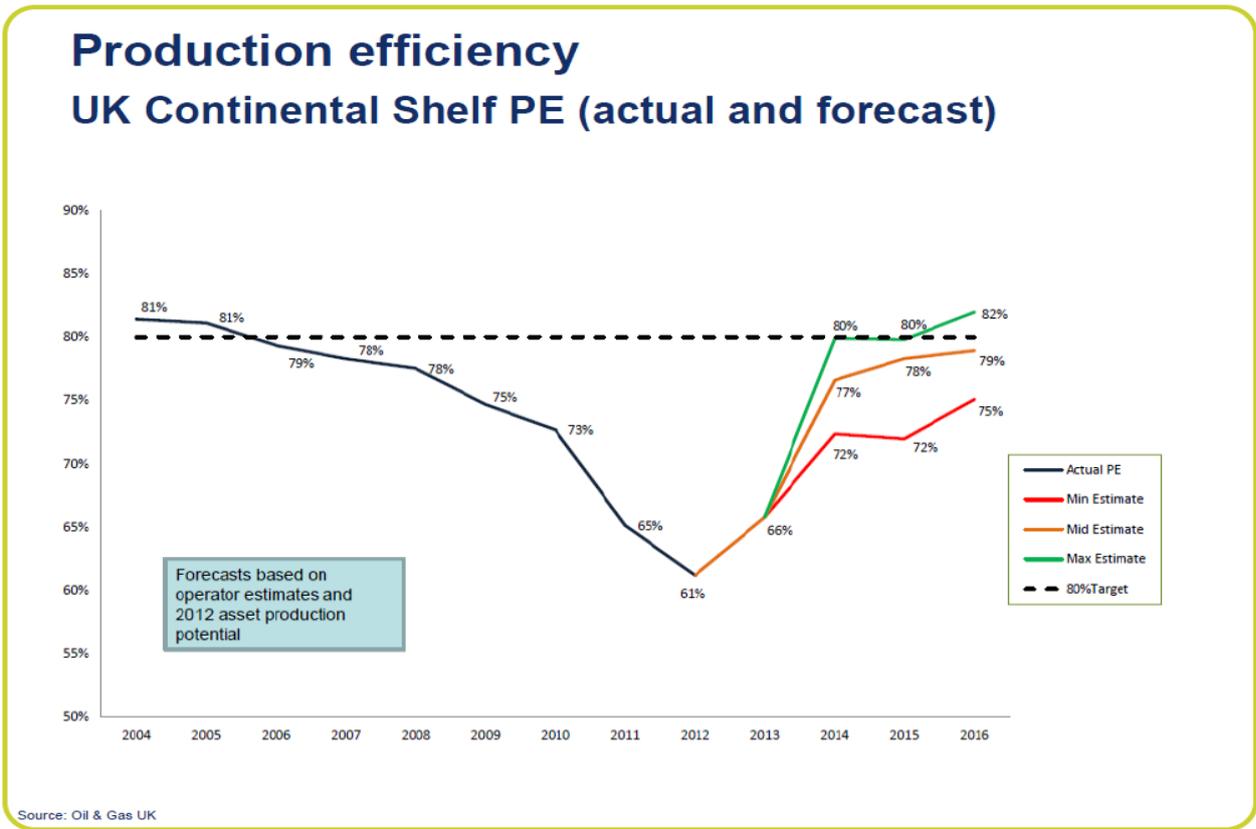


Virtually all production projections made at the beginning of this century have turned out to be substantially over optimistic. For example, the joint industry and UK Government Task Force set up in 1999 to assess the future prospects of the sector and make recommendations produced a production target for 2010 of 3 mmb/d. The outcome was around 2.4 mmb/d.

The Task Force of 1999, the Wood Review of 2013 – 14, and the follow-up work by the industry and the OGA have all diagnosed the issue very effectively. Progress has been made. As a notable example production efficiency has increased markedly and is currently estimated by OGA to be around 70%. This has contributed significantly to the recent reversal of production decline and its sustained increase for a period of several months.

The industry group which examined the subject of production efficiency in depth has expressed confidence that the improvement can continue over the next several years. Their estimates are shown in Chart 3 below.

Chart 3



However, the increases in production and its efficiency which have taken place, may reflect other issues. The HSE has noted that the increased production over the recent past has coincided with a significant increase in the backlog of safety critical maintenance. This may open the prospect of future production problems. The postponement of maintenance work can foster short-term production gains but later problems. This issue remains to be fully understood.

### 3. Economic Modelling Procedure

The present authors have built a large financial simulation model, incorporating the Monte Carlo technique for risk assessment, to analyse the prospects for exploration, development and production. To examine possible aggregate activity the modelling has been conducted with a large field database. This incorporates key individual field data on historic production, investment costs (drilling and facilities), operating costs (tariffs separately), and decommissioning costs, plus estimates of future values under the same headings relating to sanctioned fields, unsanctioned probable and possible fields, and incremental projects. There are over 370 sanctioned fields, over 170 incremental projects and over 40 fields in the probable or possible categories. There is an additional

database, categorised as technical reserves, containing over 250 fields where there are no current development plans. Some were previously in the probable or possible categories.

Future exploration activity and its fruits were also modelled. Historic exploration success rates over the past decade were calculated as were appraisal successes. This was all done separately for each main region of the UKCS, namely Southern North Sea (SNS), Central North Sea/ Moray Firth (CNS/MF), Northern North Sea (NNS), West of Shetlands (WoS), and Irish Sea (IS). The success rates, sizes of discoveries, types of resource (oil, gas or condensate), exploration and development costs for the discoveries all vary according to geographic region. For fuller details see Kemp and Stephen (2015(b)).

Using the above information, the Monte Carlo technique was employed to project discoveries in each of the 5 regions to 2045. It was assumed that the distribution of field sizes was lognormal following historic evidence. The SD was set at 50% of the mean value which was assumed to decline in accordance with historic evidence. The Monte Carlo technique was also employed to calculate field development costs for new discoveries. For each region the average development cost per boe sanctioned in recent years, but prior to the cost reductions was calculated. The SD was set at 20% of the mean value in the Monte Carlo simulations.

Investment hurdles reflecting the capital rationing experienced in recent years were employed to determine whether a new field or incremental project were developed or not. Two cases were modelled. The first is where the ratio of post-tax NPV@10%/pre-tax I@10% > 0.3. The second is where the ratio exceeds 0.5. This latter may be described as a situation of very serious capital rationing. It should be noted that use of NPV/I > 0.3 as the hurdle often excludes projects where the NPV@10% is clearly positive.

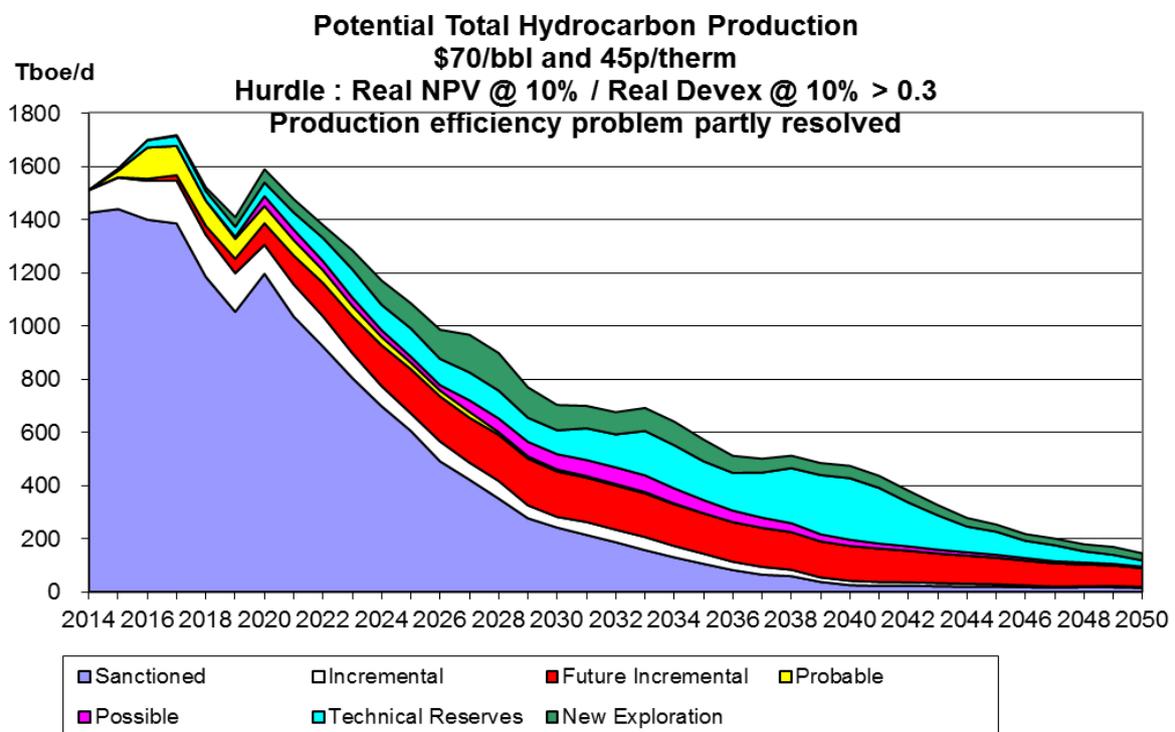
To facilitate understanding of the long term prospects the modelling was initially undertaken for conditions before the oil price collapse and cost reductions.

#### **4. Results for Long Term Prospects before the Oil Price Collapse**

Using the case of a conservative screening oil price of \$70 per barrel and 45 pence for gas in real terms, the production prospects with investment hurdles of NPV/I > 0.3 and 0.5 are shown in Charts 4 and 5 on the assumption that the production

efficiency problem is partially resolved. It is seen that there is a worthwhile short-term upturn followed by a long term decline at a fairly brisk pace. Over the period 2014 – 2050 cumulative production is 11 bnboe with the NPV/I hurdle of 0.3 and 9.5 bnboe when it is > 0.5. The field expenditures with the lower hurdle rate are shown in Chart 6. A key feature is the sharp fall in field investment over the next few years. Over the period to 2050 cumulative field investment is £81.4 bn., cumulative operating costs £135 bn. and cumulative decommissioning costs £41.8 bn., all at 2014 prices<sup>2</sup>.

Chart 4



<sup>2</sup> Another simulation was undertaken with a real oil price of \$90 and gas price of 58 pence. With an investment hurdle of NPV/I > 0.3 over the period to 2050 cumulative production was found to be in the range 14-15 bnboe depending on the extent of the improvement in production efficiency. When the investment hurdle was NPV/I > 0.5 cumulative production was in the range 11.6-12.6 bnboe. Field investment was very much higher with a cumulative total of £122 bn.

Chart 5

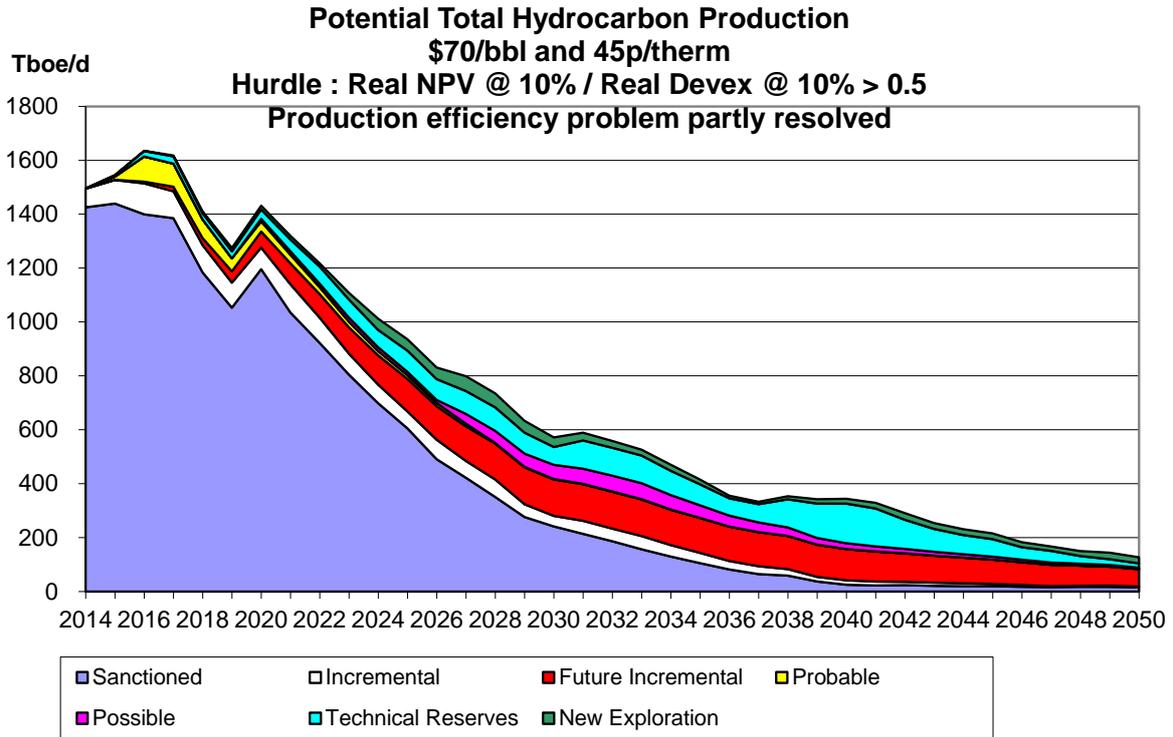
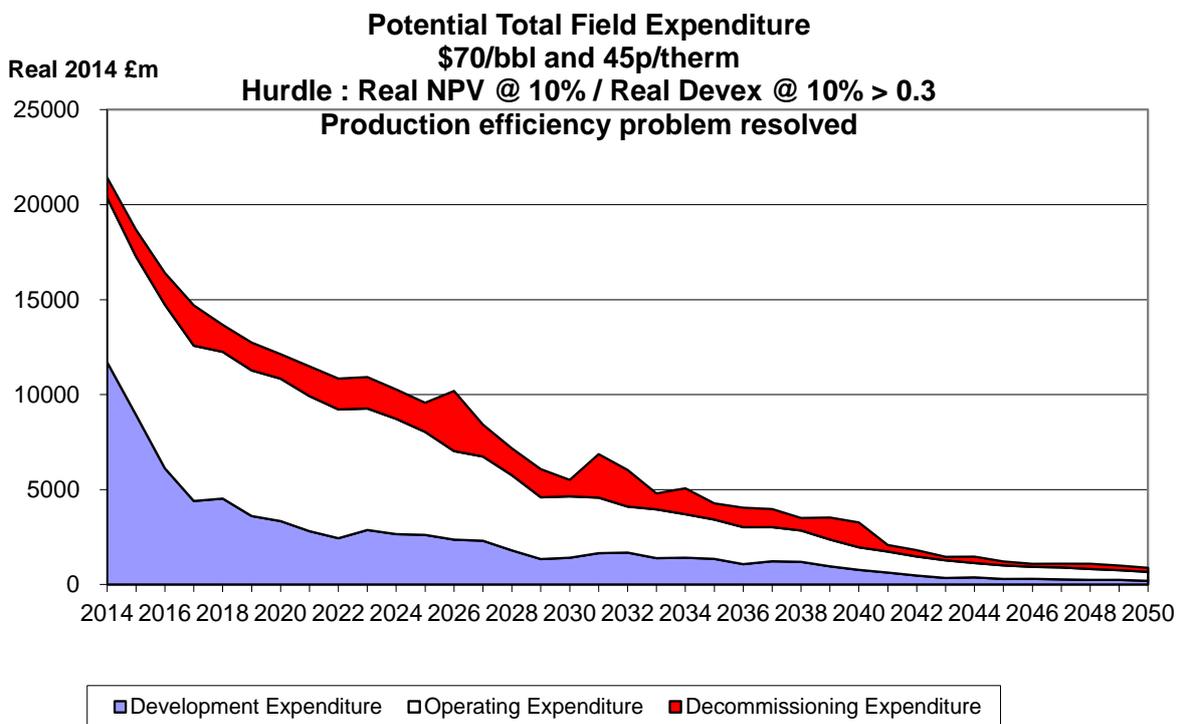


Chart 6



Further modelling was undertaken to assess the effects of cost reductions on long term activity levels. Two key effects were identified. The first was the impact on the costs of new projects and ongoing activities which in any case would have continued without the cost reductions. This effect applies both to new investment projects and to ongoing operations in existing producing fields. From the viewpoint of the supply chain this is a negative effect. The second effect relates to extra activity induced by the cost reductions. This refers to new field developments in particular. The induced effects relate to the extra investment, operating and decommissioning costs and production. These are the positive effects with respect to activity.

A case of 15% reduction in all costs was modelled. Key results are shown in Charts 7, 8 and 9 respectively for the changes in production, development expenditures, and operating expenditures under the \$70, 45 pence price scenario. Over the period to 2050 the induced extra cumulative production is 2.9 bnboe. This is a major enhancement over the 11-12 bnboe in the absence of the cost reductions. The extra cumulative field investment to 2050 is £22 bn. at 2014 prices. It is noticeable from Chart 8 that a major part of the increase comes in the relatively near future. Over the period to 2050 there is a net increase in field operating expenditures of £23.4 bn. at 2014 prices. It is seen from Chart 9 that there is a major decrease over the next few years. The operating cost reductions apply to all the existing producing fields. However, over the longer term the positive effects of the expenditures on new fields outweigh the reductions on the existing ones. Over the whole period there is also a net increase in expenditure on decommissioning of £2.8 bn., reflecting the net gains from the induced field developments.

Chart 7

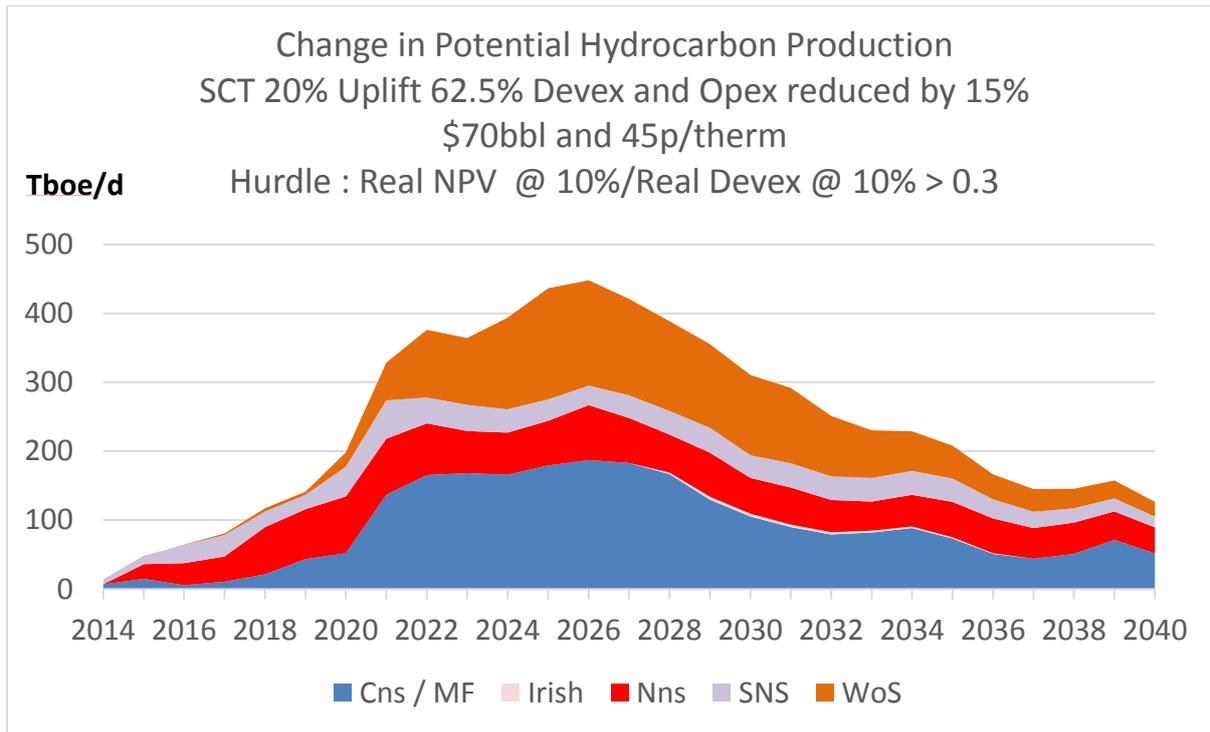


Chart 8

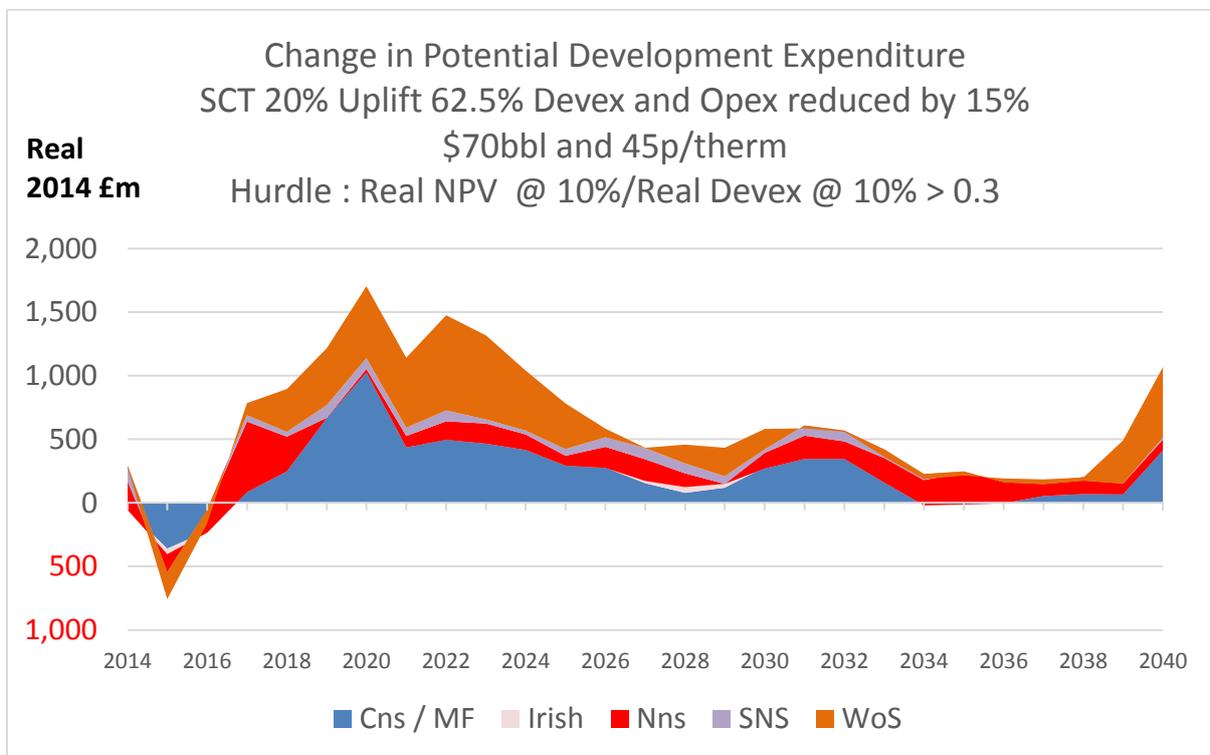
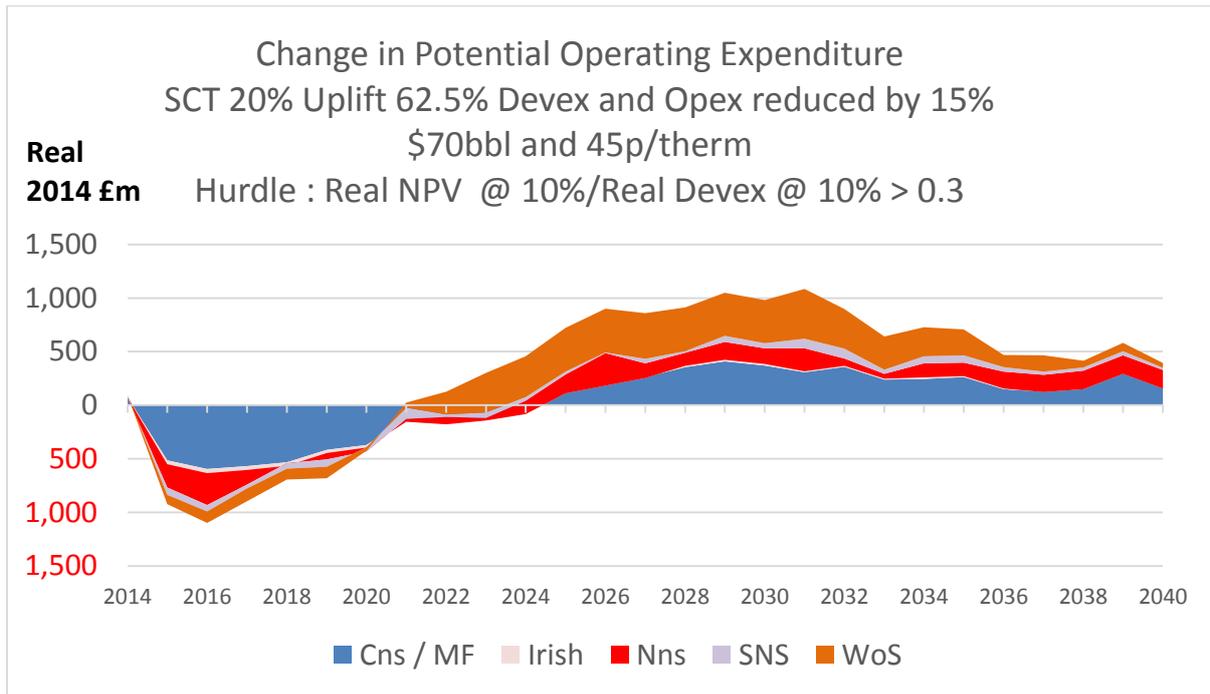


Chart 9



It is useful to compare these results with the latest estimates of the remaining potential produced by the OGA. These are shown in Table 1.

Table 1  
**UK Oil and Gas Reserves and Resources (bnboe)**

	Low	Central	High
Reserves	3.9	6.3	8.2
Contingent Resources	0.6	1.4	2.6
PAR	1.5	3.6	7.2
Undiscovered Resources (Risked)	1.9	6.0	9.2

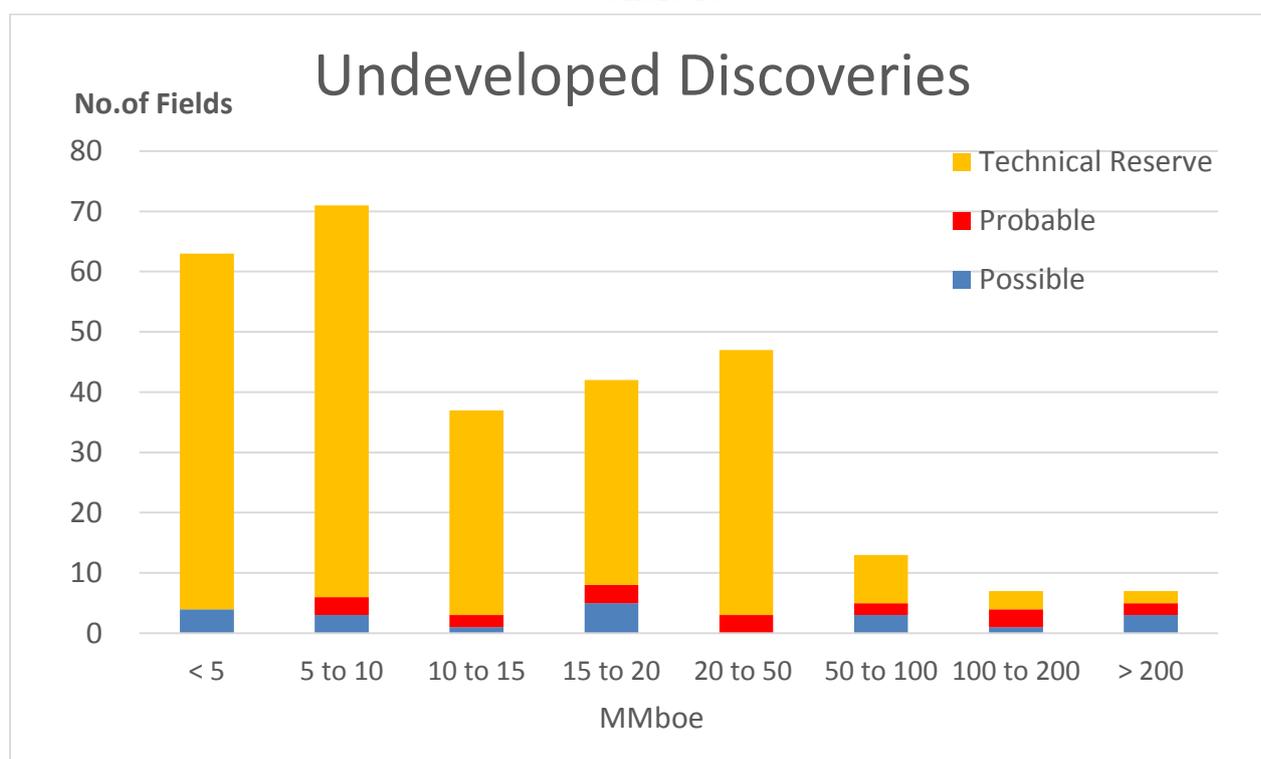
Source: OGA, July 2016

No dates or oil and gas prices are attached to the recovery of the resources, but the long run estimates of the present authors are generally consistent with the remaining potential as seen by the OGA. Currently oil and gas prices are well below the levels employed in the modelling (though not out of line with long run estimates produced by other bodies such as the IEA and US Department of Energy). Also, much more ambitious cost reductions are planned by the industry which would increase both the near term negative effects on the supply chain and the size of the positive longer term induced effects. The effects of lower prices are discussed in detail in Sections 6 and 7 below.

## 5. Maturity and Size Distribution of Undeveloped Discoveries

In the results of the modelling shown in Section 4 many existing discoveries were either uneconomic pre-tax or uncommercial after tax. A feature of a mature petroleum province is the decrease in the most likely sizes of discovery. There are diminishing returns to the exploration effort. The distribution of sizes of current undeveloped discoveries in the present authors' database is shown in Chart 10. Altogether there are 7.375 bnboe in 287 fields. The average is 25.7 mmboe, but the distribution is highly skewed. Thus there are 63 fields where the potentially recoverable resources are in reservoirs of less than 5 mmboe, and there are 71 fields where the resources are in reservoirs in the 5-10 mmboe range. There are 37 fields where the reserves are in reservoirs in the 10-15 mmboe range and there are 42 fields where the reserves are in reservoirs in the 15-20 mmboe range. Thus 1.175 bnboe are in fields where the reserves are less than 15 mmboe and 1.9 mmboe are in fields where the reserves are less than 20 mmboe. A key current challenge is how to facilitate the development of typical fields in the context of current oil and gas prices and costs. Several issues rise here including further cost reductions, tax incentives, technological progress, and more effective collaboration such as with respect to access to infrastructure. There has been much debate regarding tax incentives and these are discussed in Section 6 below.

Chart 10



## **6. Tax Incentives and New Field Developments**

New field developments are subject to Ring Fence Corporation Tax (CT). The rate has been 30% for some years. Allowances for exploration, appraisal and development are all on 100% first year basis. Supplementary Charge (SC) also applies to new field developments. The rate has varied upwards and downwards since its introduction in 2002. In 2015 it was reduced from 32% to 20% and in 2016 it was reduced to 10%. Allowances for exploration, appraisal and development are all on 100% first year basis. In addition, there is an Investment Allowance (IA) equal to 62.5% of field investment. Loan interest is not deductible. The ring fence applies to all activities in the UKCS. Thus a licensee can set the capital allowances relating to a new field development against income received from other fields, and, given that allowances are on 100% first year basis, he receives speedy tax relief. This depicts the situation of an investor with tax shelter and is here termed an ongoing investor. In current circumstances where production losses are not uncommon many investors do not have this tax shelter. In that event the investor in a new field can benefit from the Ring Fence Expenditure Supplement (RFES) which means that he can carry forward his allowances for investment and operating costs at 10% compound interest for up to 10 years starting from the initial claim period. In this paper this is termed a project investor. In the modelling the positions of both investors are analysed.

The modelling was undertaken on a set of 18 representative oil and gas fields. They are representative in terms of (a) size, and (b) costs after substantial cost reductions reflecting the position at the summer of 2016. They are based on approved developments in recent years in the 4 main regions of the UKCS. The detailed modelling for a cross section of these fields is discussed here. Full details of all the 18 fields are in Kemp and Stephen (2016).

To highlight the complex issues involved in tax design and effects on investment several tax schemes were modelled. These are (1) the scheme of 2015 with CT at 30% and SC at 20%, (2) the scheme of 2016 with CT at 30% and SC at 10%, (3) CT at 20% and SC at 20%, (4) CT at 30% and SC at 0%, and (5) CT at 20% and SC at 0%. The IA for SC at 62.5% is incorporated in all of the schemes.

To understand the effect of the tax system on investment incentives it is necessary to distinguish the effects of (a) the tax on income and (b) the relief for the

investment expenditure. The 2 effects are shown in Table 2 for the 2015 and 2016 systems.

Table 2

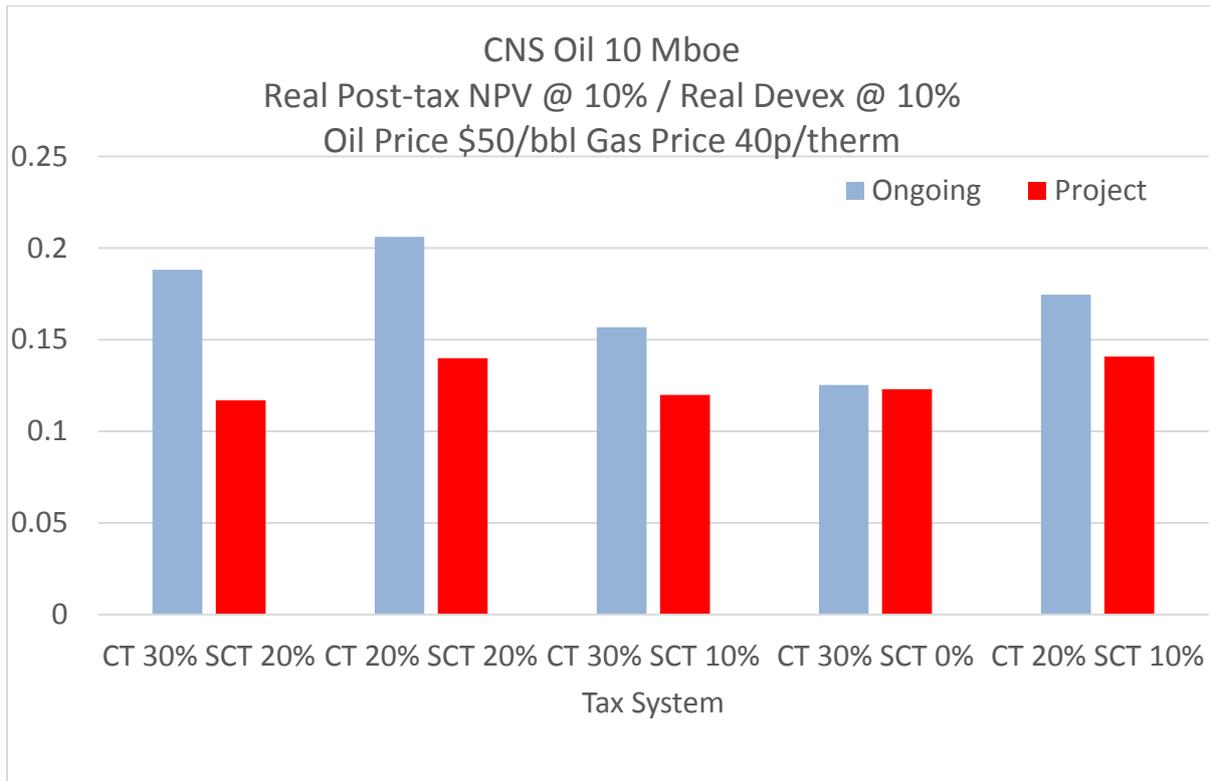
**Rates of Tax on Income and Rates of Relief for Investment  
in the UKCS**

	Tax on Income	Relief for Investment
a) 2015 terms	$0.3+0.2 = 0.5$	$0.3+0.2+0.625(0.2) = 0.625$
b) 2016 terms	$0.3+0.1 = 0.4$	$0.3+0.1+0.625(0.1) = 0.4625$

To reflect the current problem of serious capital rationing the results discussed here highlight the post-tax NPV@10% / pre-tax I@10% ratios. These are widely employed in the industry. Historically a threshold of NPV/I > 0.3 was considered to be widely acceptable, but in current circumstances OGUK (2016) suggests that a threshold of 0.5 may be appropriate.

The economic modelling found that at oil prices of \$30 and \$40 the representative fields were generally uneconomic before tax. Thus the modelling presented here concentrates on price scenarios of (1) \$50 per barrel and 40 pence per therm, both in real terms, and (b) \$60 and 45 pence. Not all the projects are viable before tax even at \$60 price. Those selected for detailed analysis here do not include the most uneconomic ones.

Chart 11



The pre-tax returns on a representative oil field of c. 10 mmbbls in the CNS under the various tax schemes at the \$50 price case are shown in Chart 11 in terms of NPV/I ratios. There are several noteworthy features. The project is unlikely to be acceptable to investors under all the tax arrangements. Under the 2015 system the returns to the ongoing investor are much higher than those for the project investor. The former obtains early tax relief against income from other fields. He is able to utilise his IA for the SC. On the other hand, the project investor carries forward his allowances with interest against the income from the new field. But he has insufficient field income against which to offset all his allowances. He cannot fully utilise the IA for SC.

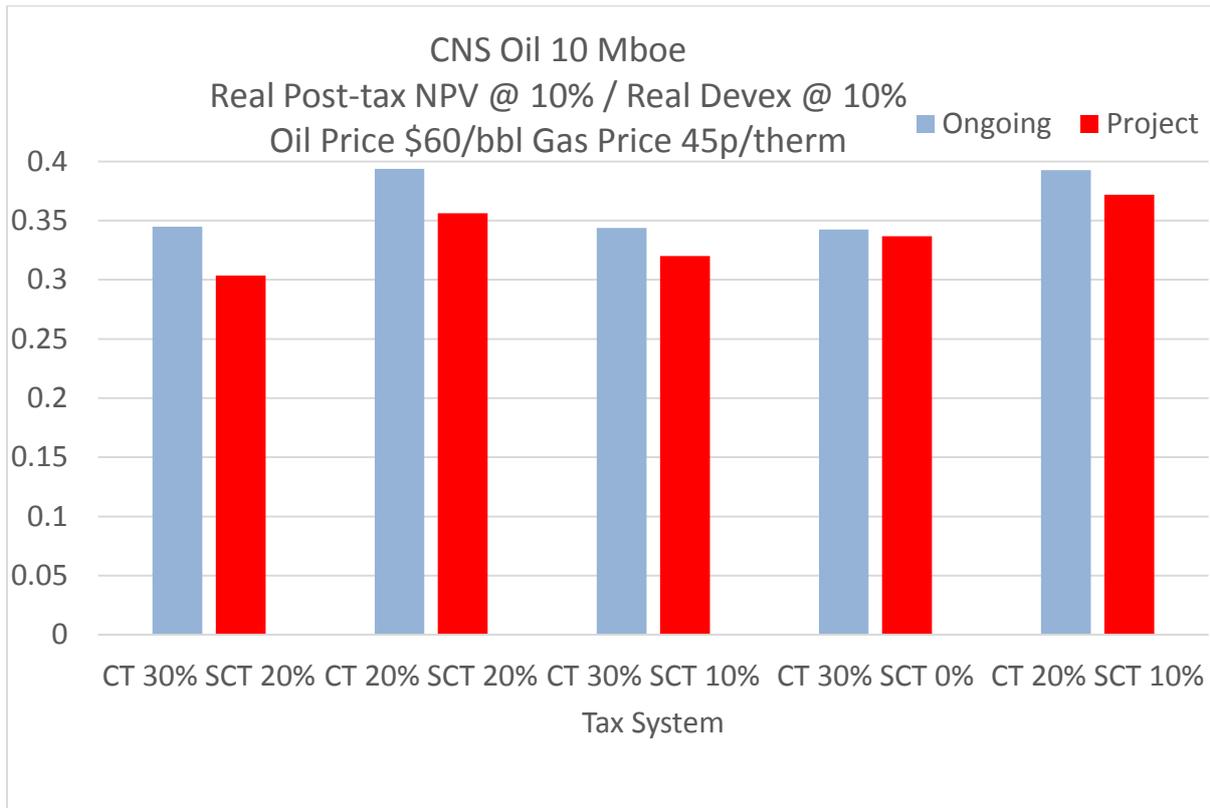
It is noteworthy that the returns to the ongoing investor are lower under the 2016 system compared to the 2015 one, despite the fact that the overall tax rate is reduced from 50% to 40%. This results because the reduction in the value of the investment relief from 62.5% to 46.25% is worth more than the reduction in the tax rate on income from the field from 50% to 40%. On the other hand, the returns to the project investor under the 2016 system are close to those under the 2015 terms. They remain below those for the ongoing investor because the latter still

has the advantage of early relief for his initial investment and fuller utilisation of the IA for the SC.

It is noteworthy from Chart 11 that the post-tax returns are higher with a system of CT at 20% and SC at 20% compared to both the 2016 system and the 2015 ones. The effective rates of relief for investment are higher with CT at 20% and SC at 20%. A given reduction in the rate of CT is more potent than the same reduction in the rate of SC because there is less loss of investment relief.

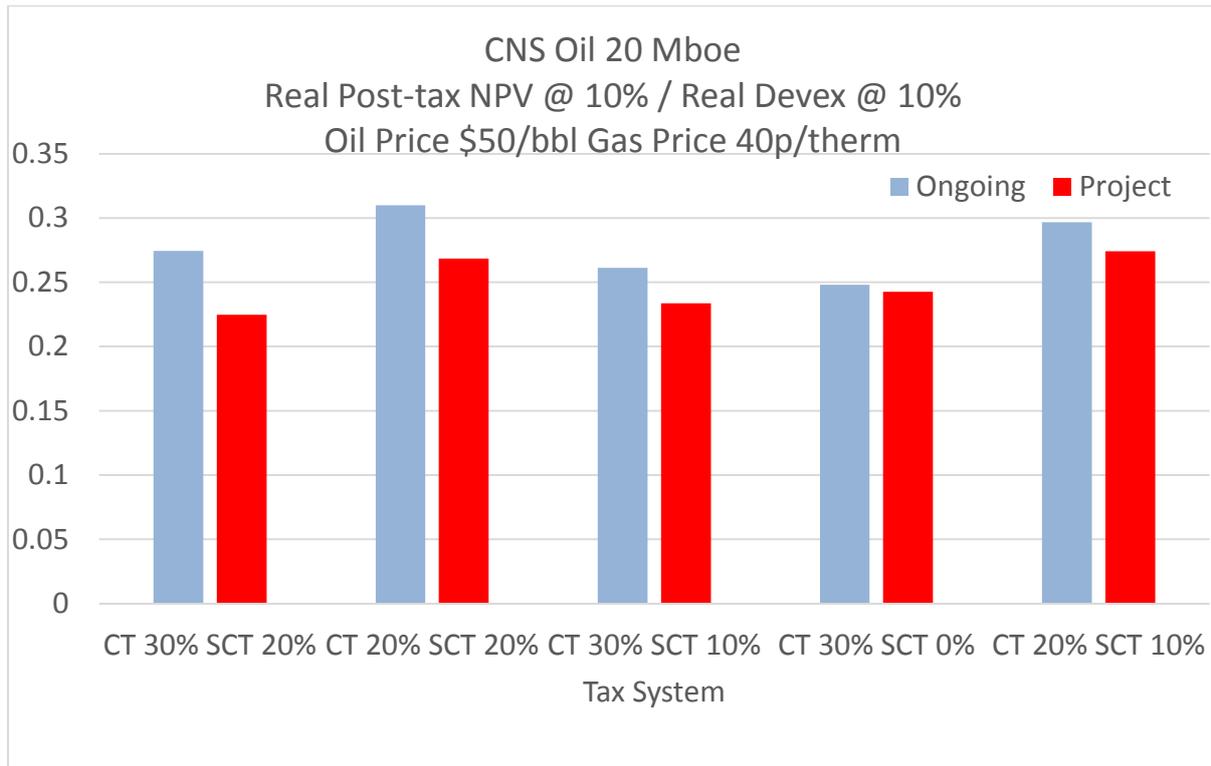
The returns to investors on the 10 mmbbls field are shown in Chart 12 under the \$60 price scenario. To set the context the pre-tax NPV/I ratio is 0.5. Under the 2015 tax system the NPV/I ratio for the ongoing investor is nearly 0.35 and for the project investor 0.3. The difference in returns is much less compared to the \$50 price case. The larger revenues permit the project investor to more fully utilise his allowances including the IA for SC. Under the 2016 tax terms there is little difference in the NPV/I ratio for the ongoing investor compared to the 2015 terms. The larger revenues permit more benefits to be received from the reduced tax rate on income. With the \$60 price the returns to the project investor under the 2016 tax terms are closer to those for the ongoing investor and higher than the return under the 2015 terms. The larger income permits a fuller utilisation of the allowances and some benefit from the reduced tax on income. The investment project is clearly acceptable if the hurdle is  $NPV/I > 0.3$ . It is also noteworthy that a higher ratio is still achieved with a tax scheme of CT at 20% and SC at 20% because of the stronger relief for the investment. At the \$60 price it is also noteworthy that the highest return for the project investor is with CT at 20% and SC at 10%. The lower rate of tax on income is worth more in this case.

Chart 12



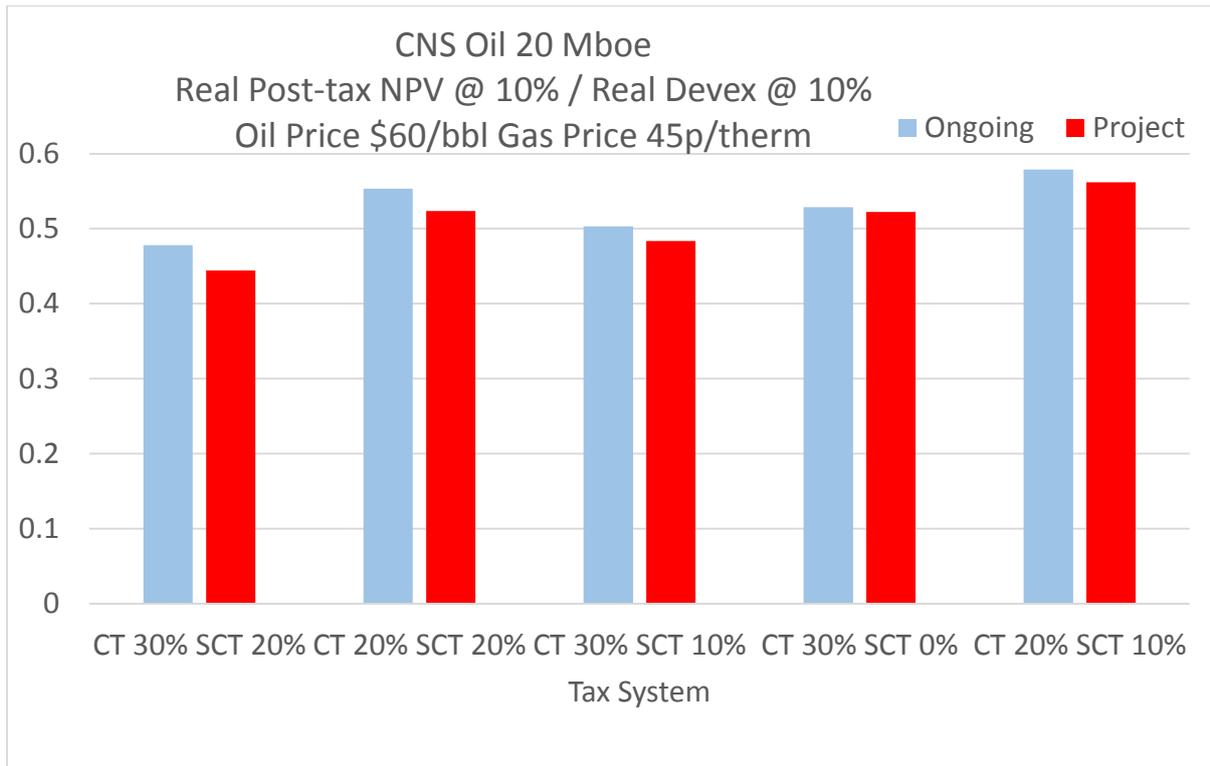
In Chart 13 the post-tax returns to investment in a representative oil field of 20 mmbbls in the CNS are shown under the \$50 price. The context is that the pre-tax NPV/I ratio is 0.35. Under the 2015 tax scheme the project is unlikely to be commercially viable to an investor in a full tax-paying position and less likely to be acceptable to a project investor. The difference in returns between the two investors is less on this field compared to the 10 mmbbls one because the larger revenues permit more effective utilisation of allowances including the IA by the project investor. The 2016 tax terms reduce the returns to the full tax-paying investor because the reduction in the value of the relief for investment still exceeds the benefit of the lower tax rate on income. The position of the project investor is slightly improved compared to the 2015 tax terms but the project remains sub-marginal. It is seen from Chart 13 that reducing the CT rate enhances returns but the project remains very marginal.

Chart 13



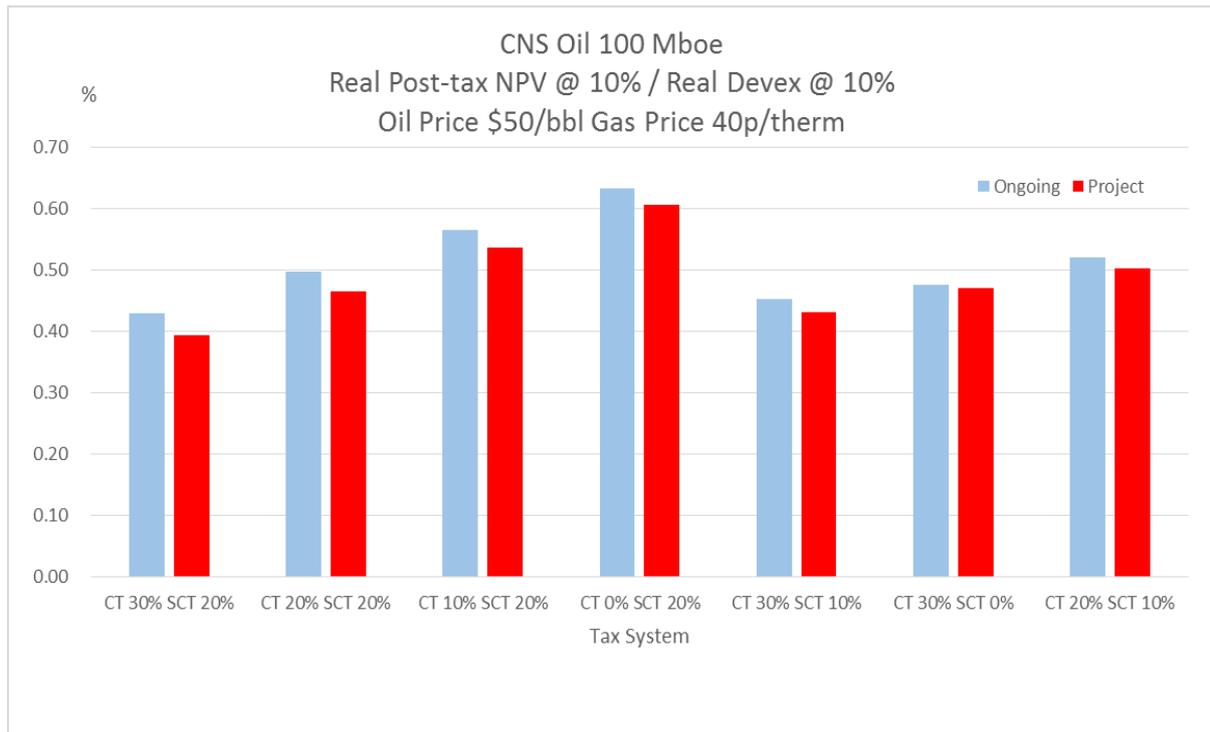
In Chart 14 the post-tax returns are shown under the \$60 price scenario. In context the pre-tax NPV/I ratio is 0.75. It is seen that under the 2015 tax terms the ratios are 0.48 for the ongoing investor and 0.44 for the project investor. The difference is relatively small because the larger revenues permit the project investor to recover his costs and utilise the IA. With the 2016 tax terms it is seen that the NPV/I ratio is 0.5 for the ongoing investor and 0.48 for the project investor. The larger revenues mean that there are greater benefits from the reduction in tax rates.

Chart 14



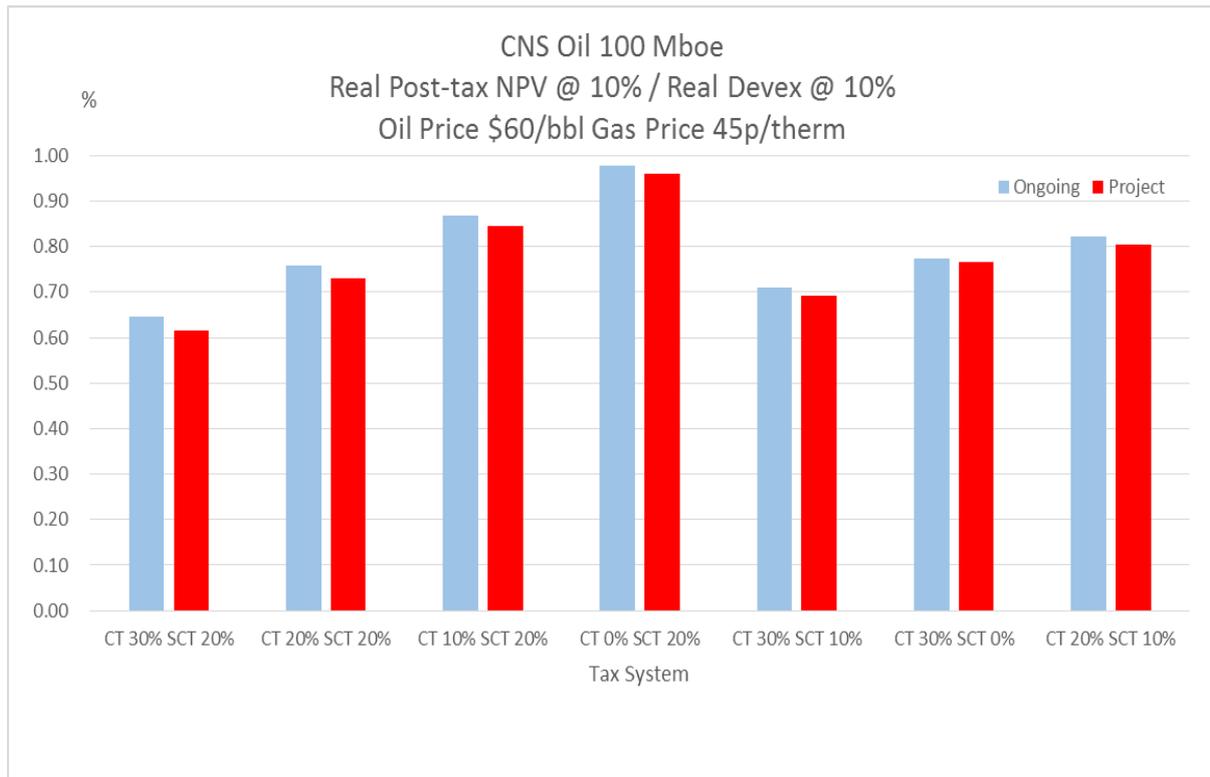
In Chart 15 the post-tax returns to investment in a field of 100 mmbbls in the CNS are shown under the \$50 oil price. Before tax the NPV/I ratio is 0.68. Under the 2015 tax terms the ratio is 0.425 for the ongoing investor and 0.39 for the project investor. Under the 2016 tax terms the ratios become 0.44 and 0.425 respectively. The project could well be commercially viable. The substantial size of the field means that the project investor recovers his costs and the benefit of the IA and still benefits to a worthwhile extent from the reduced tax rate on the income. There is thus only a minor difference between the returns to the investors in different tax positions.

Chart 15



The post-tax returns to the 100 mmbbls field are shown in Chart 16 under the \$60 price. The pre-tax NPV/I ratio is 1.15. The project is clearly acceptable to both types of investors under both the 2015 and 2016 tax terms. The 2016 terms enhance the returns because the large revenues permit substantial benefits to be received from the lower tax rate.

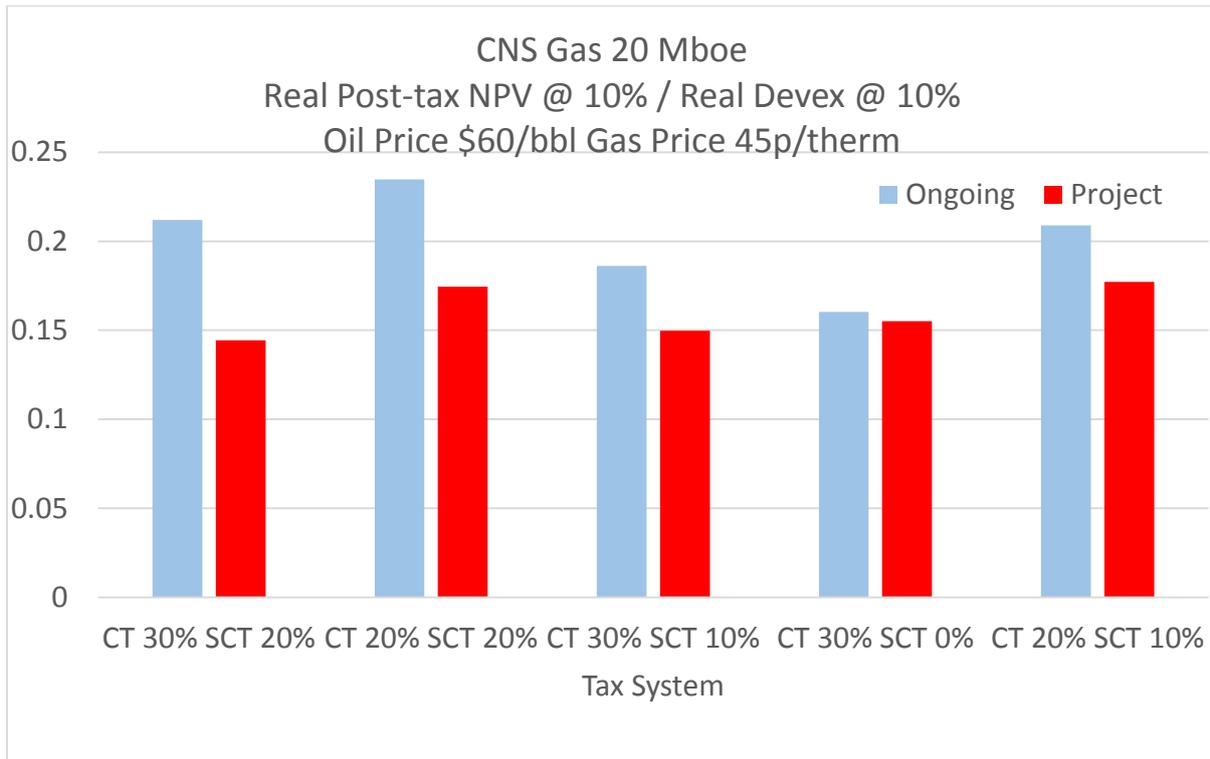
Chart 16



Sadly, currently there are very few undeveloped discoveries in the above category.

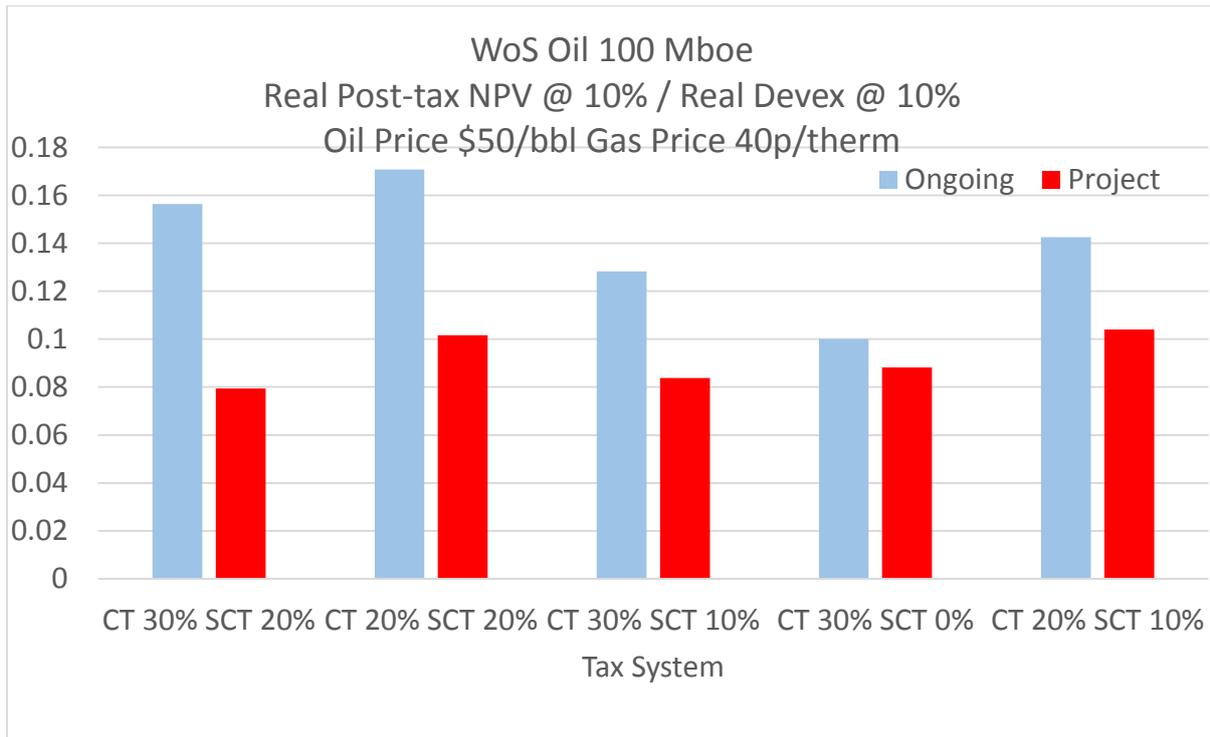
A gas project in the CNS with reserves of around 20 mmboe was modelled at the 40 pence price. It was found that the project was hopelessly uneconomic before tax and the results are not shown here. The results with a price of 45 pence are shown in Chart 17. The returns under both the 2015 and 2016 tax systems are inadequate in a capital constrained environment. There are advantages to the investor in a tax-paying position as he receives fuller and earlier relief for his costs.

Chart 17



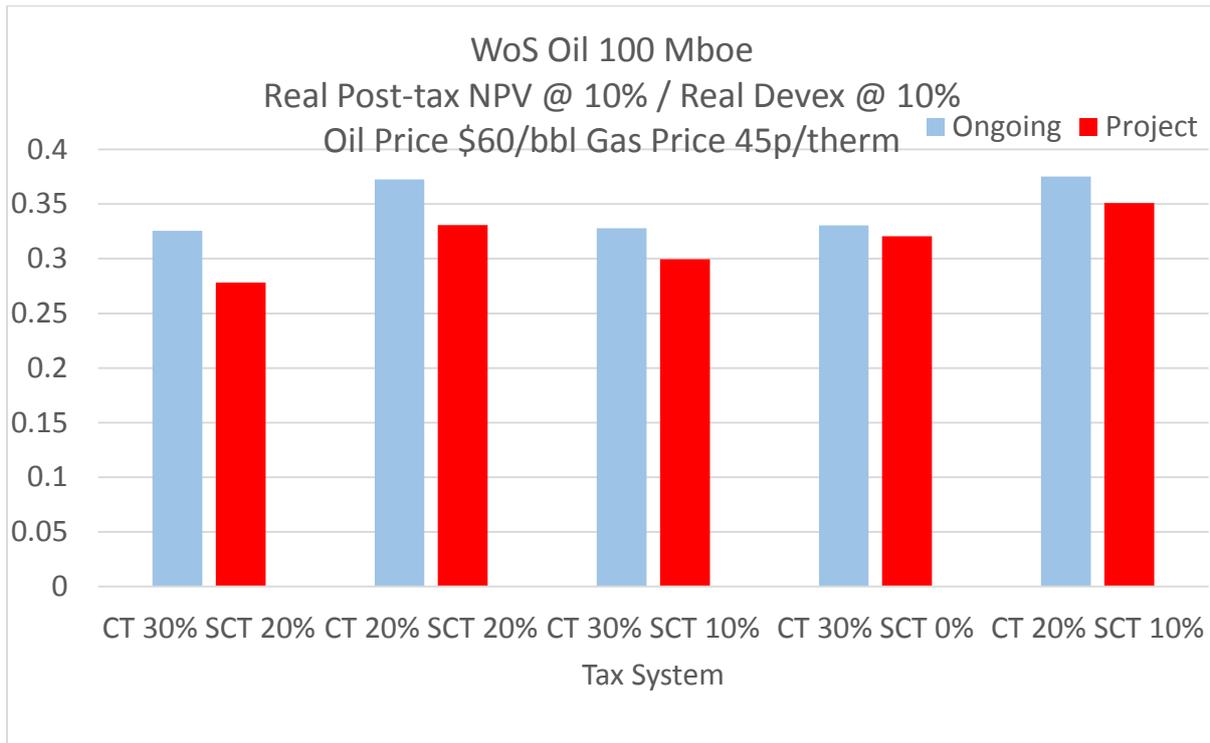
In Chart 18 the post-tax results are shown for an oil field of 100 mmbbls developed in WoS under the \$50 price. The project is clearly not commercially viable in a capital constrained world under any of the tax arrangements. Indeed it is uneconomic before tax. Under the 2015 tax scheme there is a very large difference in the NPV/I ratios between the ongoing and project investors. The former obtains the early benefit of relief for his allowances against other income. The high costs in relation to the field income inhibit the use of all the allowances by the project investor. Under the 2016 tax terms the ongoing investor is worse off because of the reduction in the value of his allowances. His expected return still comfortably exceeds that of the project investor in this generally sub-economic situation.

Chart 18



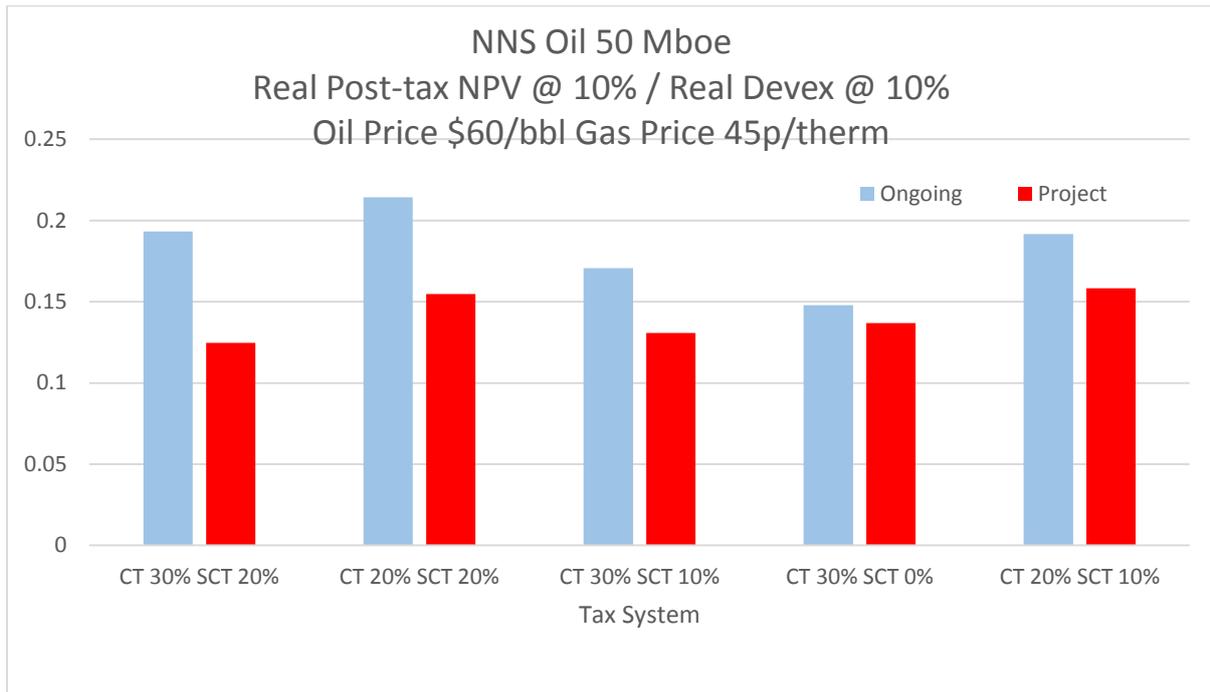
The returns from the same field under the \$60 price are shown in Chart 19. With this price the pre-tax NPV/I ratio is 0.49. Under the 2015 tax terms the post-tax ratio is 0.32 for the ongoing investor and 0.27 for the project investor. The ongoing investor benefits from early utilisation of allowances against other income. Under the 2016 tax terms the return to the ongoing investor is unchanged while the project investor's NPV/I ratio increases to 0.3. The investment project is now quite marginal after tax.

Chart 19



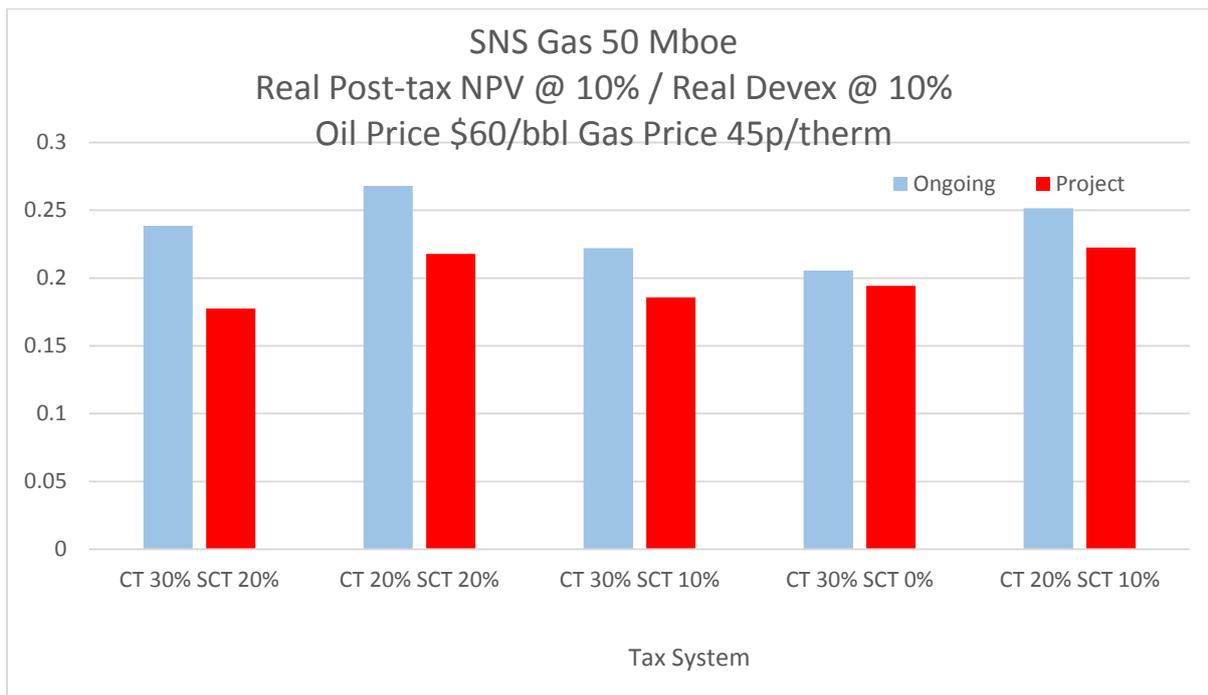
A representative oil field of 50 mmbbls in the NNS was also examined. Under the \$50 price this project was found to be hopelessly uneconomic before tax and the results are not displayed here. The results under the \$60 price are shown in Chart 20. It is seen that the returns in a capital constrained situation are below those likely to be needed. Under the 2015 tax system the NPV/I ratio for the ongoing investor is just below 0.2 while for the project investor it is 0.124. Under the 2016 tax terms the ratio for the ongoing investor is reduced to 0.17 while the project investor's ratio increases very slightly. The investment project remains unlikely to pass the hurdle in a capital constrained world.

Chart 20



The returns to a representative gas field of 20 mmboe in the SNS were also modelled. At the 40 pence price the project was hopelessly uneconomic and the results are not shown here. They are shown for the 45 pence price in Chart 21. The pre-tax NPV/I ratio is 0.27. Under the 2015 tax system the ratio for the ongoing investor is 0.24 and for the project investor 0.176. Under the 2016 tax terms the ratio for the ongoing investor is reduced to 0.22% while for the project investor it increases very slightly.

Chart 21



## 7. Modelling Exploration Economics in the UKCS

A Monte Carlo financial simulation model has been constructed to estimate the distribution of expected monetary values (EMVs) from a specified exploration effort. In the modelling the investor undertakes exploration with a success rate determined by recent experience. When a discovery is made it is appraised. There is again a success rate determined by recent experience. Appraisal success means that there is a potential commercial development. The consequences of developing the discovery are assessed with the use of the Monte Carlo technique. Key stochastic variables are the size of the discovery, the development costs, and oil and gas prices.

The time taken from initial exploration to first production has a significant effect on the full cycle returns when expressed in present value terms. The returns also depend on the extent and costs of the exploration and appraisal efforts required. In this study two scenarios were modelled reflecting the experience and performance of the industry over the past few years. For ready convenience these are termed the “fast” and “slow” cases. The phasing under the fast cycle case is

from first exploration in year  $T_0$  to first production in  $T_5$ . Under the slow case the time from first exploration to first production is  $T_0$  to  $T_7$ . In the results below the fast cycle case is shown.

The prospective returns obviously depend on the costs at the various stages of the cycle. It is assumed that the industry succeeds in its present cost reduction initiatives. After examining the experience to date in 2015 estimates of E and A well costs were derived at levels considerably below those of 2014. The study examines the SNS, CNS, NNS, and WoS separately. For the SNS E and A costs per well were estimated at 50% of the average for the UKCS. For the WoS region the costs were estimated at 1.25 times the average for the UKCS. The values employed in the study are shown in Table 3 below for each of the four regions.

Development costs also vary markedly across the four regions studied. Separate estimates were made for each region, again taking into account the reductions felt to be plausible from recent reported experiences. For modelling purposes development costs per barrel or boe were calculated. The average size of significant discovery was calculated for the period 2005-2014. Details are shown in Table 3. The absolute costs for W of S are higher than elsewhere but the larger volumes pull down the relative unit costs. Development costs were phased over 2 to 5 years depending on the size of discovery. Annual operating costs were modelled as a percentage of accumulated development costs with the percentage increasing as the size of field decreased, reflecting economies of scale.

The modelling employs the Monte Carlo technique to reflect the uncertainties facing the explorationist and field developer. The mean values were made part of distributions of the stochastic variables which determine the returns facing the explorationist. The details of the input distributions obviously vary across each of the four regions, but have some common features. Thus the distribution of

field sizes is taken to be lognormal with a standard deviation expressed as 50% of the mean. The distribution of development costs per boe is taken to be normal with a common standard deviation of 20% as a percentage of the mean. The mean oil price was set at \$55 per barrel in real terms with the assumption that it follows a mean-reverting behaviour through time. The standard deviation was set at 20% of the mean. (Minimum and maximum values from the modelling were \$11 per barrel and \$99 per barrel respectively in real terms). The mean gas price was set at 40 pence per therm in real terms with a standard deviation of 10% of the mean. Mean-reverting behaviour is assumed. (The minimum value from the modelling was 24 pence and the maximum 56 pence, both in real terms).

Other modelling assumptions relate to exploration and appraisal success rates. Significant discoveries are defined as all those published by DECC plus others known to the authors covering the period 2008-2014 inclusive. Appraisal success covers all fields for which development has been started, or firmly planned or contemplated. This definition excludes discoveries for which no field development plan is currently contemplated. All financial values in Table 3 are in real terms.

Table 3  
Assumptions for Monte Carlo modelling by region  
After Cost Reductions

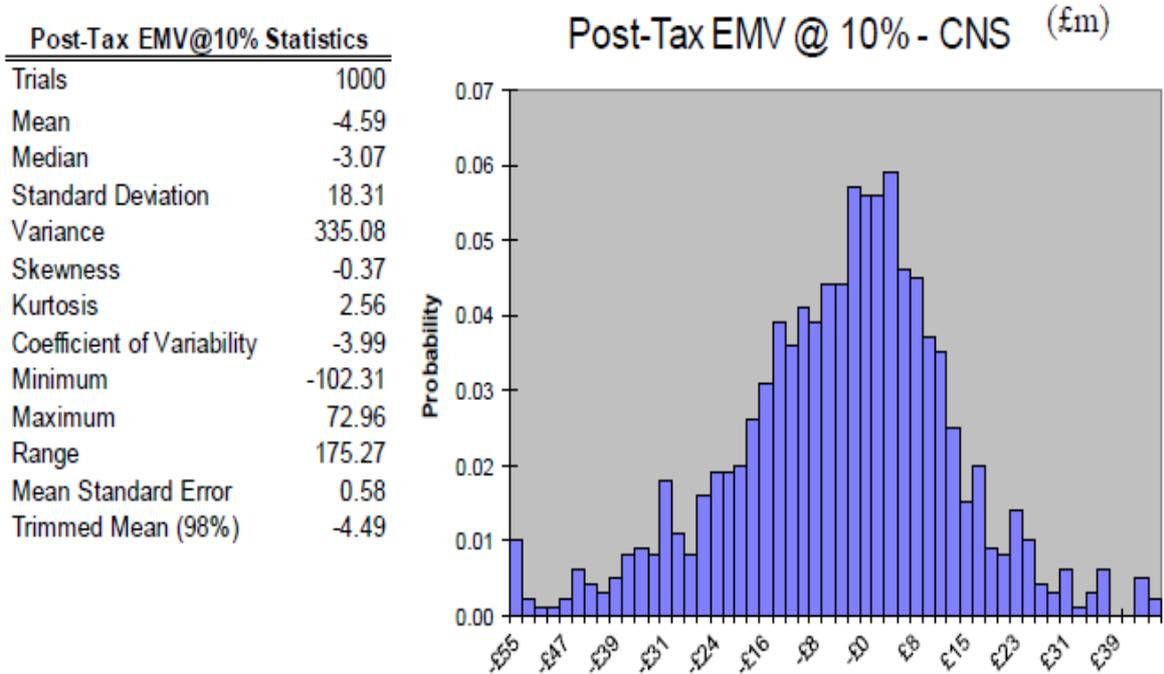
		Central North Sea	Southern North Sea	Northern North Sea	West of Shetlands
Exploration success		34.2%	35.3%	40%	50%
Chance of oil		82%	0%	88%	75%
Chance of gas		18%	100%	12%	25%
Appraisal success		47.4%	30%	50%	55.6%
Reserves	Average	39.1 mmboe	16.4 mmboe	16.5 mmboe	112.6 mmboe
	Minimum significant size	8.5 mmboe	3.55 mmboe	3.6 mmboe	24.4 mmboe
	Maximum significant size	110 mmboe	50 mmboe	50 mmboe	320 mmboe
Well costs for E & A		£24.68m.	£14.1m.	£24.68m.	£30.85m.
Average devex per boe		\$23.67	\$11.392	\$17.152	\$15.82
Minimum devex per boe		\$9.47	\$4.56	\$6.86	\$6.33
Maximum devex per boe		\$37.88	\$18.23	\$27.44	\$25.32

## 8. Results of Exploration Modelling

The distribution of post-tax EMVs@ 10% for the CNS is shown in Chart 22. The mean expected value –£4.6 million. There is a 68% probability that the EMV will be in the range –£20.6 m. – +£10.1 m., and a 95% chance that it will be in the range –£43.2 m. – +£30.7 m. There is a 58% chance that the EMV is negative. The upside potential is very limited. There is a 30% chance that the EMV will exceed +£3.86m.

Chart 22

CNS - Project (Fast) Limited IA - Initial Price \$55 p/b and 40p/therm Reduced Costs

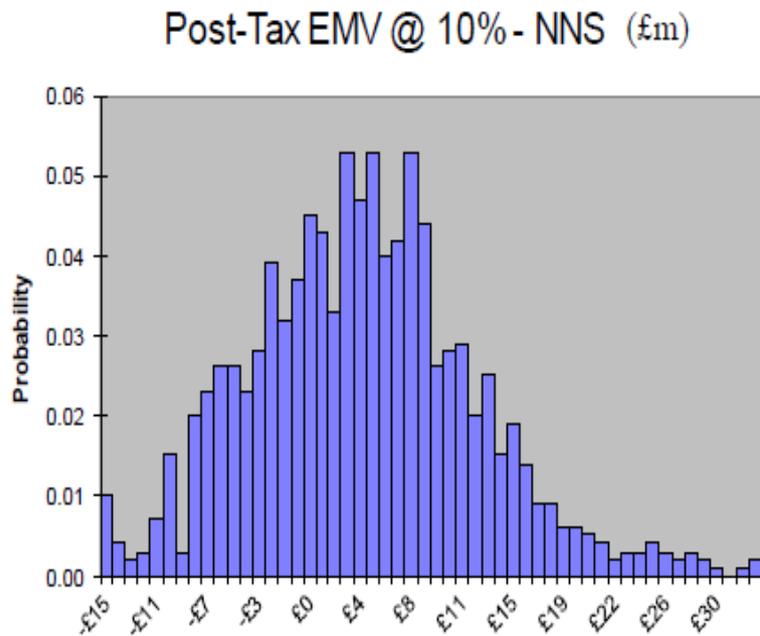


In Chart 23 the distribution of post-tax EMVs is shown for the explorationist in the NNS. The mean expected value is +£3.99m. There is a 68% probability that the EMV will be in the range -£4.4 m.- +£11.7 m., and a 95% chance that it will be in the range -£10.9 – +£24.6 m. There is a 33% chance that the EMV will be negative and a 30% chance that it will exceed +£7.64m.

Chart 23

NNS - Project (Fast) Limited IA - Initial Price \$55 p/b and 40p/therm Reduced Costs

Post-Tax EMV@10% Statistics	
Trials	1000
Mean	3.99
Median	3.63
Standard Deviation	8.95
Variance	80.10
Skewness	0.96
Kurtosis	3.84
Coefficient of Variability	2.24
Minimum	-20.92
Maximum	68.09
Range	89.01
Mean Standard Error	0.28
Trimmed Mean (98%)	3.84

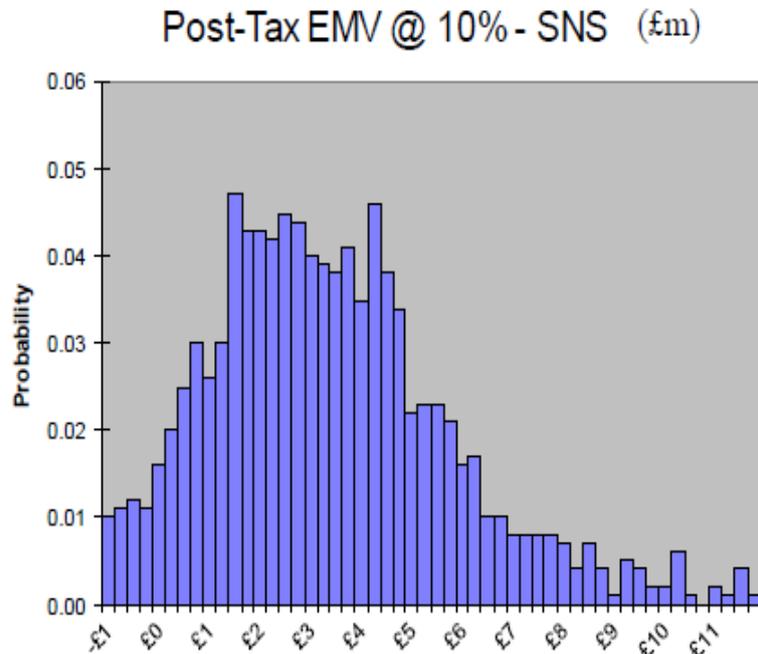


In Chart 24 the distribution of post-tax EMVs is shown for the explorationist in the SNS. The mean expected value is +£3.42m. There is a 68% chance that the EMV will be in the range +£1.1 m. – +£9.7 m., and a 95% chance that it will be in the range –£0.5 m. – +£9.7 m. While there is only a 4% chance that the EMV is negative there is a 30% chance that it will exceed +£4.3m.

Chart 24

SNS - Project (Fast) Limited IA - Initial Price \$55 p/b and 40p/therm Reduced Costs

Post-Tax EMV@10% Statistics	
Trials	1000
Mean	3.42
Median	3.10
Standard Deviation	2.51
Variance	6.32
Skewness	1.10
Kurtosis	2.39
Coefficient of Variability	0.73
Minimum	-2.16
Maximum	17.48
Range	19.64
Mean Standard Error	0.08
Trimmed Mean (98%)	3.37

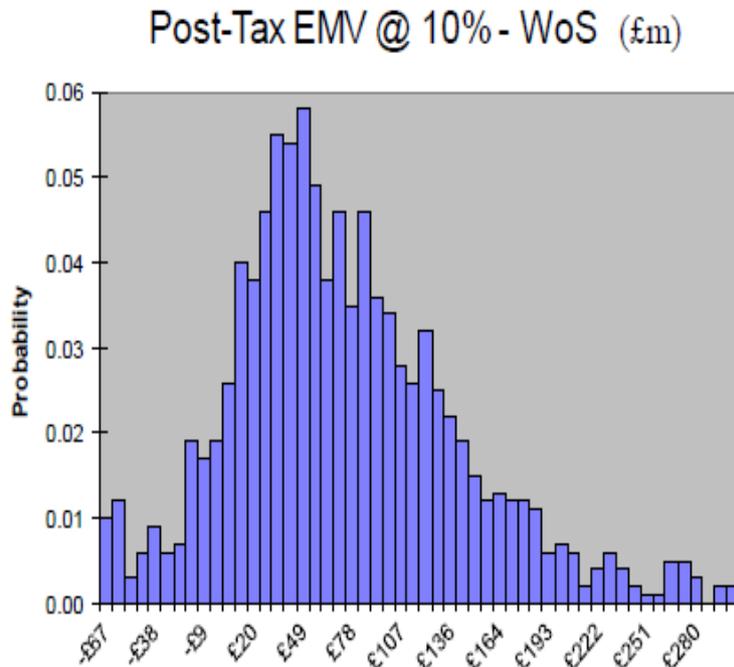


In Chart 25 the distribution of post-tax EMVs is shown for the explorationist in WoS. The mean expected value is +£71.7m. There is a 68% chance that the EMV will be in the range +£10.1m. – +£134.6 m., and a 95% chance that it will be in the range –£52.2 m. – +£253.5 m. There is an 11% chance that the EMV will be negative and a 30% chance that it will exceed +£96.9m. It should be stressed that the absolute exploration, appraisal and development costs are relatively high in the WoS region. In the other regions it is clear that the expected returns are generally unexciting in a capital constrained environment.

Chart 25

WoS - Project (Fast) Limited IA - Initial Price \$55 p/b and 40p/therm Reduced Costs

Post-Tax EMV@10% Statistics	
Trials	1000
Mean	71.72
Median	60.17
Standard Deviation	72.99
Variance	5327.65
Skewness	1.02
Kurtosis	3.27
Coefficient of Variability	1.02
Minimum	-149.83
Maximum	571.80
Range	721.63
Mean Standard Error	2.31
Trimmed Mean (98%)	70.69



The UK Government has responded to the fall in exploration activity by funding the provision of seismic data in areas where the potential is regarded as underinvestigated. The freely available data can be regarded as a public good provided to all explorers. The extra information should in due course increase the exploration success rate and subsequently produce national benefits in terms of enhanced development and production activity. Given the combination of the extremely low current exploration effort and the substantial estimates of yet-to-find resources the public investment is defensible.

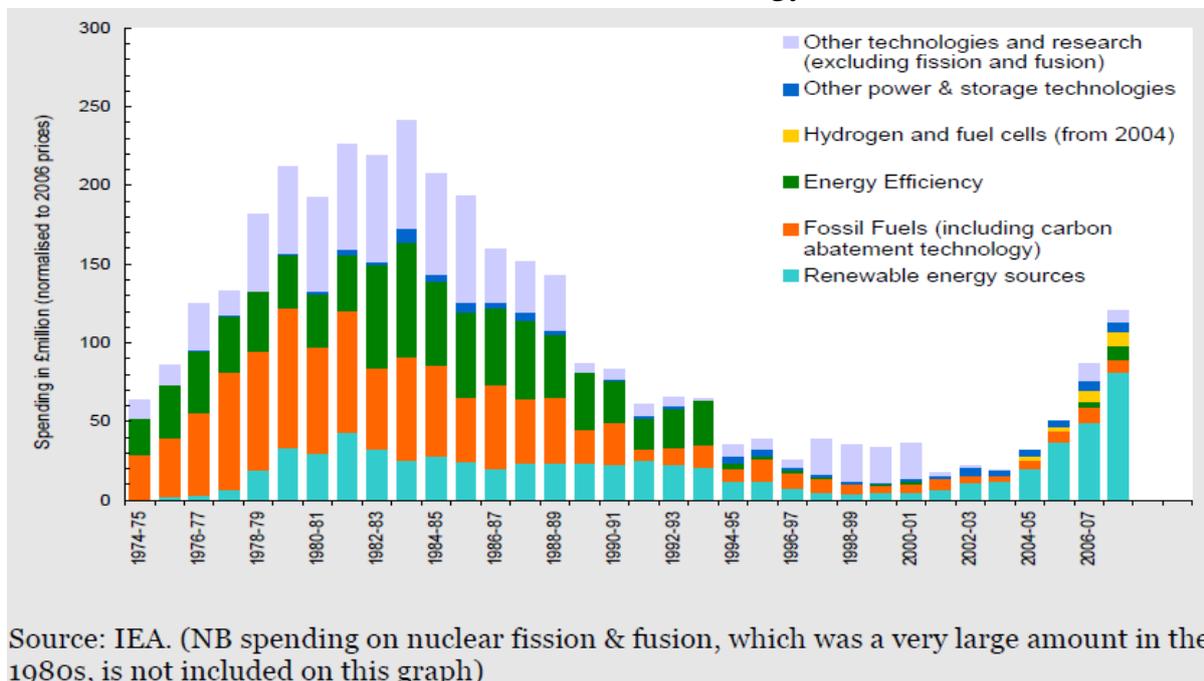
**9. Conclusions: Reinforcing the MER Strategy**

From the analysis of the economics of new field investments and exploration in current circumstances in the UKCS it is clear that at \$50 and \$60 prices there are many marginal project investment situations. The tax rate reductions introduced in 2015 and 2016 have two effects. Firstly, they enhance cash flows on existing operations. In a situation where the industry as a whole is cash flow negative this is undoubtedly appropriate. But with respect to new field investments the effects are more complex. The effect on incentives and returns to investors depends on the combined effects of the reduction in the tax rate on income and the reduction in the rate of relief for the investment costs. It was found that, on small fields where the pre-tax returns were quite modest, the reduced rate of relief could be

more important than the reduction in the tax rate on income. On larger fields and on small fields with higher oil prices the reduced tax on income is more important than the reduced rate of relief. Reductions in the rate of CT rather than SC were found to be more potent in incentivising new investments. In current circumstances there is a case for reducing the CT rate which at 30% is now far above the non-North Sea rate.

Tax incentives alone cannot ensure the revitalisation of the UKCS. The painful cost reductions currently being implemented are a regrettable necessity. To facilitate the development of the many uneconomic fields, including small pools, technological advances are necessary. Expenditure on R and D in the fossil fuels segment of the energy sector has been relatively low for a considerable number of years. The long term trend is shown in Chart 26. There is a need to enhance this if the recovery factor is to be significantly improved. The new Oil and Gas Technology Centre will hopefully be a major catalyst in this area.

Chart 26  
R and D in the UK Energy Sector



Source: IEA. (NB spending on nuclear fission & fusion, which was a very large amount in the 1980s, is not included on this graph)

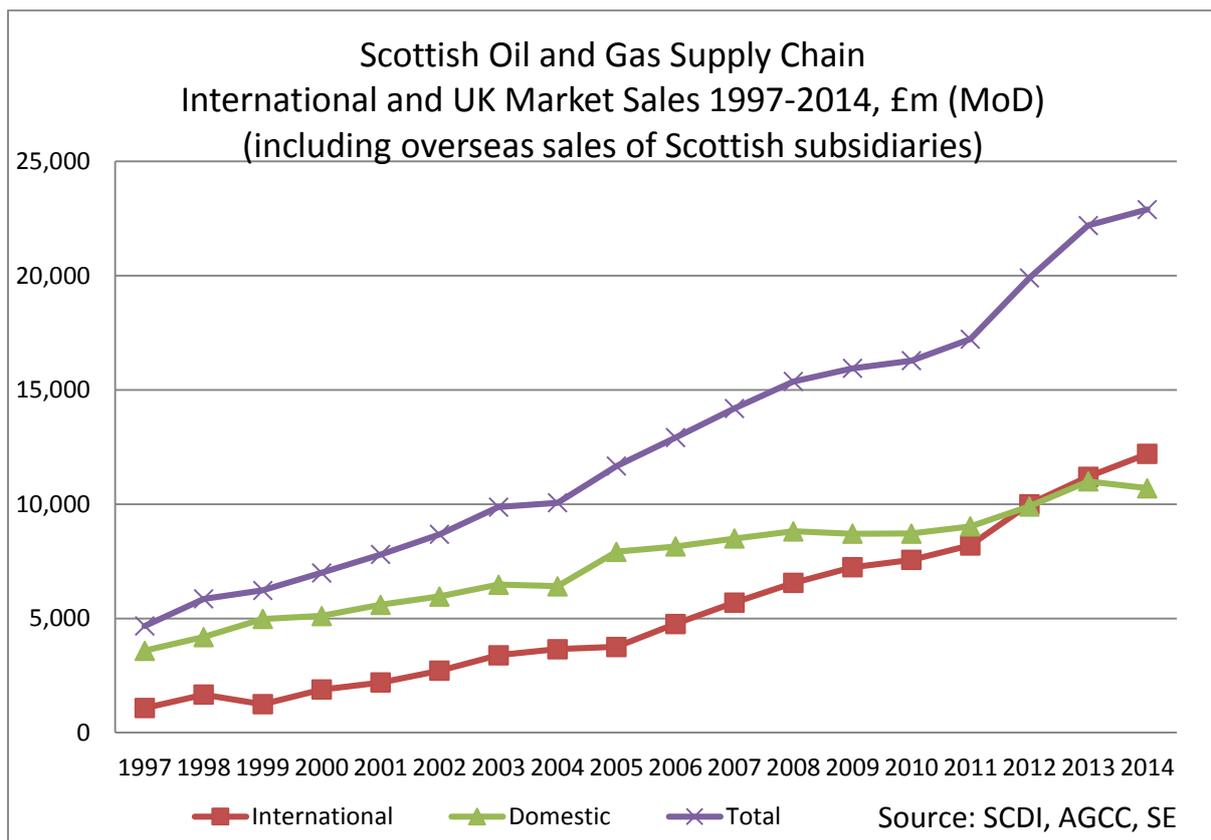
Secondary source: M. Wicks (2009)

The Wood Review has emphasised the need for more collaboration among licensees and contractors to enhance economic recovery. This relates to several areas such as third party access to infrastructure and sharing of information, such as relating to decommissioning. This recommendation is within the context of

traditional competition among licensees and among contractors. The UK also has competition laws to which all companies have to adhere. To facilitate collaboration without falling foul of competition laws can be a challenge. To reduce uncertainty in this area it is suggested that the OGA and Competition and Markets Authority (CMA) issue joint Guidance Notes which would clarify what collaborative agreements are consistent with competition laws and which are inconsistent.

It is also suggested that the emphasis on objectives could be geared to Maximisation of Total Value Added from the whole sector including the supply chain. This would include exports from the supply chain. The UK/Scottish supply chain has become increasingly active in overseas markets over the last two decades. For the Scottish supply chain this is indicated in Chart 27.

Chart 27



It is seen that sales to export markets have grown markedly to exceed 53% of the total. As the UKCS declines but the world market continues to grow export activity should also continue to grow. But a continued healthy home market will be necessary to encourage companies to maintain bases in the UK.

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