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The Long Term Prospects for Activity in the UK Continental Shelf

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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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d) Economics of Gas/Oil Exploitation in West of Shetland/Scotland Region
e) Further Analysis of Taxation on mature PRT-paying Fields
f) Further Analysis of Field Allowances for Small Fields, HP/HT Fields, and Heavy Oil Fields for Supplementary Charge
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The Long Term Prospects for Activity in the UK Continental Shelf

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And
Linda Stephen

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The Long Term Prospects for Activity in the UK Continental Shelf

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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 major changes in (1) oil and gas prices (and expectations regarding their future behaviour), (2) exploration success rates, (3) investment and operating costs, (4) costs and availability of finance, and (5) the tax system. Recently tax reliefs were introduced for investments in fields characterised by heavy oil, HP/HT or gas in remote locations. In this paper financial modelling is employed to produce long term projections of activity to 2041. The outputs highlighted are production of oil and gas, field investment and operating costs, and decommissioning costs.

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, recently-updated, 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 nearly 340 sanctioned fields, 177 incremental projects relating to these fields, 34 probable fields, and 46 possible fields. These unsanctioned fields are currently being examined for development. An additional database contains 252 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) 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 2036. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 5 years was calculated separately for 6 areas of the UKCS (Southern North Sea, (SNS), Central North Sea (CNS), Moray Firth (MF), Northern North Sea (NNS), West of Scotland (WOS), and Irish Sea (IS)), and the results employed for use in 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 3 future oil/gas price scenarios were employed as follows:

Table 1 Future Oil and Gas Price Scenarios		
	Oil Price (real) $/bbl	Gas Price (real) pence/therm
High	90	70
Medium	70	50
Low	50	30

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2011, 2030, and 2035:

Table 2 Exploration Wells Drilled			
	2011	2030	2035
High	38	32	25
Medium	32	22	20
Low	25	18	15

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

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 that higher effort involves the acceptance of higher risk. For the

UKCS as a whole 3 success rates were postulated as follows with the medium one reflecting the average over the past 5 years.

Table 3 **Success Rates for UKCS**	
Medium effort/Medium success rate	= 27%
High effort/Low success rate	= 25%
Low effort/High success rate	= 29%

It should be noted that success rates have varied considerably across 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 these success rates over the time period.

The mean sizes of discoveries made in the historic period for each of the 6 regions were calculated. They are shown in Table 4. It was then assumed that the mean size of discovery would decrease in line with recent historic experience. Such decline rates are quite modest.

Table 4 Mean Discovery Size MMboe	
SNS	**8.2**
CNS	**31.84**
NNS	**67.61**
MF	**14.94**
WoS	**74.7**
IS	**7.14**

For purposes of the Monte Carlo modelling of new discoveries the 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 6 regions to 2036. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

Table 5 **Total Number of Discoveries to 2036**	
High effort/Low success rate	216
Medium Effort/Medium Success Rate	165
Low effort/High success rate	161

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. Thus in the SNS development costs were found to average nearly $12.05 per boe because of the small size of fields. In the CNS they averaged $17.27/boe and in the NNS they averaged $13.65/boe. Operating costs over the lifetime of the fields were also calculated. The averages were found to be $11.47/boe in the SNS, $12.36/boe in the CNS and $11.82/boe in the NNS. Total lifetime field costs (including decommissioning but excluding E and A costs) were found to average

$24.62 per boe in the SNS, $31.95 per boe in the CNS, and $26.71 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 modeled 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 in the exploitation costs. Thus the field lifetime costs in small fields could become very high on a per boe basis.

With respect to fields in the category of technical reserves it was recognised that many have remained undeveloped for a long time, 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 the mean development costs are over $22/boe and in NNS over $18/boe. For purposes of Monte Carlo modelling a normal distribution of the recoverable reserves for each field with a SD = 50% of the mean was assumed. With respect to development costs the distribution was assumed to be normal with a SD = 20% of the mean value.

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 20, 17, and 13 respectively under the High, Medium, and Low Price Cases. These constraints do <u>not</u> apply to incremental projects which are <u>additional</u> to new field developments.

A noteworthy feature of the 177 incremental projects in the database validated by operators 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 5 years indicated a decline rate in the volumes. On the basis of this, and from a base of 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 <u>all</u> 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. Recent mean discovery sizes are shown in Table 4 but, given the lognormal distribution, 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, 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 through allowances. 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. The development project goes ahead when the NPV/I ratio as defined above in real terms ≥ 0.3. 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. This includes the field allowances introduced in Finance Act 2009.

In the light of experience over the past few years some rephasing of the timing of the commencement dates of new field developments and incremental projects from those projected by operators was undertaken related to the probability that the project would go ahead. Where the operator indicated that a new field development had a probability ≥ 80% of going ahead the date was left unchanged. Where the probability ≥ 60% < 80% the commencement date was slipped by 1 year. Where the probability ≥ 40% < 60% the date was slipped by 2 years. Where the probability was ≥ 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 ≥ 50% the date was retained but where it was < 50% it was slipped by 1 year.

3. Results

A. Numbers of Fields in Production

The numbers of producing fields under the 3 oil/gas price scenarios are shown in Charts 1 – 3. Under the low scenario it is seen that the numbers fall very steeply from 293 in 2009 to 45 in 2041. The sharp decrease reflects (1) the small numbers of new fields and incremental projects which are triggered under the investment hurdle specified, (2) the sharp production decline rates in sanctioned fields, thus hastening their COP dates, and (3) the (comparatively) small number of new discoveries under the low price case. Under the \$70, 50 pence case (Chart 2) the numbers of producing fields remain well in excess of 250 until after 2020 after which there is a steady decline to 115 in 2041. It is seen that under this scenario the development of far more new discoveries is triggered compared to the low price case. Similarly, it is seen that substantial numbers of fields in the category of technical reserves are triggered. In Chart 3 it is seen that the numbers of fields in production actually increase to a peak in excess of 322 in the 2017. After that there is a gradual decrease but the total still exceeds 312 in 2022. Thereafter the decline is faster but there are still nearly 170 producing fields in 2041. Compared to the \$70, 50 pence case there is a noteworthy increase in the numbers of high cost fields in the category of technical reserves.

Chart 1

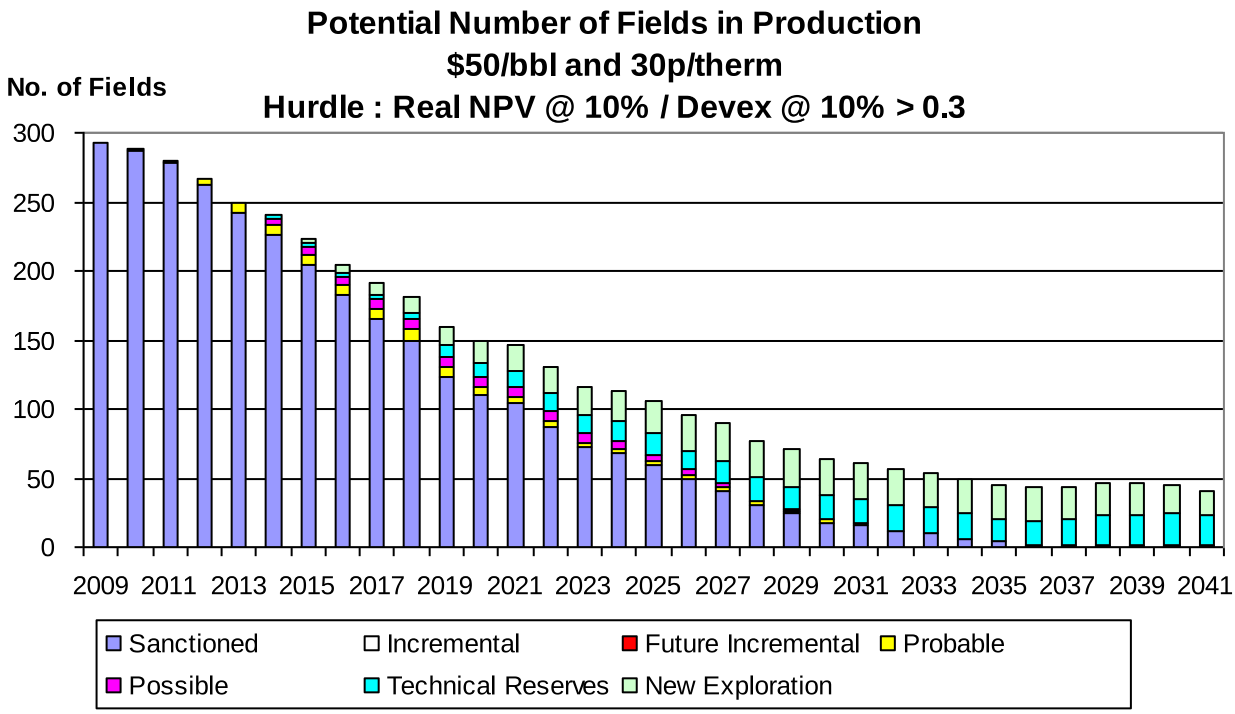


Chart 2

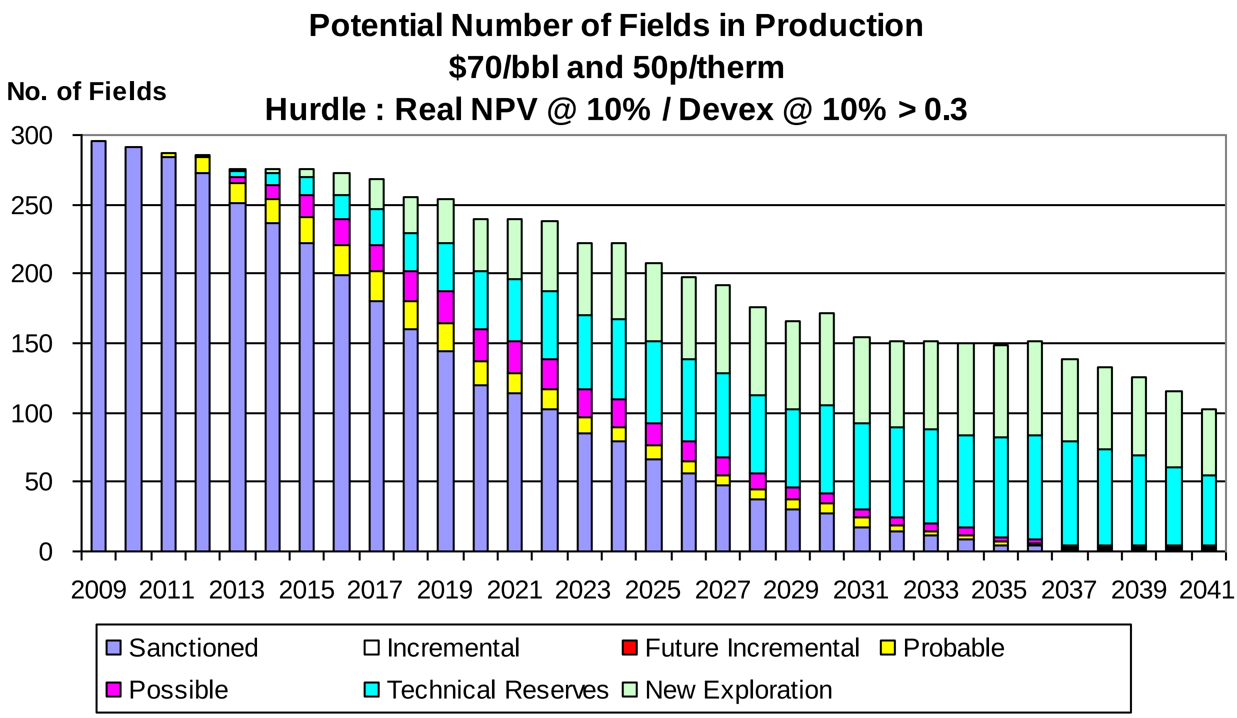
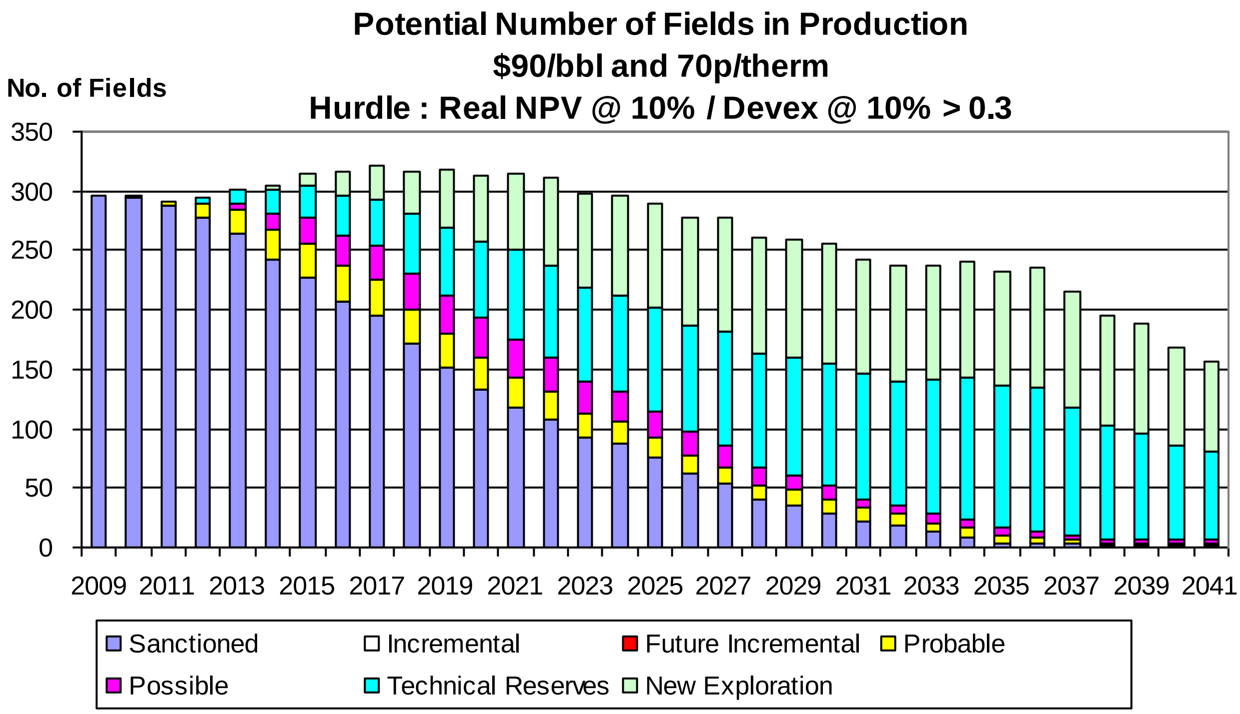


Chart 3



B. Production

(i) Oil

Prospective oil production under the 3 price cases is shown in Charts 4 – 6. In the low price case (Chart 4) it is seen that oil production falls at a fast pace over the period and, compared to 1.34 mm b/d in 2009, is around 0.41 mm b/d in 2040. Output from the sanctioned fields falls at a brisk pace. This is moderated somewhat in the longer term by the development of incremental projects. A noticeable feature is the small contribution from fields in the probable and possible categories. In the long term there is a worthwhile contribution from future discoveries but little from the high cost fields in the category of technical reserves.

In Chart 5 the prospective oil production under the $70, 50 pence case is shown. There is substantial potential production from the technical reserves fields and new discoveries. Ultimate decline begins in 2017 after which it falls to around 0.79 mm b/d in 2040. It is seen that there is a very substantial contribution from fields in the categories of future incremental, new discoveries and technical reserves in the longer term.

In Chart 6 the prospects under the $90, 70 pence case are shown. In this scenario the technical reserve fields and new discoveries maintain very substantial production. Ultimate decline does not begin until 2028 to reach around 1.04 mm b/d in 2040. The remarkably low decline rate over the next decade is principally due to the development of very substantial numbers of fields in the category of future incremental projects, technical reserves, as well as considerable output from new discoveries. The tax recent reliefs play a worthwhile role in this high production case. It should be stressed that this scenario is highly optimistic. In particular an underlying assumption is that capital rationing and consequentially tough investment hurdle rates do not hamper new developments to a marked extent. In the current circumstances of capital markets it would not be surprising if higher costs of capital and tougher investment hurdles than are incorporated in this scenario did prevail in some cases, particularly in relation to high cost fields in the technical reserves category. Thus the results should be regarded as very optimistic.

Chart 4

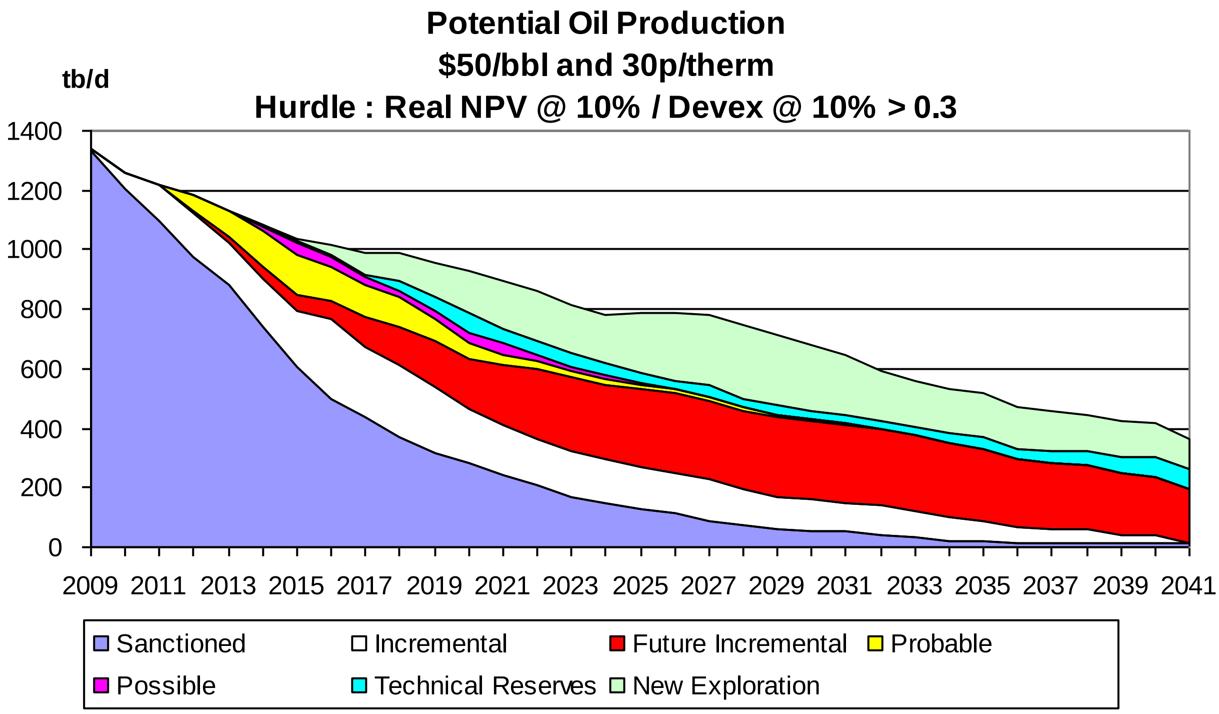


Chart 5

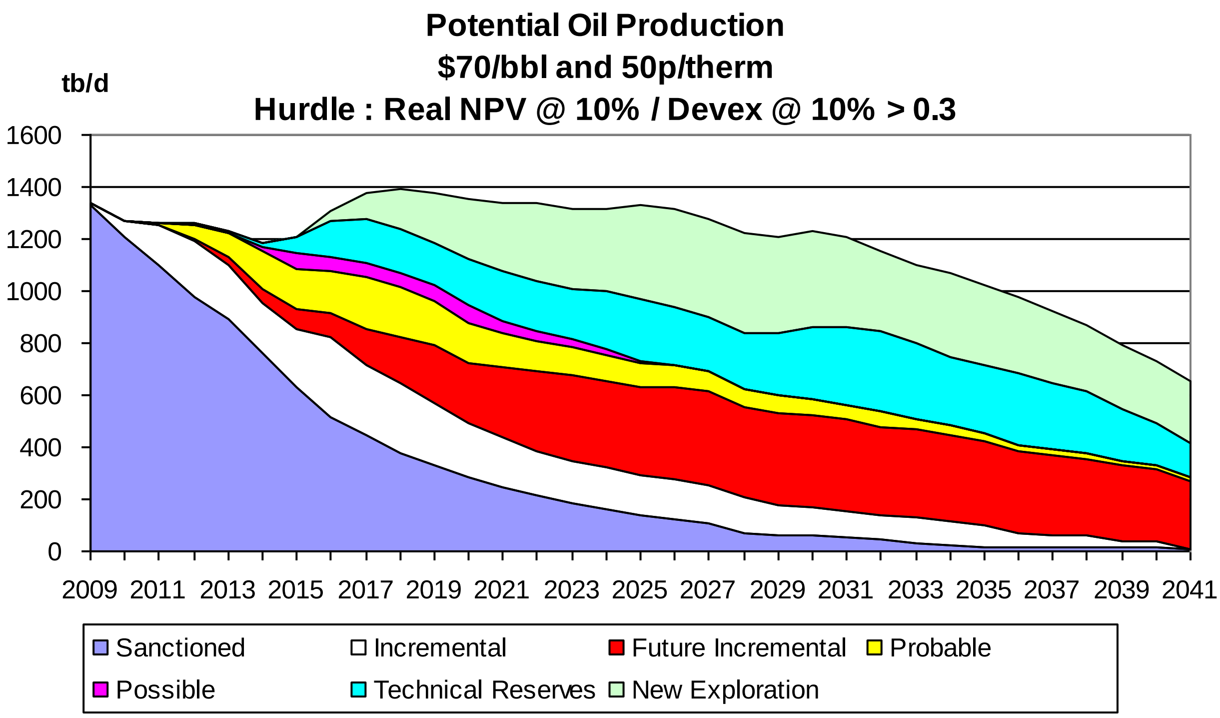
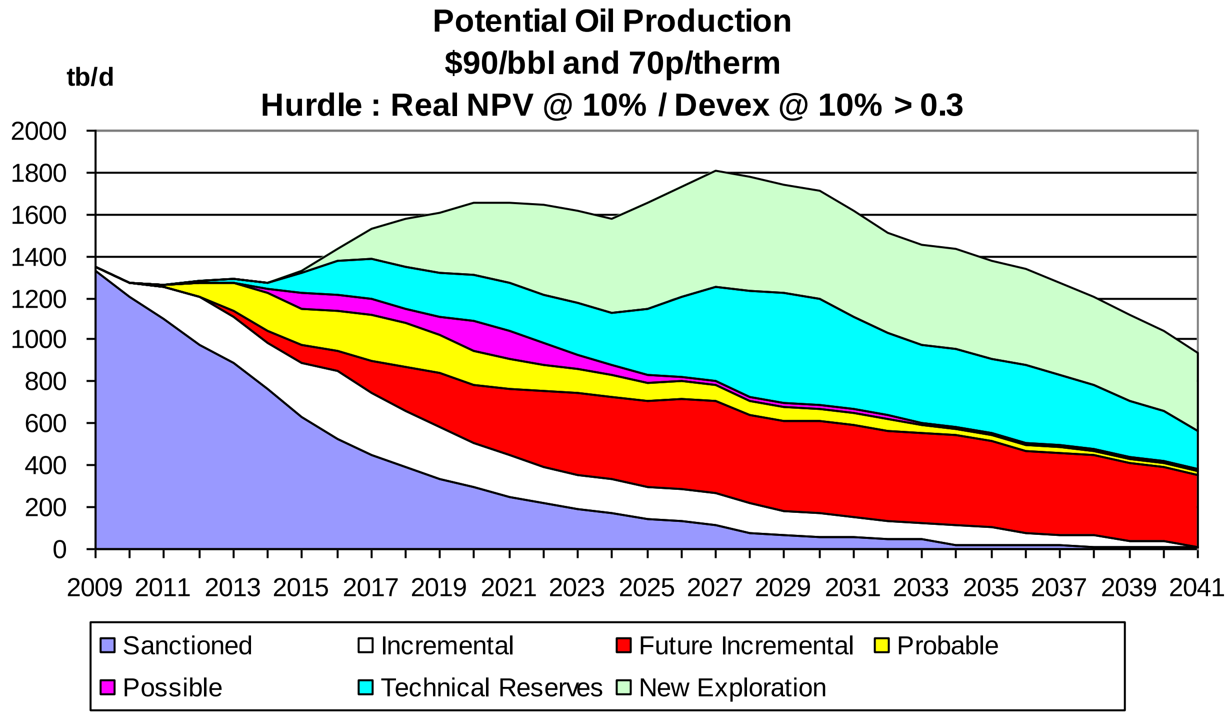


Chart 6



In Charts 7 – 9 prospective oil production under the 3 price cases are shown categorised according to 6 geographical areas of the UKCS. Under the $50, 30 pence case (Chart 7) it is seen that the CNS remains the most important area of production for many years. The W of S region becomes relatively more important in the later part of the period but cannot prevent the decline rate from being persistently steep.

Under the $70, 50 pence case (Chart 8) the CNS, WoS and NNS play major roles in maintaining production. In the longer term the W of S region becomes increasingly important. Under the $90, 70 pence case (Chart 9) the major contributions from the CNS, WoS and NNS in maintaining production are noteworthy, but the most striking feature is the much larger contribution from the W of S region. At this price the high cost fields in this region including new discoveries become economic.

Chart 7

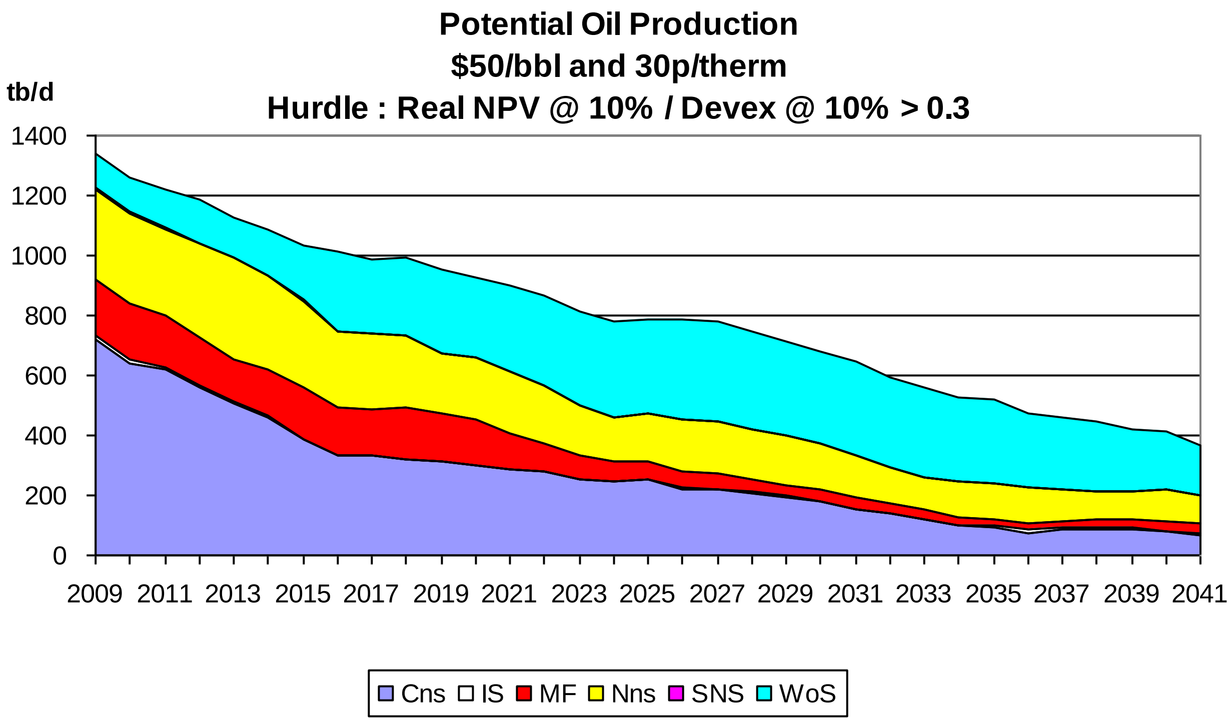


Chart 8

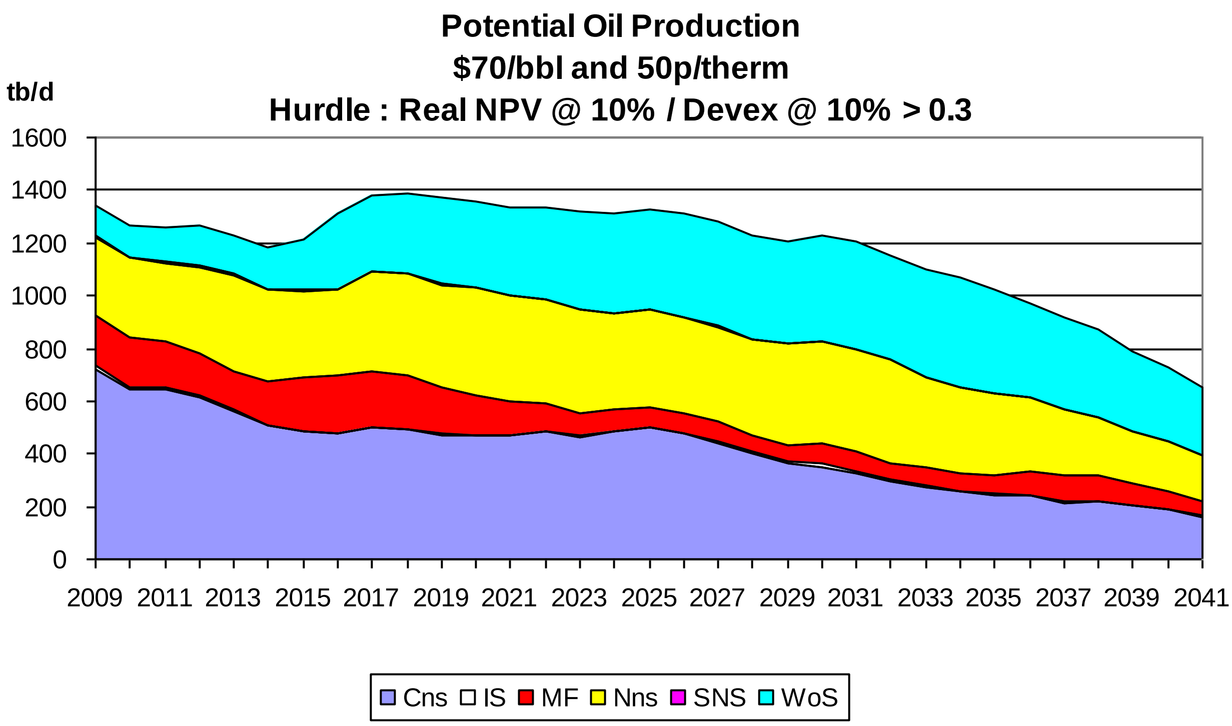
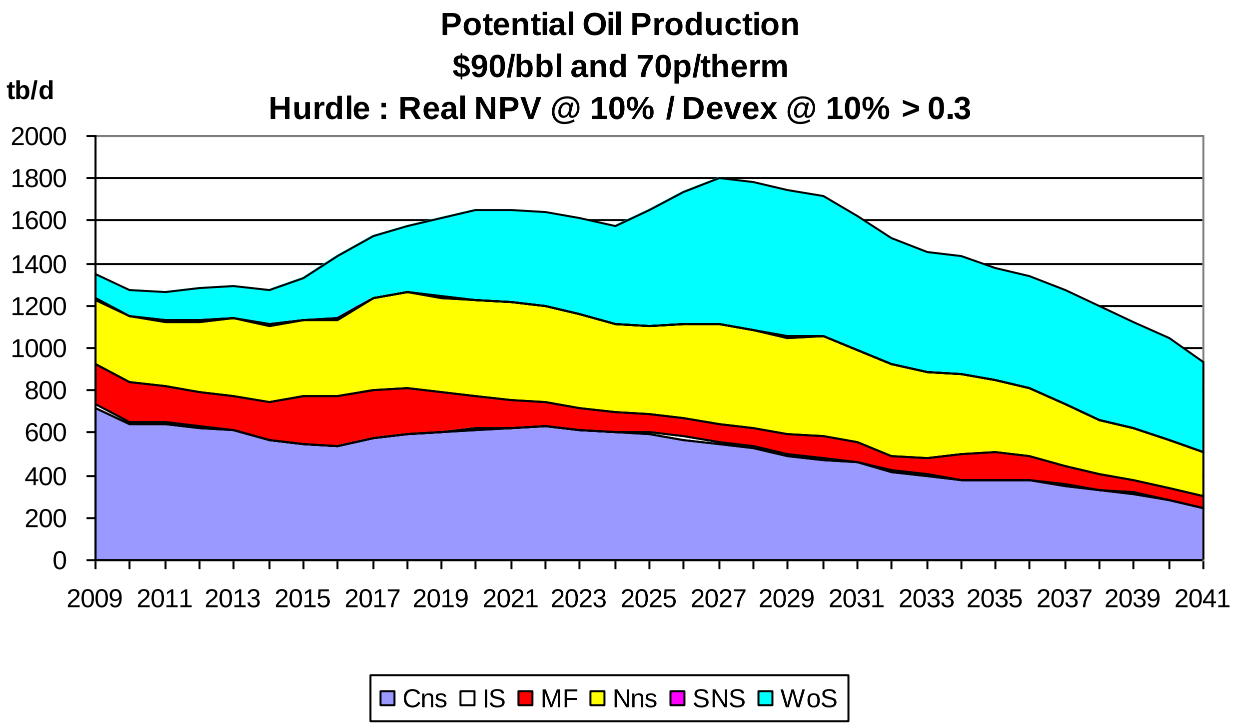


Chart 9



(ii) Natural Gas

Natural gas production prospects are shown under the various categories of fields and projects in Charts 10 – 12. Under the $50, 30 pence price case (Chart 10) it is seen that output falls at a very fast pace, especially over the next decade. It is noticeable that very few new field developments are triggered over the whole period. By 2040 production is only around 450 mm cf/d.

Under the $70, 50 pence case (Chart 11) the production decline rate is noticeably lower. Under this price scenario there is substantial output from new fields, including significant contributions from future discoveries and those in the category of technical reserves. By 2040 production is 1.118 b cf/d.

Under the $90, 70 pence case (Chart 12) the production may decline until 2014 then increase to 5.955 b cf/d in 2016. Compared to the lower price cases there is substantially greater output from probable/possible fields, technical reserves, and new discoveries. In 2040 production is 2.005 b cf/d.

Chart 10

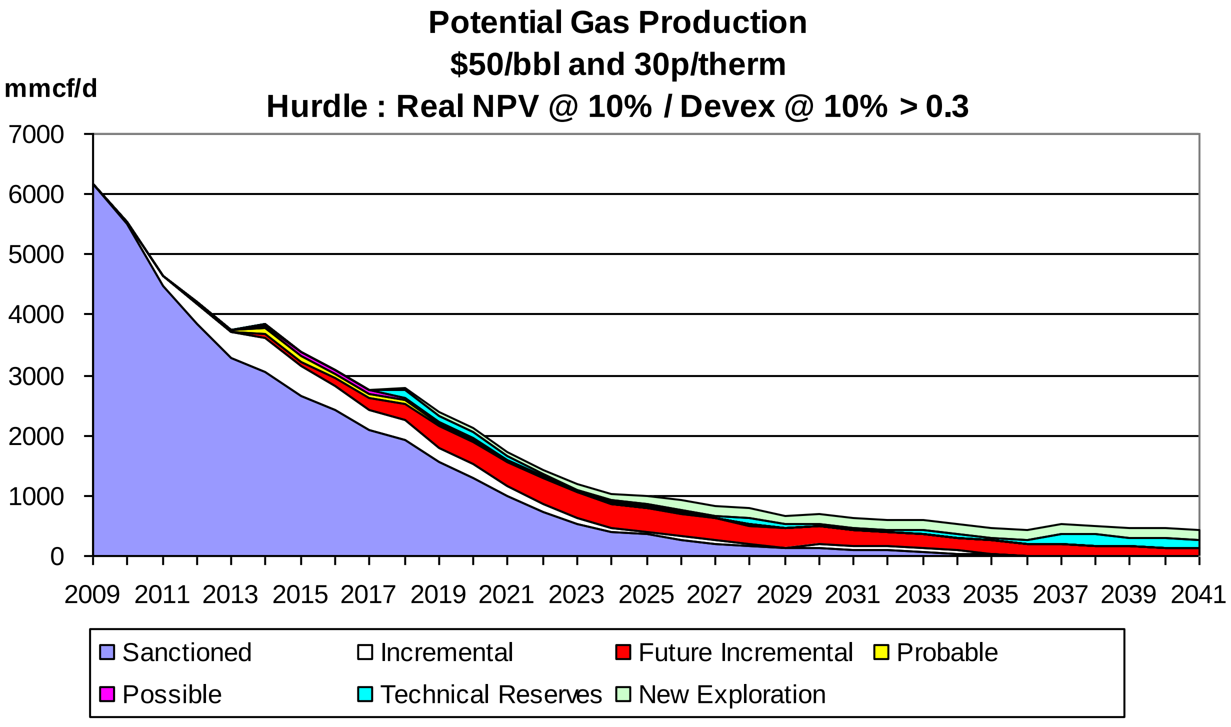


Chart 11

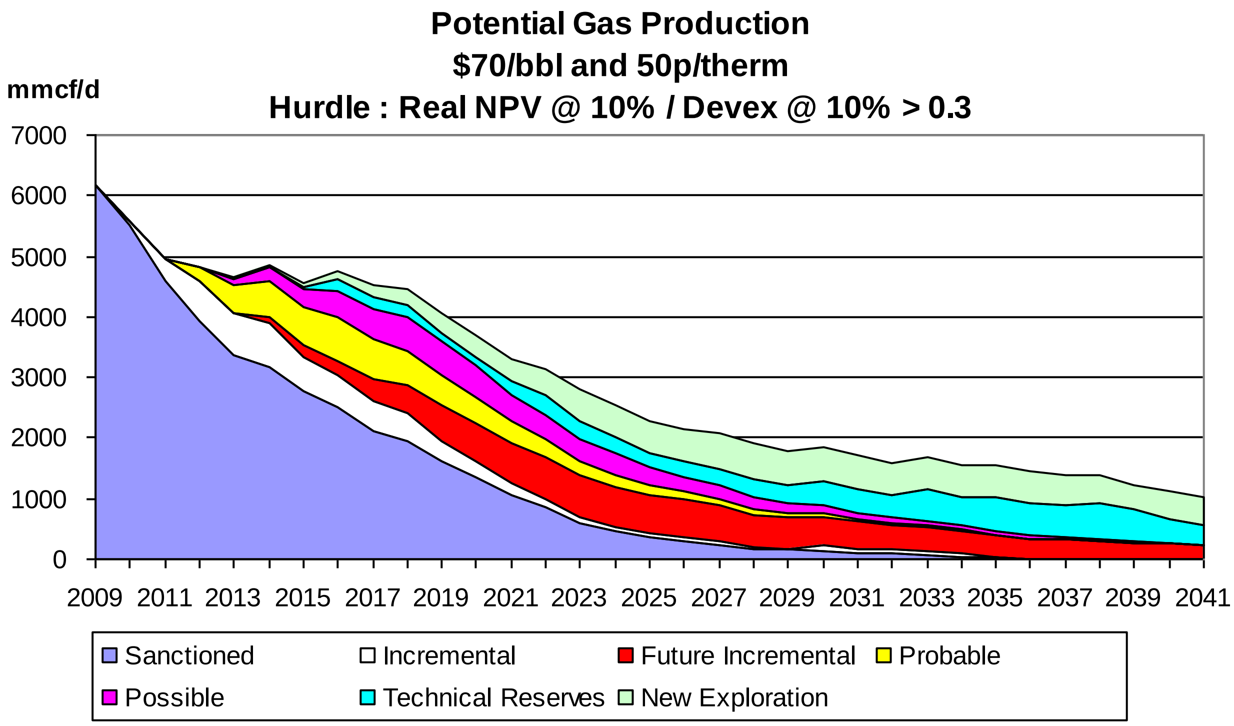
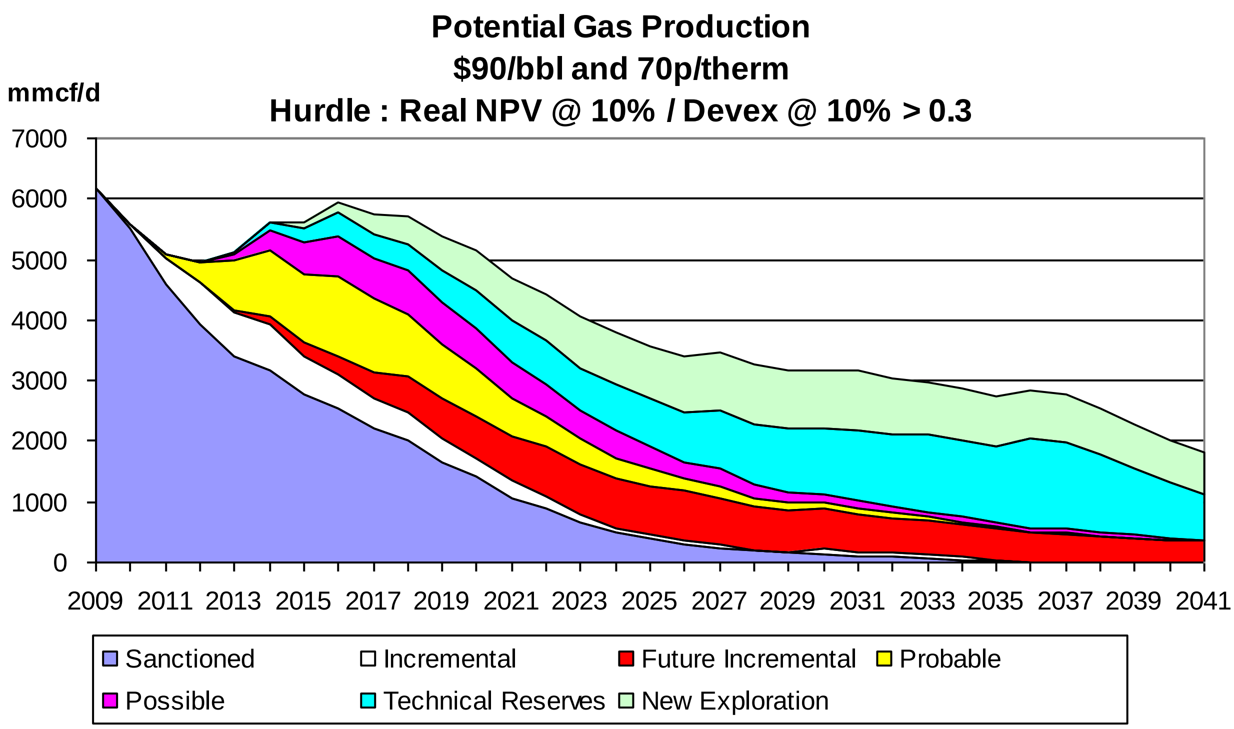


Chart 12



Prospective gas production from the 6 geographic areas of the UKCS is shown in Charts 13 – 15. Under the $50, 30 pence case (Chart 13) it is seen that the SNS continues to make a substantial contribution to the total for many years ahead. It is also noticeable that there is only a tiny contribution from the W of S region. The new fields in this high cost area are uneconomic under this scenario.

The production prospects under the $70, 50 pence case (Chart 14) highlight substantially greater contributions from the CNS and SNS and more modest increases from W of S compared to the low price case. But the W of S share of the total remains quite low. Many projects in this region remain uneconomic. Under the $90, 70 pence case (Chart 15) there is a potential peak in 2016. In this scenario output from the SNS and CNS is considerably higher over the period. But the contribution from W of S remains fairly modest though it is higher compared to the $70, 50 pence case.

Chart 13

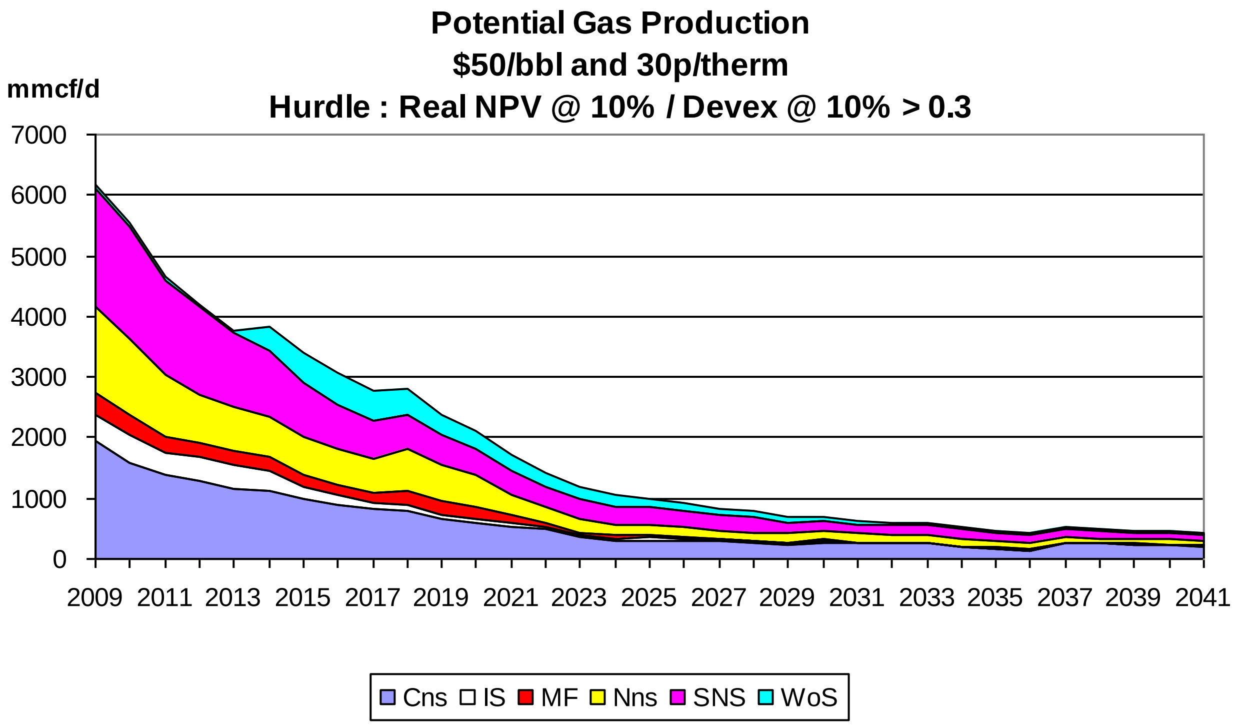


Chart 14

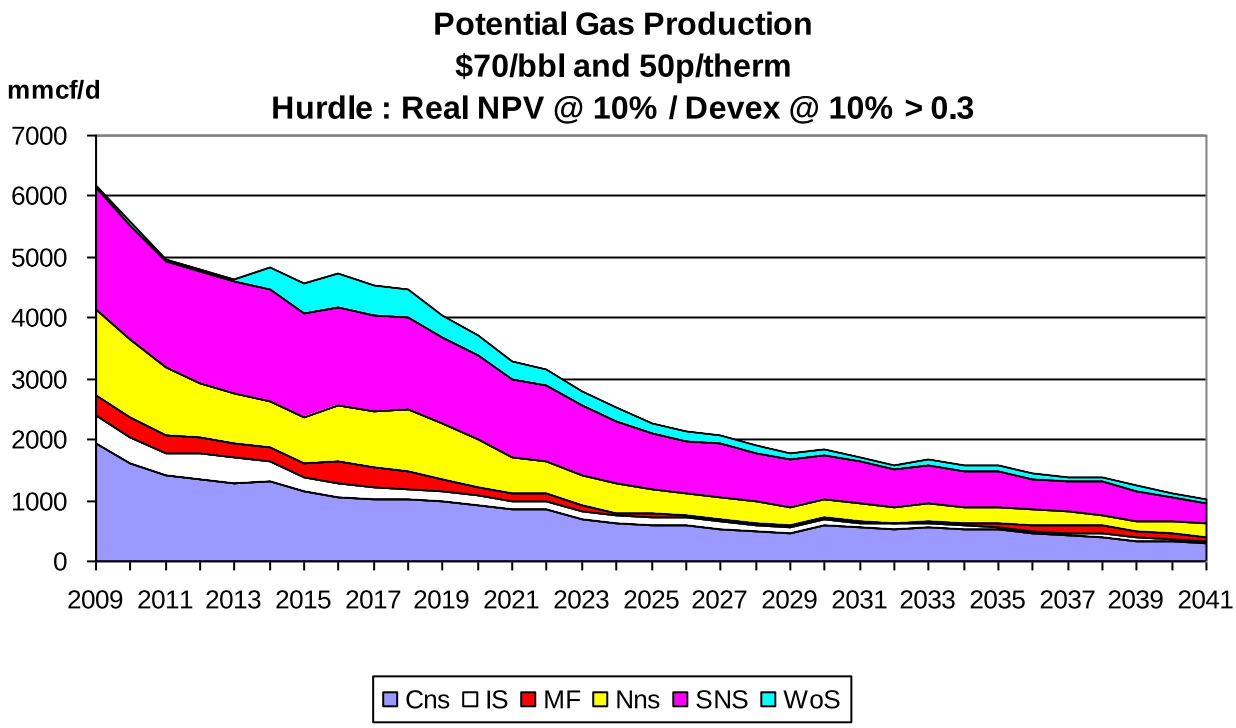
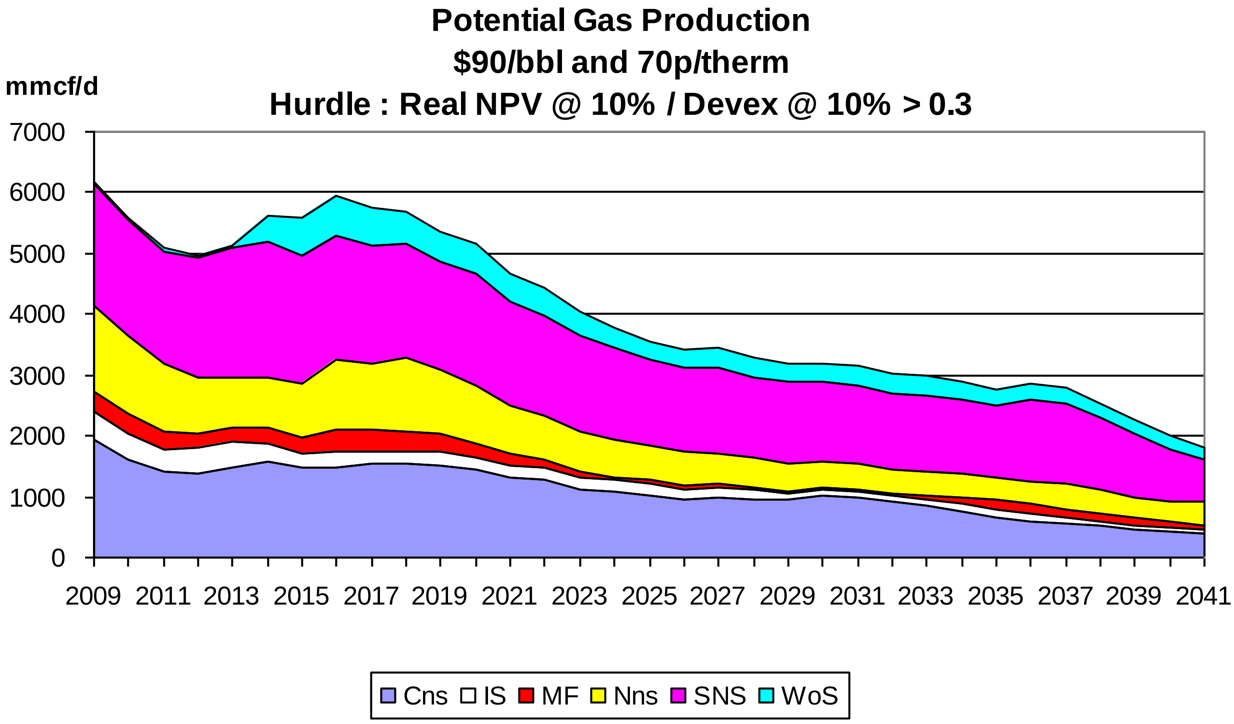


Chart 15



(iii) Total Hydrocarbons

Prospective total hydrocarbon production (including NGLs (not shown separately)) is shown in Charts 16 – 18 under the 3 price cases classified by the different categories of investment project. In the $50, 30 pence case (Chart 16) the sharp rate of decline over the next decade is a noteworthy feature. In 2010 production is around 2.29 mm boe/d which is well below the PILOT aspirational target of 3 mm boe/d. By 2020 output is around 1.32 mm boe/d and in 2040 it is 0.53 mm boe/d.

Under the $70, 50 pence case (Chart 17) future production may peak at 2.214 mm boe/d in 2017. In 2030, it is 1.73 mm boe/d and in 2040 it is 0.932 mm boe/d. In the longer term it is seen that there are substantial contributions from fields in the categories of new discoveries, technical reserves, and incremental projects.

In the $90, 70 pence case (Chart 18) future output may peak in 2018 at 2.625 mm boe/d. In 2027 it is 2.443 mm boe/d. In 2040 production is around 1.41 mm boe/d. In this scenario in the longer term output from fields in the categories of incremental projects, technical reserves and new discoveries is very substantial. The average annual number of new field developments (excluding all incremental projects) in this scenario in the period 2010 – 2035 is 17.3. This is extremely challenging for the oil and gas cluster and the probability of these developments being executed on an ongoing basis should be regarded as being relatively low.

Chart 16

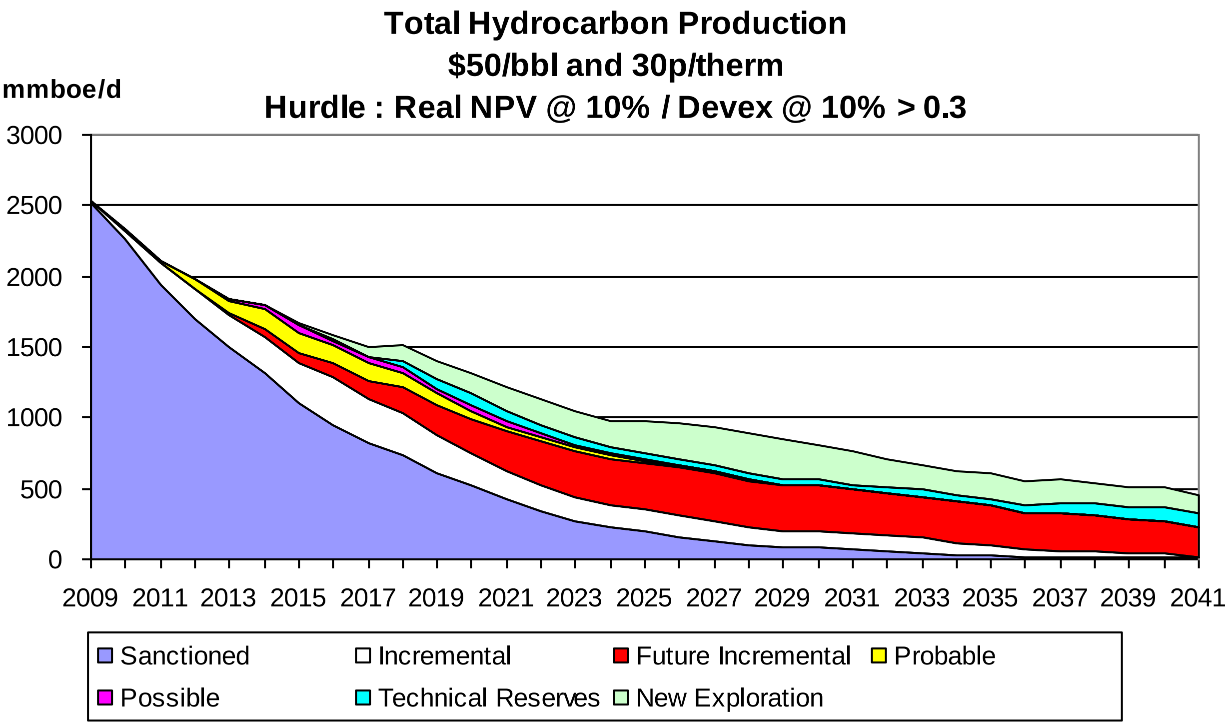


Chart 17

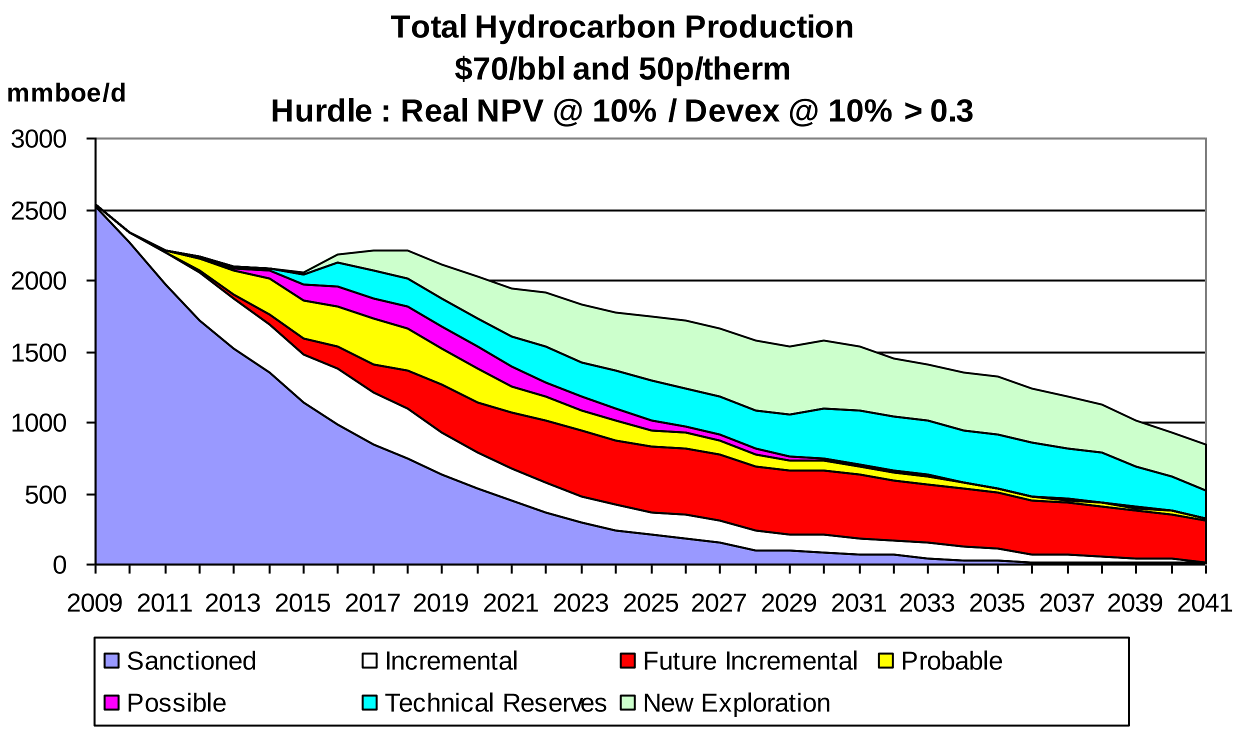
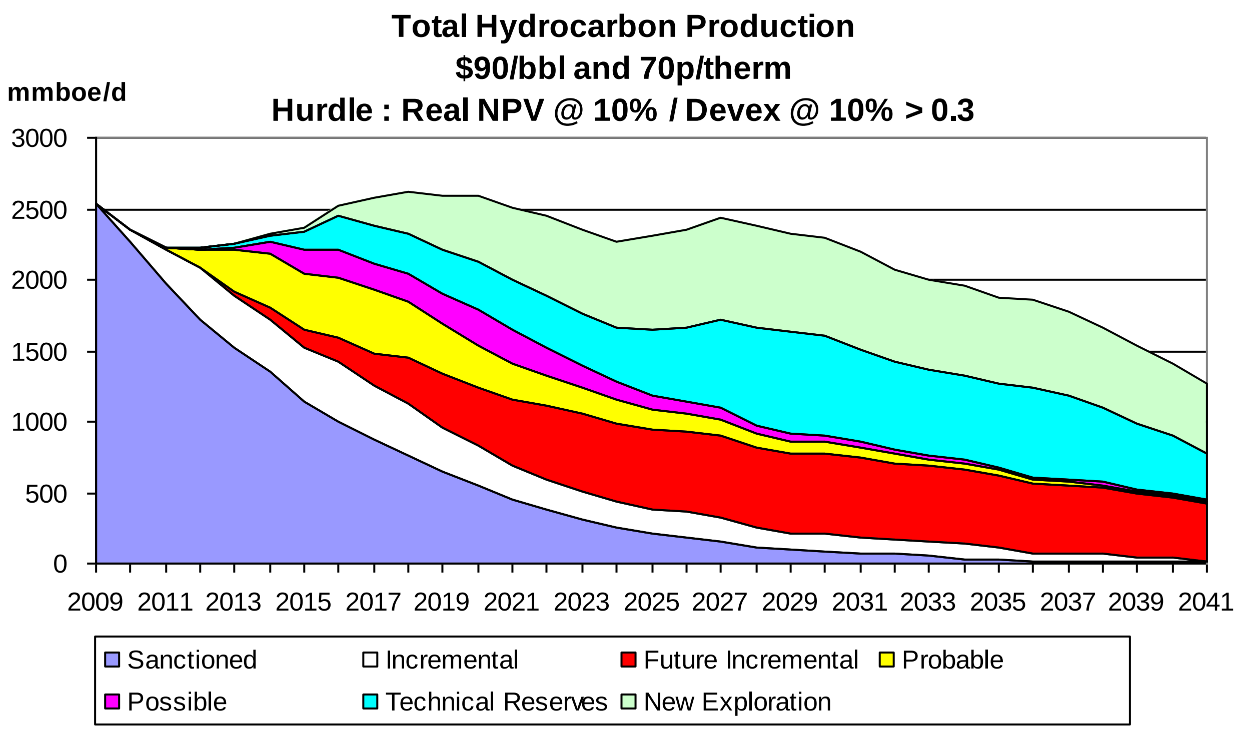


Chart 18



The prospects for total hydrocarbon production classified by the 6 regions of the UKCS are shown in Charts 19 – 21. Under the $50, 30 pence price scenario (Chart 19) the importance of the CNS throughout the period, and the NNS in the near and medium terms, are emphasised. The W of S region is seen to make a significant contribution in the longer term. In the $70, 50 pence case (Chart 20) the CNS remains the most important contributor to total production. The comparative share of the W of S region becomes greater. In the $90, 70 pence case (Chart 21) the CNS remains the largest contributor to aggregate output over the whole period, followed by the NNS. In the longer term the W of S region becomes the second largest contributor to the total.

Chart 19

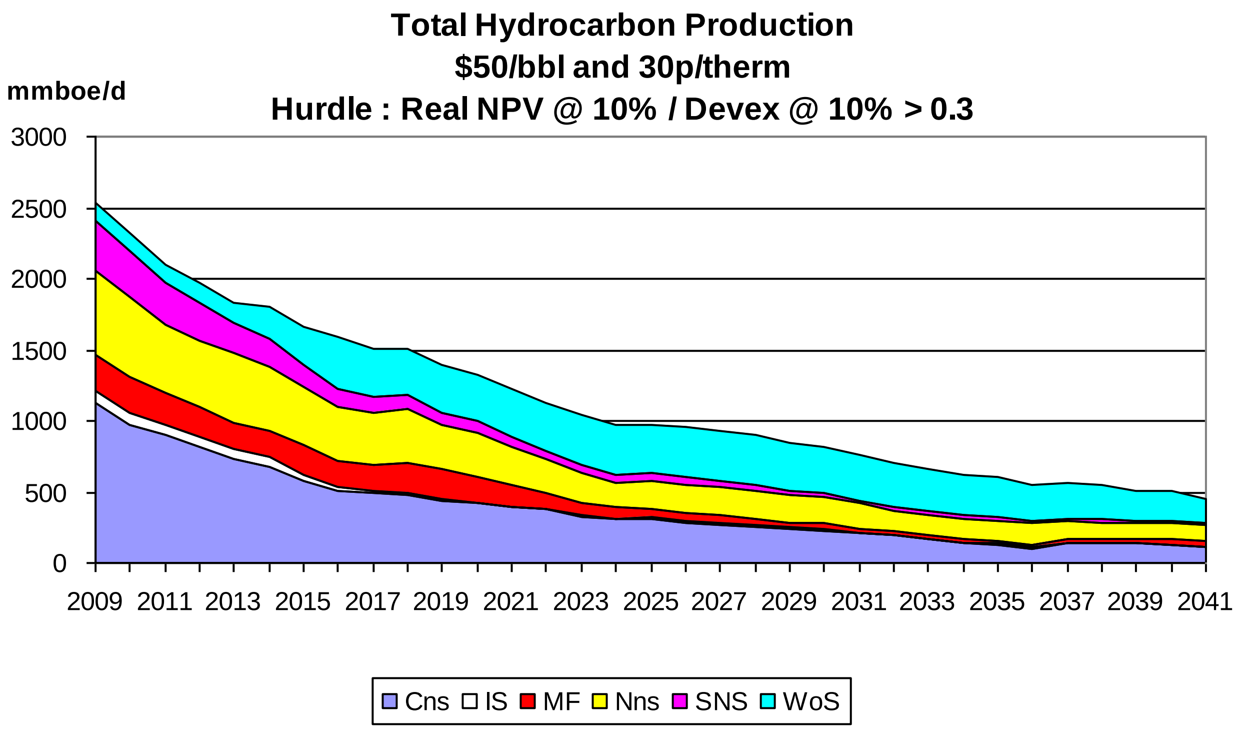


Chart 20

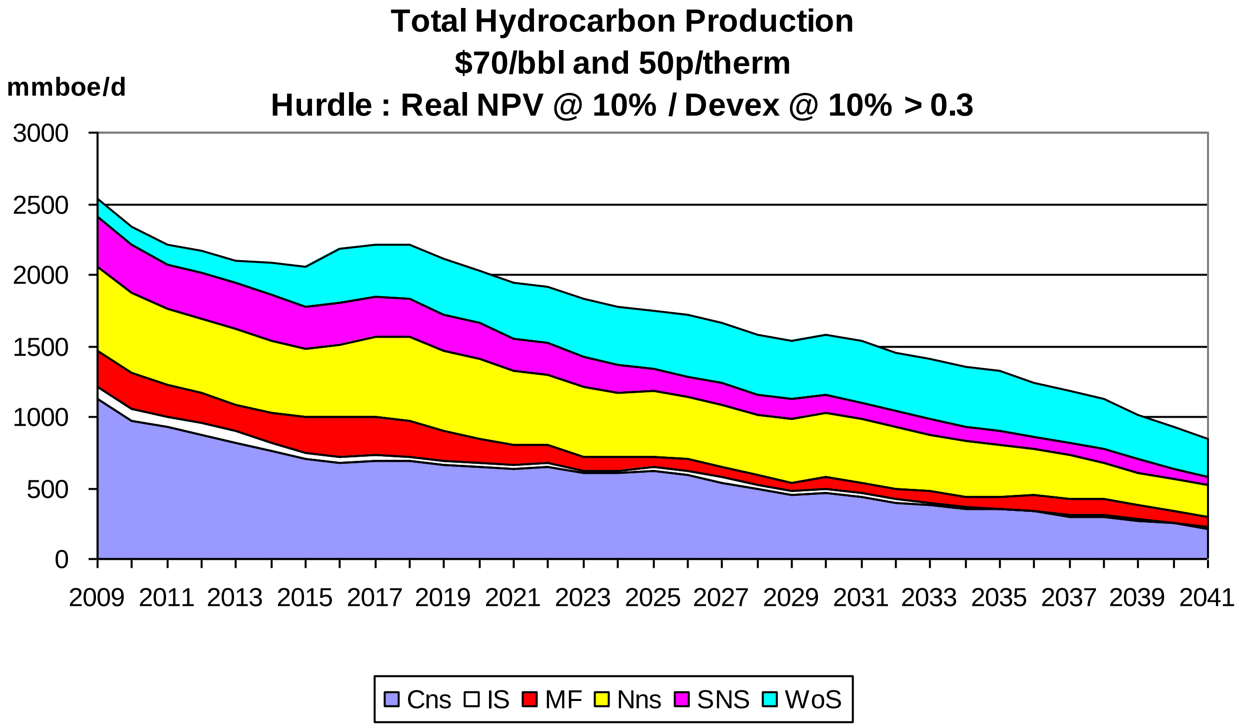
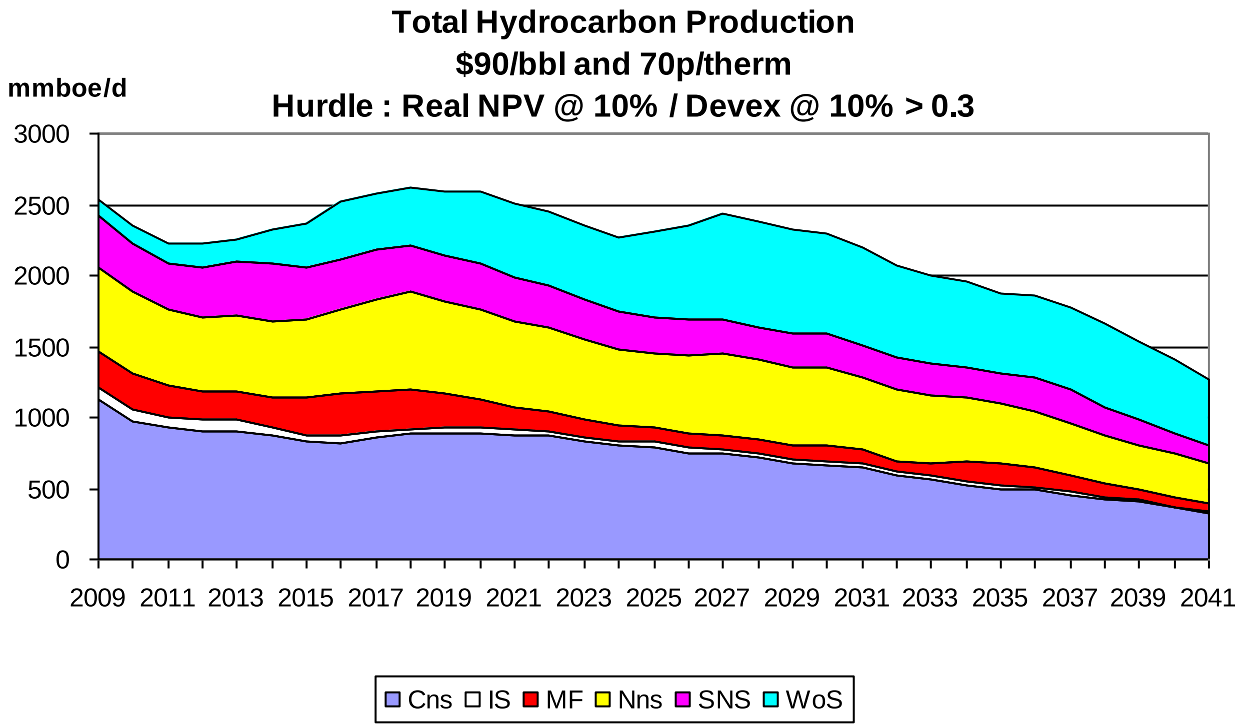


Chart 21



C. Development Expenditures

Field development expenditures classified according to types of fields and projects are shown in Charts 22 – 24. In the $50,30 pence case (Chart 22) it is seen that over the next few years they fall dramatically from £5.103 billion (at 2010 prices) in 2012. In 2020 they are £2.21 billion, £1.047 billion in 2030 and £0.761 billion in 2040. In the $70, 50 pence case (Chart 23) investment increase to exceed £7.79 billion in 2014, but then falls to £3.561 billion in 2030. In 2040 development costs may be £1.44 billion. In the $90, 70 pence case (Chart 24) development expenditures are seen to increase sharply over the next few years to 2014 reflecting the development of significant numbers of fields in the probable, possible and technical reserves categories. Investment remains at relatively high levels over the period to 2024, after which it falls to £1.935 in 2040. This scenario should be regarded as very optimistic.

Chart 22

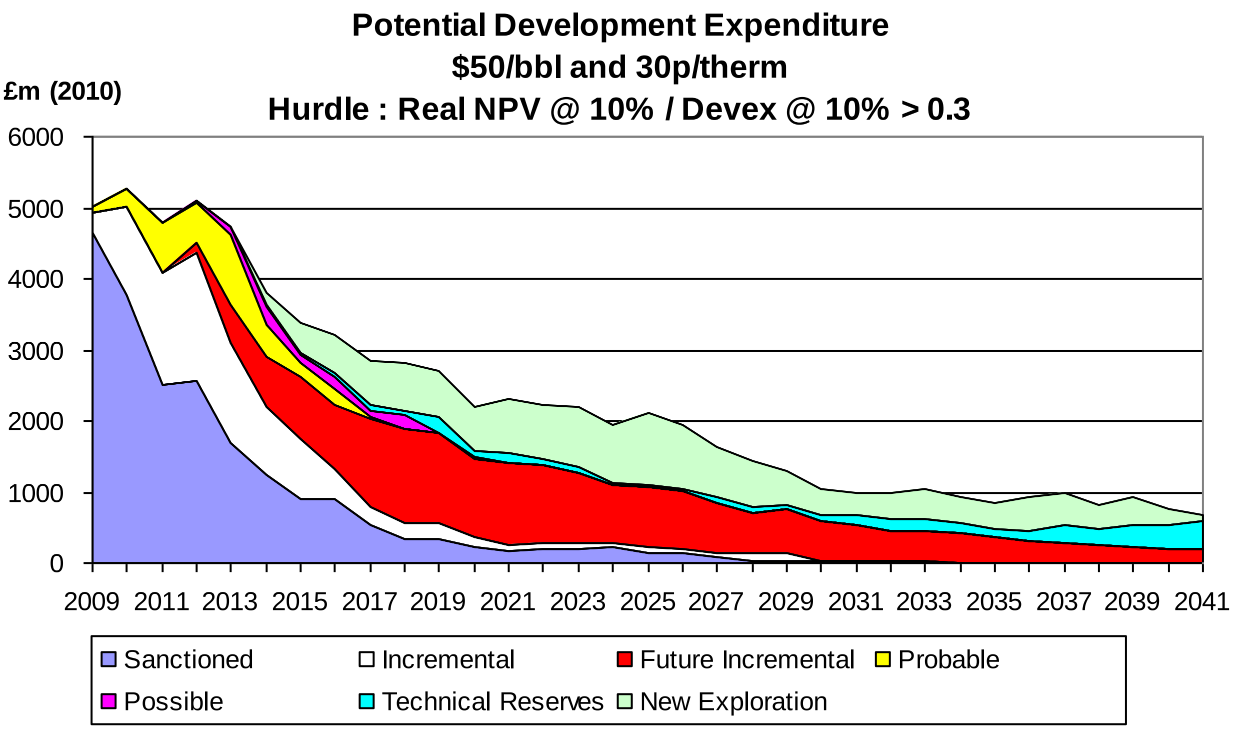


Chart 23

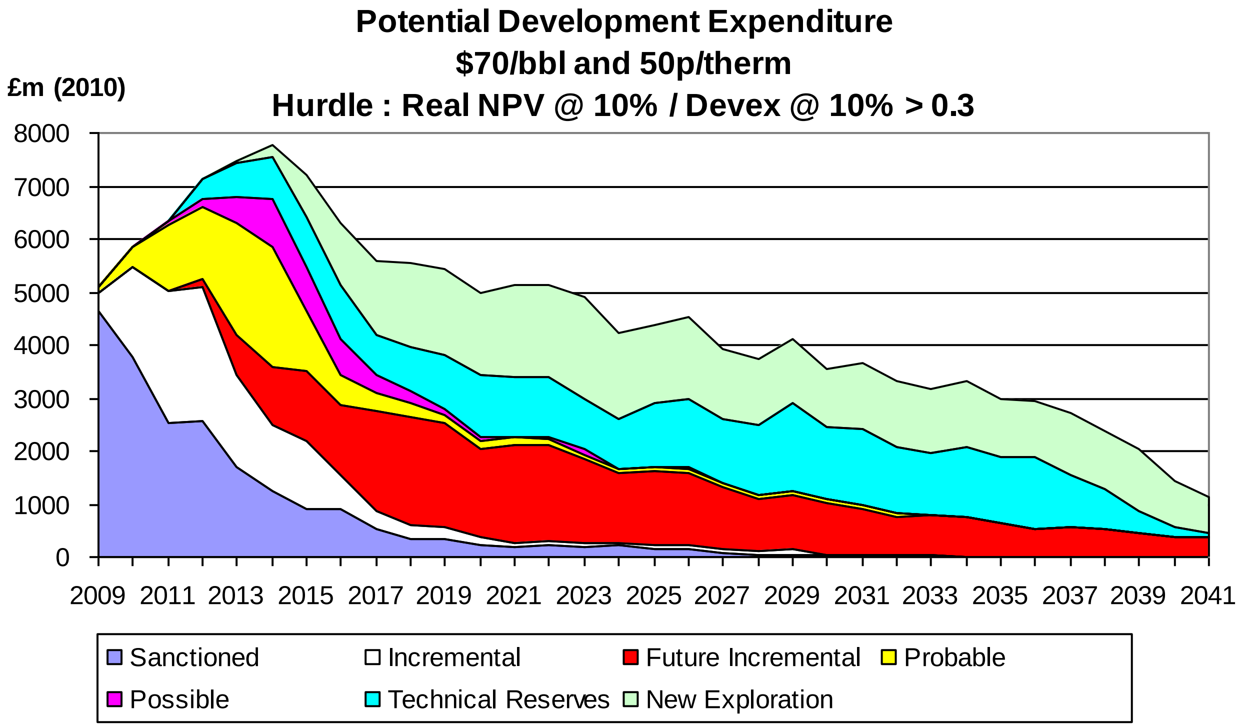
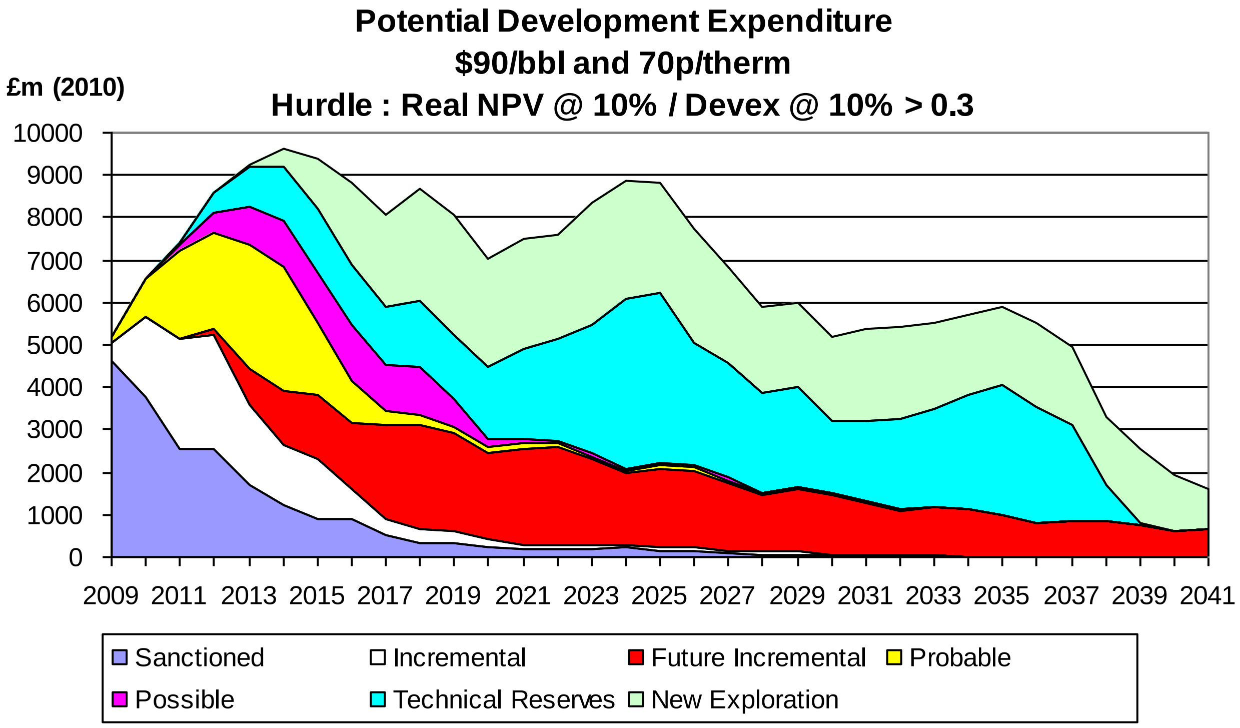


Chart 24



D. Operating Expenditures

The behaviour of field operating expenditures in the 3 scenarios is shown in Charts 25 – 27. Under the $50,30 pence case (Chart 25) expenditures fall at a very fast pace reflecting (1) the decline in the number of producing sanctioned fields with many attaining their COP dates, and (2) the very small numbers of new field developments. Under the $70, 50 pence case (Chart 26) sanctioned fields take longer to reach their COP dates and in the medium and longer term the substantial numbers of new field developments in the categories of new discoveries and technical reserves enhance the associated operating expenditures. Under the $90, 70 pence case (Chart 27) there is some decrease in the short term, but until 2039 the level of expenditure is always high, namely within the £6 – £8 billion range (at 2010 prices). The main reason in the longer term is the large expenditure on fields in the categories of new discoveries and technical reserves.

Chart 25

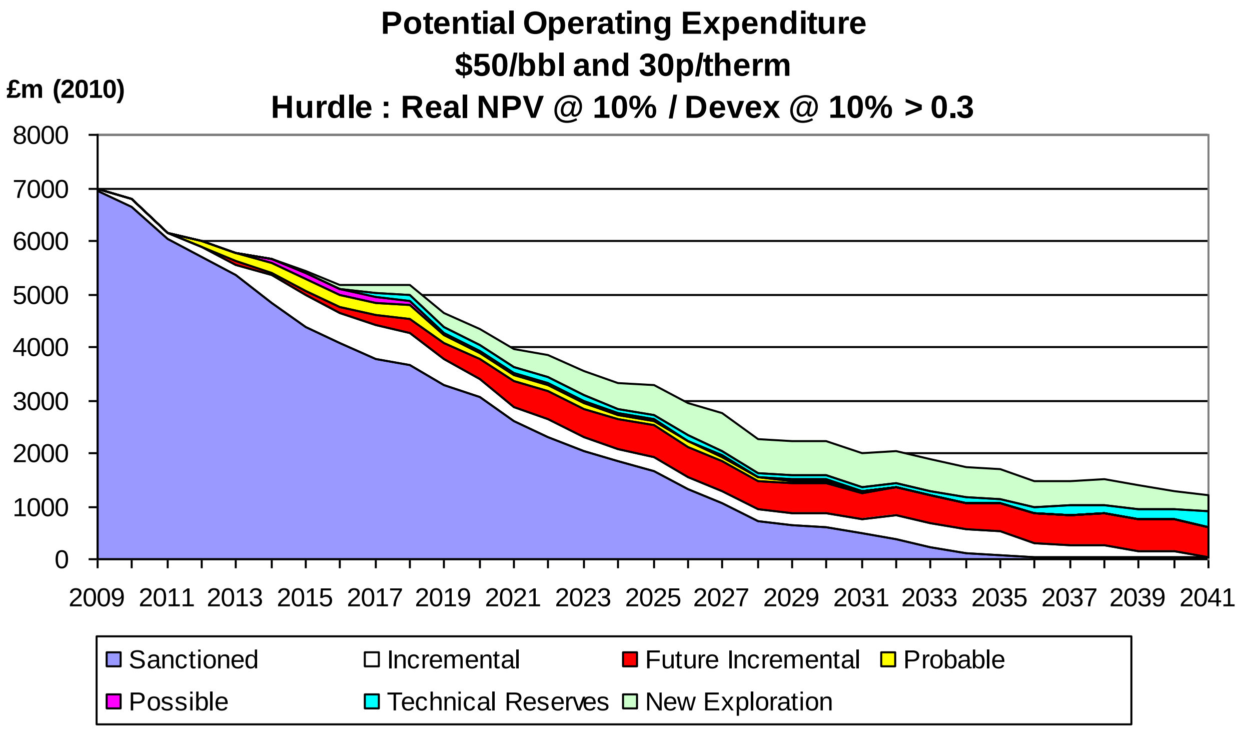


Chart 26

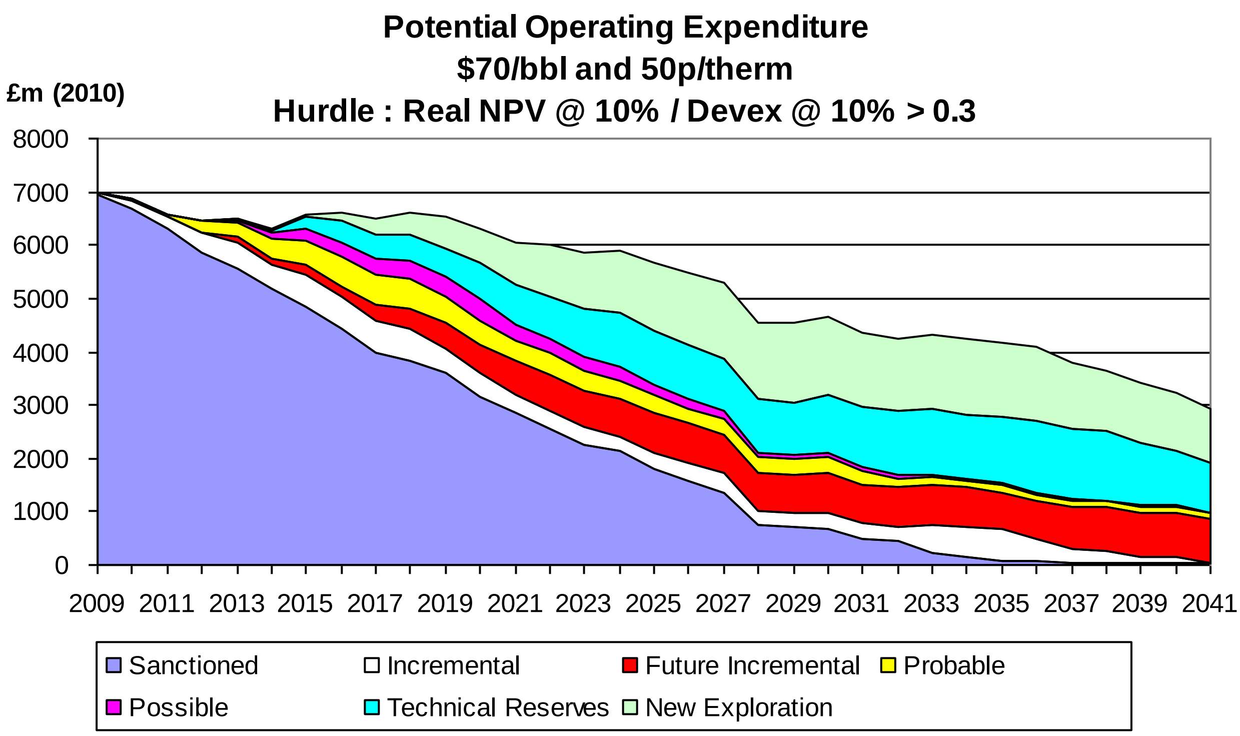
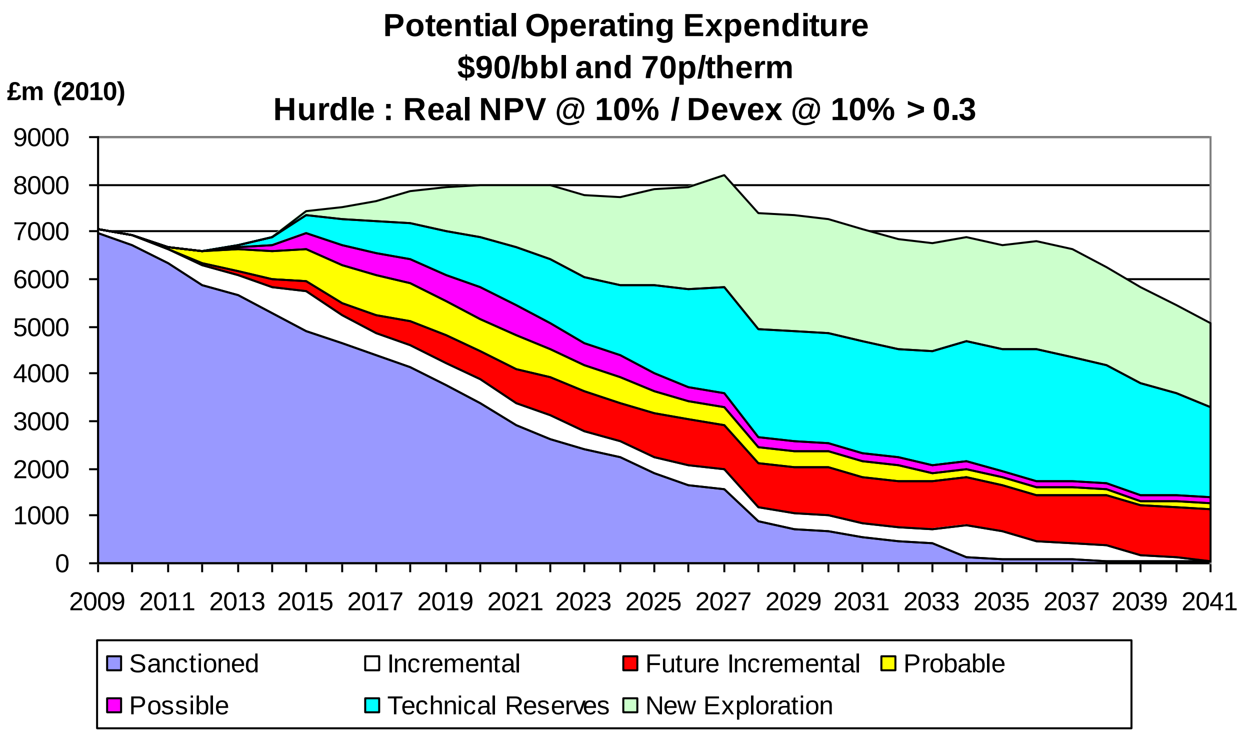


Chart 27



E. Total Field Expenditures (Excluding E and A)

Total potential field expenditures (development costs, operating costs plus decommissioning costs (excluding E & A)) are shown in Charts 28 – 30. Under the $50,30 pence case (Chart 28) total expenditures decline quite quickly from £12.681 billion in 2010 to £7.357 billion in 2020, £3.68 billion in 2030 and £2.671 billion in 2040. Under the $70, 50 pence case (Chart 29) total field expenditures peak in 2014 at £15.132 billion then decline to £12.611 in 2020, £8.768 billion in 2030 and £5.252 in 2040. Under the $90, 70 pence case (Chart 30) total field expenditure increases to £17.459 billion in 2014 then peaks again in 2025 at £18.684 billion and it could be £8.063 billion in 2040. Fields in the categories of new discoveries and technical reserves are mainly responsible for this last figure.

Charts 28

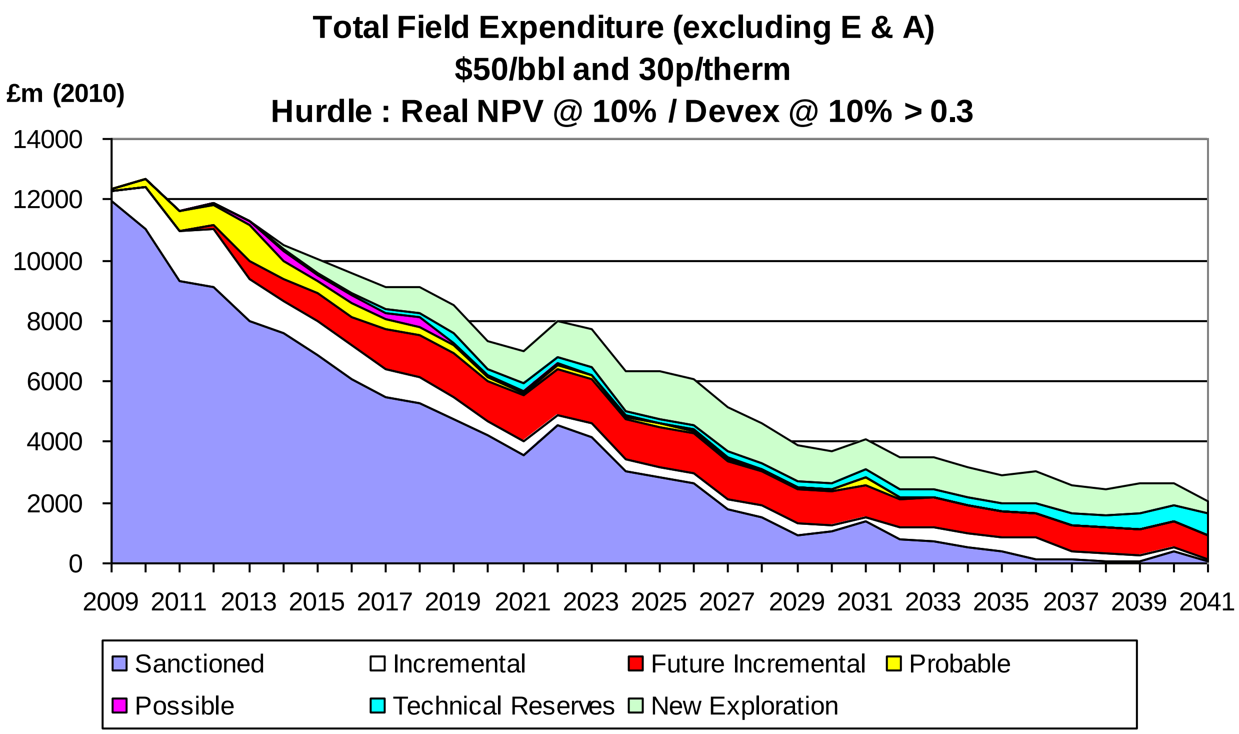


Chart 29

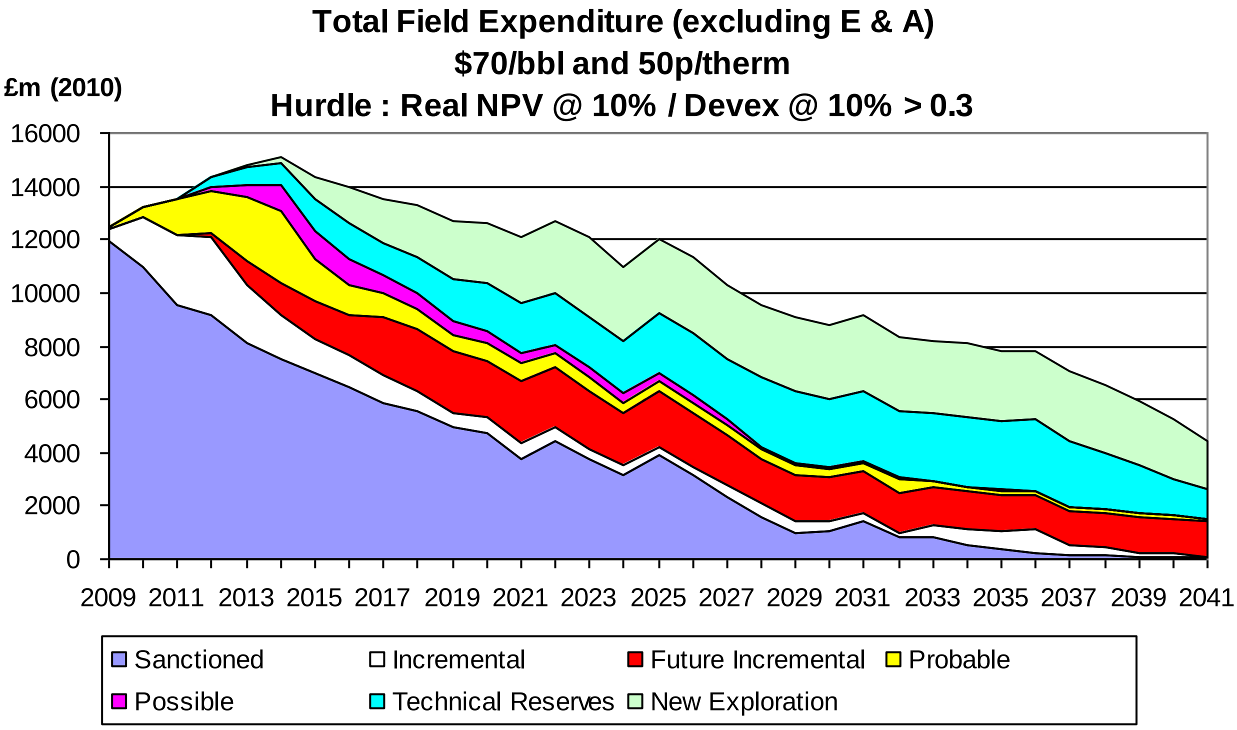
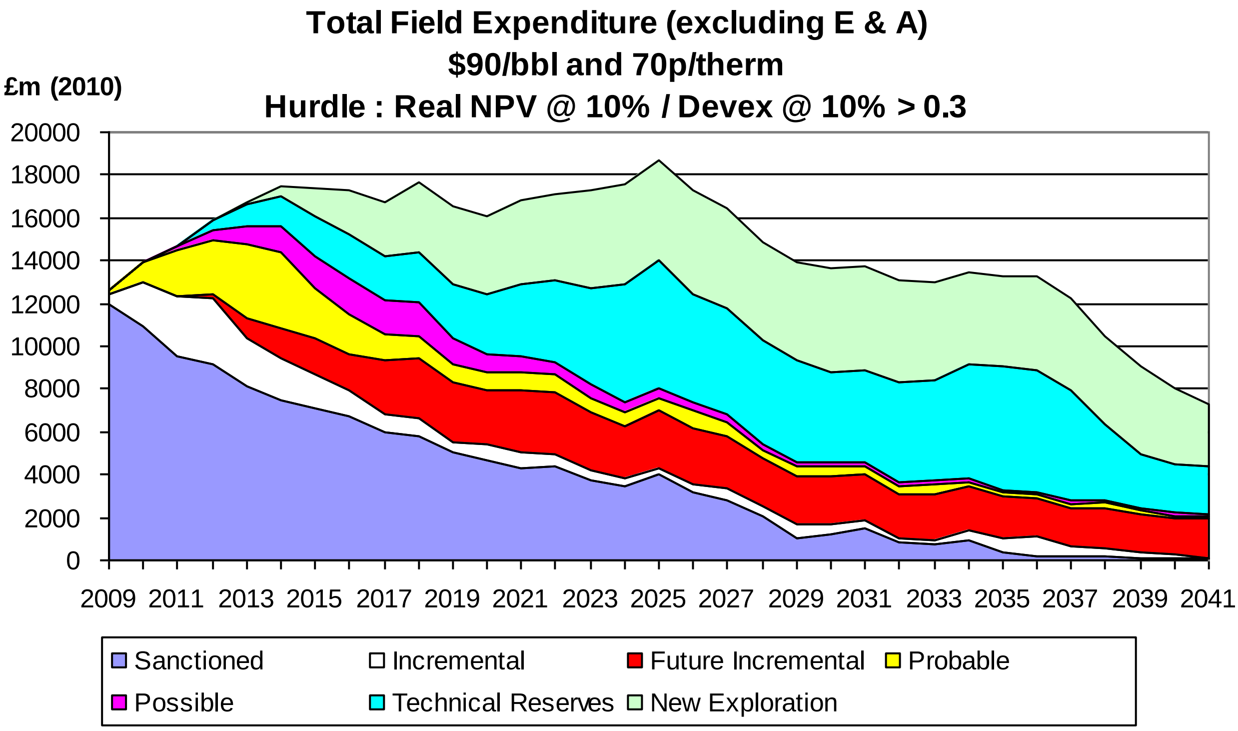


Chart 30



The prospects for total field expenditures classified by the 6 regions of the UKCS are shown in Charts 31 – 33. Under the $50, 30 pence price scenario (Chart 31) the importance of the CNS and NNS throughout the period is clear. In the $70, 50 pence case (Chart 32) the NNS is the most important contributor to total production. The comparative share of the W of S region becomes greater. In the $90, 70 pence case (Chart 33) the CNS, NNS and WoS are the major contributors to total expenditure.

Chart 31

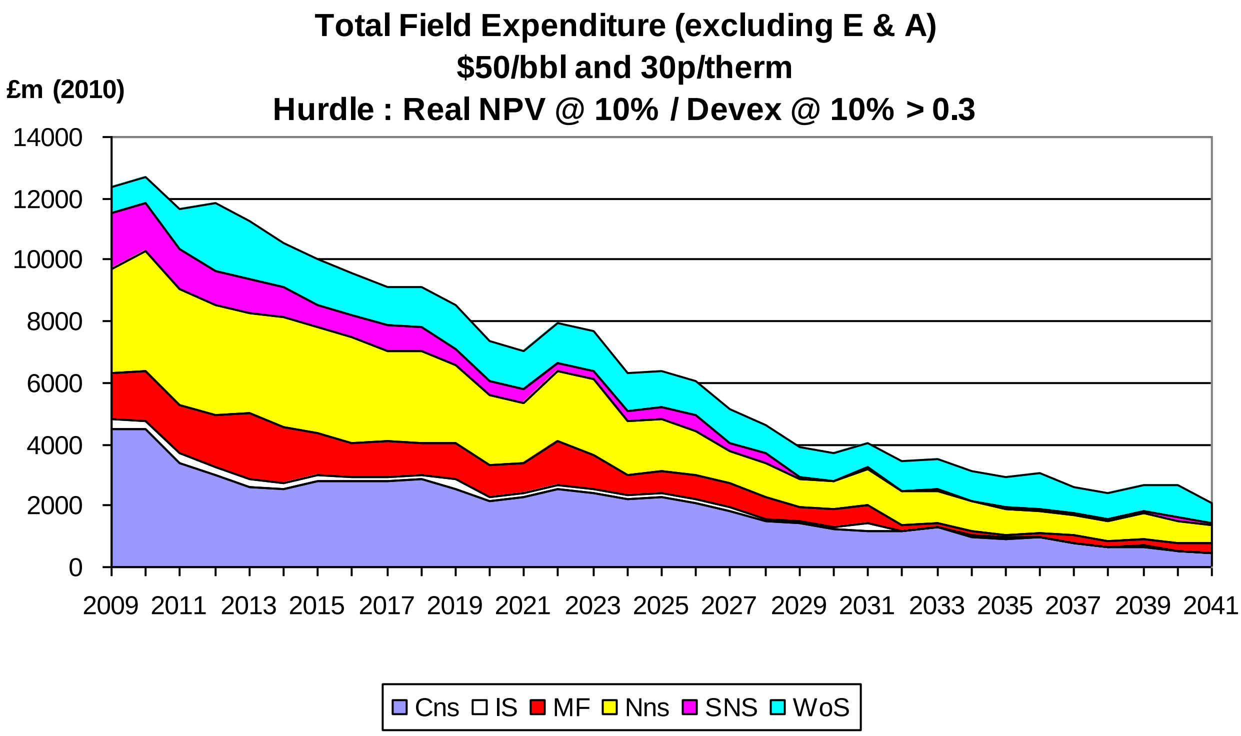


Chart 32

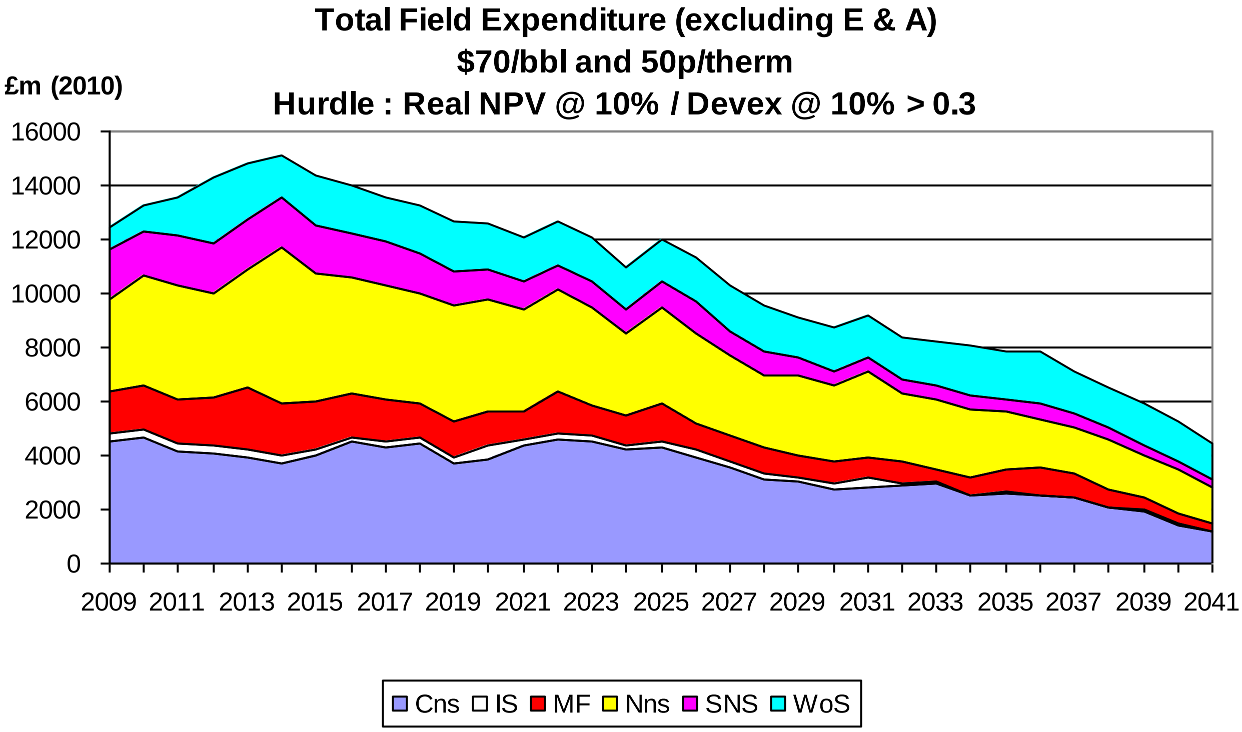
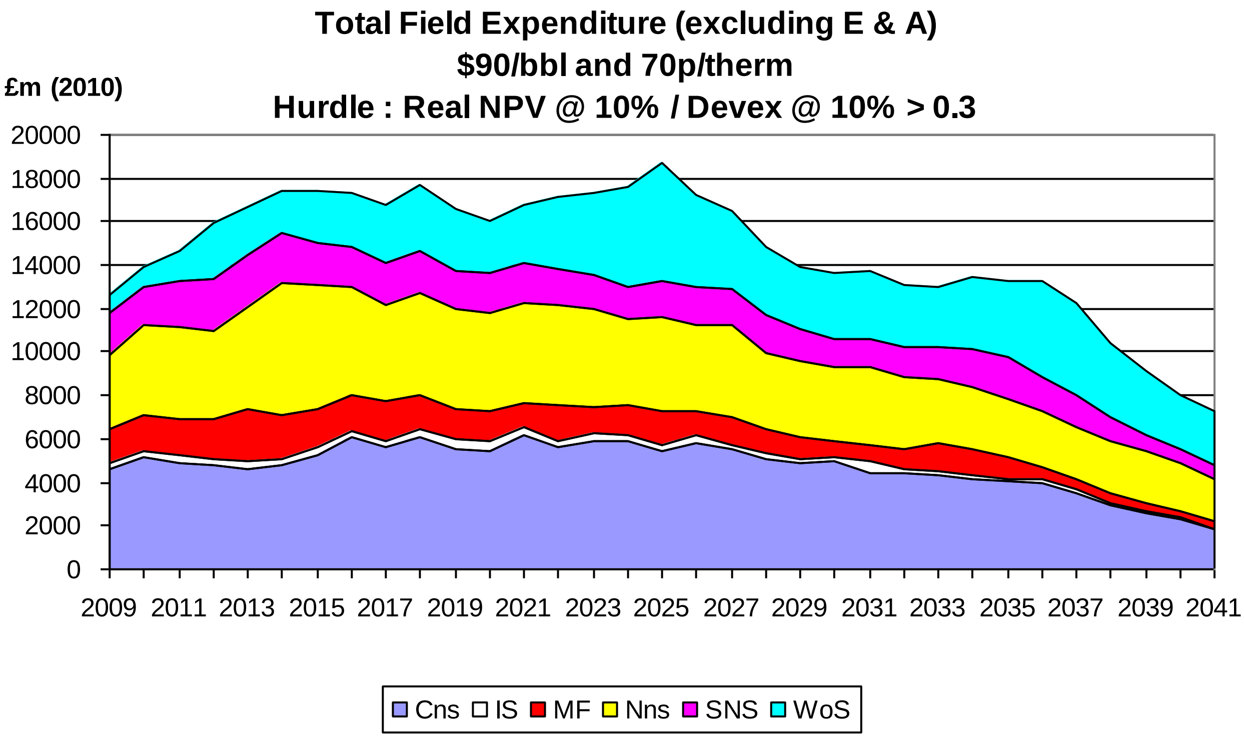


Chart 33



F. Decommissioning Expenditures

The behaviour of decommissioning expenditures under the $50, 30 pence scenario is shown in Charts 34 and 35. It is seen that expenditure increases dramatically from 2015 and increases again in 2023. Over the whole period to 2041 cumulative expenditures are around £26.194 billion (at 2010 prices). The overwhelming proportion of total expenditure is seen to be on already sanctioned fields. The expenditures under the $70, 50 pence scenario are shown in Charts 36 and 37. The broad pattern over the period is not very different from the low price case. But in this scenario there are more new field developments, and, given their small size, many of these reach their COP dates before 2041. The result is that the cumulative decommissioning costs to 2041 are £28.813 billion (at 2010 prices).

Chart 34

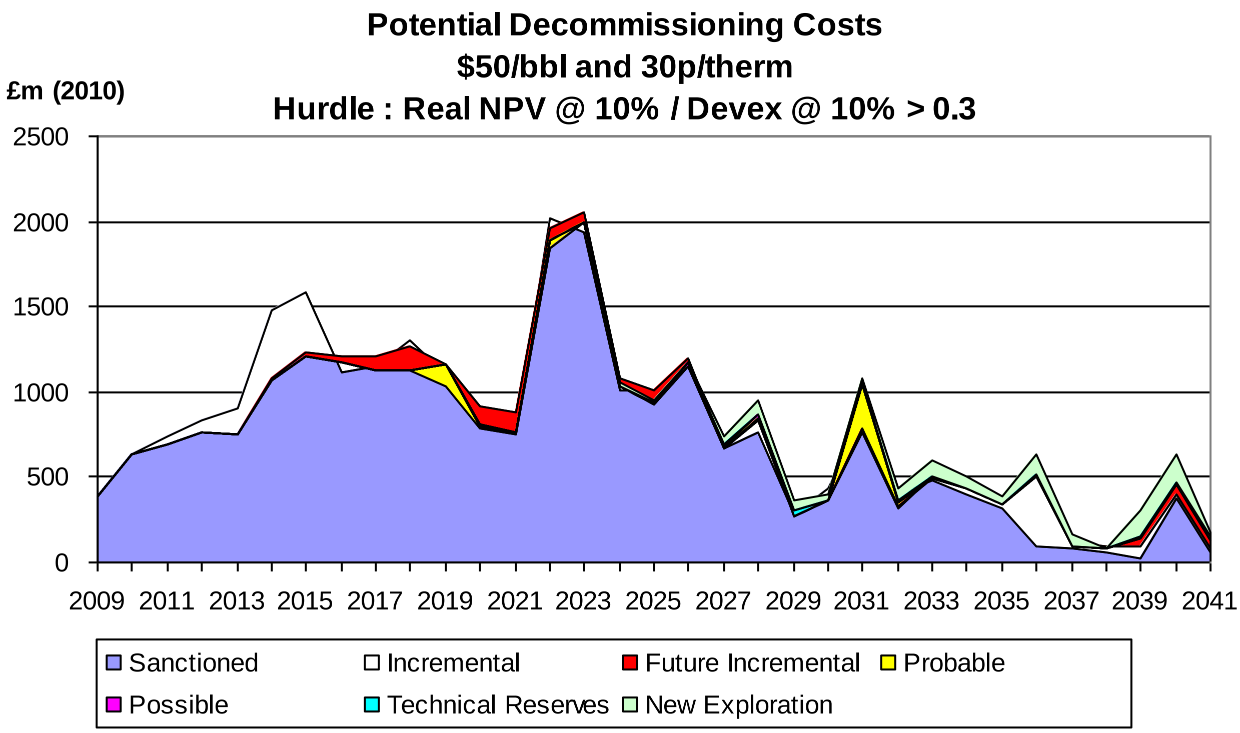


Chart 35

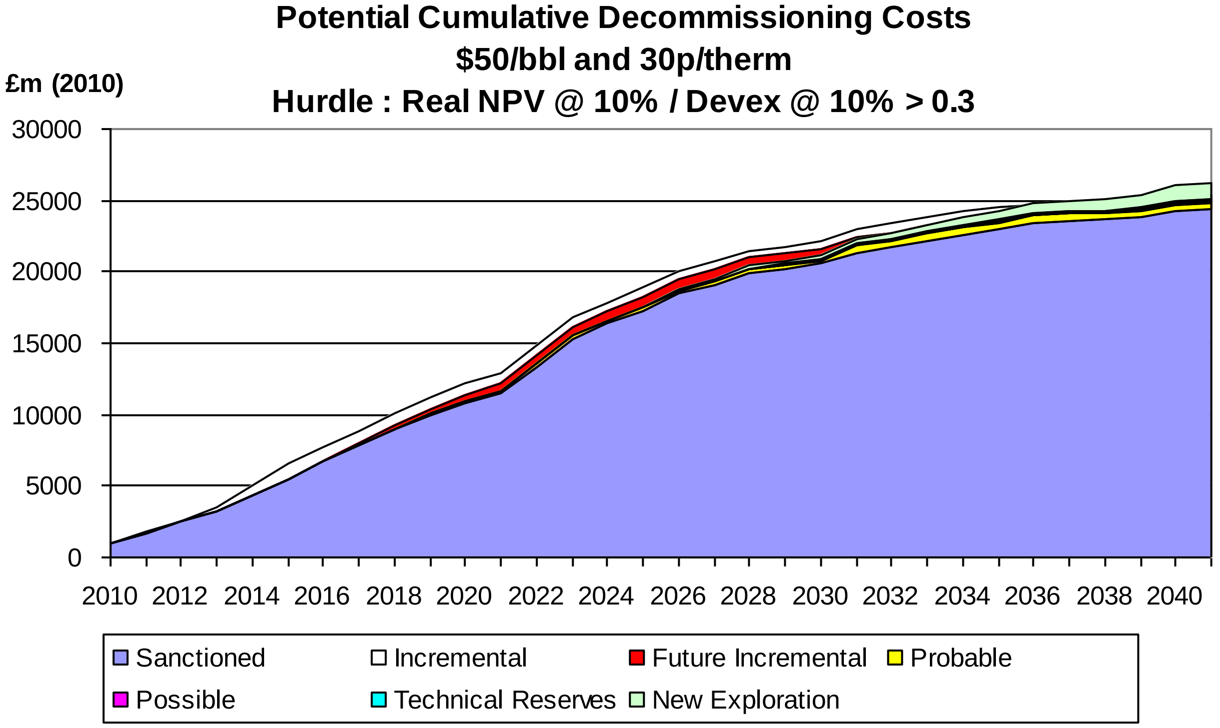


Chart 36

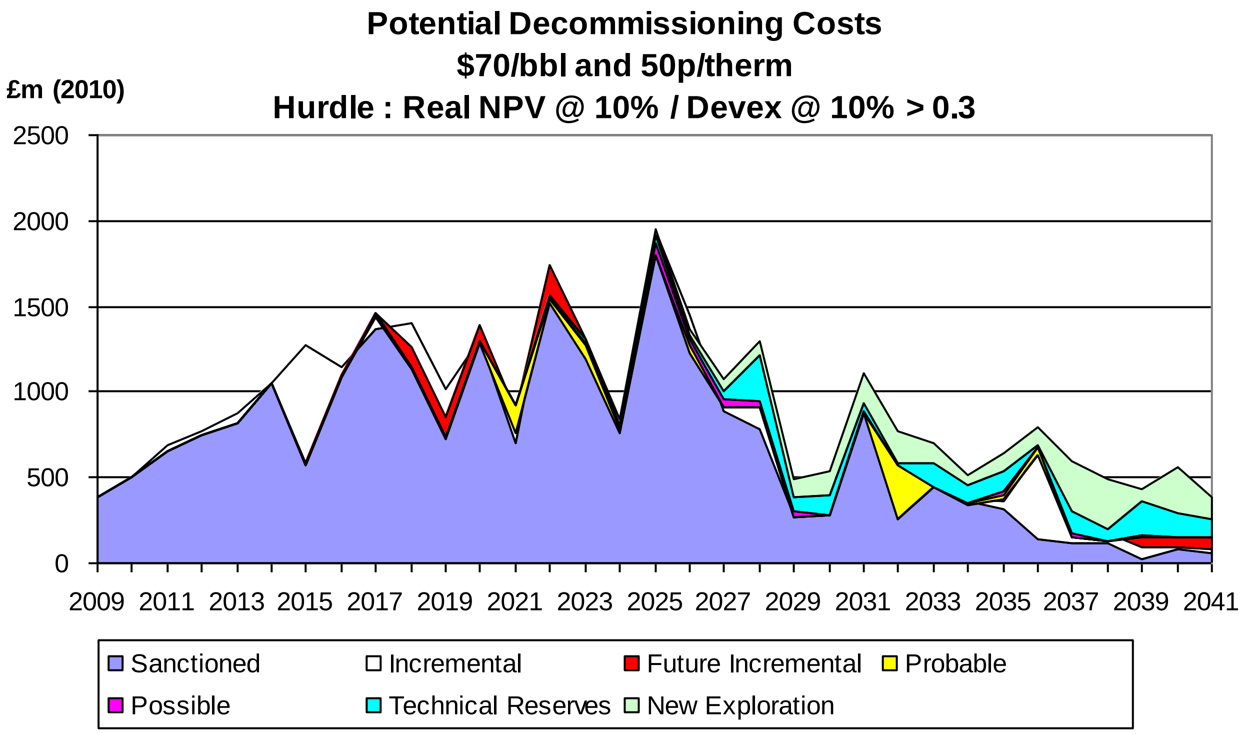
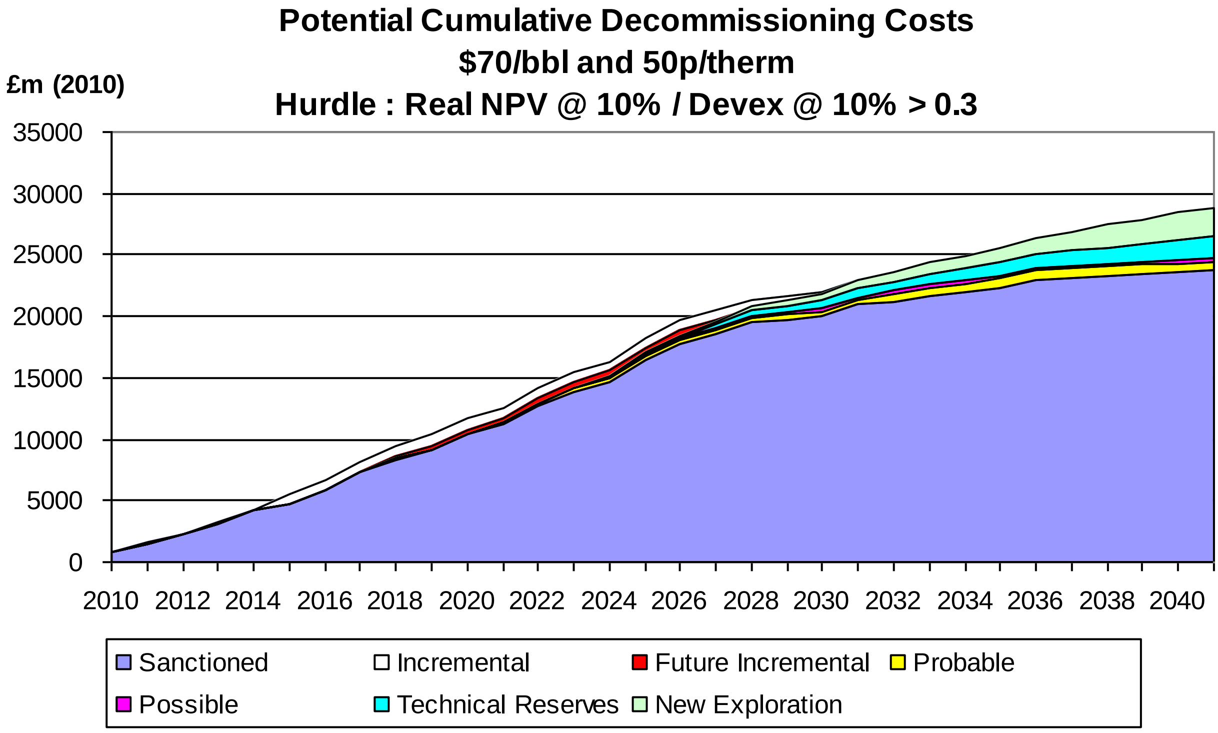


Chart 37



The expenditures under the $90, 70 pence case are shown in Charts 38 and 39. While the broad pattern remains the same as for the other scenarios there are far more new developments and many reach their COP dates by 2040. The result is that the cumulative expenditure by 2041 is £31.339 billion (at 2009 prices). It is seen that the high cost fields in the category of technical reserves make a significant contribution to the increase in the aggregate cost.

Chart 38

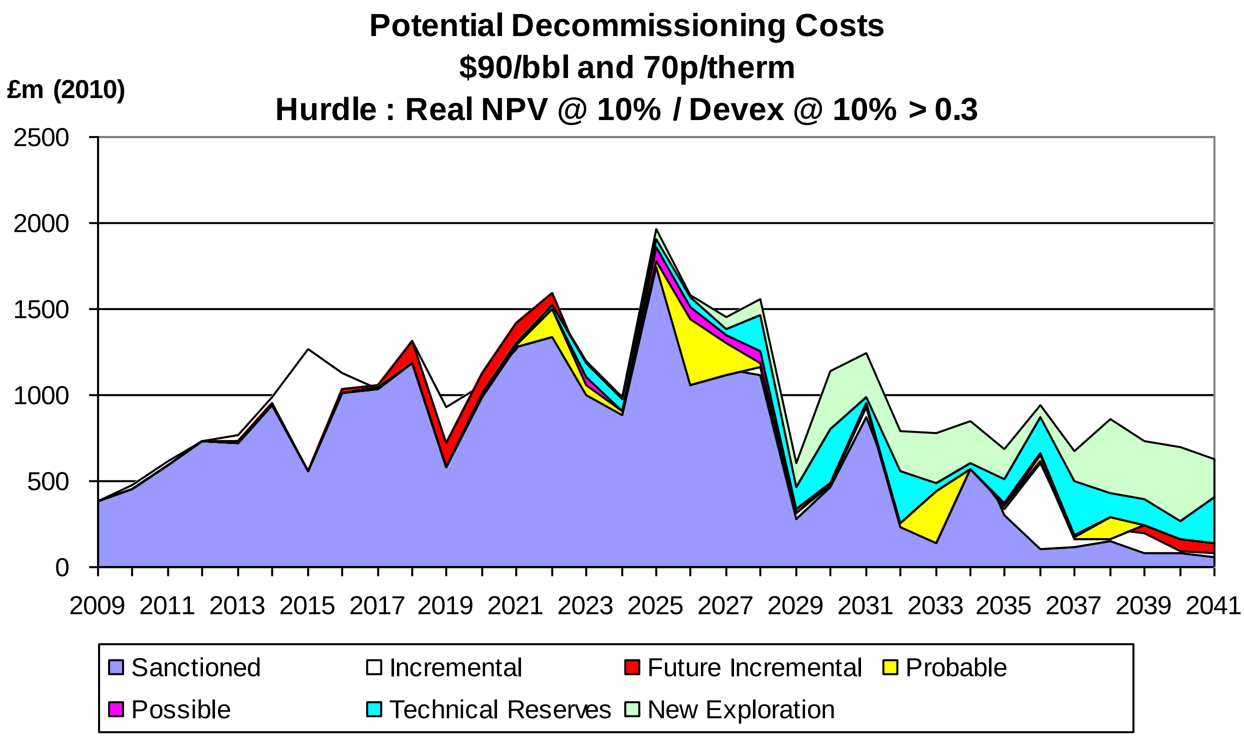
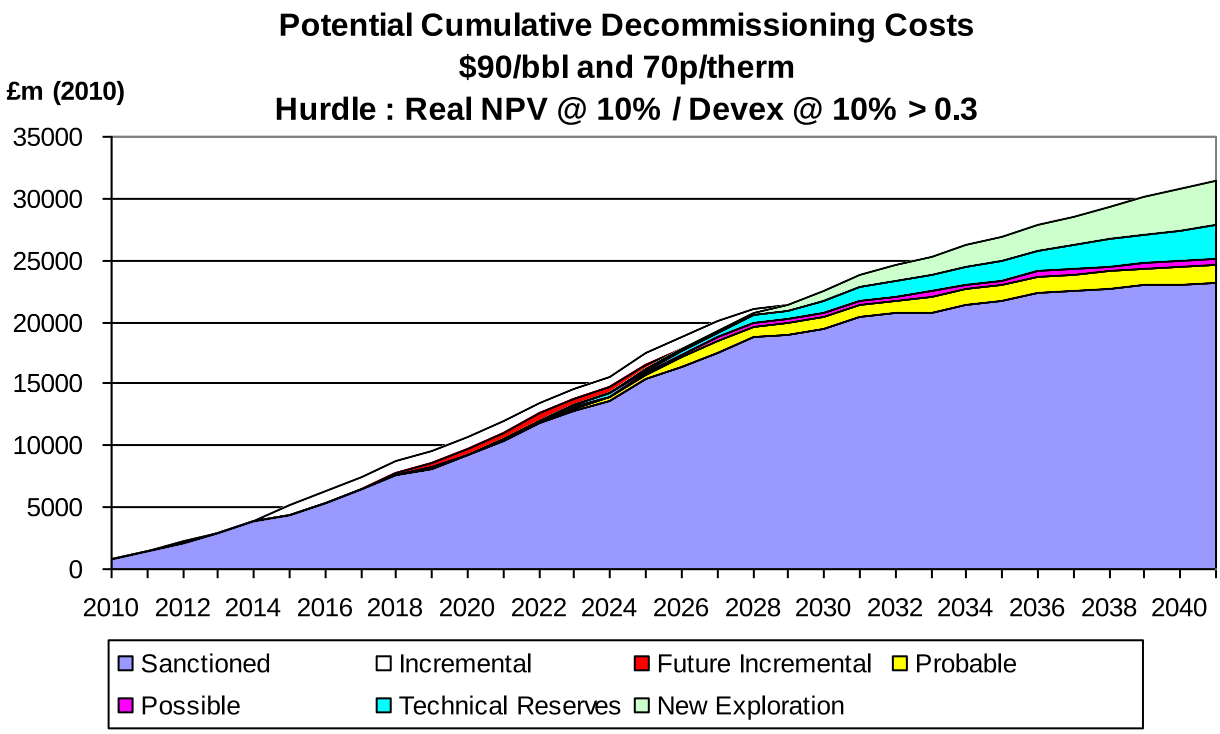


Chart 39



G. Consistency of Projections with Official Estimates of Remaining Potential

Estimates of the remaining potential from the UKCS are made every year by DECC. Their latest estimates[1] indicate a low number of 10.2 bn boe, a central estimate of 20.6 bn boe (the upper point of a considerable range depending on exploration success rates), and a high estimate of 35.8 bn boe.

The cumulative production 2010 – 2041 (inclusive) resulting from the modelling undertaken in this study is shown in Table 6.

It is seen that under the low price scenario total depletion over the period 2010 – 2041 amounts to 12.885 bn boe. The greater element comes from currently sanctioned fields. It is noteworthy that the contribution from possible and probable fields is very small. Most do not pass the investment hurdle under this scenario. In the $70, 50 pence scenario total depletion over the period is 19.863 bn boe. There is a greatly enhanced contribution from new discoveries, technical reserves, and future incremental projects. Under the $90, 70 pence case total depletion over the period is 25.553 bn boe. Compared to the medium price case there is a substantially greater contribution from possible fields, and technical reserves. It is noteworthy that only under this scenario does a considerable proportion of the reserves in the probable category become economic.

[1] See https://www.og.decc.gov.uk/information/statistics.htm

Table 6

Cumulative Potential Production from 2010 to 2041 (Mmboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

	Sanctioned	Current Incremental	Future Incremental	Probable Fields	Possible Fields	Technical Reserves	New Exploration	TOTAL
$50/bbl and 30p/therm	5756	1769	2615	405	141	511	1689	**12885**
$70/bbl and 50p/therm	5912	2085	3703	1374	611	2718	3460	**19863**
$90/bbl and 70p/therm	5989	2191	4604	1813	977	4683	5276	**25533**

The cumulative hydrocarbon production 2009 – 2041 under the same modelling assumptions is shown by the 6 geographic areas in Table 7.

Table 7

Cumulative Potential Production from 2010 to 2041 (Mmboe)
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

	Cns	IS	MF	Nns	SNS	WoS	TOTAL
$50/bbl and 30p/therm	4216	234	1197	2974	988	3276	**12885**
$70/bbl and 50p/therm	6437	368	1616	5149	2204	4088	**19863**
$90/bbl and 70p/therm	8290	448	1784	5992	3170	5849	**25533**

The general dominance of the CNS in the total is clearly apparent. Under the $70, 50 pence case the W of S region becomes increasingly significant. Perhaps surprisingly the NNS makes a very substantial contribution in this scenario as well.

There is broad consistency between the independent modelling conducted in this study and the official estimates of the remaining potential. The results of the present modelling have been terminated in 2041, but production continues after that date albeit at very low levels. The input assumptions on exploration effort, prospectivity, success rates, and pace of new field developments in the modelling are optimistic for the high price case, and the total depletion to 2041 under this scenario should be regarded as an indication of the maximum which could be achieved. As noted production will continue after 2041.

H. Contribution of Smaller Fields

It was felt to be interesting to examine the contribution of fields of different sizes to potential production and development costs. Tables 8, 9 and 10 give this information for the low, medium and high prices respectively. It is seen that under the low price scenario there are 27 fields with reserves of 5 Mboe or less which pass the economic hurdle, 70 with reserves of less than 15 Mboe and 97 with reserves of 25 Mboe or less. The fields with 5 Mboe or less contribute 79 Mboe to production and account for £652 million of development costs. The fields with reserves of less than 15 Mboe contribute 487 Mboe to production and account for £3,771 million of development costs, whilst fields with reserves of 25 Mboe or less contribute 726 Mboe to production and account for £8,150 million of development costs.

Table 8

$50, 30p	New Exploration	Possible	Probable	Tech. Res.	Total
No of Fields					
<= 5 Mboe	1	0	0	26	27
5 to 10 Mboe	7	2	2	39	50
10 to 15 Mboe	16	6	2	46	70
15 to 20 Mboe	24	6	4	50	84
20 to 25 Mboe	30	8	5	54	97
25 to 30 Mboe	36	8	5	58	107
30 to 40 Mboe	41	8	6	59	114
40 to 50 Mboe	45	9	7	59	120
> 50 Mboe	58	9	9	61	137
Mboe					
<= 5 Mboe	5	0	0	74	79
5 to 10 Mboe	49	14	13	177	253
10 to 15 Mboe	160	56	13	258	487
15 to 20 Mboe	299	56	44	326	726
20 to 25 Mboe	438	99	67	413	1018
25 to 30 Mboe	598	99	67	525	1289
30 to 40 Mboe	764	99	106	557	1527
40 to 50 Mboe	931	141	152	557	1781
> 50 Mboe	1833	141	405	690	3069
Real 2010 Devex £m					
<= 5 Mboe	31	0	0	622	652
5 to 10 Mboe	373	105	137	1361	1976
10 to 15 Mboe	1347	359	137	1928	3771
15 to 20 Mboe	2772	359	307	2450	5889
20 to 25 Mboe	4009	708	460	2974	8150

25 to 30 Mboe	5314	708	460	3343	9824
30 to 40 Mboe	6694	708	786	3624	11811
40 to 50 Mboe	7954	1031	992	3624	13601
> 50 Mboe	14743	1031	3468	3854	23096

Under the medium price scenario there are 58 fields with reserves of 5 Mboe or less which pass the economic hurdle, 190 with reserves of less than 15 Mboe, and 258 with reserves of 25 Mboe or less. The fields with 5 Mboe or less contribute 174 Mboe to production and account for £1,629 million of development costs. The fields with reserves of less than 15 Mboe contribute, 1414 Mboe to production and account for £13,007 million of development costs, whilst fields with reserves of 25 Mboe or less contribute 2725 Mboe to production and account for £25,936 million of development costs.

Table 9

$70, 50p	**New Exploration**	**Possible**	**Probable**	**Tech. Res.**	**Total**
No of Fields					
<= 5 Mboe	11	1	0	46	58
5 to 10 Mboe	40	6	6	82	134
10 to 15 Mboe	64	11	7	108	190
15 to 20 Mboe	75	15	10	130	230
20 to 25 Mboe	91	19	11	137	258
25 to 30 Mboe	105	22	13	145	285
30 to 40 Mboe	116	25	14	152	307
40 to 50 Mboe	128	26	15	157	326
> 50 Mboe	148	27	23	167	365
Mboe					
<= 5 Mboe	43	4	0	127	174

5 to 10 Mboe	250	41	43	391	725
10 to 15 Mboe	556	96	57	705	1414
15 to 20 Mboe	748	166	107	1084	2104
20 to 25 Mboe	1102	255	129	1239	2725
25 to 30 Mboe	1484	338	182	1456	3460
30 to 40 Mboe	1853	440	221	1684	4199
40 to 50 Mboe	2385	482	267	1911	5044
> 50 Mboe	3901	611	1379	2894	8784
Real 2010 Devex £m					
<= 5 Mboe	340	45	0	1245	1629
5 to 10 Mboe	2000	364	407	3860	6630
10 to 15 Mboe	4803	679	532	6993	13007
15 to 20 Mboe	6787	1392	826	10610	19614
20 to 25 Mboe	10504	2014	984	12434	25936
25 to 30 Mboe	14254	2612	1352	14148	32366
30 to 40 Mboe	17583	3315	1678	16278	38854
40 to 50 Mboe	22917	3638	1884	18994	47433
> 50 Mboe	35812	4139	10922	29847	80720

Under the high price scenario there are 73 fields with reserves of 5 Mboe or less which pass the economic hurdle, 261 with reserves of less than 15 Mboe, and 360 with reserves of 25 Mboe or less. The fields with 5 Mboe or less contribute 226 Mboe to production and account for £2,174 million of development costs. The fields with reserves of less than 15 Mboe contribute 1990 Mboe to production and account for £18,965 million of development costs, whilst fields with reserves of 25 Mboe or less contribute 3910 Mboe to production and account for £39,285 million of development costs.

Table 10

$90, 70p	New Exploration	Possible	Probable	Tech. Res.	Total
No of Fields					
<= 5 Mboe	16	4	2	51	73
5 to 10 Mboe	55	10	8	112	185
10 to 15 Mboe	85	18	9	149	261
15 to 20 Mboe	102	24	13	180	319
20 to 25 Mboe	125	27	15	193	360
25 to 30 Mboe	143	31	17	202	393
30 to 40 Mboe	163	34	20	213	430
40 to 50 Mboe	182	35	21	220	458
> 50 Mboe	215	38	32	238	523
Mboe					
<= 5 Mboe	60	14	7	145	226
5 to 10 Mboe	351	56	50	592	1050
10 to 15 Mboe	733	147	65	1046	1990
15 to 20 Mboe	1032	252	134	1580	2999
20 to 25 Mboe	1545	318	178	1869	3910
25 to 30 Mboe	2034	428	232	2114	4808
30 to 40 Mboe	2729	532	343	2472	6076
40 to 50 Mboe	3579	573	388	2799	7339
> 50 Mboe	5966	981	1818	5021	13786
Real 2010 Devex £m					
<= 5 Mboe	485	144	112	1433	2174
5 to 10 Mboe	2824	530	519	6237	10110
10 to 15 Mboe	6178	1301	644	10843	18965
15 to 20 Mboe	9226	2410	1233	16462	29331

20 to 25 Mboe	14810	2875	1582	20019	39285
25 to 30 Mboe	19835	3630	1950	22036	47451
30 to 40 Mboe	26638	4333	3080	25584	59635
40 to 50 Mboe	35886	4656	3286	29330	73158
> 50 Mboe	58308	8546	15715	57407	139977

Under the low price case over the period to 2041 there are 84 viable fields with reserves of less than 20 mmboe and they contribute 23.6% of aggregate production from all new fields (excluding incremental projects) over the period. Under the medium price there are 230 viable fields with reserves of less than 20 mmboe and these contribute 24% to aggregate output from all new fields (excluding incremental projects) over the period. Under the high price there are 319 viable fields with reserves less than 20 mmboe and they contribute nearly 22% to aggregate output from all new fields (excluding incremental projects). If the definition had included fields with reserves less than 25 mmboe the respective contributions to total output from all new fields (excluding incremental projects) would have been 33.2%, 31.7% and 28.4%.

4. Conclusions

In this study detailed modelling has been undertaken of the longer term prospects for activity in the UK Continental Shelf (UKCS). The three cases modelled are designed to reflect the outcomes of long term investment scenarios. The results highlight a wide range of long term prospects for activity levels. There is a noticeable sensitivity of investment and production activity in relation to oil and gas price assumptions. In the low price case ($50, 30 pence in real terms) investment and production fall very sharply throughout the study period to 2041. Only 45 fields would remain in production in 2041 compared to nearly 300 in 2009. Production falls from 2.3 mm boe/d in 2010 to 0.53 mm boe/d in 2041. In the period 2010 – 2041 cumulative production is only 12.9 bn boe. Most new fields and incremental projects are uneconomic.

Under the $70, 50 pence case substantial numbers of new fields and incremental projects become viable. Investment holds up at current levels for a considerable number of years but still falls at a noticeable pace thereafter. There are still 115 producing fields in 2041. Production falls to below 1 mm boe/d in 2041. Over the period 2010 – 2041 cumulative production is 19.9 bn boe.

Under the $90, 70 pence price case field investment increases from present levels and remains buoyant for many years ahead. Very many new fields and projects become viable. There are nearly 170 producing fields in 2041. In 2040 production is 1.4 mm boe/d. Cumulative production over the period 2010 – 2041 inclusive is 25.5 bn boe.

The results of the modelling highlight the importance of small fields in total activity levels. Under the low price case over the period to 2041 there are 97 viable new fields (excluding incremental projects) with reserves less than 25 mmboe and these contribute 33% to aggregate output from all new fields (excluding incremental projects) over the period to 2041. At the medium price there are 258 viable new fields with reserves less than 25 mmboe and they contribute 32% to total output from all new fields (excluding incremental projects) over the period. Under the high price case there are no less than 360 viable new fields with reserves less than 25 mmboe and these contribute nearly 28% to total output from all new fields (excluding incremental projects) over the period. It is noticeable that some large, high cost fields become viable only under the high price case.

The attainment of the very high levels of activity exhibited in the $90, 70 pence, and even in the $70, 50 pence case for part of the study period, requires not only that these prices are employed for investment screening purposes, but the response of the entire oil and gas cluster is sufficient to maintain a consistently high level of project design, development, and completion. It should be emphasised that prices of $90 and 70 pence (in real terms) are unlikely to be employed currently for investment screening purposes as cautious values have conventionally been employed. Thus the probability of the attainment of the high case scenario is relatively low.

The attainment of the activity levels under the 3 scenarios clearly involves the continuous triggering of new field developments. Under the low price scenario the average yearly number of new field developments (excluding all incremental projects) in the period 2010 – 2035 inclusive is 4.3. This was determined by the economic investment hurdle. There would be much unutilised capacity within the oil and gas supply cluster in this scenario.

Under the medium price case the average yearly number of new field developments triggered in the period 2010 – 2035 is 12. In line with historic experience this should be within the capability of the oil and gas supply cluster.

Under the high price scenario the average number of new field developments in the period 2010 – 2035 is 17.3 and in the period to 2041 it is 14.9. While this pace of development is consistent with historic experience at some periods of development of the UKCS the frequent attainment of annual developments in the range of 18 – 20 per year plus many incremental projects would be very challenging for the industry. Cost inflation would very likely be a common feature.

It should be stressed that the prospects indicated in the modelling depend on the various DECC and PILOT initiatives continuing to bear fruit over the period. Those initiatives refer to fallow field/blocks, stewardship of mature fields, infrastructure Code of Practice, and the continued availability and integrity of that infrastructure. All this cannot be taken for granted. The need for tax incentives to stimulate investment in mature PRT-paying fields remains valid, and amendments to the field allowance for the Supplementary Charge could further enhance investment in costly activities such as tight gas development. In the modelling undertaken in this study it is clear that the field allowance for the Supplementary Charge has a significant effect in facilitating the development of heavy oil fields in the NNS area.