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**Price Sensitivity, Capital Rationing  
and Future Activity  
in the UK Continental Shelf  
after the Wood Review**

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and  
Linda Stephen

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**Aberdeen Centre for Research in Energy Economics and  
Finance (ACREEF)**

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## **NORTH SEA ECONOMICS**

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

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

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

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

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**Price Sensitivity, Capital Rationing and Future Activity**  
**in the UK Continental Shelf after the Wood Review**

Professor Alexander G. Kemp and Linda Stephen

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# **Price Sensitivity, Capital Rationing and Future Activity** **in the UK Continental Shelf after the Wood Review**

Professor Alexander G. Kemp  
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## **1. Introduction**

The investment environment in the UK Continental Shelf (UKCS) is constantly changing. This reflects the effects of several factors including changes in (1) oil and gas prices and expectations regarding their future behaviour, (2) perceived exploration prospectivity and success rates, (3) investment and operating costs, (4) terms and availability of finance, and (5) the tax system. Recently oil and gas prices have fallen substantially. In this paper the price sensitivity of future activity is examined within the context of other possible changes to the operating environment, but before the Tax Review.

Recently activity has been personified by dramatically high field investment with an all-time record (in real terms) of over £14 billion being achieved in 2013. This was concentrated in a relatively small number of large and very expensive developments. The very large amount spent to some extent reflects rampant cost inflation, and draws attention away from the relative decline in the volume of production drilling. Thus in the period 2000-2006 the average annual number of development wells drilled was 225 while in the period 2009-2013 it was 125 with only 120 being drilled in 2013. Much publicity has been given to the low number of exploration wells drilled in recent years with the average annual number in the period 2011-13 being 17. Since 2000 the



average annual number has been 26.7, compared to 24.3 in the period 2008-2013. Over the period 2000-2013 the average annual number of appraisal wells drilled was 37.8 and 37.3 in the period 2008-2013. But in the period 2011-2013 the average fell to 29.3.

As broad indicators of inflation in the upstream oil industry the CERI indices are often employed. For upstream capital costs the index increased from 110 in Q3 of 2000 to 229 for Q3 of 2013. For operating costs the CERI index increased from 100 in 2000 to 196 in Q3 of 2013. It may be that these indices understate the costs in the UKCS, especially in the regions where semi-submersible and heavy duty rigs are required.

Of course, it is costs per unit which are important in assessing the investment climate. Production has been falling at a relatively fast pace in recent years and this has significantly increased the unit operating costs on sanctioned fields. In turn, this has been due in no small measure to the decline in production efficiency from 81% in 2004 to 61% in 2012. Production efficiency is the ratio of actual production to the maximum efficient rate, taking market conditions into account. The seriously adverse effect of this on returns to investors and the nation has been clearly recognised in the Wood Review. The industry is already taking steps to remedy this, and it can be expected that implementation of Wood Review proposals will accelerate and intensify these efforts.

The present study examines the future prospects for activity levels to 2050 employing financial simulation modelling, including use of the Monte Carlo technique. Two cases are developed with respect to production efficiency. In the first case there is assumed to be a substantial resolution to the production efficiency problem. In the second

there is a partial resolution to the study. Specifically, in the first case it is assumed that over the next 5 years production efficiency in the sanctioned fields is at 72% (.9 x .8) after which all the deferred production is regained over the period 2019-2025. In the second case it is assumed that production efficiency is 60% (.75 x .8) in the sanctioned fields over the next 5 years but the deferred production is not effectively recovered. In each case the recovered production is constrained by the economic limit of the fields in question. Cessation of production occurs when persistent operating losses occur.

The large financial model incorporates the current complex petroleum tax system including the various field allowances for Supplementary Charge (SC) introduced over the past few years. The proposed new uHP/HT allowance is not included as full details are not yet known. A summary of the tax changes made over the past few years is given in Appendix I. The detailed results of the modelling are shown for the period covering the period to 2050.

## **2. Methodology and Data**

The projections of production and expenditures have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 379 sanctioned fields, 171 incremental projects relating to these fields, 23 probable fields, and 20 possible fields. The unsanctioned fields are currently being examined for development. An additional database contains 254 fields defined as being in the category of technical reserves. Only summary data on

reserves (oil/gas/condensate) and block locations are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2040. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types of discovery (oil, gas, condensate). A moving average of the behaviour of these variables over the past 5 years was calculated separately for 5 areas of the UKCS (Southern North Sea, (SNS), Central North / Moray Firth (CNS/MF), Northern North Sea (NNS), West of Scotland (WoS), and Irish Sea (IS)). The results were employed for use by the Monte Carlo analysis. Because of the very limited data for WoS and IS over the period judgemental assumptions on success rates and average sizes of discoveries were made for the modelling.

It is postulated that the exploration effort depends substantially on a combination of (a) the expected success rate, (b) the likely size of discovery, and (c) oil/gas prices. In the present study 2 future oil/gas price scenarios were employed as follows:

<b>Table 1</b>		
<b>Future Oil and Gas Price Scenarios</b>		
	<b>Oil Price (real)</b> \$/bbl	<b>Gas Price (real)</b> pence/therm
<b>High</b>	90	58
<b>Medium</b>	70	45

These price scenarios are designed to reflect investment screening prices, not market values. In this context it should be noted that, before the recent price fall, banks typically employed oil prices in the \$65-\$75 range to assess loan applications. In MOD terms the price scenario starting with \$90 in 2014 becomes \$219 in 2050, and the scenario starting with \$70 in 2014 becomes over \$170 in 2050.

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2014, 2030, 2040, and 2045:

<b>Table 2</b>				
<b>Exploration Wells Drilled</b>				
	2014	2030	2040	2045
High	26	20	16	12
Medium	22	15	10	7

It is postulated that success rates depend substantially on a combination of (a) recent experience, and (b) size of the effort. It is further suggested that higher effort is associated with more discoveries but with lower success rates compared to reduced levels of effort. This reflects the view that low levels of effort will be concentrated on the lowest risk prospects, and thus higher effort involves the acceptance of higher risk. For the UKCS as a whole 2 success rates were postulated as follows with the medium one reflecting the average over the past 5 years.

<b>Table 3</b>	
<b>Success Rates for UKCS</b>	
Medium effort/Medium success rate	28%
High effort/Lower success rate	25%

It should be noted that success rates have varied considerably across the 5 sectors of the UKCS. Thus in the CNS and SNS the averages have exceeded 30% while in the other sectors they have been well below the average for the whole province. It is assumed that technological progress will maintain historic success rates over the time period.

The mean sizes of discoveries made in the historic periods for each of the 5 regions were calculated. It was then assumed that the mean size of discovery would decrease in line with recent historic experience. They are shown in Table 4.

<b>Table 4</b>		
<b>Mean Discovery Size MMboe</b>		
<b>year</b>	<b>2014</b>	<b>2045</b>
<b>SNS</b>	<b>10</b>	<b>5</b>
<b>CNS/MF</b>	<b>30</b>	<b>12</b>
<b>NNS</b>	<b>25</b>	<b>10</b>
<b>WoS</b>	<b>75</b>	<b>25</b>
<b>IS</b>	<b>12</b>	<b>4</b>

For purposes of the Monte Carlo modelling of the size of new discoveries the standard deviation (SD) was set at 50% 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 5 regions to 2040. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

<b>Table 5</b>	
<b>Total Number of Discoveries to 2045</b>	
High effort/Lower success rate	157
Medium Effort/Medium Success Rate	131

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated. These reflect substantial cost inflation over the last few years. Investment costs per boe depend on several factors including not only the absolute costs in different operating conditions (such as water depth) but on the size of the fields. For all of the UKCS the average development cost was \$18.5 per boe with the highest being \$99. In the SNS development costs were found to average just over \$15 per boe. In the CNS/MF, they averaged \$21 per boe, and in the NNS they averaged \$18.4 per boe with the highest being \$99. Operating costs over the lifetime of the fields were also calculated. The averages were found to be \$13 per boe for all of the UKCS, \$8.5 per boe in the SNS, \$12.4 per boe in the CNS/MF, and \$18 per boe in the NNS. Total lifetime field costs (including decommissioning but excluding E and A costs) were found to average \$36.8 per boe for all of the UKCS, \$24.6 per boe in the SNS, \$34.5 per boe in the CNS/MF, and \$49.4 per boe in the NNS.

Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with a SD = 20% of the mean value was employed. For new

discoveries annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale. Thus the field lifetime costs in small fields could become very high on a boe basis.

With respect to fields in the category of technical reserves it was recognised that many present major challenges, and so the mean development costs in each of the basins was set at \$5/boe higher than the mean for the new discoveries in that basin. Thus for the CNS/MF the mean development costs are \$25.6 per boe, and in NNS over \$23.4 per boe. The distribution of these costs was assumed to be normal with a SD = 20% of the mean value. A binomial distribution was employed to find the order of new developments of fields in this category.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. The ceilings were assumed to be linked to the oil/gas price scenarios with maxima of 18 and 15 respectively for the High and Medium price cases. These constraints do not apply to incremental projects which are additional to new field developments.

There is a wide range in the development and operating costs of the set of incremental projects currently being examined for development. For all of the UKCS the mean development costs are \$15.3 per boe but the highest is over \$79 per boe. In the SNS the average development costs are \$9.7 per boe, but in the NNS it is \$17 per boe. While operating costs are often relatively low and average \$5 per boe across all of the UKCS,

they are very high in a number of cases, with examples in the \$50 - \$86 per boe range over their lifetime.

A noteworthy feature of the 171 incremental projects in the database is the expectation that the great majority will be executed over the next 3 or 4 years. It is virtually certain that in the medium 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 to be linked not only to currently sanctioned fields, but also to those presently classified as in the categories of probable, possible, technical reserves, and future 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 6 years indicated a decline rate in the volumes. On the basis of this, and utilising the information of the key characteristics of the 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. Their sizes and costs reflect recent trends.

With respect to investment decision making and project screening criteria oil companies (even medium-sized and smaller ones) currently assess their opportunities in the UKCS in comparison to those available in other parts of the world. Capital is allocated on this basis with the UKCS having to compete for funds against the opportunities in other provinces. A problem with the growing maturity of the UKCS is the relatively small



average field size and the high unit costs. Mean discovery sizes are shown in Table 4, but, given the lognormal distributions, the most likely sizes are below these averages. It follows that the materiality of returns, expressed in terms of net present values (NPVs), is quite low in relation to those in prospect in other provinces (such as offshore Angola, or Brazil, for example). Oil companies frequently rank investment projects according to the NPV/I ratio. Accordingly, this screening method has been adopted in the present study. Specifically, the numerator is the post-tax NPV at 10% discount rate in real terms and the denominator is pre-tax field investment at 10% discount rate in real terms. This differs from the textbook version which states that I should be in post-tax terms because the expenditures are tax deductible. Oil companies maintain that they allocate capital funds on a pre-tax basis, and this is employed here as the purpose is to reflect realistically the decision-making process. In one scenario the development project goes ahead when the NPV/I ratio as defined above in real terms  $\geq 0.3$ . To reflect the effects of tougher capital rationing another scenario when the hurdle is NPV/I  $\geq 0.5$  is also shown. The 10% real discount rate reflects the weighted average cost of capital to the investor. The modelling has been undertaken under the current tax system, including all the field allowances introduced in 2012. The modelling is initially undertaken in MOD terms with an inflation rate of 2.5%. This incorporates the effects of any fiscal drag. The results are then converted to real terms.

In the light of experience over the past few years some rephrasing of the timing of the commencement dates of new field developments and incremental projects from those projected by operators was undertaken relating to the probability that the project would go ahead. Where the operator indicated that a new field development had a probability  $\geq 80\%$

of going ahead the date was left unchanged. Where the probability  $\geq 60\% < 80\%$  the commencement date was slipped by 1 year. Where the probability  $\geq 40\% < 60\%$  the date was slipped by 2 years. Where the probability was  $\geq 20\% < 40\%$  the date was slipped by 3 years, and where the probability was  $< 20\%$  it was slipped by 4 years. If an incremental project had a probability of proceeding  $\geq 50\%$  the date was retained but where it was  $< 50\%$  it was slipped by 1 year.

### **3. Results**

#### **(a) Hurdle NPV/I > 0.3, Production Efficiency Problem Largely Resolved**

##### **(i) New Field Development and COP to 2050**

In Chart 1 the numbers of new field developments and COP dates are shown at the \$90, 58 pence price scenario with the production efficiency problem largely resolved over the next several years. It is seen that the numbers of fields in production fall steadily over the period to reach very low levels in 2050. Over the period there are 271 new field developments triggered, of which 16 are in the probable category, 9 in the possible category, 147 in the category of technical reserves, and 99 future discoveries.

In Chart 2 the corresponding results are shown for the \$70, 45 pence prices case. In this scenario the numbers of new field developments triggered are considerably less. There are 149 over the period to 2050 of which 11 are in the probable category, 5 in the possible category, 94 in technical reserves, and 39 from new discoveries in the period 2014-2045.

Chart 1

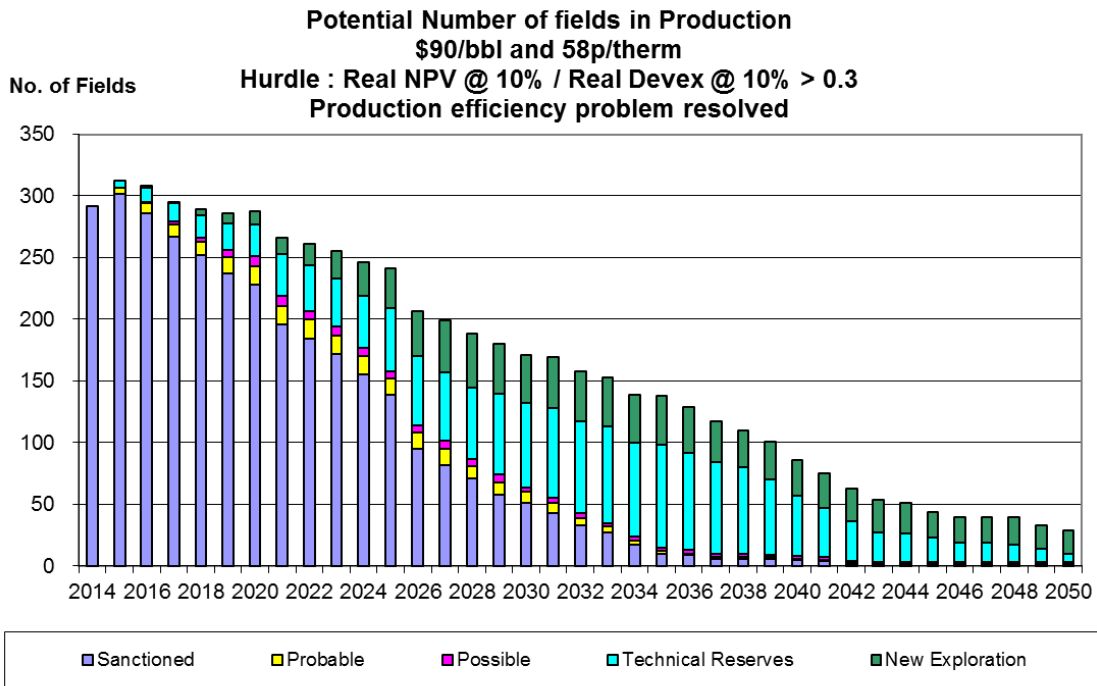
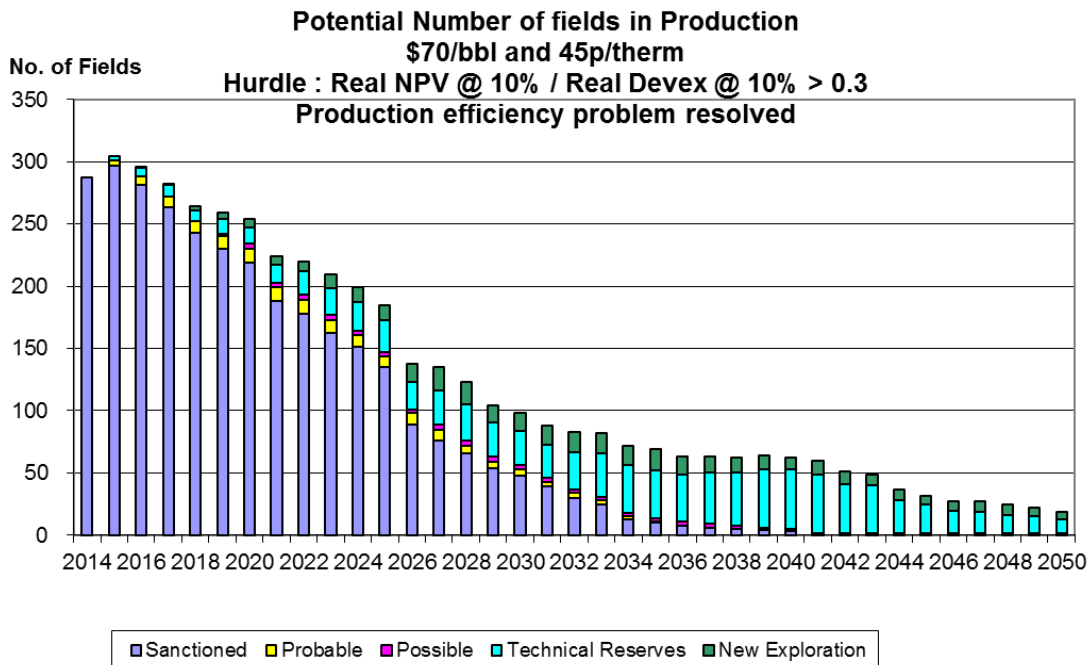


Chart 2



## **(ii) Total Hydrocarbon Production**

In Chart 3 total hydrocarbon production over the period to 2050 is shown for the \$90, 58 pence case. As discussed above this scenario reflects substantial success in resolving the production efficiency problem. Over the period cumulative production is just over 15 billion barrels of oil equivalent (bnboe) of which 6.9 bn comes from sanctioned fields, 0.9 bn from current incremental projects, 1.7 bn from future incremental projects, 0.9 bn from probable fields, 0.4 bn from possible fields, 2.4 bn from technical reserves, and 1.9 bn from future discoveries.

In Chart 4 total production under the \$70, 45 pence scenario is shown. Over the period to 2050 the total is 11.9 bnboe, of which 6 bn comes from sanctioned fields, 0.7 bn from current incremental projects, 1.5 bn from future incremental projects, 0.5 bn from probable fields, 0.4 from possible fields, 1.5 bn from technical reserves, and 1.1 bn from new discoveries. The reduction compared to the \$90 case is primarily among the high cost technical reserves and new discoveries. There are, of course, significantly fewer new discoveries with the lower price scenario.

Chart 3

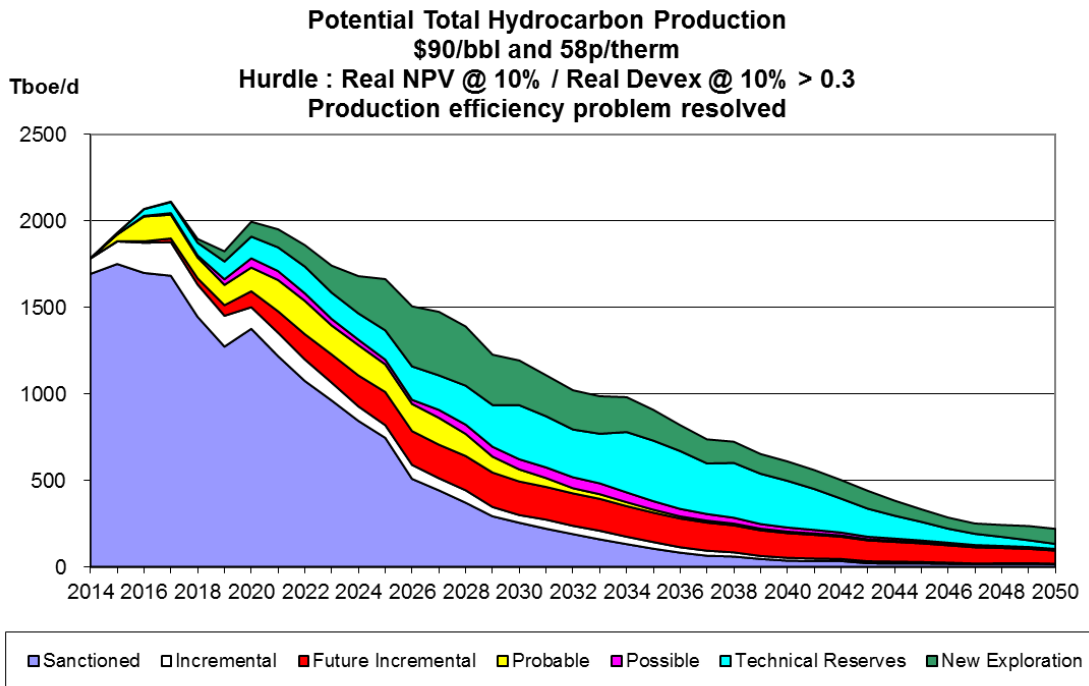
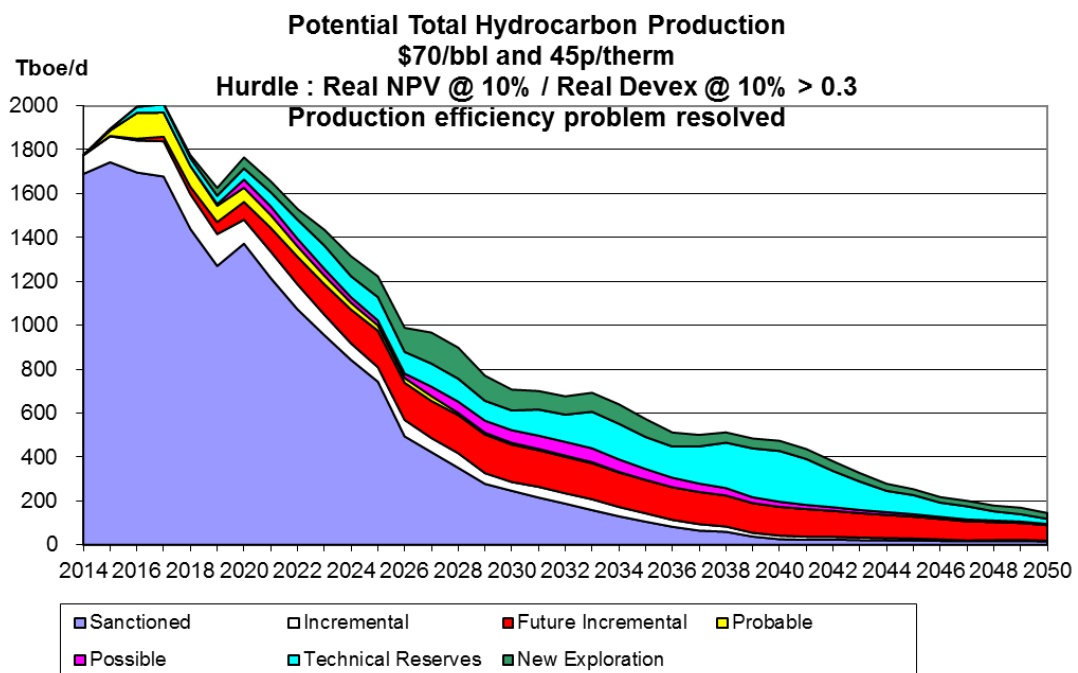


Chart 4



### **(iii) Field Expenditures**

In Charts 5 and 6 field-related expenditures are shown under the \$90, 58 price case. The decrease from current levels over the next few years is notable, particularly with development expenditures. Over the period to 2050 cumulative development expenditures amount to £122 bn at 2014 prices. Cumulative operating expenditures amount to £175 bn. Cumulative decommissioning expenditures are £45 bn.

In Charts 7 and 8 total field expenditures are shown under the \$70, 45 pence case. There is a steep decrease over the next few years, particularly with respect to development expenditures. Over the period to 2050 cumulative development expenditures are £81.4 bn. Cumulative operating expenditures are £135 bn., and total decommissioning expenditures £41.8 bn. There are less new field developments and thus lower numbers decommissioned by 2050 compared to the \$90 price case.

Chart 5

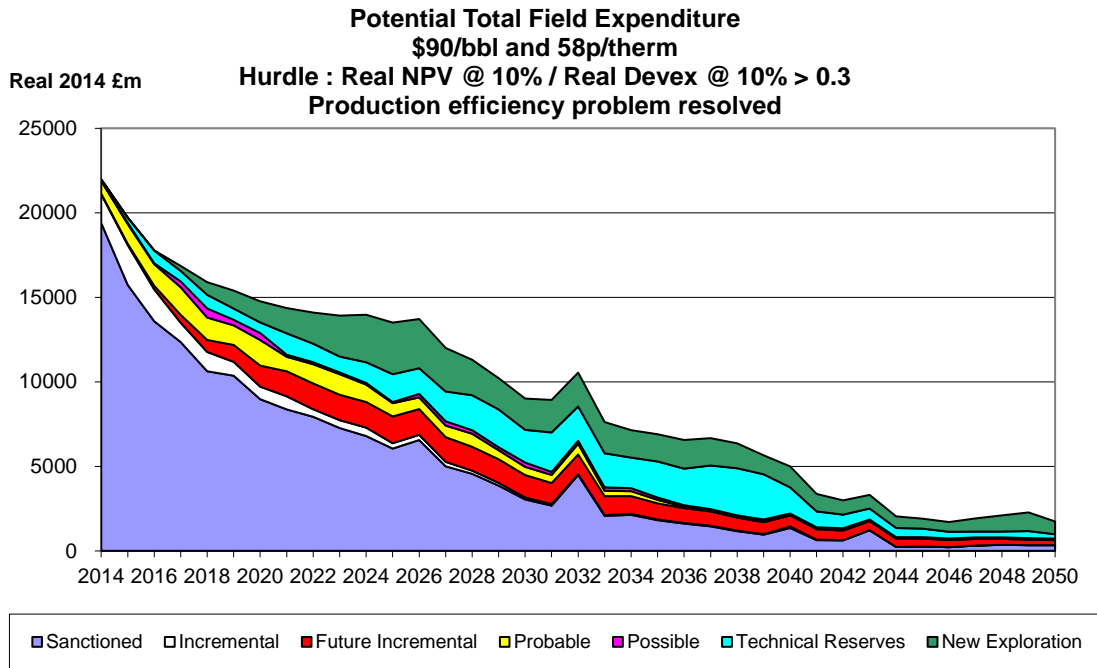


Chart 6

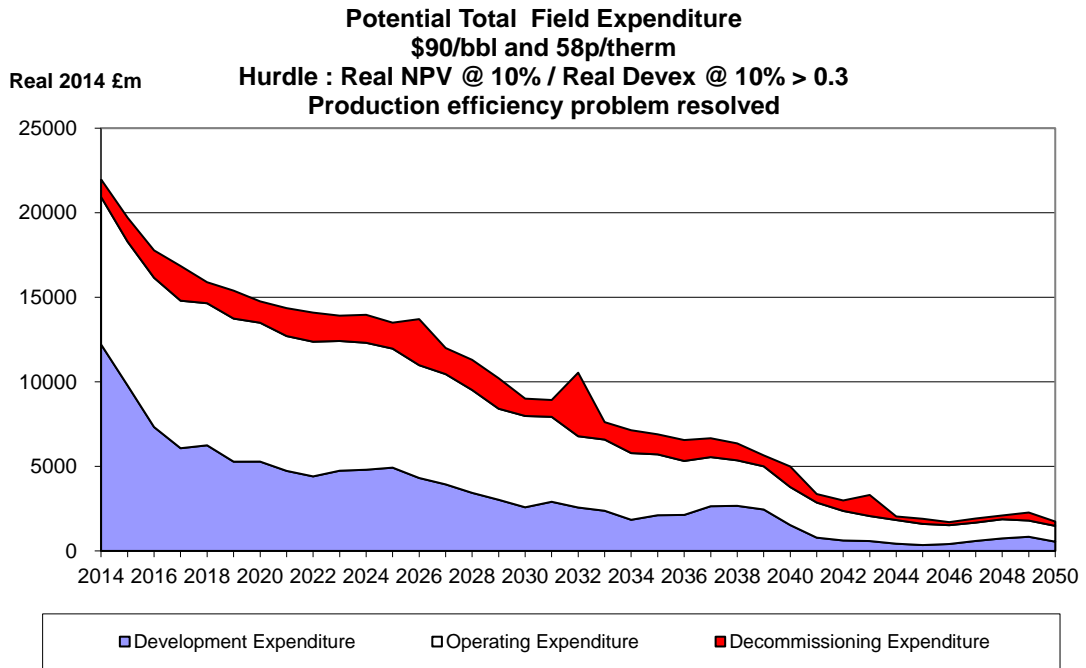


Chart 7

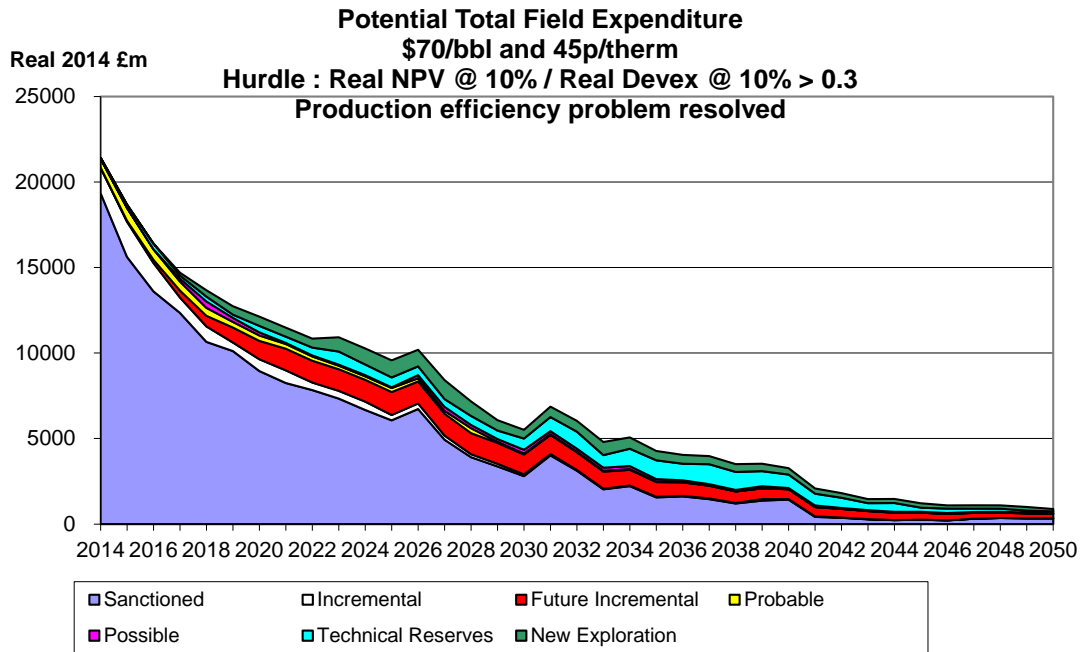
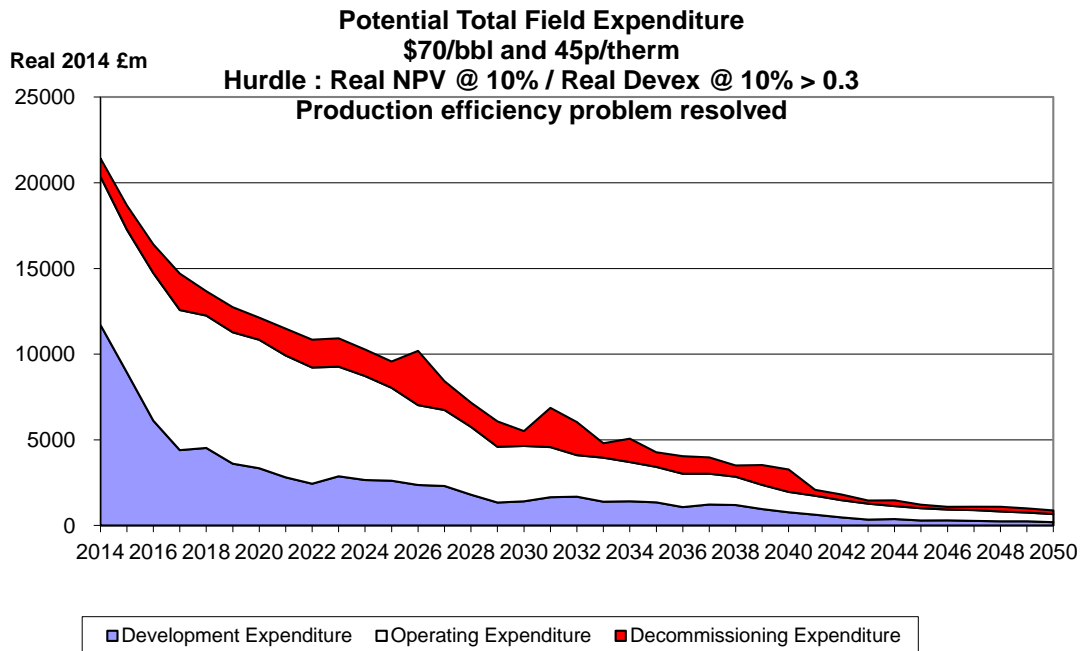


Chart 8





**(iv) Numbers of Fields Decommissioned**

In Chart 9 the numbers of fields being decommissioned over the period to 2050 are shown under the \$90, 58 pence case. Altogether 578 fields are decommissioned of which 332 are already sanctioned, 15 are probable fields, 8 are possible, 143 are technical reserves, and 80 are new discoveries.

In Chart 10 the numbers of fields being decommissioned under the \$70, 45 pence case are shown. Over the period to 2050 462 fields are decommissioned of which 329 are in the sanctioned category, 11 are probable fields, 4 are possible fields, 85 are technical reserves, and 33 are new discoveries. There is a significant reduction compared to the \$90 case in the numbers of decommissioned fields in the categories of technical reserves and new discoveries.

Chart 9

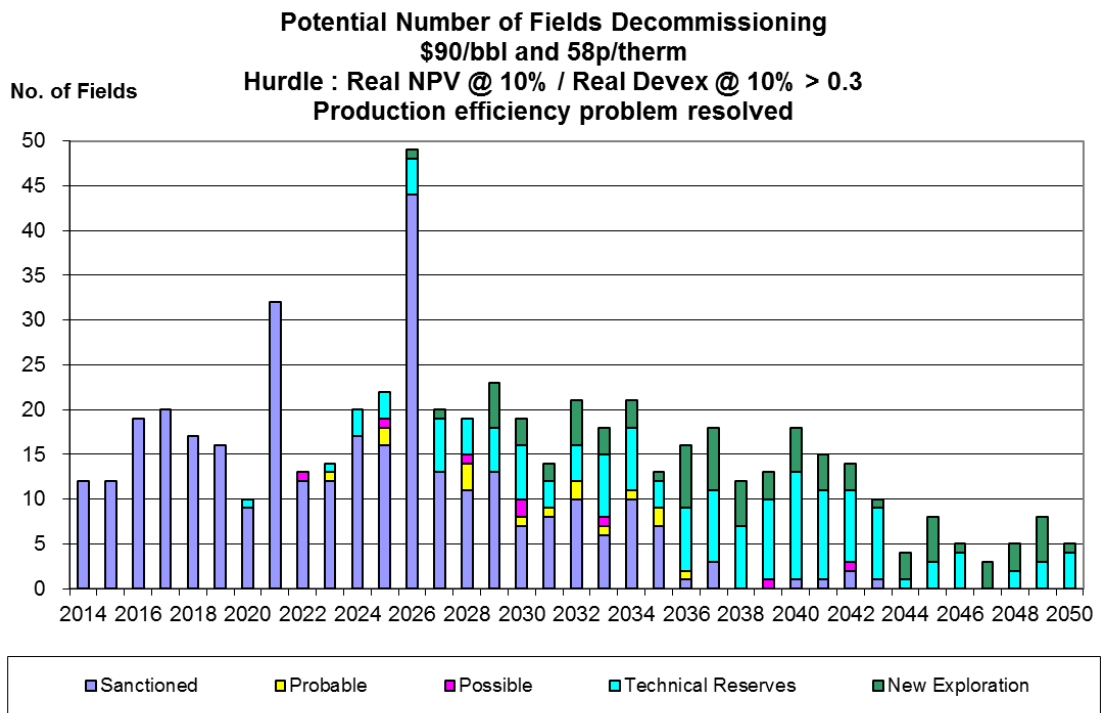
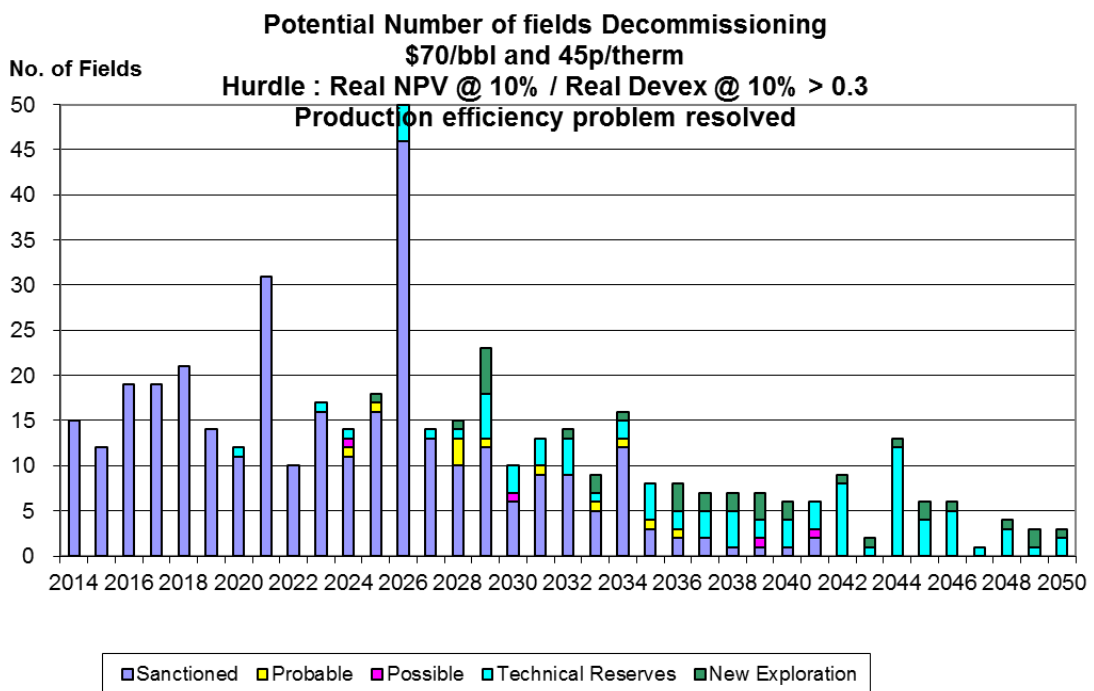


Chart 10



**(b)Hurdle Rate 0.3, Production Efficiency Problem Partly Resolved**

**(i) Total Hydrocarbon Production**

The main effect of a partial remedy to the production efficiency problem is obviously on the production profile. In Chart 11 total hydrocarbon production over the period to 2050 is shown under the \$90, 58 pence case. It is seen that there is still a significant rebound in production, but over the period the total cumulative output is 14.1 bnboe of which 6 bn comes from sanctioned fields, 0.9 bn from current incremental projects, 1.7 bn from future incremental projects, 0.9 bn from probable fields, 0.4 bn from possible fields, 2.4 bn from technical reserves and 1.9 bn from new discoveries. The main negative effect is from the sanctioned fields.

In Chart 12 the corresponding figures are shown for the \$70, 45 pence case. Cumulative production is 11 bnboe of which 5.9 bn comes from sanctioned fields, 0.8 bn from current incremental projects, 0.28 bn from probable fields, 0.36 bn from possible fields, 1.4 bn from technical reserves, and 0.75 bn from new discoveries.

The effects of the changes in assumptions regarding production efficiency on field expenditures are fairly modest and are not shown here.

Chart 11

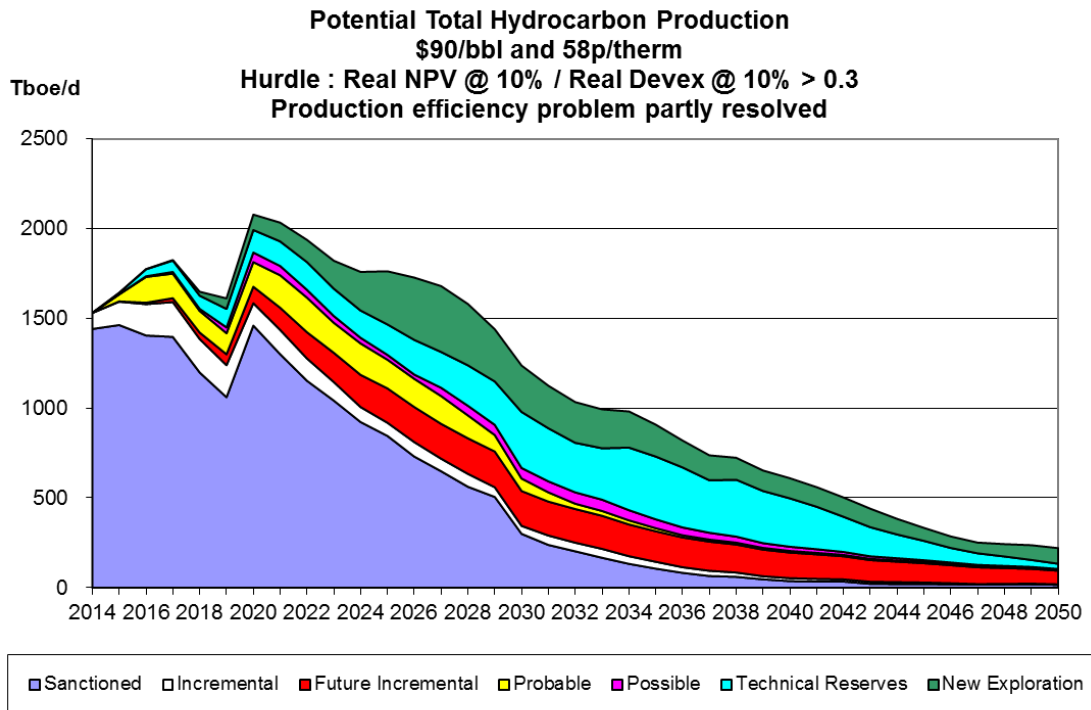
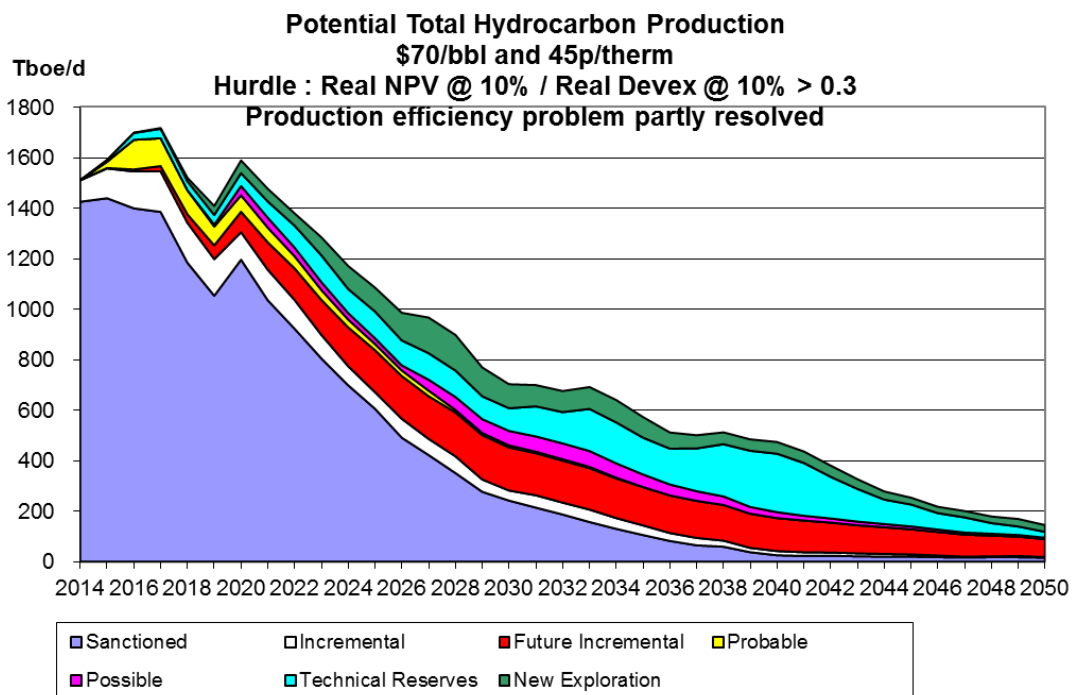


Chart 12



**(c) Hurdle Rate  $NPV/I > 0.5$ , Production Efficiency Problem Largely Resolved**

**(i) New Field Developments and COP to 2050**

In Chart 13 the numbers of fields in production are shown when the investment hurdle is  $NPV/I > 0.5$  (reflecting serious capital rationing), under the \$90, 58 pence price case. The numbers decline at a brisk pace throughout the period to 2050. There are 188 new field developments over the period (compared to 271 when the hurdle was  $NPV/I > 0.3$ ). There are 12 fields in the probable category, 6 in the possible one, 109 from technical reserves, and 61 from new discoveries.

In Chart 14 the corresponding results are shown under the \$70, 45 pence case. It is seen that the numbers of fields in production decrease at a sharp pace throughout the period. There are only 85 new field developments in total over the period (compared to 149 with the hurdle of  $NPV/I > 0.3$ ). There are 5 developments in the probable category, 2 in the possible, 61 from technical reserves, and 17 from new discoveries.

Chart 13

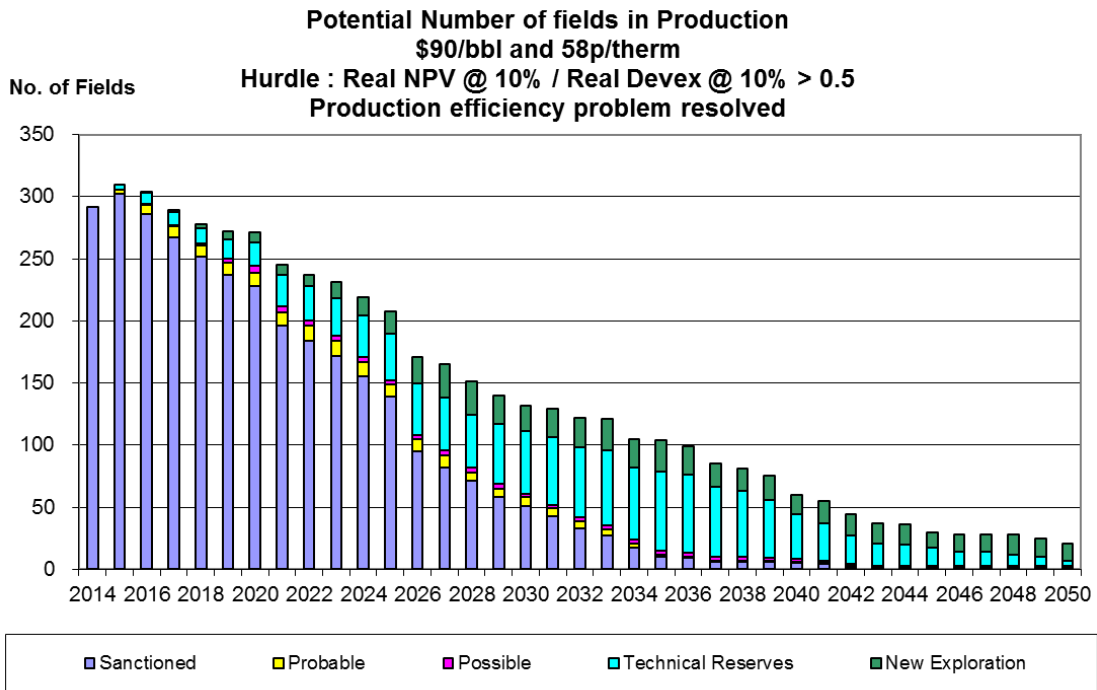
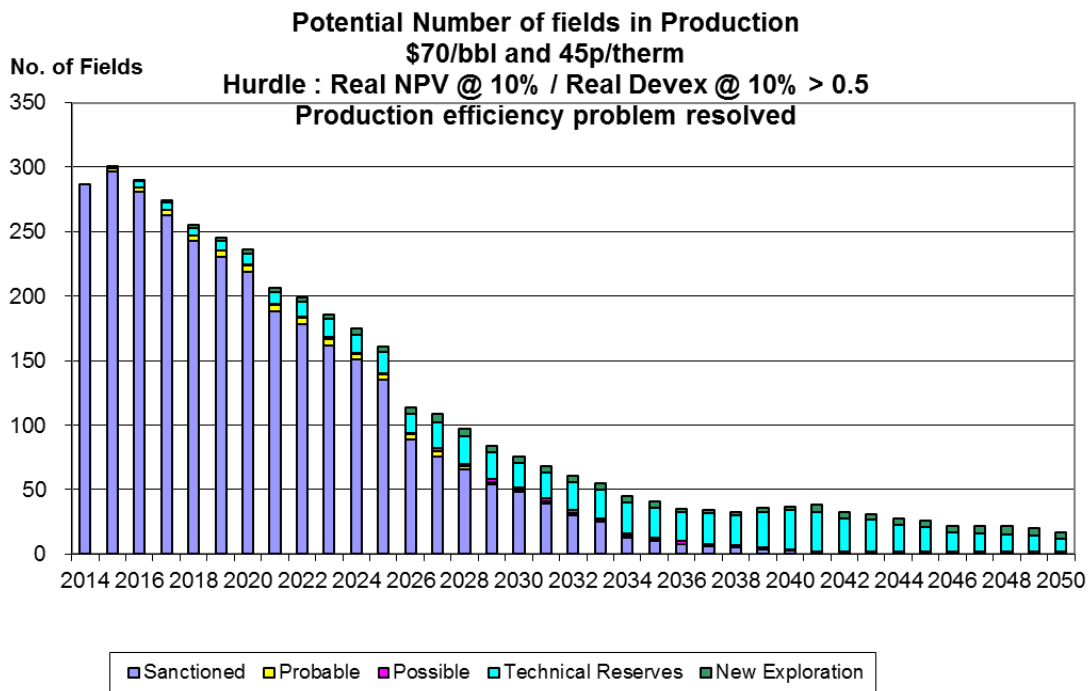


Chart 14



## **(ii) Total Hydrocarbon Production**

In Chart 15 total hydrocarbon production to 2050 is shown under the \$90, 58 pence price case. There is some upturn in the near term, but in the long run production falls at a brisk pace. The cumulative total over the period is 12.6 bnboe of which 6.9 bn comes from sanctioned fields, 0.7 bn from current incremental projects, 1.5 bn from future incremental projects, 0.5 bn from probable fields, 0.4 bn from possible fields, 1.5 bn from technical reserves, and 1.1 bn from new discoveries. Compared to the case with the hurdle  $NPV/I > 0.3$  there is much less output from fields in the categories of technical reserves and new discoveries.

In Chart 16 production under the \$70, 45 pence scenario is shown with the  $NPV/I > 0.5$  hurdle. The decline rate is steep for much of the period. Total cumulative production is 10.4 bnboe, of which 6.8 bn comes from sanctioned fields, 0.6 bn from current incremental projects, 1.3 bn from future incremental projects, 0.2 bn from probable fields, 0.3 bn from possible fields, 0.9 bn from technical reserves, and 0.3 bn from new discoveries. When the investment hurdle was  $NPV/I > 0.3$  the total production was 11.9 bn. The reduction is greatest among fields in the categories of technical reserves and new discoveries.

Chart 15

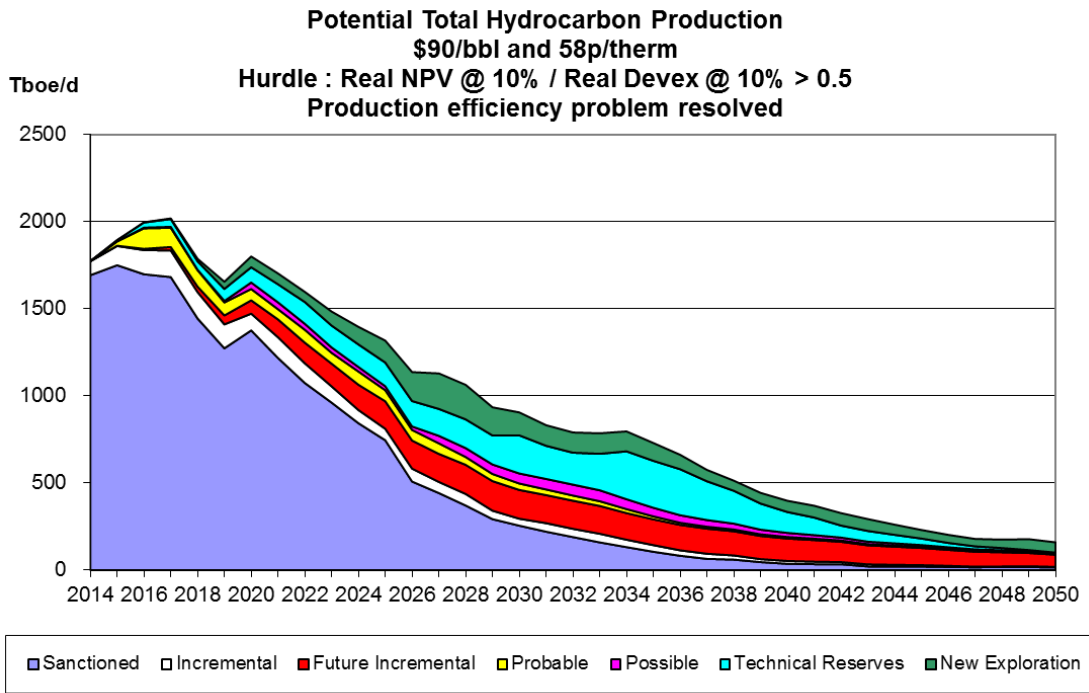
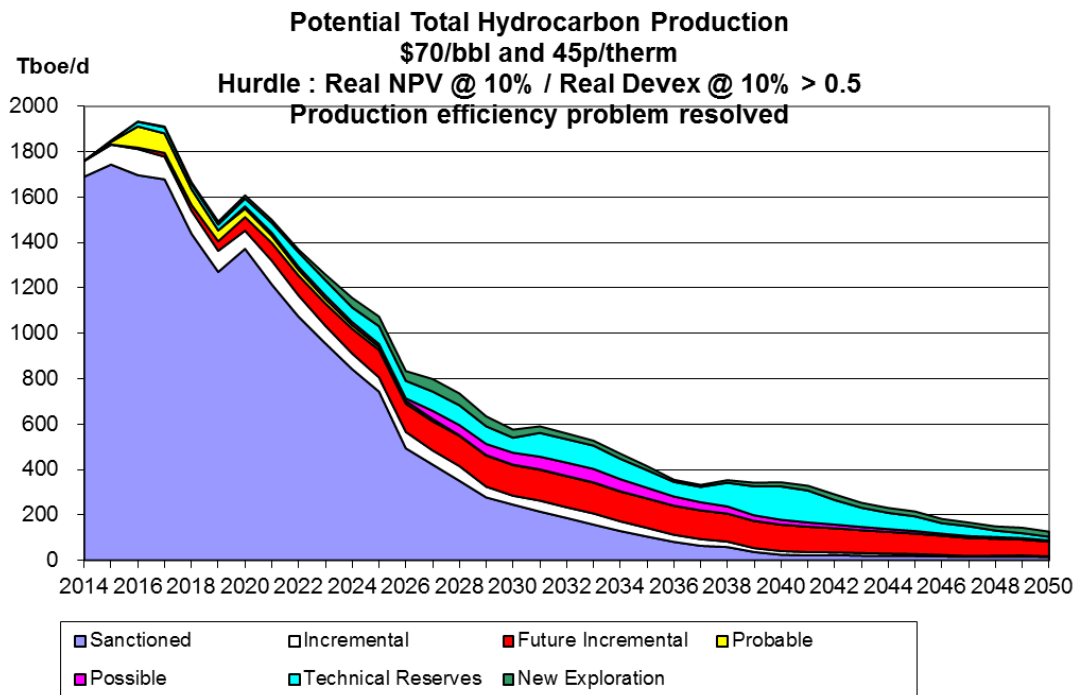


Chart 16





### **(iii) Field Expenditures**

In Charts 17 and 18 field expenditures are shown respectively by category of project and by type under the \$90, 58 pence case. It is seen that total expenditures fall sharply over the next few years, particularly with respect to new field developments. Over the whole period to 2050 cumulative development expenditure is £87.8 billion. This compares with £122 bn when the hurdle is  $NPV/I > 0.3$ . Cumulative operating expenditures are £148 bn compared £176 bn with the hurdle at  $NPV/I > 0.3$ . Total decommissioning expenditures are £42.5 bn compared to £45 bn when the hurdle was  $NPV/I > 0.3$ .

In Charts 19 and 20 field expenditures are shown by category of project and by type under the \$70, 45 pence case. It is seen that total expenditures fall sharply over the next few years. Over the period to 2050 cumulative development expenditures are only £63.5 billion (compared to £81.4 bn when the hurdle was  $NPV/I > 0.3$ ). Cumulative operating expenditures are £121 bn (compared to £135 bn at the  $NPV/I > 0.3$  hurdle). Cumulative decommissioning expenditures are £40.2 bn (compared to £42 bn when the investment hurdle is  $NPV/I > 0.3$ ).

Chart 17

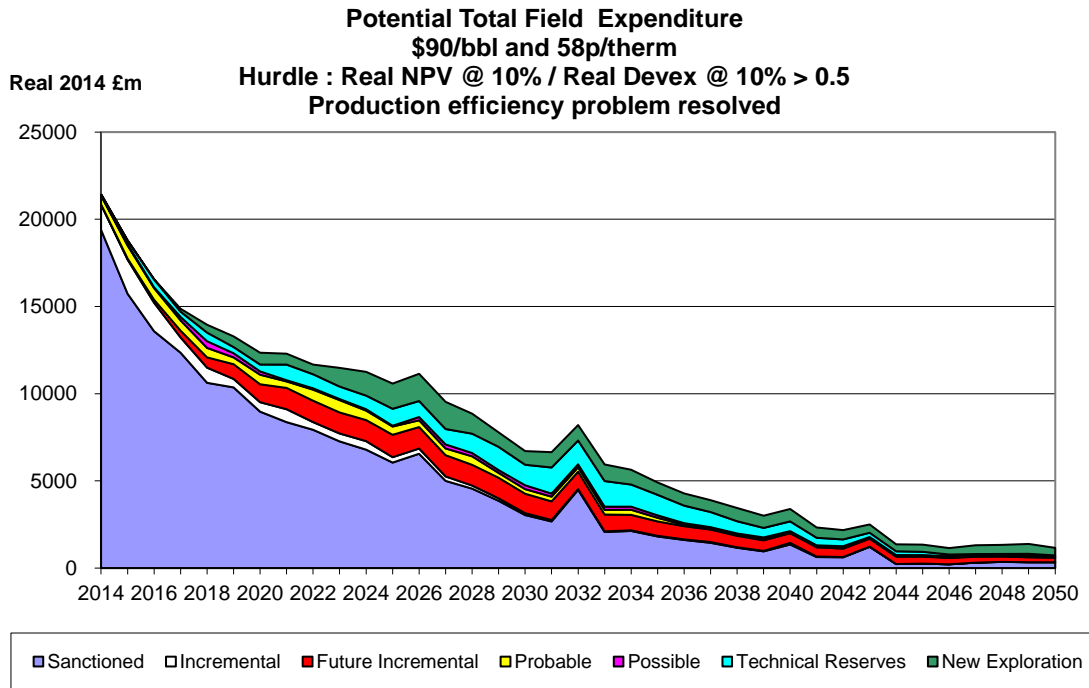


Chart 18

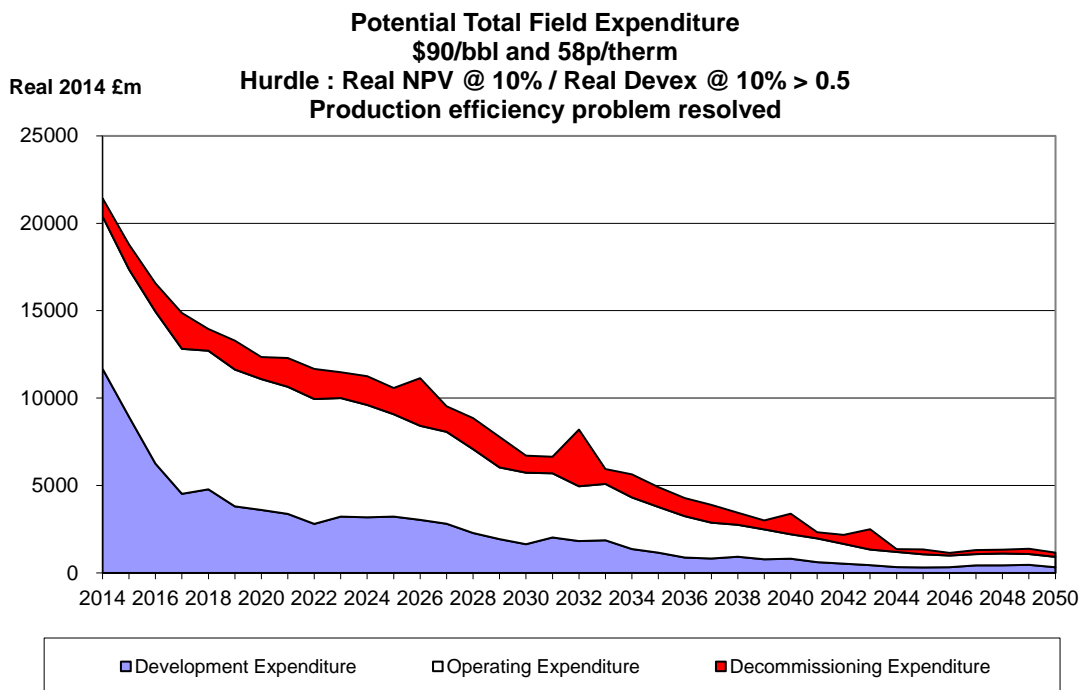


Chart 19

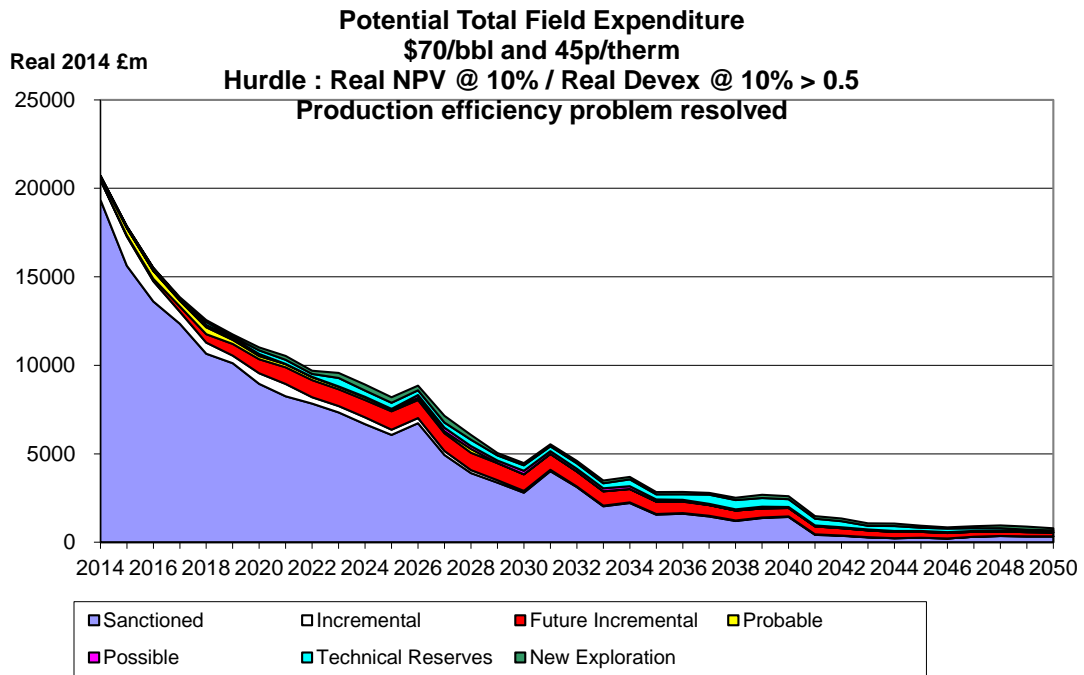
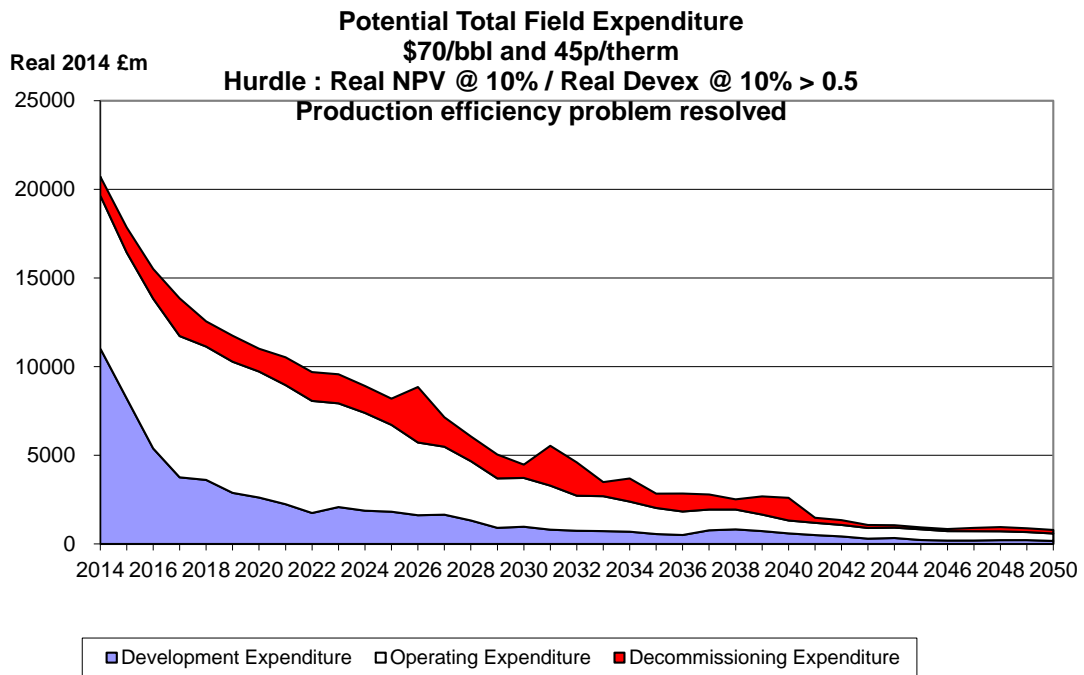


Chart 20



**(iv) Numbers of Fields Decommissioned**

In Chart 21 the numbers of fields being decommissioned over the period are shown at the \$90, 58 price case. Over the period 503 fields are decommissioned. This compares with 578 when the investment hurdle was  $NPV/I > 0.3$ . The main reductions in the numbers relate to new fields in the categories of technical reserves and new discoveries. With the higher hurdle there are significantly less new field developments in these two categories.

In Chart 22 the numbers of fields being decommissioned are shown under the \$70, 45 pence case. Over the whole period 399 fields are decommissioned under this scenario. This compares with 462 when the investment hurdle was  $NPV/I > 0.3$ . There are significantly less developments in the categories of technical reserves and new discoveries.

Chart 21

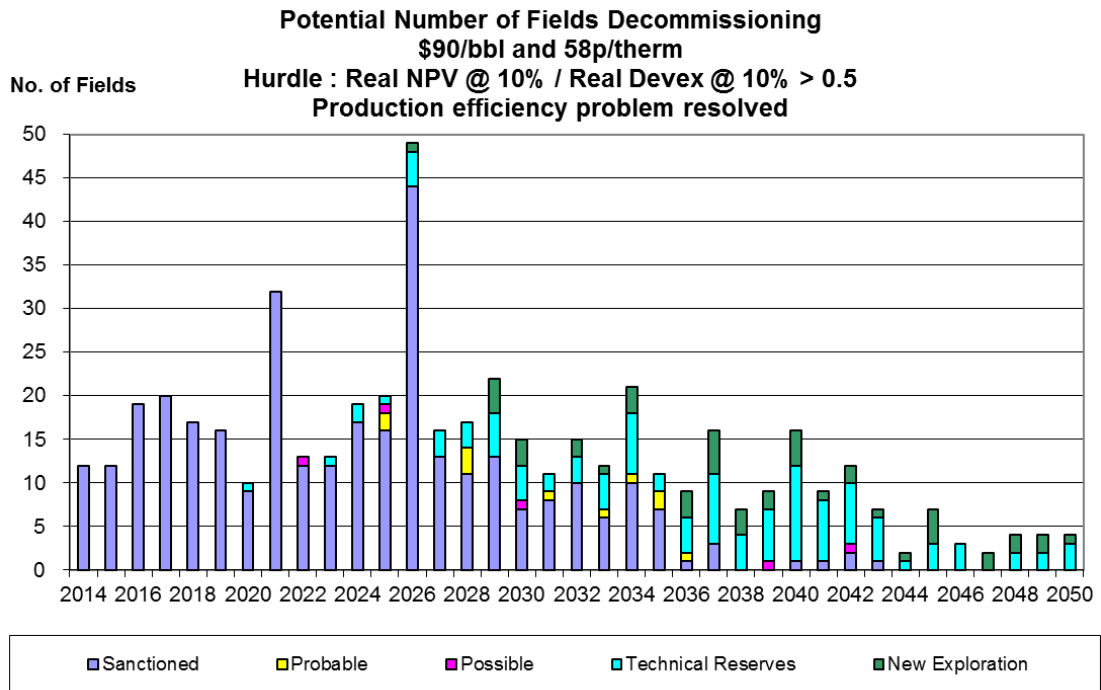
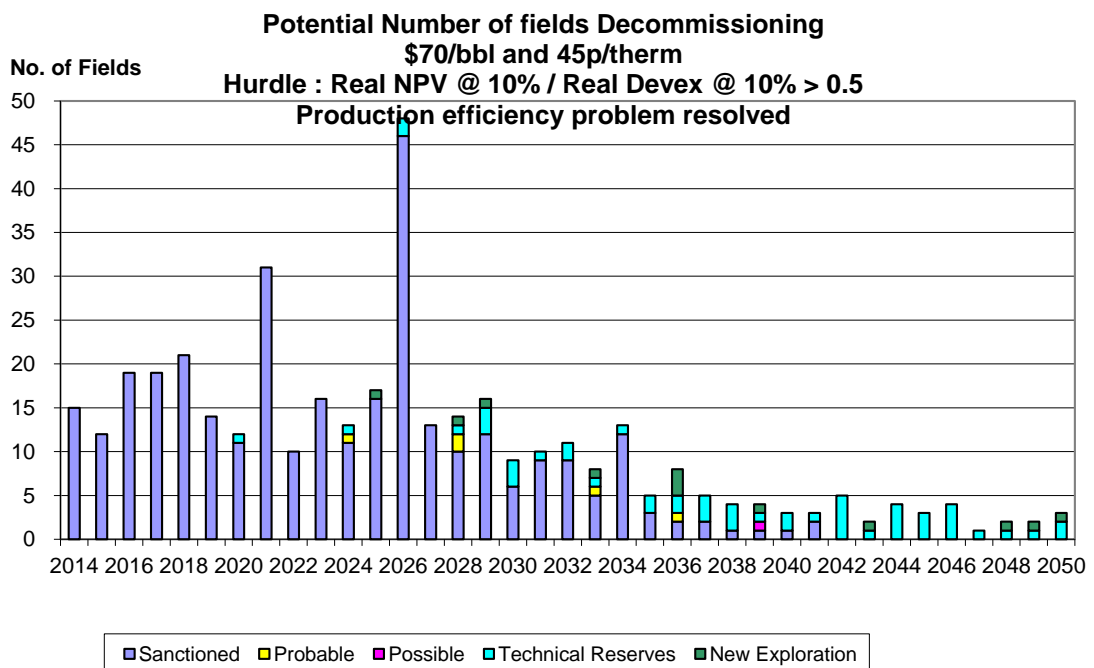


Chart 22



**(d) Hurdle Rate NPV/I > 0.5 Production Efficiency Problem Partly Resolved**

**(i) Total Hydrocarbon Production**

The main effect of a partial solution to the production efficiency problem is obviously on hydrocarbon production. In Chart 23 total hydrocarbon production under the \$90, 58 pence case is shown when there is only limited success in enhancing efficiency. The partial success leads to some increase, but the long term trend is sharply downwards. Cumulative production to 2050 is 11.7 bnboe of which 6 bn comes from sanctioned fields, 0.7 bn from current incremental projects, 1.5 bn from future incremental projects, 0.5 bn from probable fields, 0.4 bn from possible fields, 1.5 bn from technical reserves and 1.1 bn from new discoveries.

The corresponding figures for production under the \$70, 45 pence case are shown in Chart 24. The main feature is the steep decline over a prolonged period. Total cumulative production is 9.5 bnboe of which 5.9 bn comes from sanctioned fields, 0.6 bn from current incremental projects, 1.3 bn from future incremental projects, 0.2 bn from probable fields, 0.3 bn from possible fields, 0.9 bn from technical reserves, and 0.3 bn from new discoveries. When the investment hurdle was  $NPV/I > 0.3$  the total recovery in the period was 11 bnboe.

Chart 23

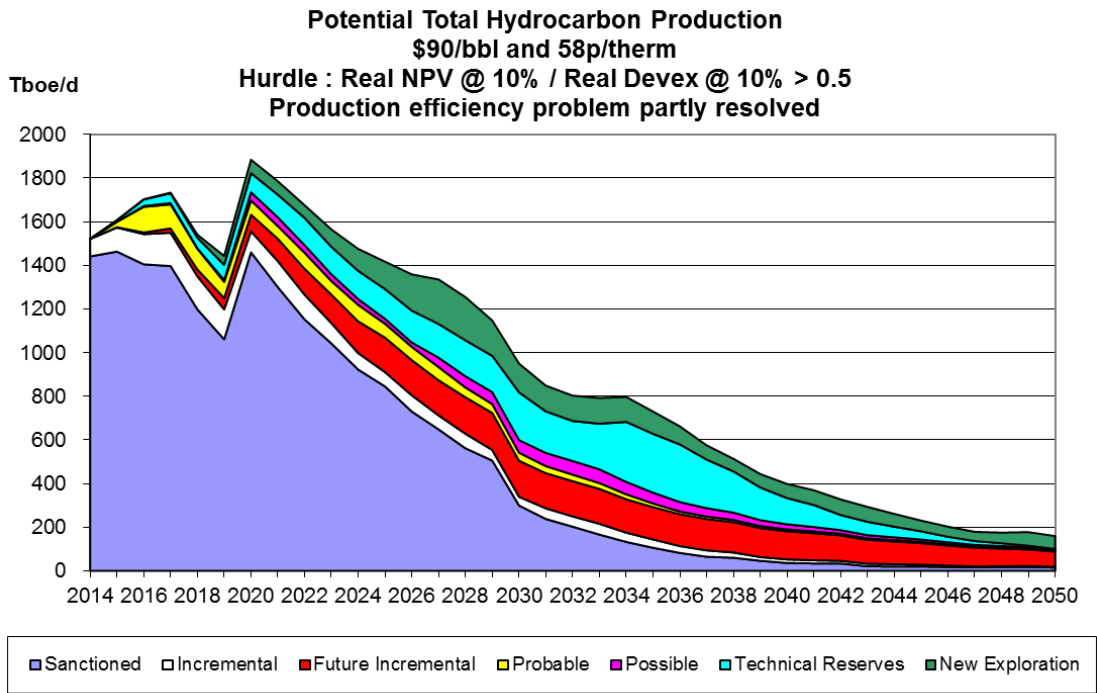
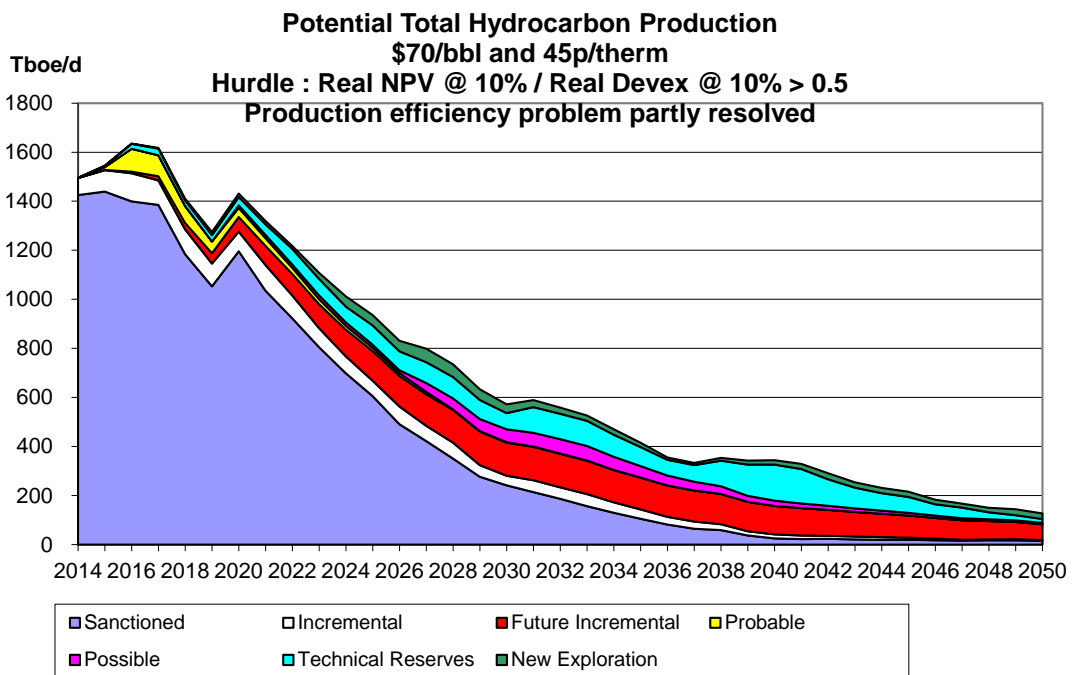


Chart 24



#### 4. Conclusions

Oil price volatility is a feature of the international petroleum industry. The recent substantial fall was a surprise to many observers, given the actual and potential supply disruptions in several major producing countries. Given the very subdued growth in oil demand, the buoyant supply position in the USA, and the further potential increases from producing countries currently suffering from supply disruptions and sanctions, the possibility that the lower prices will continue for some time cannot be entirely discounted. Capital rationing is also a prevalent feature of the current investment climate. It is affecting large, medium and small companies alike.

In these circumstances it is useful to assess the implications of these two phenomena on the future prospects for activity in the UKCS. Investment screening prices of (1) \$90 and 58 pence in constant real terms and (2) \$70 and 45 pence were chosen. The second price scenario is believed to be used by banks in screening loan applications. Investment hurdles of (1)  $NPV/I > 0.3$  and (2)  $NPV/I > 0.5$  were chosen to represent modest and serious capital rationing facing investors.

The results of the modelling indicate that long term activity in the UKCS reflected in production, investment and operating expenditures is very sensitive to movements in the screening prices and investment hurdles. In the near term investment in new field developments would fall substantially under the lower price and higher investment hurdles. The price fall has come at a particularly unfortunate time giving the pre-existence of the capital rationing problem. This has also come at a time when the Wood Review recommendations have still to be



implemented. But it is better to be fully informed of the challenges facing the industry. Both the implementation of the Wood Review and the Tax Review need to take these current challenges into account.

## Appendix I

### Recent Tax Changes in UKCS

CT at 30%

SC at 32% (from 2011)

All E and A and D costs deductible on 100% first year basis

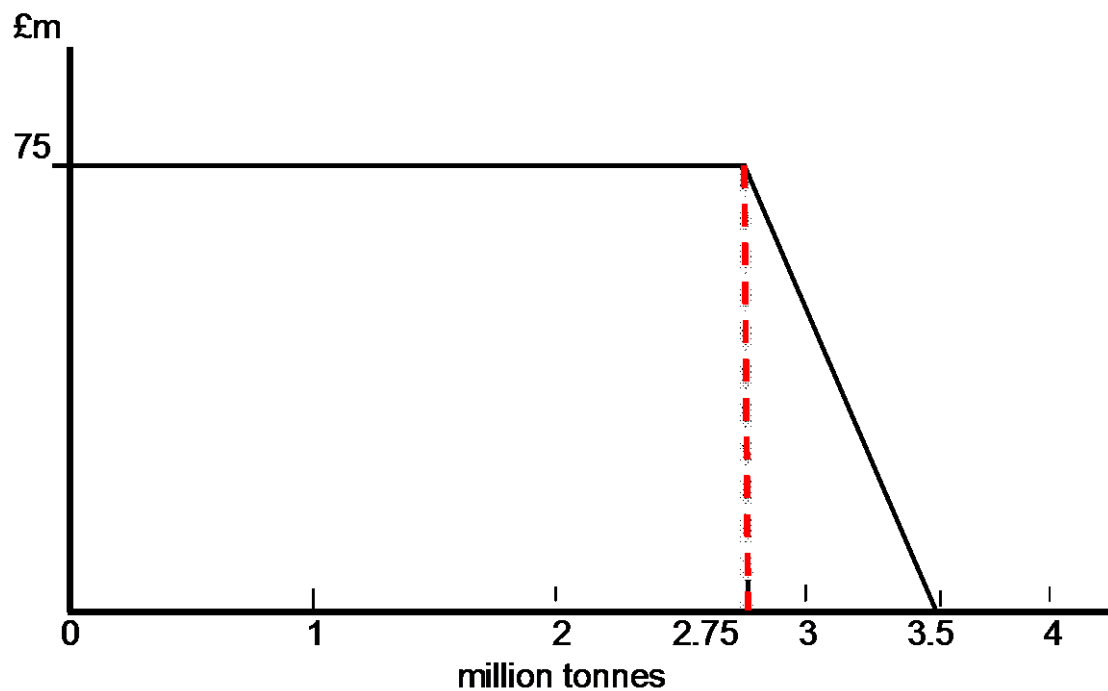
Budget 2009 introduced:

Field Allowance for Supplementary Charge

### Budget 2009

- The field allowance for small fields is £75 million for fields with oil reserves (or gas equivalent) of 2.75 million tonnes or less, reducing on a straight line basis to nil for fields over 3.5 million tonnes. In any one year the maximum field allowance (for a field with total allowance of £75 million) is £15 million.

**Field Allowance for Small Fields (2009)**



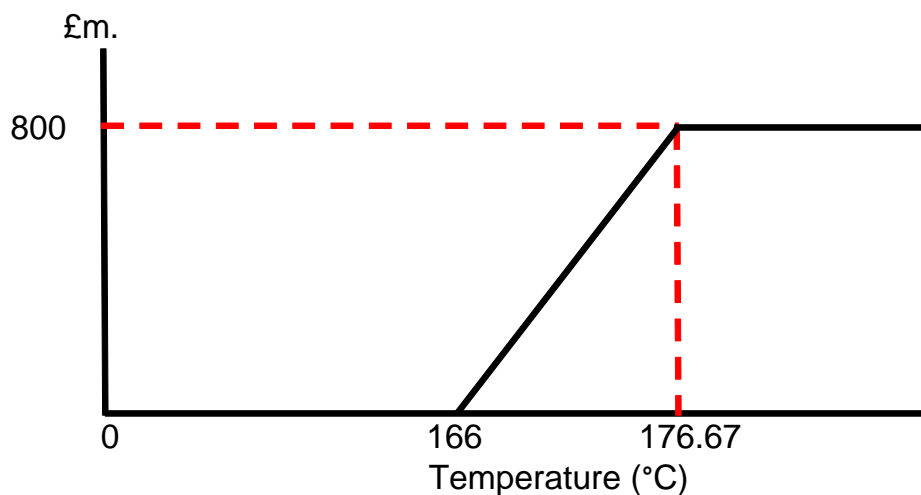
- The field allowance for ultra heavy oil fields is £800 million for fields with an American Petroleum Institute gravity below 18 degrees and a viscosity of more than 50 centipoise at reservoir temperature and pressure. In any one year the maximum field allowance is £160 million.
- The field allowance for ultra high temperature/pressure fields is £800 million for fields with a temperature of more than 176.67 degrees Celsius and pressure of more than 1034 bar in the reservoir formation. In any one year the maximum field allowance is £160 million.

Pre-Budget Report 2009

- In PBR 2009 qualifying criteria for HP/HT fields modified to 166°C and 862 bar. Allowance increases on SL basis from £500m. at 166°C to £800m. at 176.6°C.

**Field Allowance for HP/HT Fields**

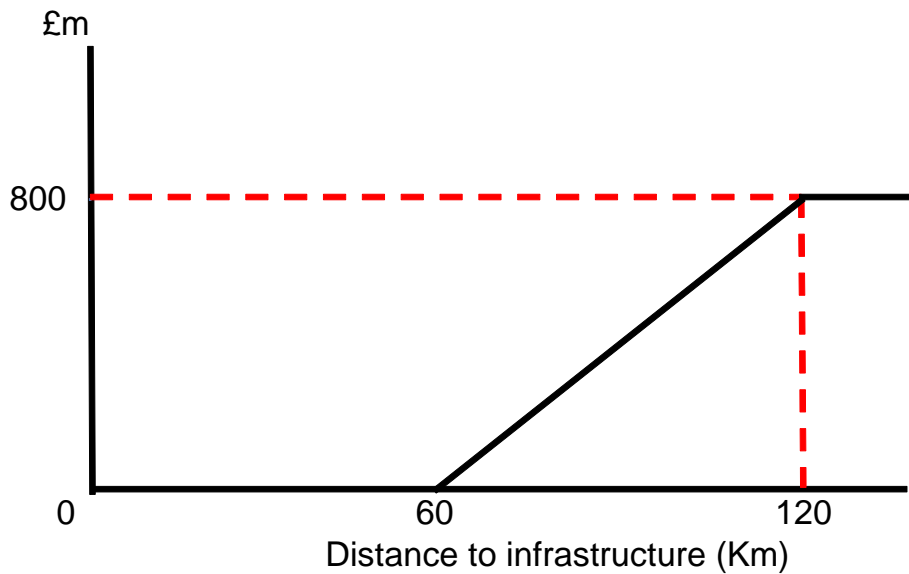
Pressure of over 862 bar required



- In January 2010 field allowance of up to £800m. (max. £160m. in any 1 year) extended to remote, deep-water gas fields.
- Qualifying criteria:

- (a) gas more than 75% of reserves
- (b) field located in water depth > 300 metres
- (c) distance from field to relevant infrastructure > 60 km. Allowance increases linearly from £0 at 60k. to £800m. at 120 km.

**Field Allowance for Remote, Deep Water Gas Fields**



Budget 2011

SC increased from 20% to 32%

	Tax Rates	
	Pre Budget	Post Budget
PRT fields	75%	81%
Non-PRT fields	50%	62%

	Decommissioning Relief	
	Pre Budget	From 2012
PRT fields	75%	75%
Non-PRT fields	50%	50%

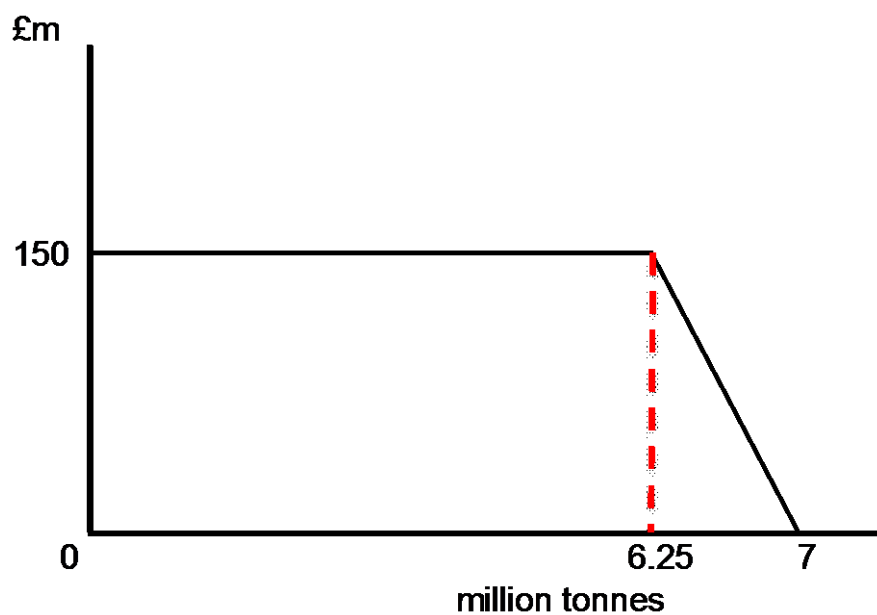
## July 2011

- Increase in Ring Fence Expenditure Supplement interest rate from 6% to 10%, taking effect from January 2012. (In 2003 exploration /appraisal supplement (EES) was introduced allowing unused exploration and appraisal allowances to be carried forward at 6% compound interest for a maximum period of 6 years. From January 2006 the allowance was extended to development costs and renamed the Ring Fence Expenditure Supplement (RFES)).

## Budget 2012

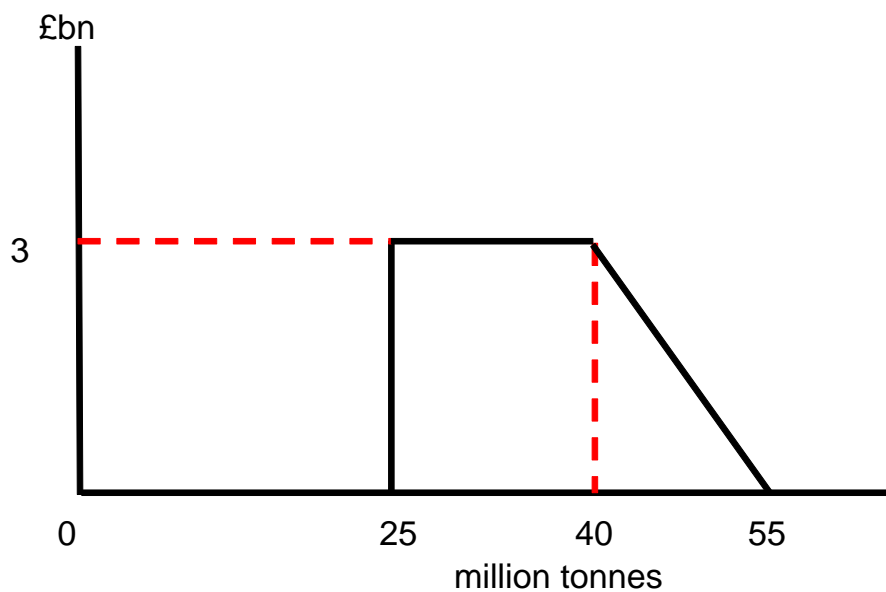
- Field allowances extended to fields already developed (incremental projects).
- Small field allowance increased from total of £75m. to £150m. and size of qualifying fields increased from 2.75m. tonnes or less to 6.25m. tonnes or less. The extended allowance is tapered to zero at 7m. tonnes (compared to 3.5m. tonnes).

**Field Allowance for Small Fields (2012)**



- £3bn. field allowance (over 5 years) for new fields with qualifying criteria:
  - (a) Water depth > 1000 metres
  - (b) Minimum reserves of 25m. tonnes
  - (c) Maximum reserves of 40m. tonnes with taper to £0 at 55m. tonnes

### Field Allowance for Large, Deep Water Fields



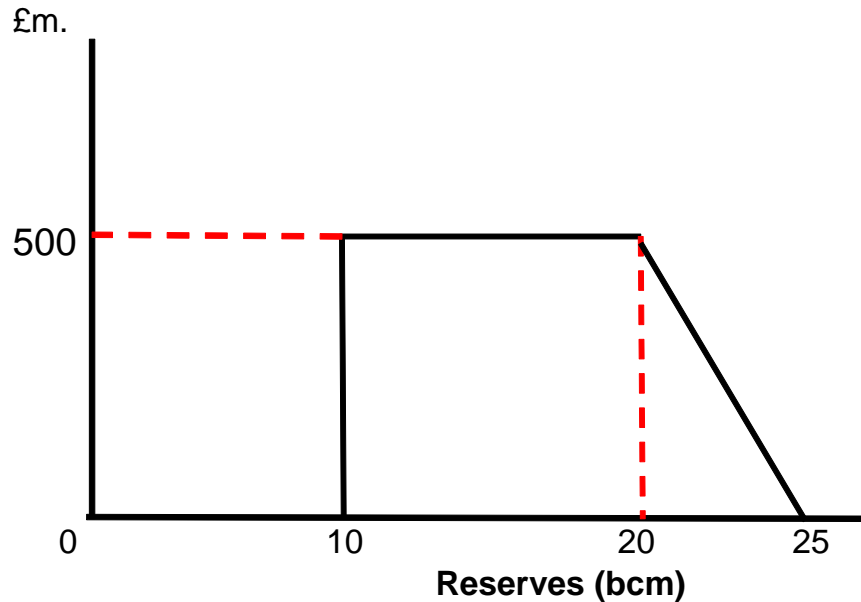
- The Government to introduce legislation in Finance Bill 2013 giving it statutory authority to sign contracts with companies operating in the UK an UK Continental Shelf, to provide assurance on the relief they will receive when decommissioning assets.

### July 2012

- Announcement of field allowance of £500 million. (over 5 years) for large, shallow water, gas fields.
- Qualifying criteria:
  - (a) Water depth < 30 metres

(b) Reserves more than 10 bcm and less than 20 bcm with taper to 25 bcm

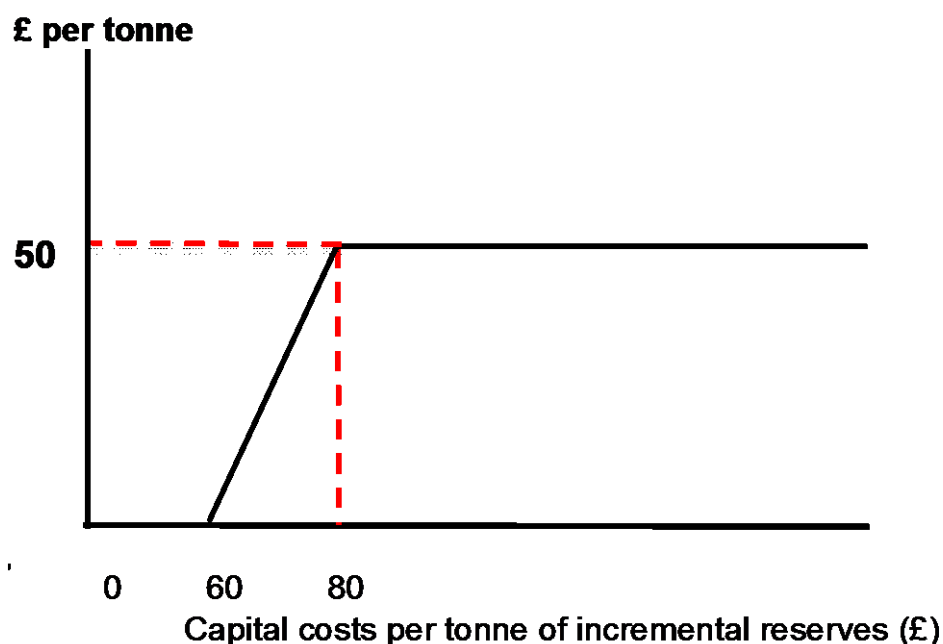
### Field Allowance for Large, Shallow Water Gas Fields



### September 2012

- Announcement of Brownfield Allowance (BFA) for incremental projects in producing fields.
- Qualifying criteria: capital costs per incremental tonne of reserves exceeding £60. Allowance increases linearly to maximum of £50 per tonne when capital costs reach £80 per tonne.
- Allowance spread over 5 years.
- Maximum allowance: £250m. in non-PRT-paying fields  
£500m. in PRT-paying fields.
- B.F.A. currently does NOT apply to CO<sub>2</sub> EOR

## Brownfield Allowance



### December 2013

Introduction of an allowance against SC of 75% of capital expenditure on onshore oil and gas projects

Extension of RFES from 6 to 10 accounting periods for all ring fence onshore oil and gas losses

From 2014 extension of reinvestment relief to protect a chargeable gain being subject to CT where a company sells an asset relating to petroleum exploration and appraisal and reinvests the proceeds in the UK or UKCS

### Budget 2014

Proposal to introduce a new allowance of at least 62.5% of capital expenditure against SC for ultra HP/HT oil and gas projects. Qualifying expenditure to include exploration and appraisal in areas adjacent to the field

Announcement of full tax review for UKCS