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Prospects for Activity Levels in the UKCS to 2035 after the 2006 Budget

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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, the impact of the Gas Levy on incremental investments in mature gas 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 Group.

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Prospects for Activity Levels in the UKCS to 2035
after the 2006 Budget

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1. **Introduction**

The prospects for activity levels in the UK Continental Shelf (UKCS) are a function of several factors including prospectivity, (size of field and expected success rate), costs of exploration, appraisal and development, oil and gas prices, the availability and cost of access to infrastructure, technological progress, and the tax régime applied to the various activities. This study incorporates all these factors in the modelling of prospective activity to 2035, including the impact of the tax changes announced in December 2005.

The study examines the potential contributions to activity from existing sanctioned fields, incremental projects relating to these, undeveloped fields (including those currently being examined for development and those still not fully appraised), and new discoveries made from further exploration. Technological progress is assumed to continue in accordance with recent trends. Thus no major step-changes are assumed. It is assumed that the PILOT initiatives relating to fallow blocks/discoveries and the Infrastructure Code of Practice bear fruit, and that the offshore infrastructure will be maintained/reinforced to permit the development of many small fields and incremental projects in the longer term.

2. Methodology and Assumptions

The projections of production and expenditures have been made through the use of financial 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 316sanctioned fields, 112 incremental projects (76 probable and 23 possible) relating to these fields, 19 probable fields, and 23 possible fields. All these are as yet unsanctioned but are currently being examined for development. An additional database contains 215 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block location 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 2030. 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 10 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	40	36
Medium	30	28
Low	25	24

These values are below current market levels but are used to reflect values generally used by investors when assessing long-term investments.

The postulated numbers of annual exploration wells for the whole of the UKCS are as follows:

Table 2
Exploration Wells

	2006	2030
High	50	38
Medium	38	27
Low	31	20

The annual numbers are modelled to decline in a 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:

Table 3 Success Rates
Medium effort/Medium success rate = 23%
High effort/Low success rate = 19%
Low effort/High success rate = 24%

It is assumed that technological progress will maintain these success rates over the time period.

The mean sizes of discoveries made in the period for each of the 6 regions were calculated. It was then assumed that the mean size of discovery would decrease in line with this historic experience. Such decline rates are quite modest. For 2004 the average size of discovery for the whole of the UKCS was 34 million barrels of oil equivalent (mmboe). 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 2030. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

Table 4 Total Number of Discoveries to 2030	
High Effort/Low Success Rate	221
Medium Effort/Medium Success Rate	179
Low Effort/High Success Rate	146

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated (See Section 3). These reflect substantial cost inflation over the last 2 years. 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 the whole of the UKCS the average development costs on this basis were $9.45/boe. 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 in the exploitation costs of fields.

With respect to fields in the category of technical reserves it was recognised that many have remained undeveloped for a long time, but it was assumed that, reflecting the high current costs and prospective technological progress, their development costs would be aligned with those for new discoveries for each of the regions. 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. This subject is currently very pertinent in the UKCS. The ceilings were assumed to be linked to the oil/gas scenarios with maxima of 22, 20 and 17 respectively under the High, Medium, and Low Price Cases. These constraints do <u>not</u> apply to incremental projects which are additional to new field developments. To put these assumptions in perspective 13 new fields received development approval in 2005.

A noteworthy feature of the 112 incremental projects in the database validated by operators is the expectation that the great majority will be executed over the 3 years from 2006. 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 not only on currently sanctioned fields but also on 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 112 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.

The financial modelling incorporated a discount rate, field economic cut-off, and the full details of the current petroleum tax system including the changes in the 2006 Budget. The base case emphasised has a post-tax discount rate of 10% in real terms but some examples of the results with 15% real discount rate are also shown. An important assumption is that adequate infrastructure will be available to facilitate the development of the future projects. It is also important to note that it is assumed that investment decisions are made on the basis of the oil/gas prices indicated. When the prospective investments in probable and possible fields and incremental projects were subjected to economic analysis it was found that most were quite small and the returns in terms of NPVs were correspondingly often small on the assumptions described above. It was felt that, to reflect the relationship between the risks and rewards involved, a minimum expected NPV at the discount rates employed would be necessary before the project/field was sanctioned. For purposes of this study minimum NPVs of £10 million and £5 million were employed as thresholds.

3. Results of Modelling

a) Features of Fields/Projects being Examined for Development

To highlight the current position of the industry with respect to consideration of investment some key features of the fields/projects were examined. Summary results are shown in Table 5 which shows the consequence of the economic modelling under the $40, 36p. price scenario. A striking feature of the probable/possible fields is their relatively small size with the average being under 15 mmboe and the 68% range being 2.3-22.1 mmboe. The unit development costs are relatively high reflecting both recent cost escalation and the lack of economy of scale. Thus the average is $9.45/boe (real terms). The total lifetime average cost is $15.3/boe. This excludes the costs of capital.

Less surprising are the results for the probable incremental projects where the average size is 8.4 mmboe. The range at the 68% level is 1.9-13.5 mmboe. The average development cost is $7.7/boe and the average lifetime cost $10.9/boe. The average size of possible incremental project is 19.9 mmboe, but this finding is greatly affected by one very large project. Thus the 68% range is 3-19 mmboe. The average development cost is $9.75/boe and the average take cost $13.2/boe.

The average size of fields in the technical reserves category is 23.4 mmboe with the 68% range being 3.1-32.2 mmboe. The Monte Carlo modelling produced an average development cost of $10.1/boe with the total costs being as much as $20/boe.

The Monte Carlo modelling produced an average size of new discovery of just under 27 mmboe with the 68% range being 11.9-44.8 mmboe. The modelling produced average development costs of $8.9/boe and average total costs of $19.5/boe.

$40/bbl and 36p/therm		Table 5								
	NPV @ 10% £m		**MBOE**		**Devex /bbl $**		**Opex /bbl $**		**Devex + Opex + Aban /bbl $**	
Probable Incremental Projects										
Average		37.24		8.44		7.71		2.92		10.90
sd		39.84		8.88		7.56		3.79		12.02
68%	4.34	70.69	1.86	13.50	3.12	11.43	0.00	7.01	3.12	19.11
95%	-1.41	119.17	0.37	30.97	0.00	16.23	-0.05	12.32	-0.05	30.47
Possible Incremental Projects										
Average		63.27		19.90		9.75		3.33		13.22
sd		147.28		46.61		5.93		3.49		9.96
68%	2.01	80.90	3.03	18.88	4.63	15.17	0.44	5.79	5.07	20.95
95%	-3.25	347.62	0.51	129.86	0.00	22.19	0.00	12.10	-0.00	35.49
Probable + Possible										
Average		61.32		14.52		9.45		5.08		15.29
sd		49.45		11.53		6.73		3.24		10.61
68%	-7.70	104.11	2.27	22.15	2.00	14.50	0.00	7.06	2.00	22.98
95%	2.98	153.47	2.65	44.35	3.28	19.24	0.00	12.26	3.28	33.55
Probable Future Fields										
Average		63.88		14.90		8.91		5.02		14.70
sd		50.32		13.74		8.22		2.61		11.53
68%	25.21	135.87	4.48	22.91	4.74	11.11	4.03	6.20	8.92	18.56
95%	1.58	150.88	2.79	47.19	4.19	28.51	0.00	10.57	4.19	41.52
Possible Future Fields										
Average		59.20		14.21		9.90		5.12		15.79
sd		49.74		9.64		5.34		3.75		9.68
68%	19.98	102.13	6.17	22.03	4.39	16.11	0.44	7.63	4.95	25.19
95%	6.57	170.07	3.08	33.68	2.70	19.08	0.00	13.04	2.70	33.83
All Technical Reserve Fields										
Average		63.09		23.40		10.12		9.01		20.01
sd		101.92		53.08		16.50		3.40		20.29
68%	9.82	101.78	3.14	32.19	6.66	11.19	6.10	12.26	13.40	24.57
95%	2.11	317.40	1.00	116.09	3.91	13.56	0.50	14.81	4.54	29.71

$40/bbl and 36p/therm				**Table 5 (cont)**						
All New Exploration Fields										
Average		76.79		26.98		8.89		9.79		19.56
sd		60.96		19.31		2.05		2.08		4.33
68%	28.31	129.71	11.86	44.75	6.91	10.93	7.78	11.88	15.38	23.90
95%	14.21	219.80	7.23	80.19	4.95	13.00	5.54	13.99	10.98	28.28

The size distribution of all future fields and projects is shown in Chart 1. It is seen that the majority are below 20 mmboe while the number exceeding 60 mmboe is quite small. It is noteworthy that a very significant proportion of the fields with reserves exceeding 40 mmboe are in the future discoveries category.

In Chart 2 the distribution of the NPVs from the fields/projects having positive returns at 10% real discount rate is shown on a post-2006 Budget basis under the $30, 28p price scenario. (The future incremental projects are not shown). It was found that 500 fields/projects had positive returns but only 365 had NPVs exceeding £10 million and 473 had NPVs exceeding 5 million. A very low proportion had NPVs exceeding £100 million. If a 15% discount rate were employed 473 fields/projects had positive NPVs but only 317 had NPVs exceeding £10 million.

The exercise was repeated for the $40, 36p. scenario and the results are shown in Chart 3. In this case 578 fields/projects had positive NPVs at 10% discount rate and 519 of them had returns in excess of £10 million. At 15% discount rate 574 fields/projects had positive returns and with 488 of these they exceeded £10 million.

In Chart 4 the results under the $25, 24p. scenario are shown. In this case 390 fields/projects had positive NPVs but only 221 had returns in excess of £10 million. At 15% discount rate 385 fields/projects had positive returns but only 185 had returns in excess of £10 million.

Chart 1

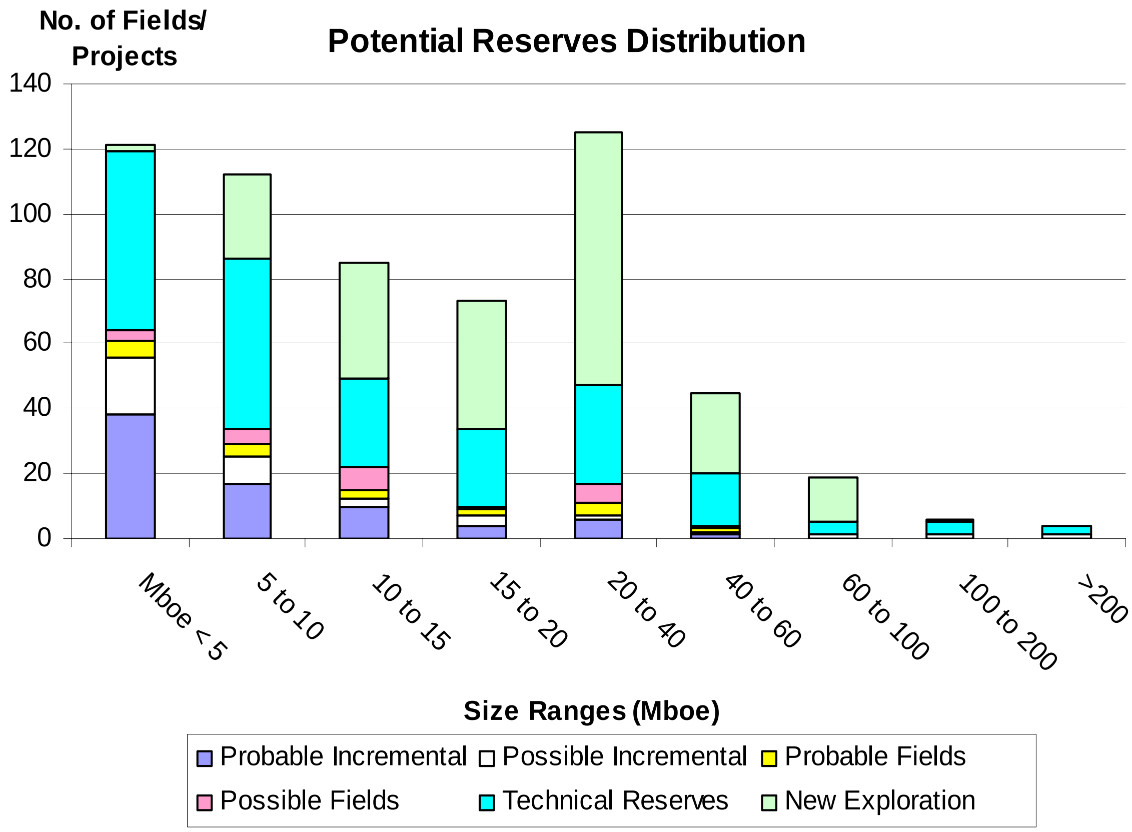


Chart 2

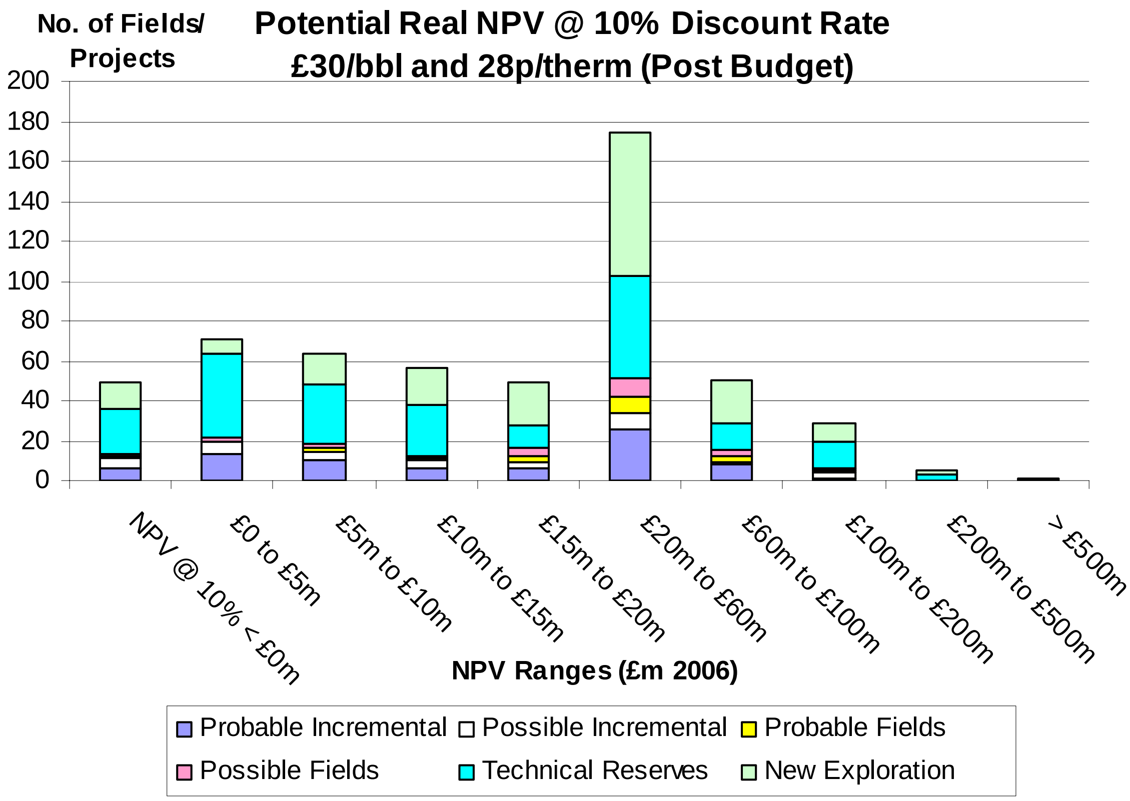


Chart 3

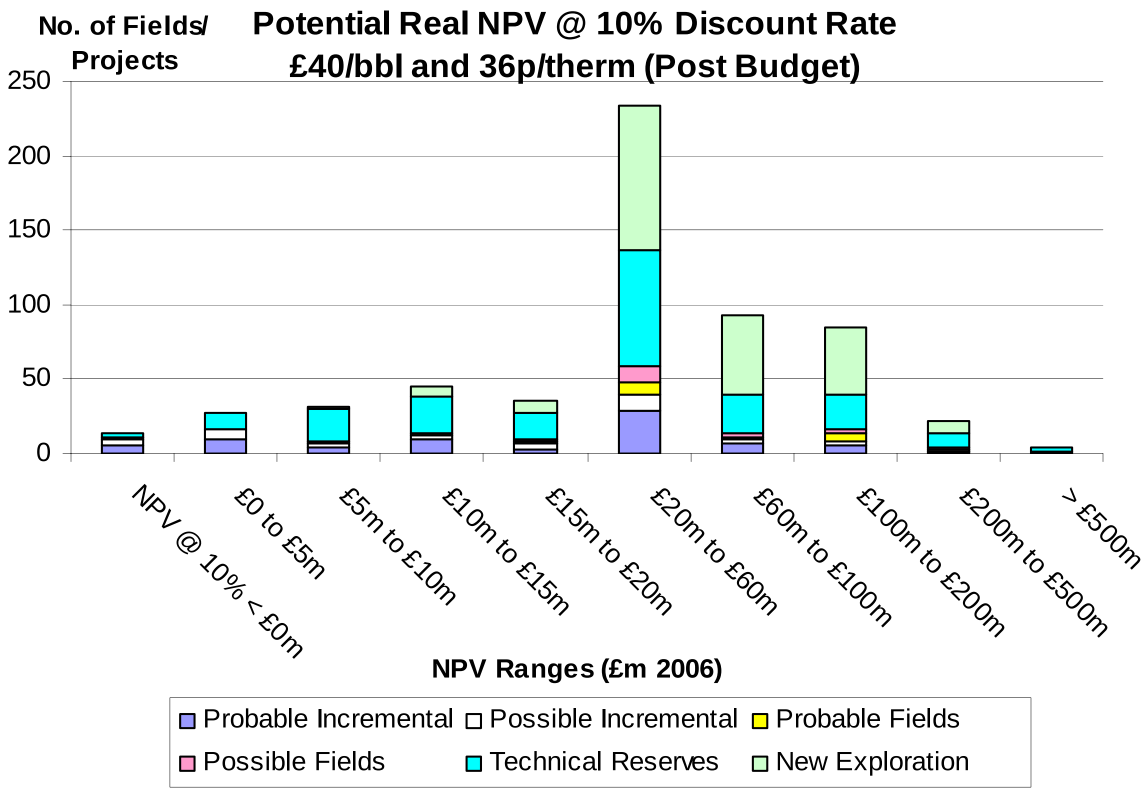
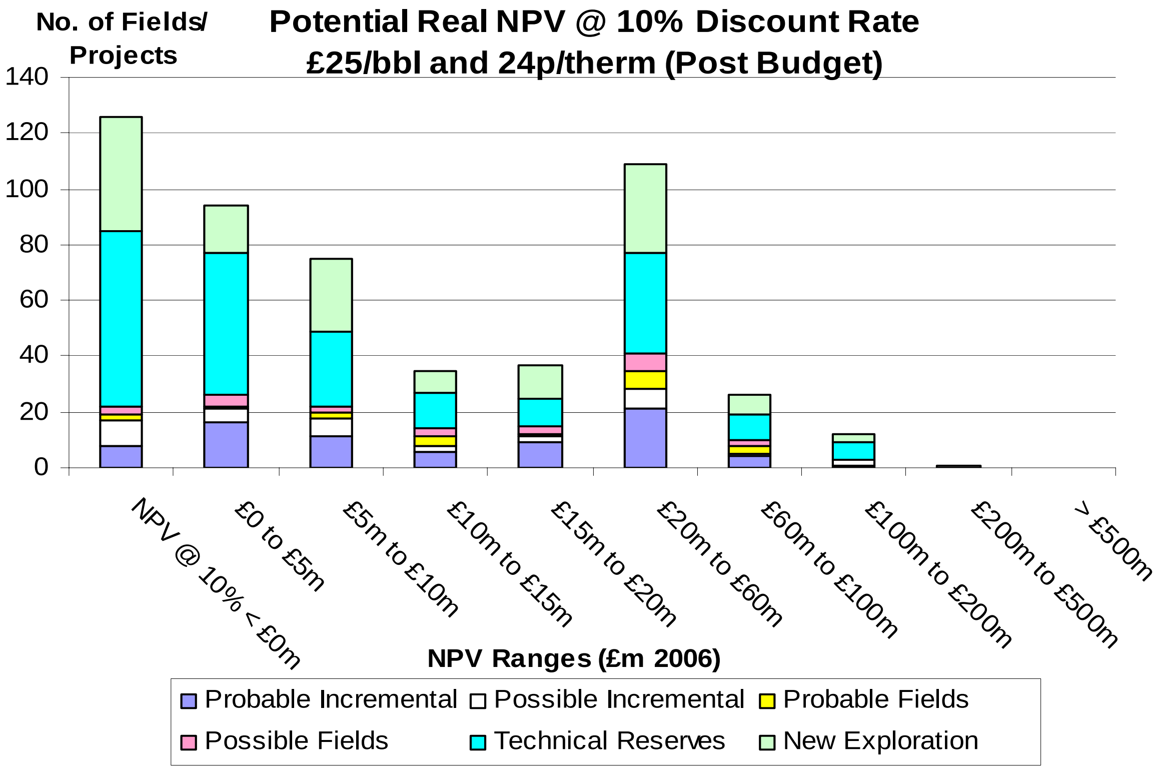


Chart 4



b) <u>Number of Fields in Production</u>

In indicating future activity levels the base case shown uses a 10% real, post-tax discount rate with a minimum NPV of £10 million. A basic indicator of the changing activity levels is the number of fields in production. These are shown in Charts 5, 6, and 7 by the different categories of fields under the 3 price scenarios. Incremental projects are not shown separately. Under the \$30, 28 pence case the numbers rise to a peak of around 280 in 2010. By 2020 the total is around 270. Currently sanctioned fields constitute the majority until 2017, but by 2020 new discoveries and fields in the technical reserves categories constitute the great majority of the fields.

Under the $40, 36 pence case the number of fields increases to a peak of 320 in 2014-2105 after which there is a decrease to around 265 in 2020. In that year the great majority of fields are in the technical reserves/new discoveries categories.

Under the $25, 24p. scenario the number of fields in production increases to around 275 over the next few years but falls off rapidly after 2010. By 2020 there are less than 120 producing fields with a substantial proportion still being from those already sanctioned.

Chart 5

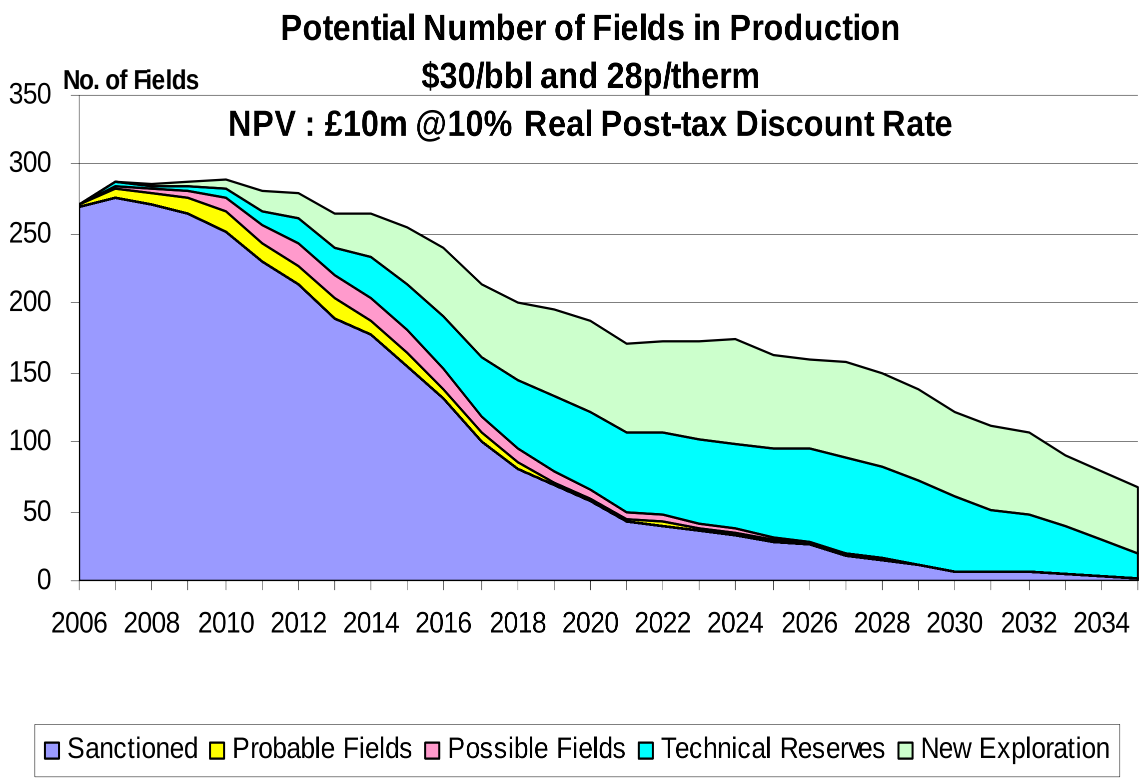
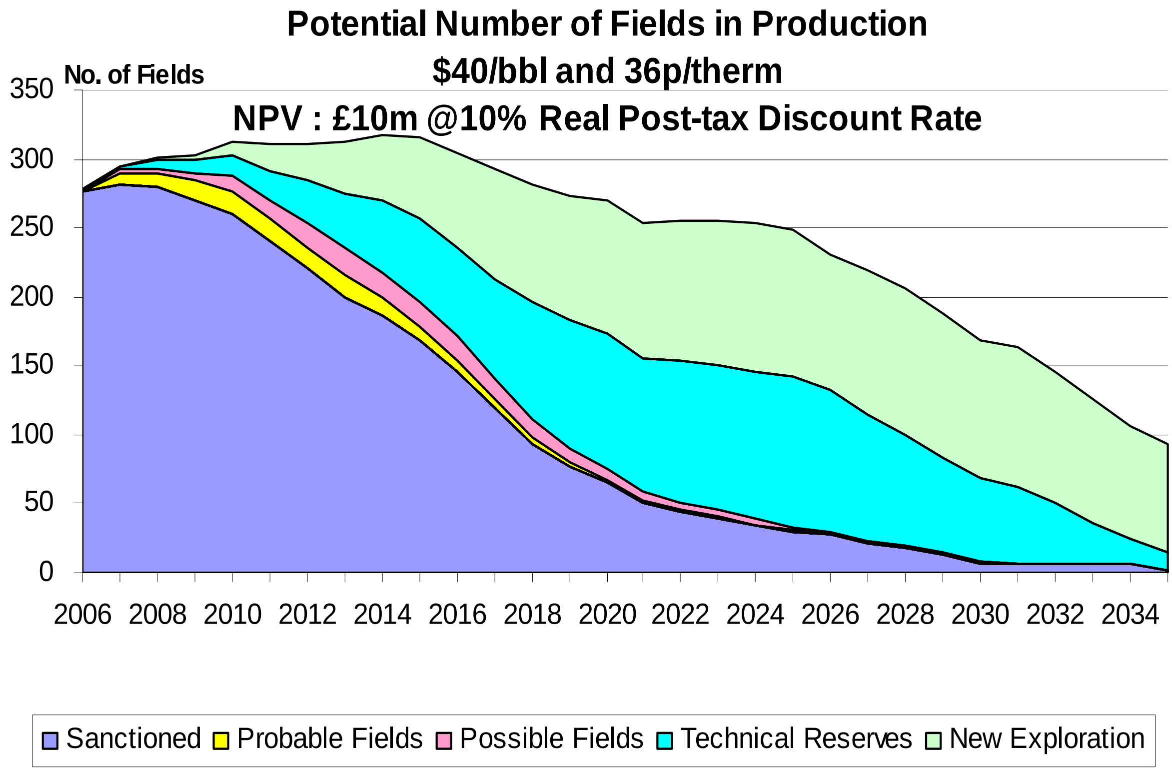
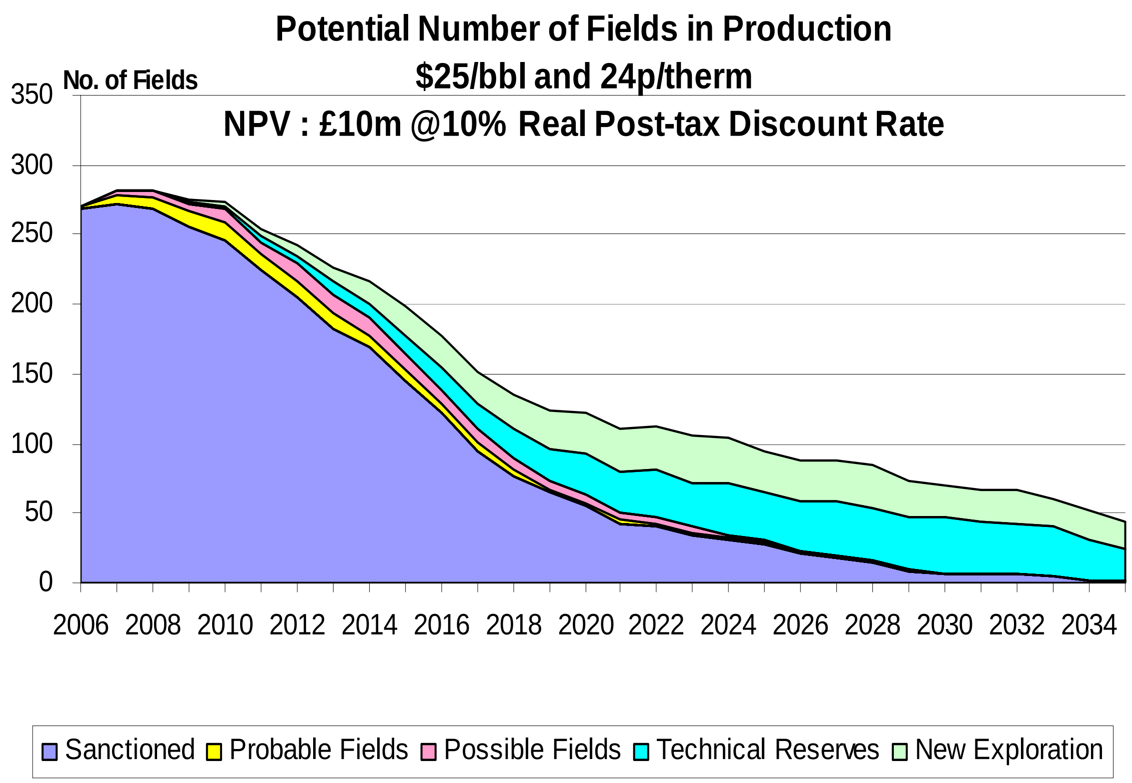


Chart 6



Potential Number of Fields in Production
$40/bbl and 36p/therm
NPV : £10m @10% Real Post-tax Discount Rate
No. of Fields
350
300
250
200
150
100
50
0
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Sanctioned
Probable Fields
Possible Fields
Technical Reserves
New Exploration

Chart 7



c) <u>Production</u>

Potential oil production (excluding NGLs) under the $30, 28 pence scenario is shown in Chart 8. After a worthwhile increase in 2007-2008 a key feature is the fairly fast decline from sanctioned fields. In the later part of the period the pace of decline moderates such that in 2020 production from this category of field is around 200,000 b/d. Incremental projects make a major contribution to the moderation of the decline rate over the next few years.

Other features of the results are the major long-term contributions made by fields in the technical reserves category and new discoveries from 2015. In 2020 total production is around 1.2 mmb/d and in future incremental projects, technical reserves, and new discoveries contribute the great majority of the output.

In Chart 9 prospective production of natural gas (excluding NGLs) is shown. In 2010 6.9 bcf/d is produced and 4 bcf/d in 2020. Production from the sanctioned fields falls at a fairly fast pace after 2007, but by 2013 this category of field still accounts for over 50% of total output. By 2020 technical reserves and new discoveries account for around 60% of total production.

Chart 8

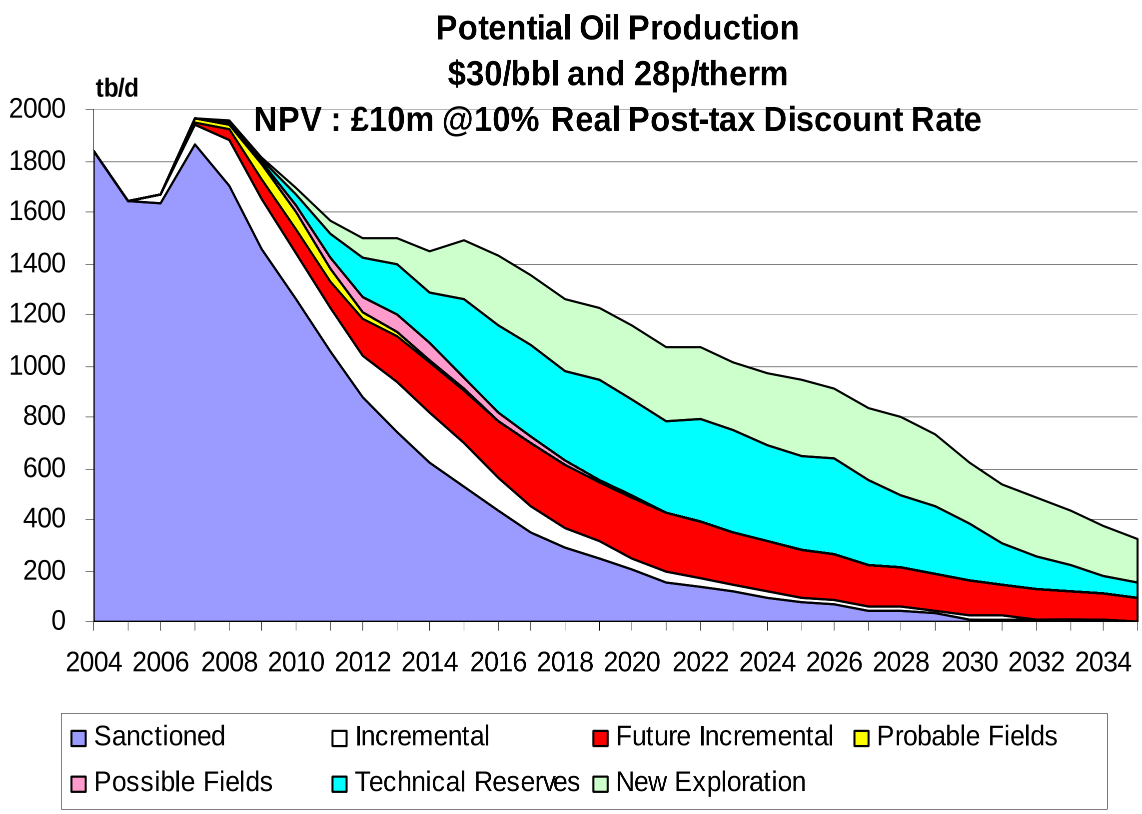
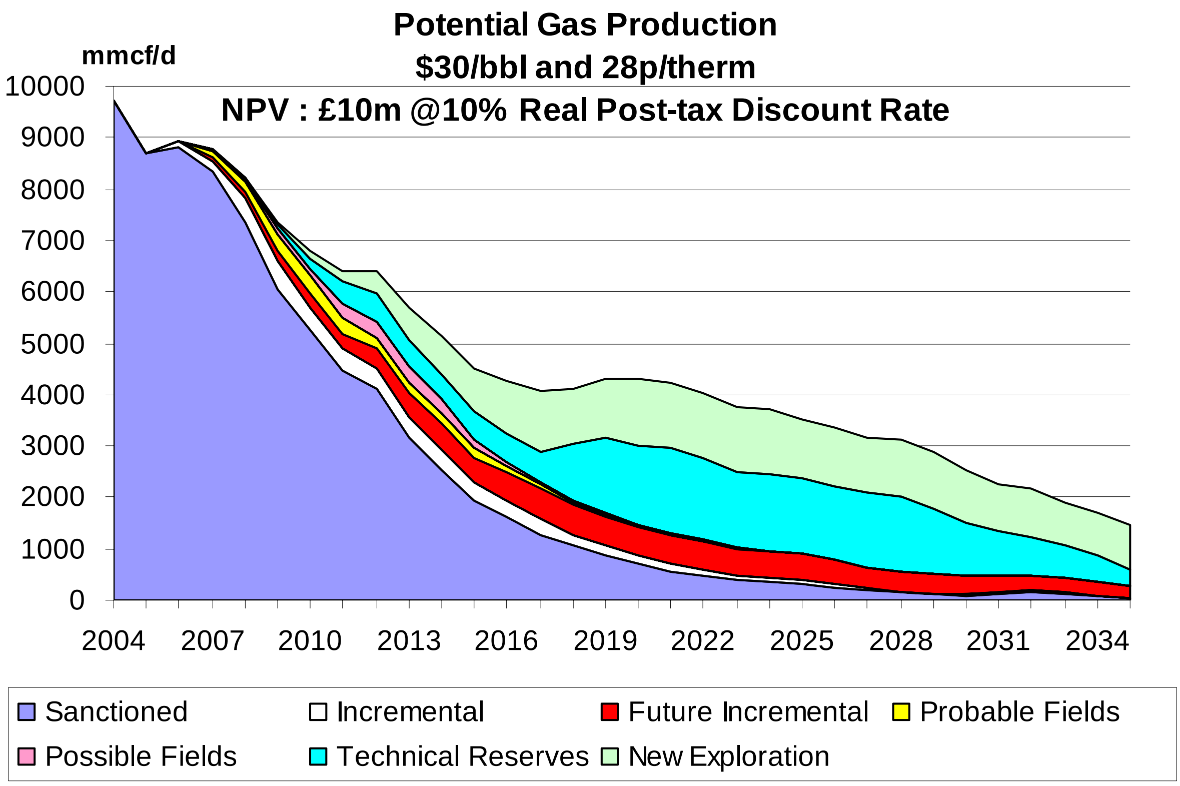


Chart 9



In Chart 10 prospective total hydrocarbon production (including NGLs) is shown under the $30, 28 pence scenario. From 3.35 mmboe/d in 2005 it grows to nearly 3.7 mmboe/d in 2007 but falls to just below 3 mmboe/d in 2010. By 2010 it is just below 2 mmboe/d and by 2030 just over 1 mmboe/d. By 2020 the great majority of the production comes from future incremental projects and fields in the technical reserves and new discovery categories.

With the modelling being done on a regional basis production by main geographic areas can be shown. In Charts 11, 12, and 13 the results are shown for oil, gas, and total hydrocarbon production respectively. The growing importance of oil from West of Shetland is a notable feature. For gas it is seen that the SNS, while clearly becoming less important, continues to make very significant contributions to the total for many years ahead. Gas from West of Shetland makes a worthwhile contribution from 2010 onwards. Over the period it is seen that West of Shetland becomes relatively more important in its contribution to total hydrocarbon production.

Chart 10

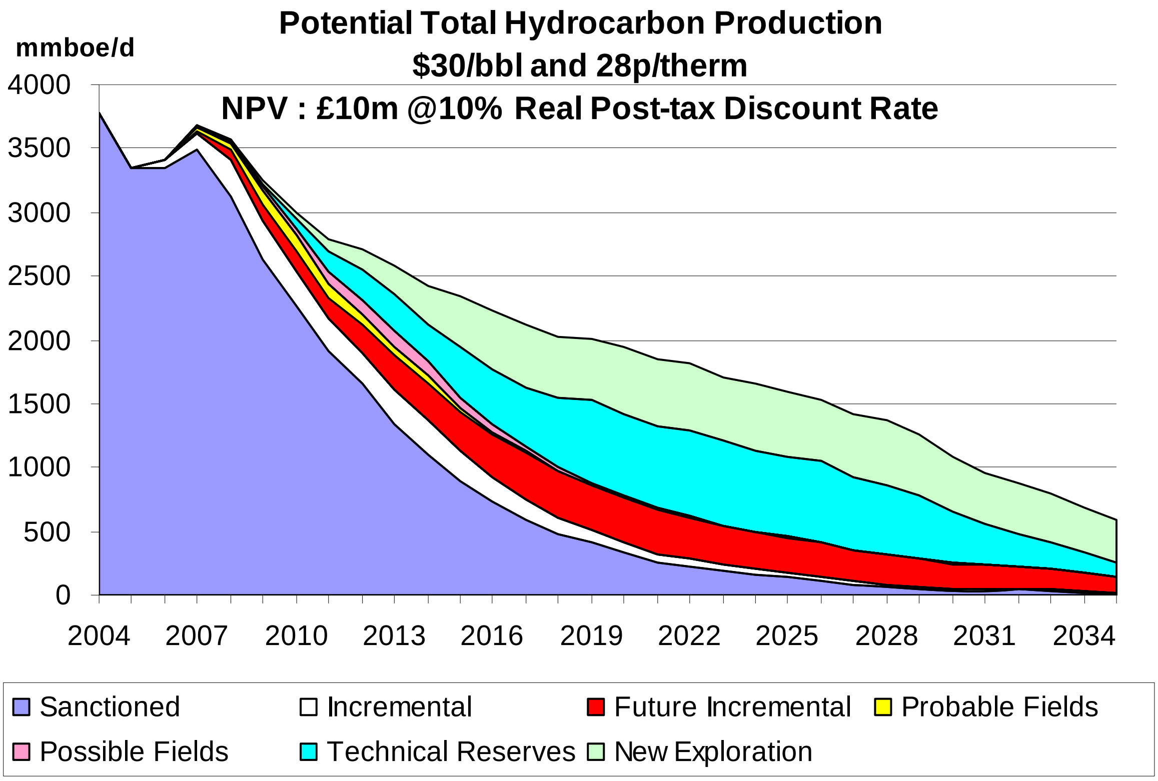


Chart 11

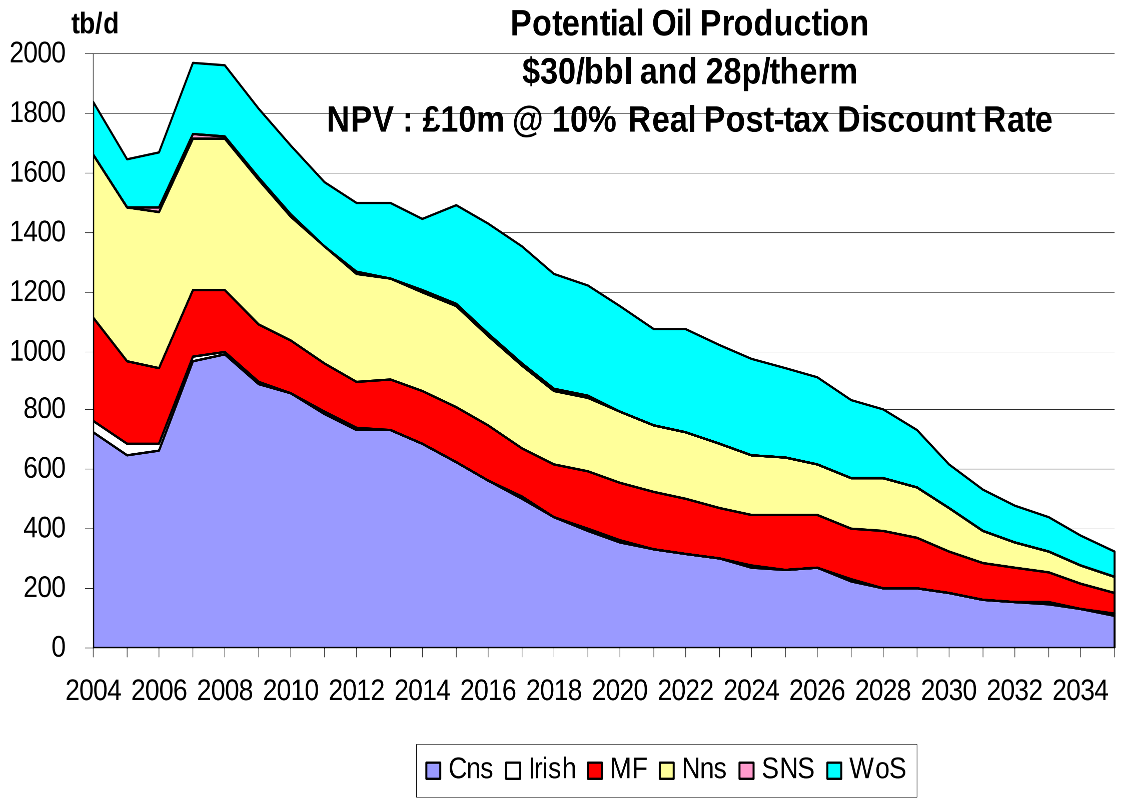


Chart 12

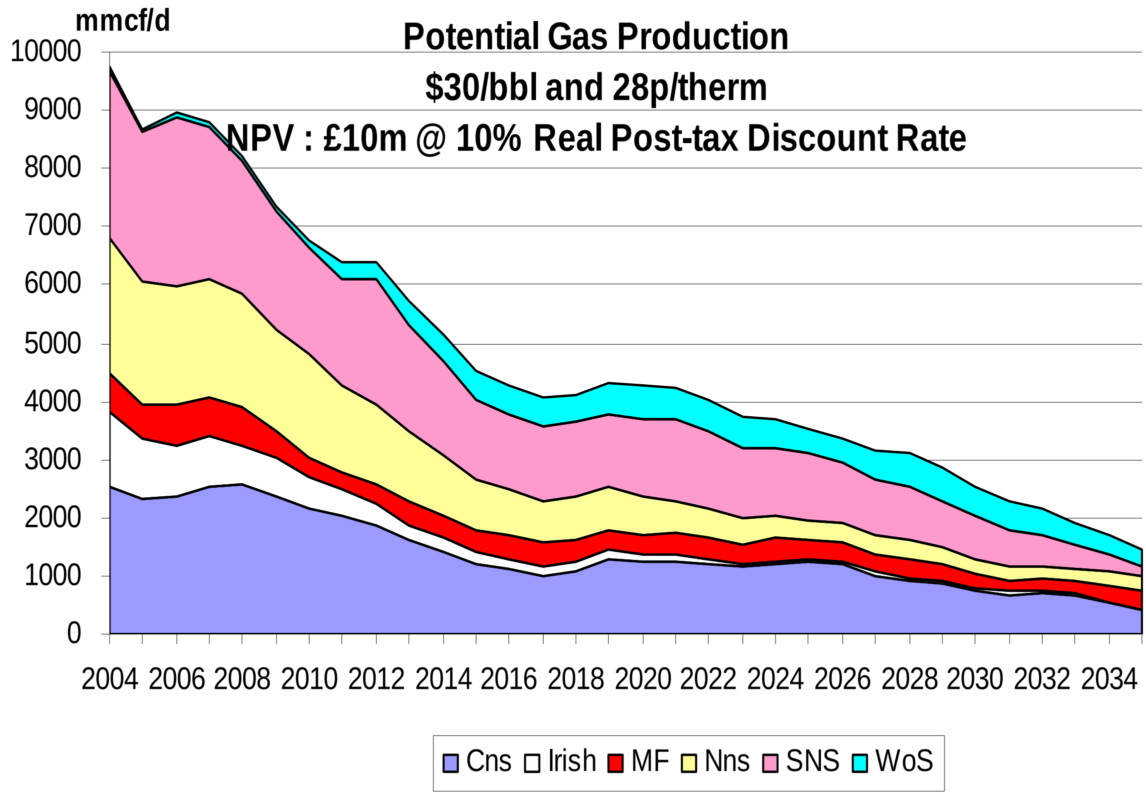
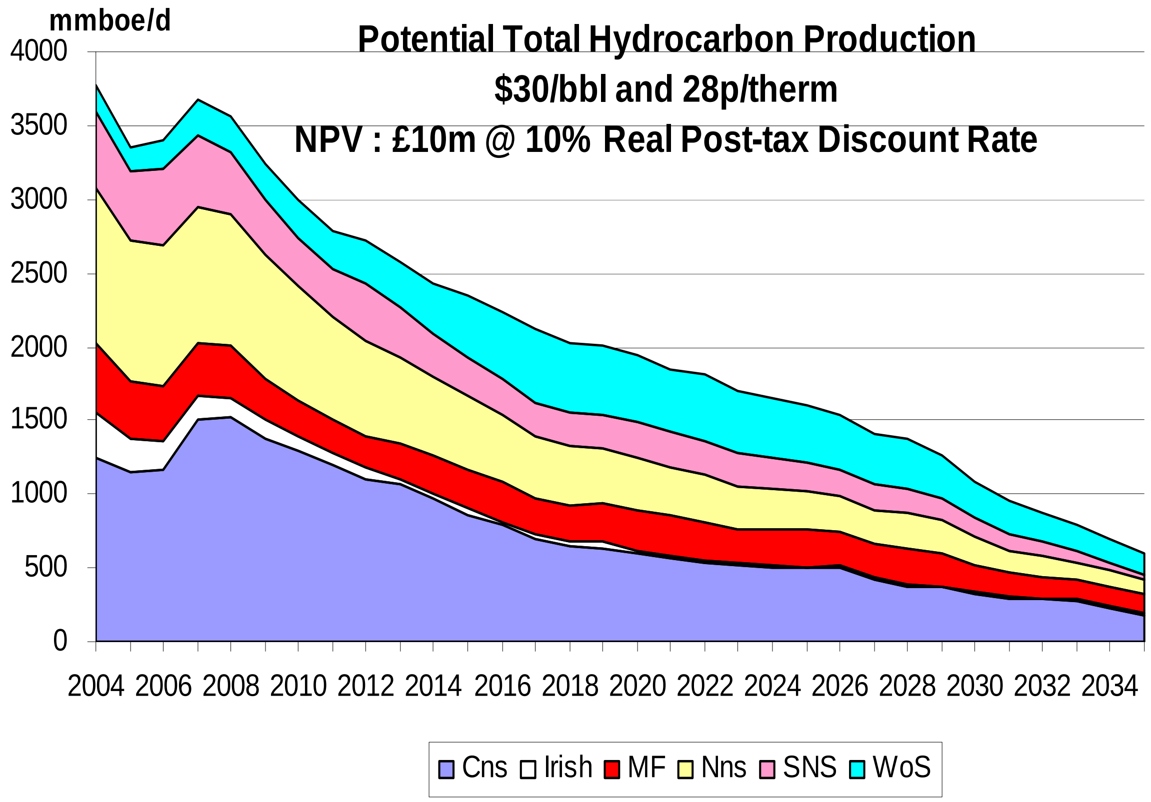


Chart 13



In Chart 14 oil production prospects under the $40, 36 pence case are shown. Exploration activity and the pace and volume of new field developments are significantly higher under this scenario. Aggregate production holds up very well in the short-term, but falls to 1.7 mmb/d in 2010. There is only a gentle fall after that due to the development of large numbers of fields in the categories of new discoveries and technical reserves. By 2020 output is 1.35 mmb/d with the great majority coming from technical reserves, new discoveries and future incremental projects.

In Chart 15 gas production under the $40, 36 pence scenario is shown. Output falls to around 7 bcf/d in 2010. Thereafter the development of large numbers of field in the categories of technical reserves and new discoveries moderates the decline rate. By 2020 output is 5.59 bcf/d.

In Chart 16 total hydrocarbon production (including NGLs) is shown under the $40, 36 pence scenario. In this case the PILOT target of 3 mmboe/d in 2010 is attained. The moderation to the decline rate in the following few years is noteworthy. It depends overwhelmingly on the development of many fields in the technical reserves and new discoveries categories. By 2020 production has fallen to 2.35 mmboe/d.

In Charts 17, 18 and 19 the regional breakdown of oil, gas, and total hydrocarbon production is shown. It is noticeable that at the higher price oil production from West of Shetland becomes relatively more important. Though there is only a moderate extra gas output the contribution of this region to total hydrocarbon output is greater than under the $30, 28 pence case.

Chart 14

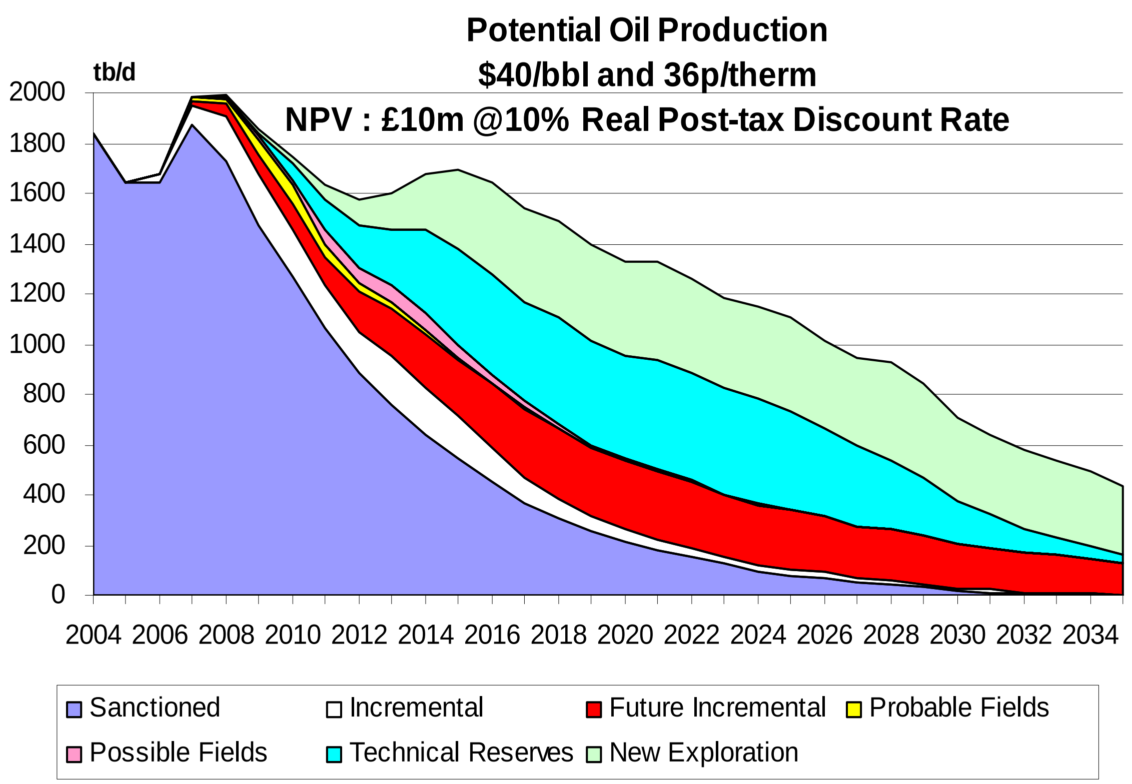


Chart 15

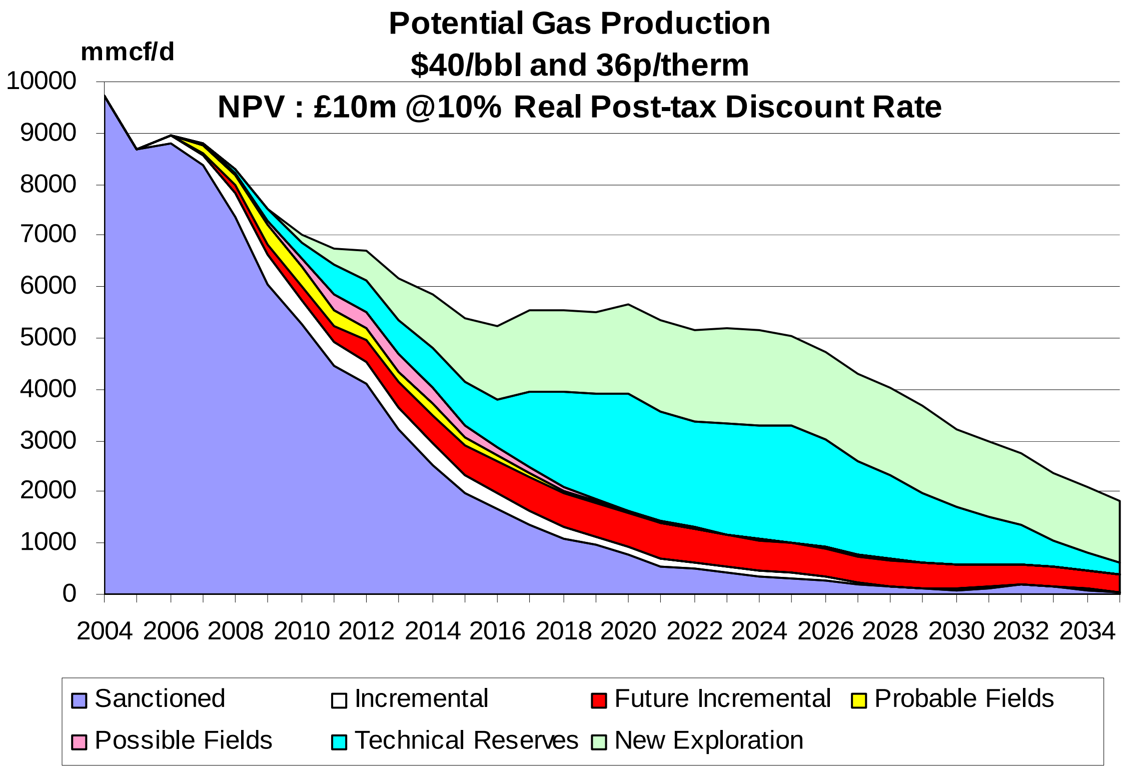


Chart 16

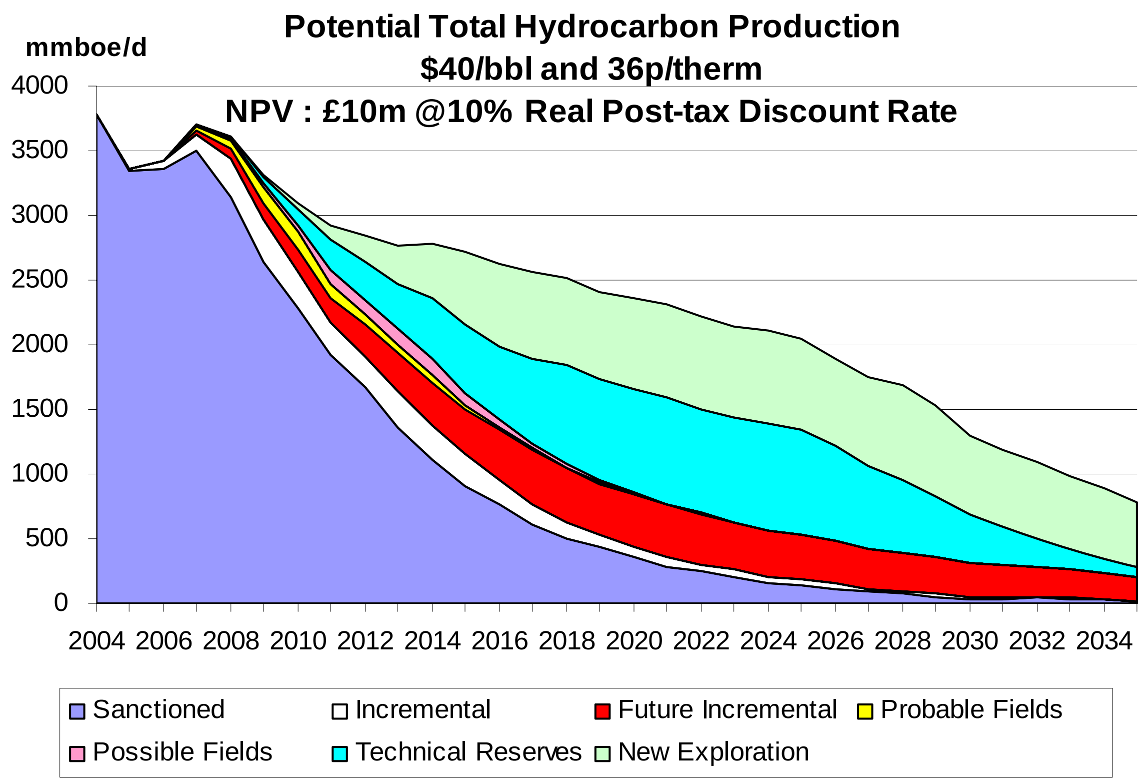


Chart 17

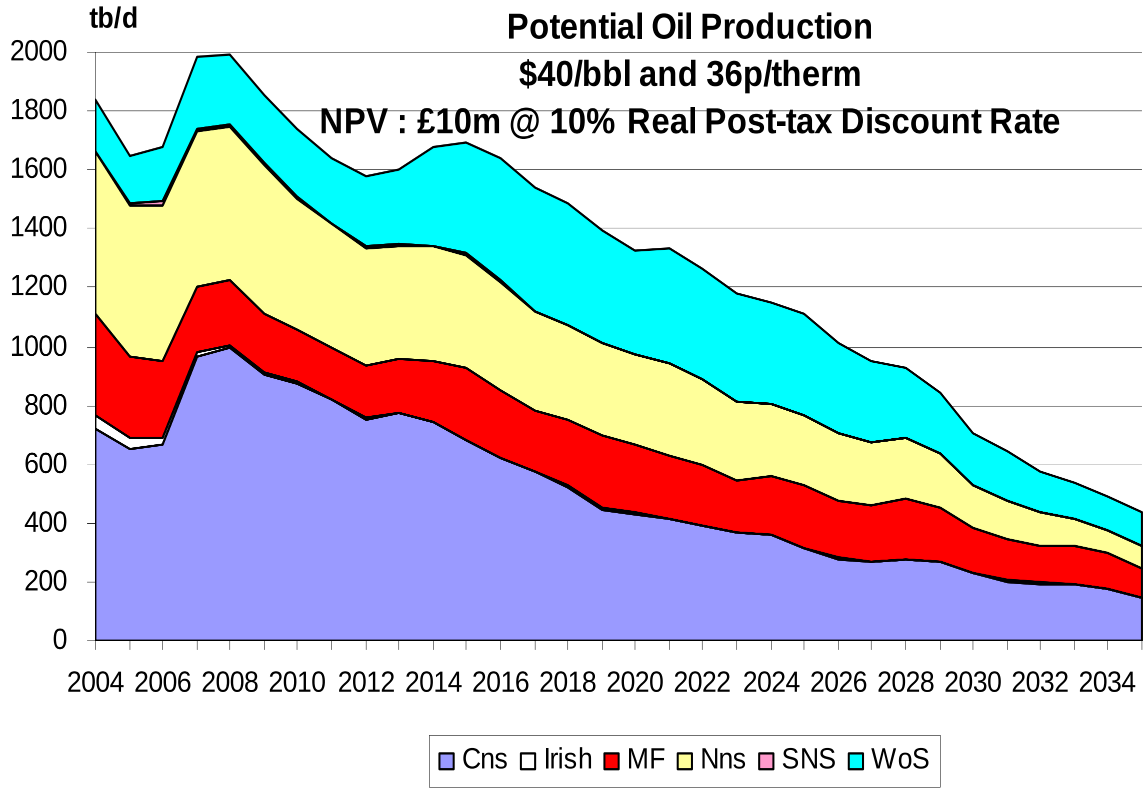


Chart 18

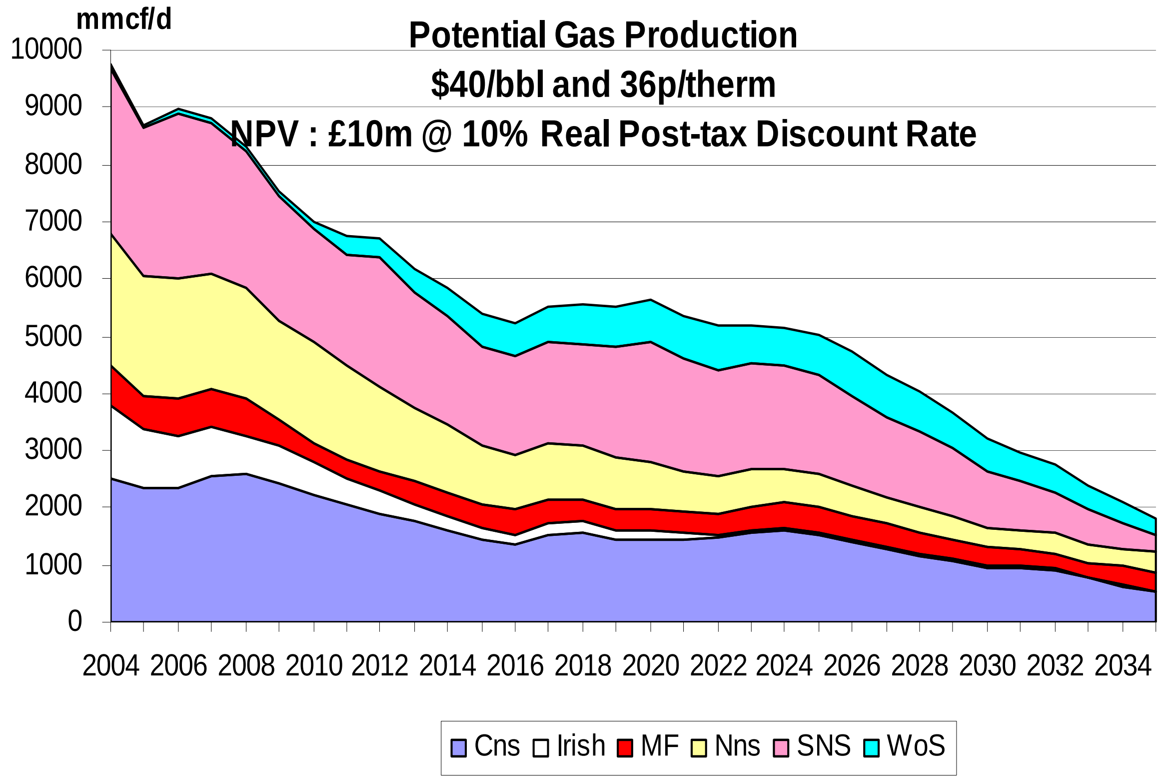
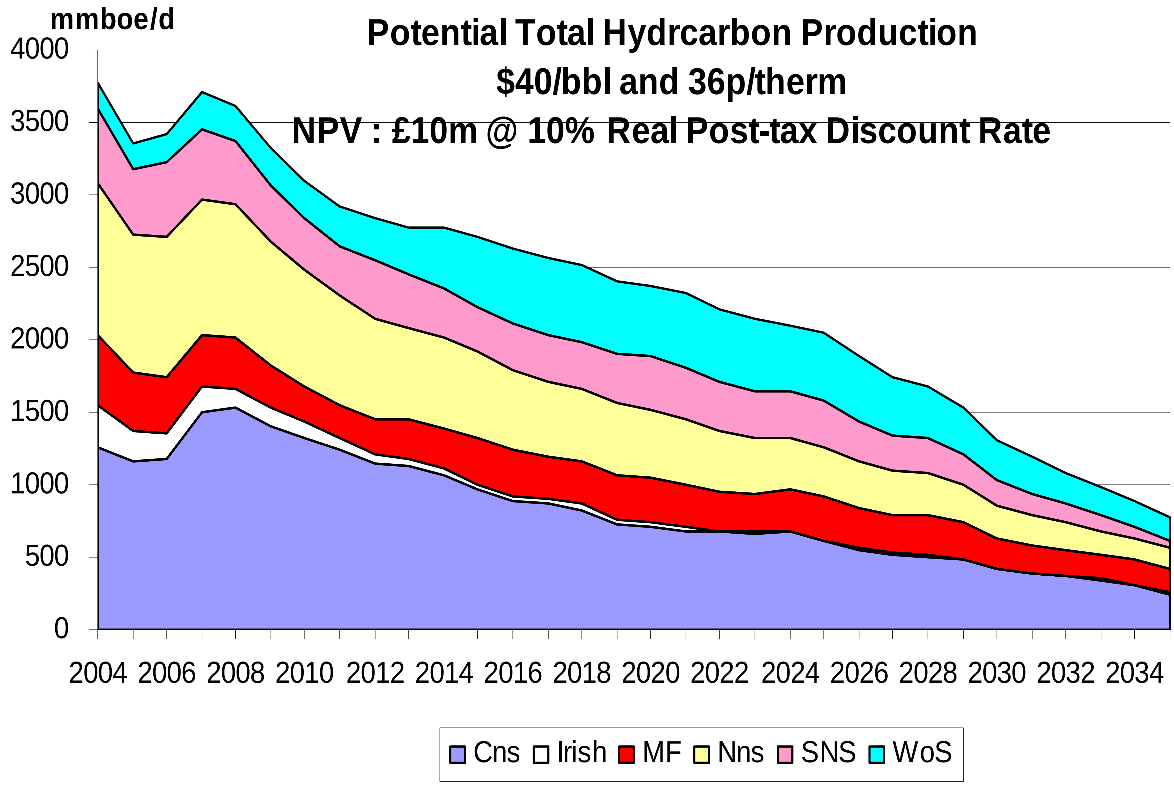


Chart 19



In Charts 20, 21 and 22 oil, gas and total hydrocarbon production are shown under the $25, 24p scenario. Oil production falls quickly after 2008 to a level of just over 1.5 mmb/d in 2010. By 2020 it is around 0.75 mmb/d. The longer term contributions from technical reserves and new discoveries are very much less under this scenario.

A similar picture emerges with gas production. It falls sharply from 8.8 bc/f in 2007 to 6.6 mcf/d in 2010. In 2020 it is around 3 bcf/d. Total hydrocarbon production is around 3.68 mmboe/d in 2007 but falls to 2.8 mmboe/d in 2010 and 1.3 mmboe/d in 2020. The long term price sensitivity of both oil and gas production is highlighted by the results.

The results under the $25, 24 pence scenario on a regional basis are shown in Charts 23, 24 and 25. The smaller contribution of the high cost West of Shetland region is highlighted.

d) Consistency with Official Estimates of Reserves

It was felt appropriate to test for consistency the projections made above against independent estimates of remaining reserves. In Table 6 cumulative production is shown from 2006 to 2035 under the 3 scenarios according to category of development. It is seen that in the $25, 24 pence case the grand total is 17.5 bn boe. Under the $30, 28 pence it is 21.6 bn boe, and under the $40, 36 pence case 24.6 bn boe. Total cumulative production to date is around 35.4 bn boe. The central DTI estimate of total potential remaining reserves is 23.1 bn boe with the low estimate being 13 bn boe and the high one 43.3 bn boe. The results of this study are felt to be consistent with these estimates of remaining potential.

Chart 20

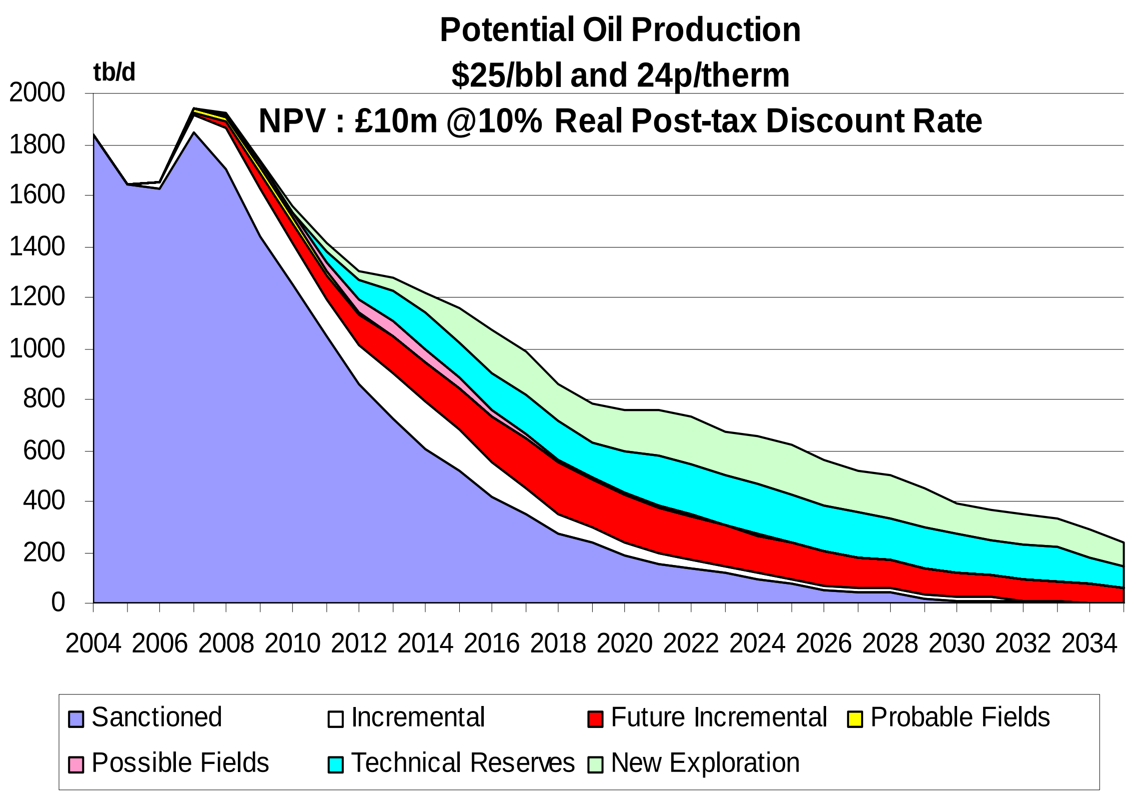


Chart 21

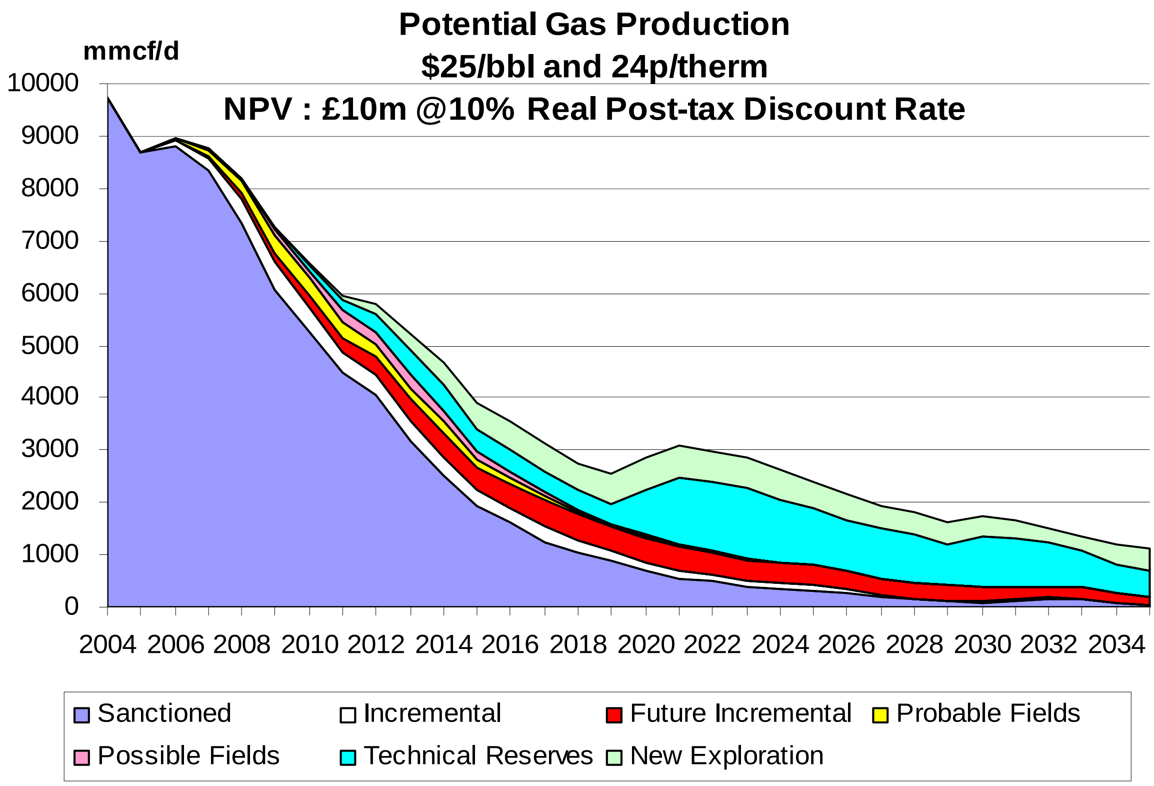


Chart 22

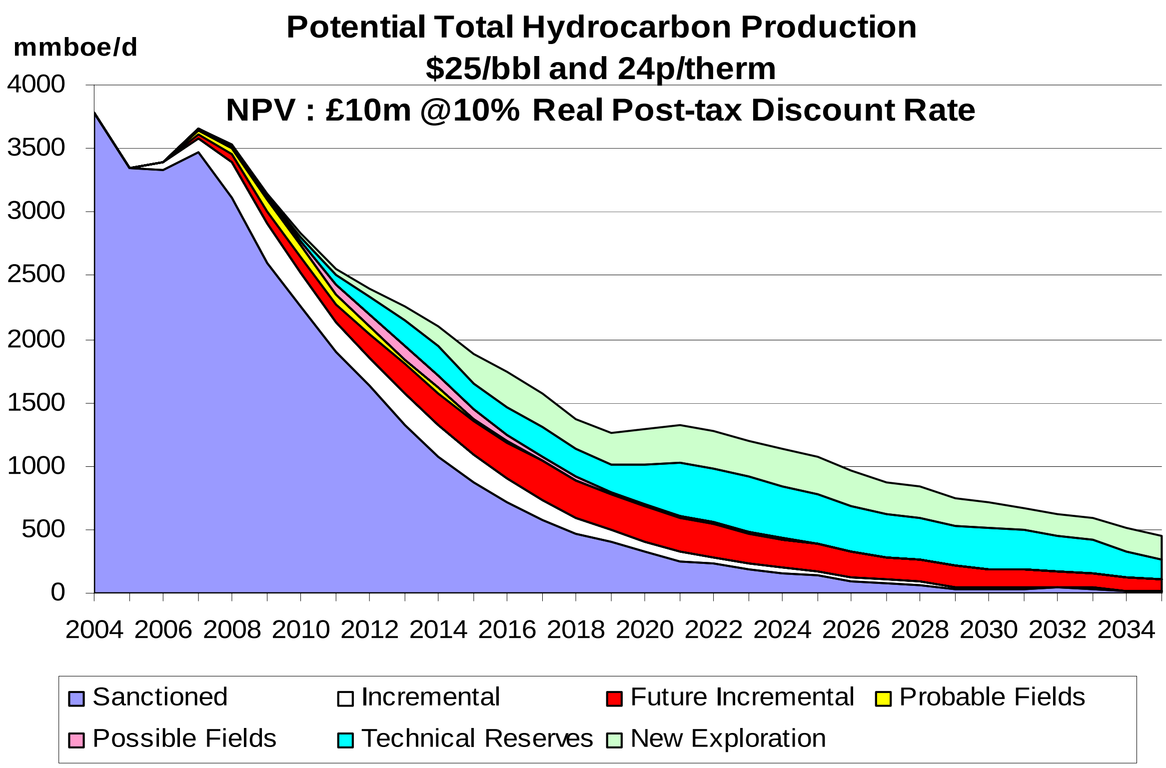


Chart 23

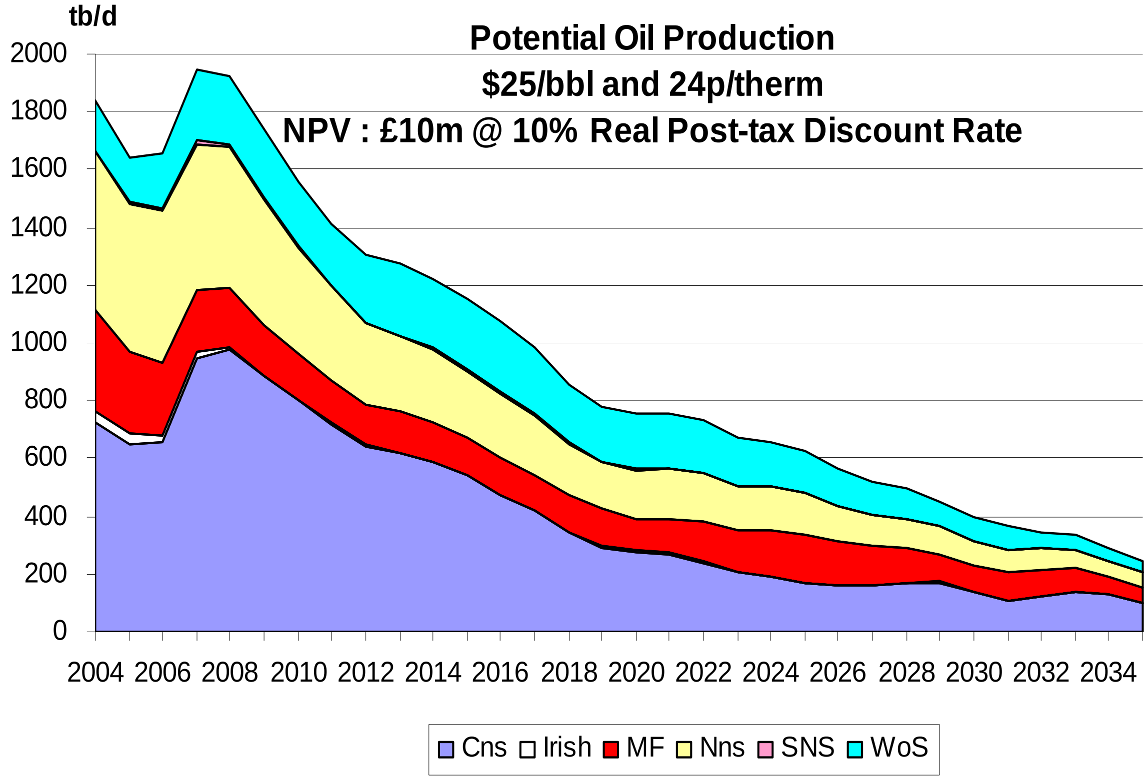


Chart 24

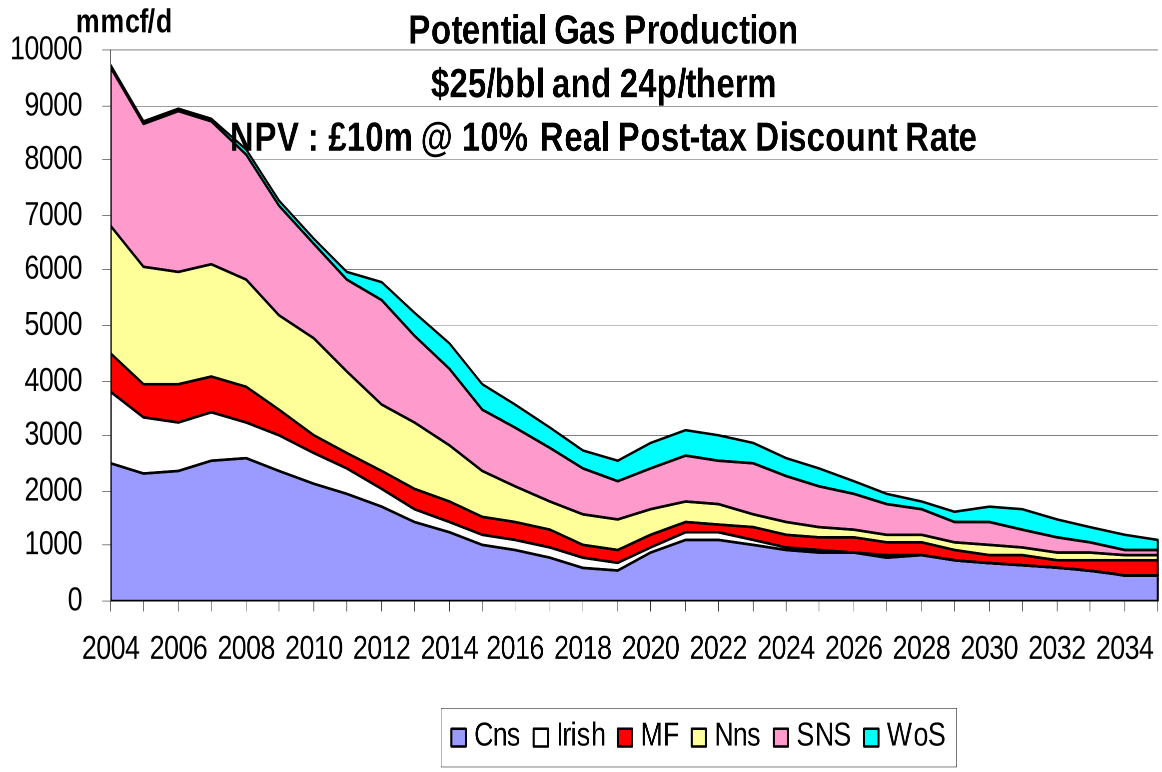


Chart 25

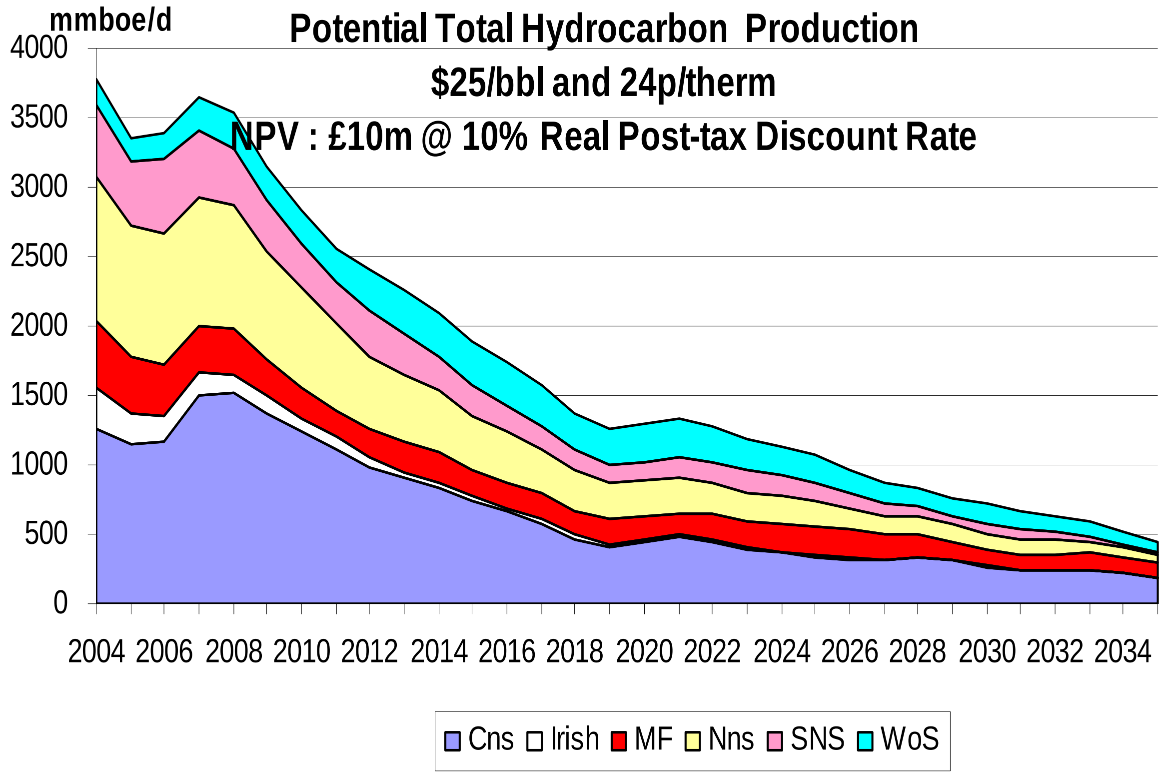


Table 6

Cumulative Potential Production from 2006 to 2035 (bn boe)

Sanctioned		Current Incremental	Future Incremental (all fields)	Probable (excluding incremental)	Possible (excluding incremental)	Technical Reserves (excluding incremental)	New Exploration (excluding incremental)	Aggregate (rounded)
$25 24p	9.3	1.2	2.0	0.20	0.25	2.6	2.0	17.5
$30 28p	9.4	1.2	2.5	0.27	0.3	4.1	3.8	21.6
$40 36p	9.5	1.25	3.0	0.28	0.3	4.85	5.4	24.6

e) <u>Total Development Expenditures</u>

Development expenditures under the $30, 18 pence cases are shown in Charts 26, 27 and 28 (at 2006 prices). In the early part of the period the expenditures are dominated by the requirements for the sanctioned fields, current incremental projects, and probable fields. Thus the total field investment could be £4.7 billion in 2006 and be well over £4 billion in 2007. After that there is a significant price sensitivity to the prospective levels. At the $30, 28 pence case field investment falls off but remains on average at well over £3 billion per year to 2016. Under the $40, 36 pence case, while there are annual variations, the average annual level of field investment is in excess of £4 billion to 2016. Under the $25, 24 pence case field investment falls very substantially from 2007 onwards.

Chart 26

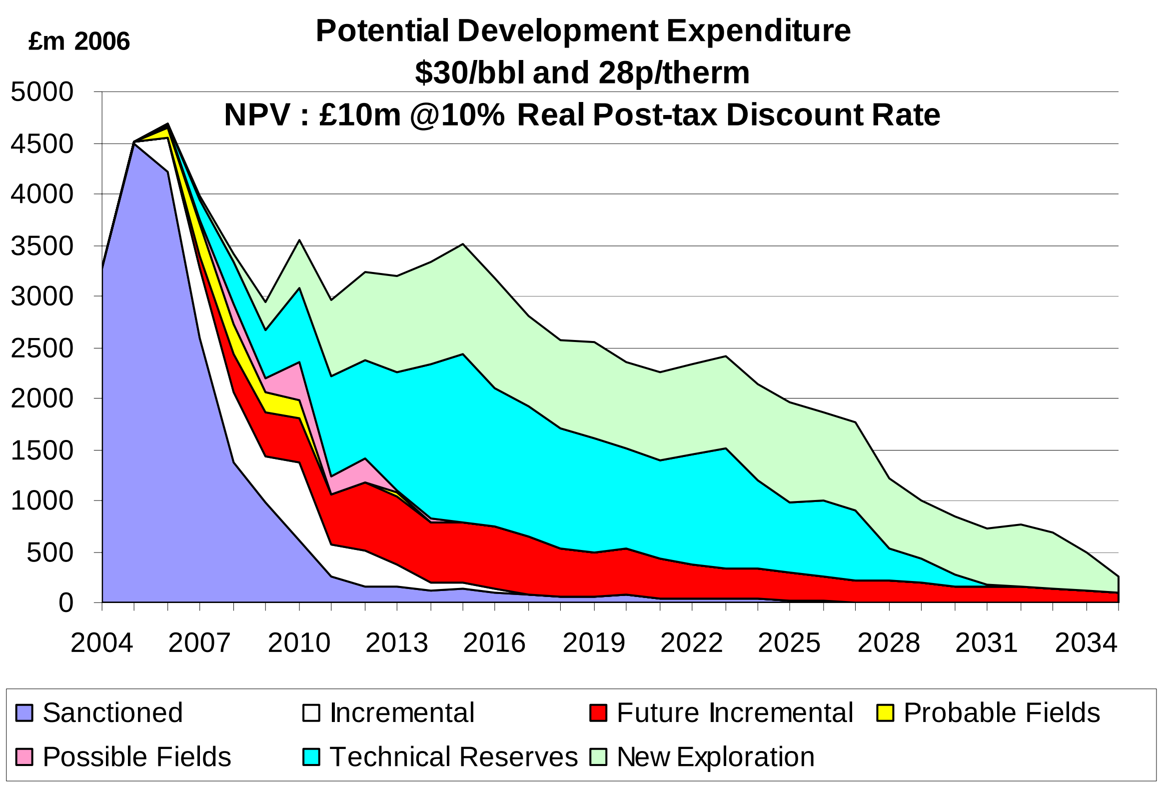


Chart 27

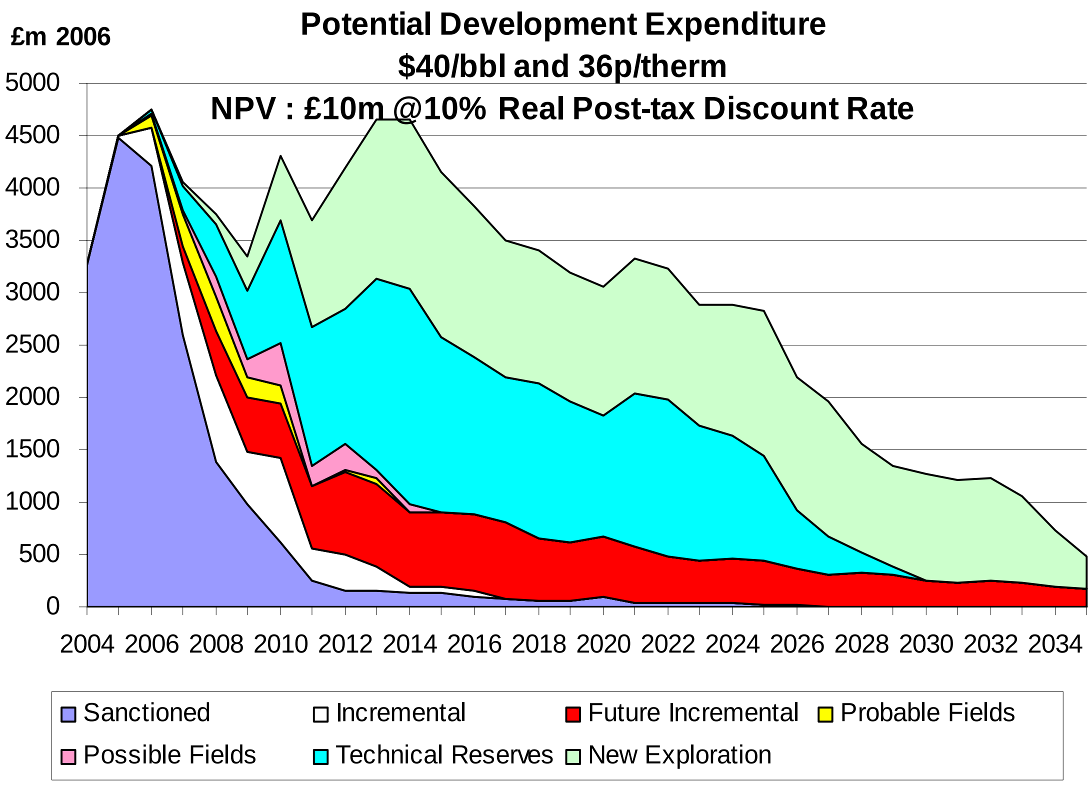
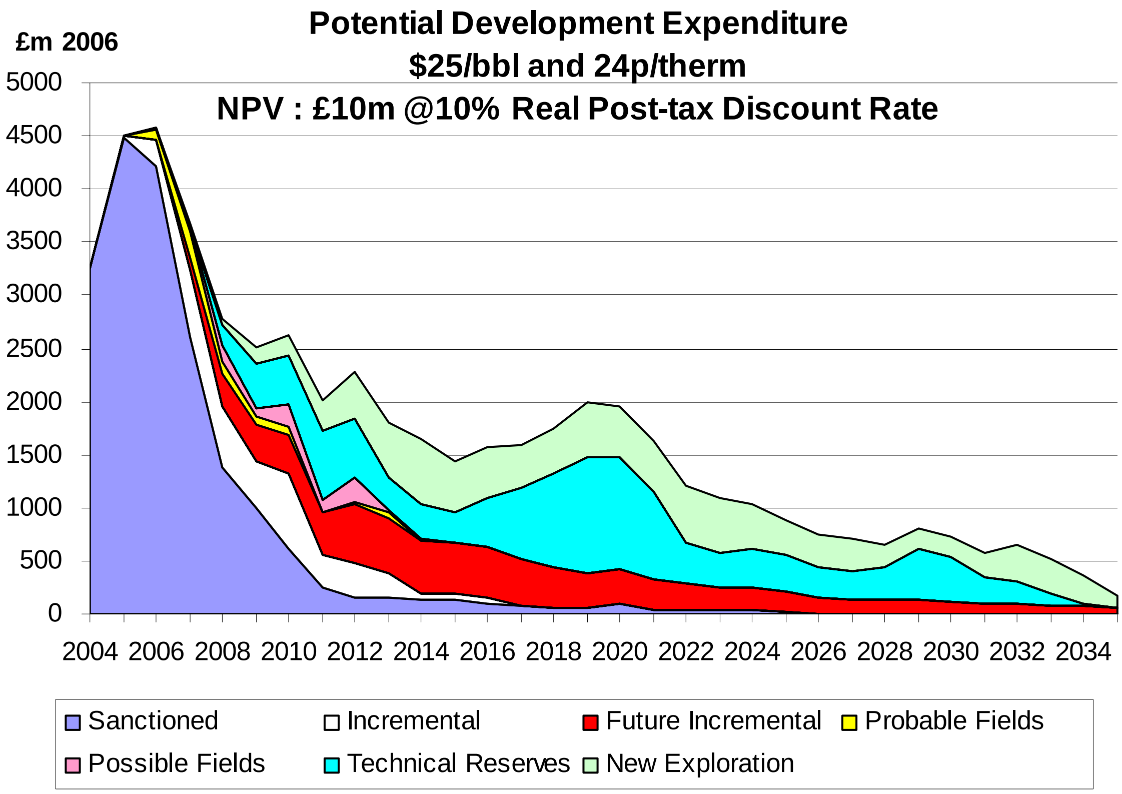


Chart 28



f) Operating Expenditures

In Charts 29, 30 and 31 prospective operating expenditures are shown. Under the $30, 28 pence case they exceed £5 billion in 2006 and 2007 and then fall off at a modest pace but still attain a level of £4.3 billion in 2010. The fall-off thereafter is rather faster reflecting the cessation of production of many fields.

Under the $40, 36 pence case the fall-off from the peak in 2006-2007 is very modest and in 2010 the level is still £4.5 billion, which level is also attained as far ahead as 2015. Under the $25, 24 pence case the operating expenditures fall-off at a quite rapid rate.

Chart 29

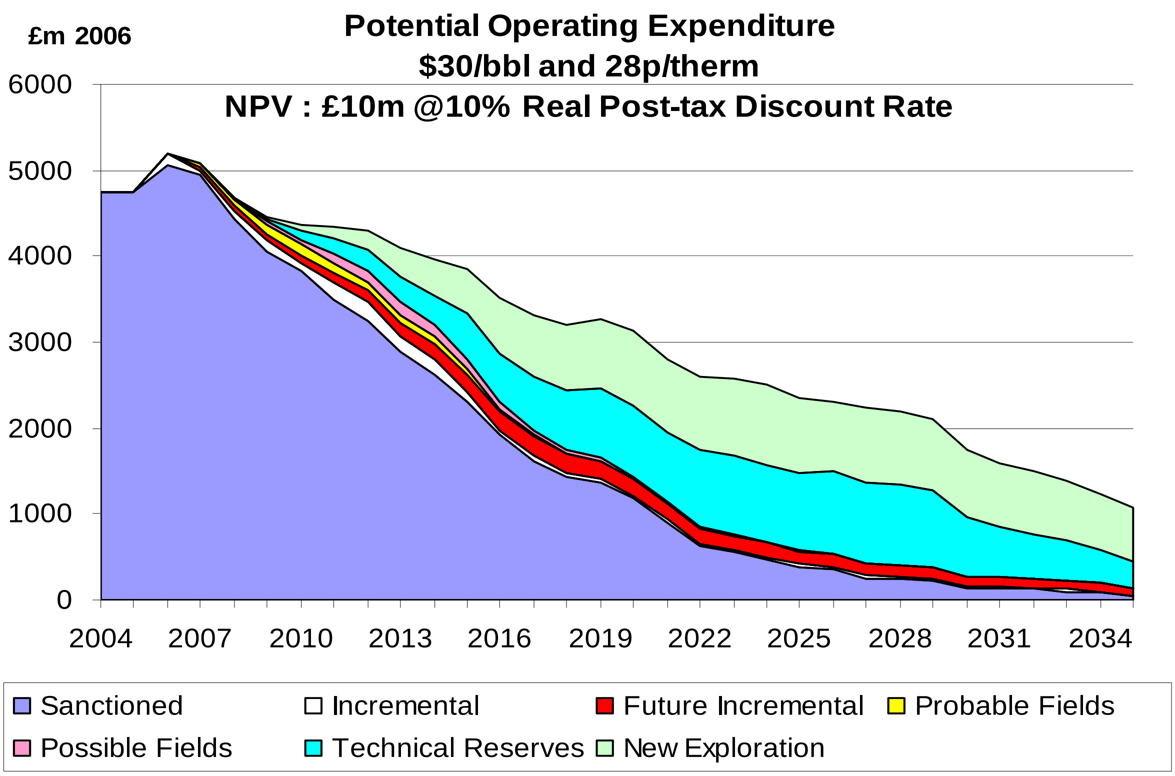


Chart 30

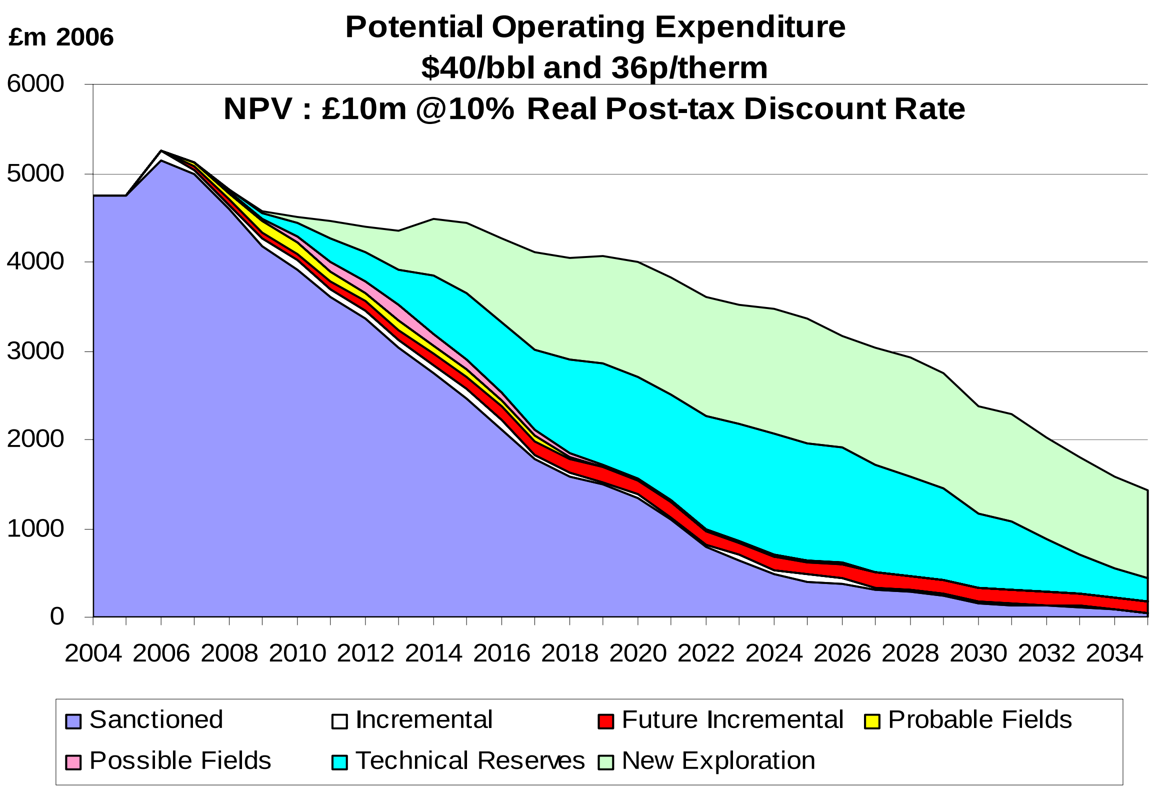
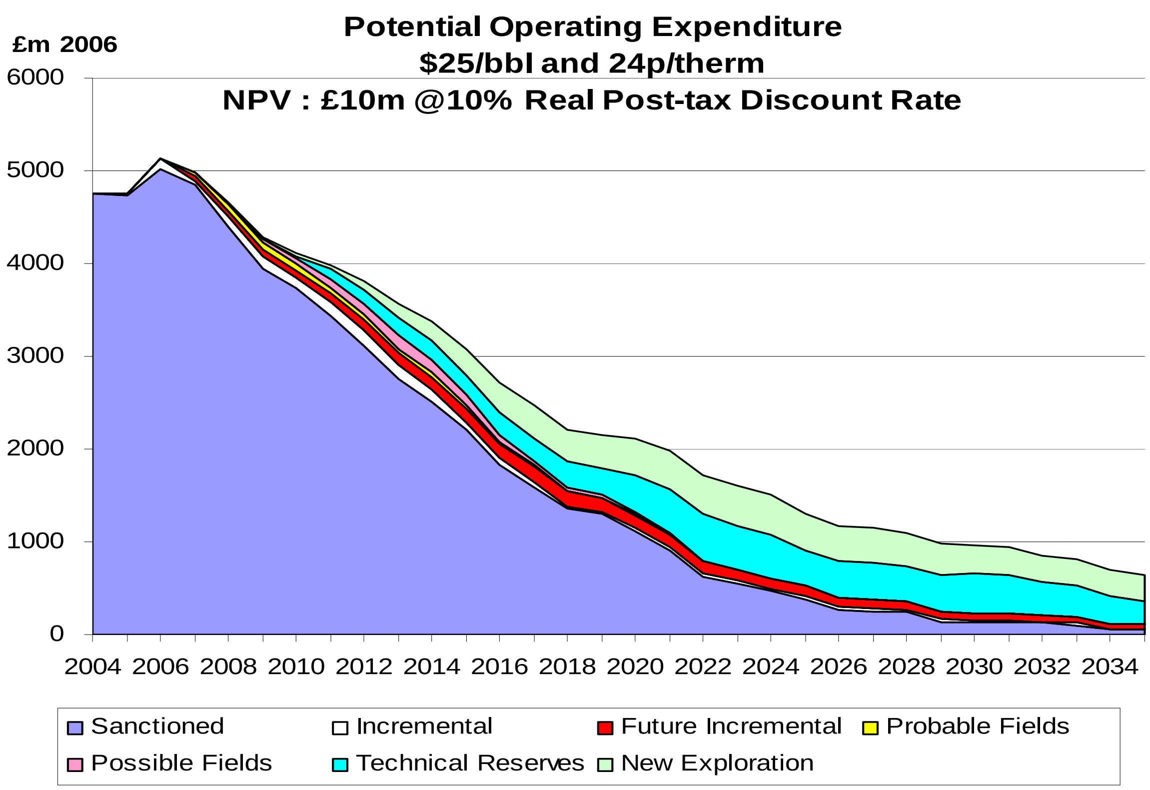


Chart 31



g) Decommissioning Expenditures

Prospective decommissioning costs to 2035 are shown under the 3 scenarios in Charts 32-34. It should be stressed that the expenditures relate to field decommissioning and generally exclude main pipelines and terminals which may or may not remain operational by the end of the period. If they were decommissioned within the period the total would be considerably higher. It should be noted that the negative costs show circumstances where the decommissioning of some facilities has been postponed through the presence of incremental projects. The values above the zero line indicate the total costs incurred over the whole period.

The phasing varies according to the price scenario as higher prices prolong the economic lives of fields. It is also noteworthy that the cumulative total of decommissioning costs in the period to 2035 increases as the oil price increases. This is because the number of new projects/fields being developed increases with price, but, because they are mostly small, many of these reach cessation of production by 2035. Under the central case total decommissioning costs are over £14 billion by that date.

Chart 32

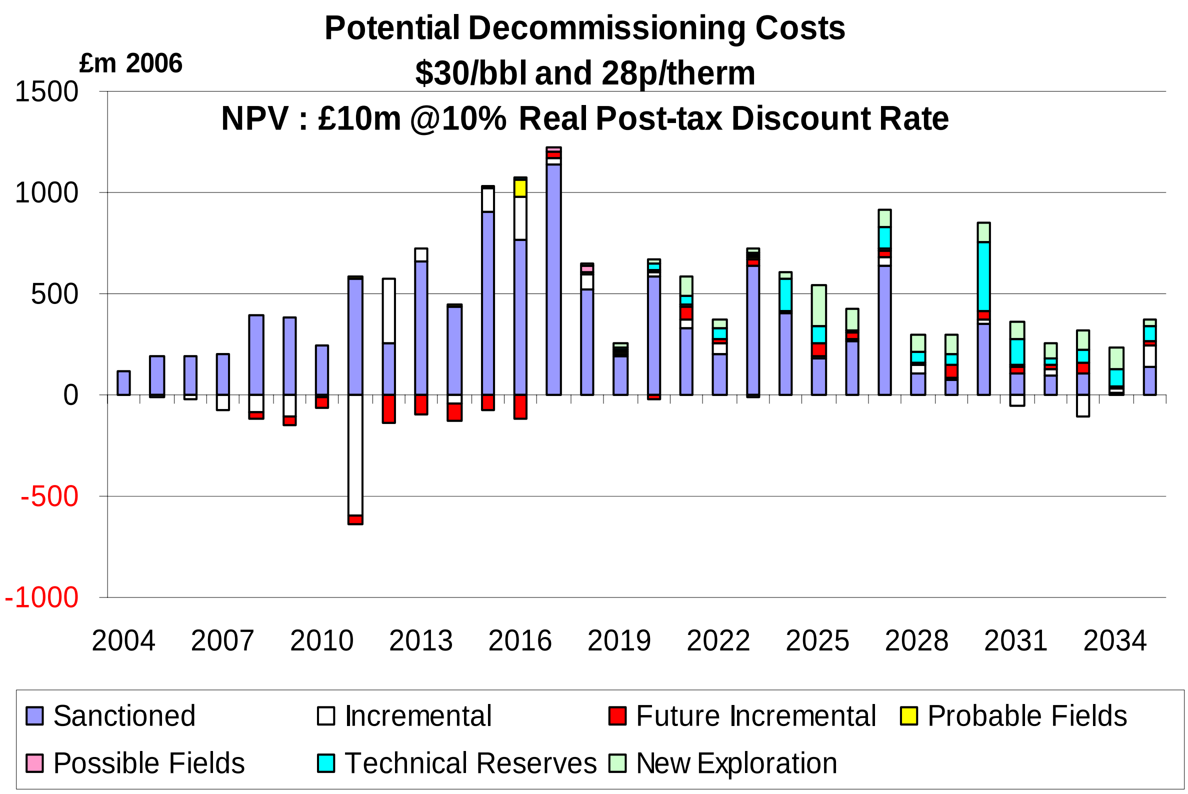


Chart 33

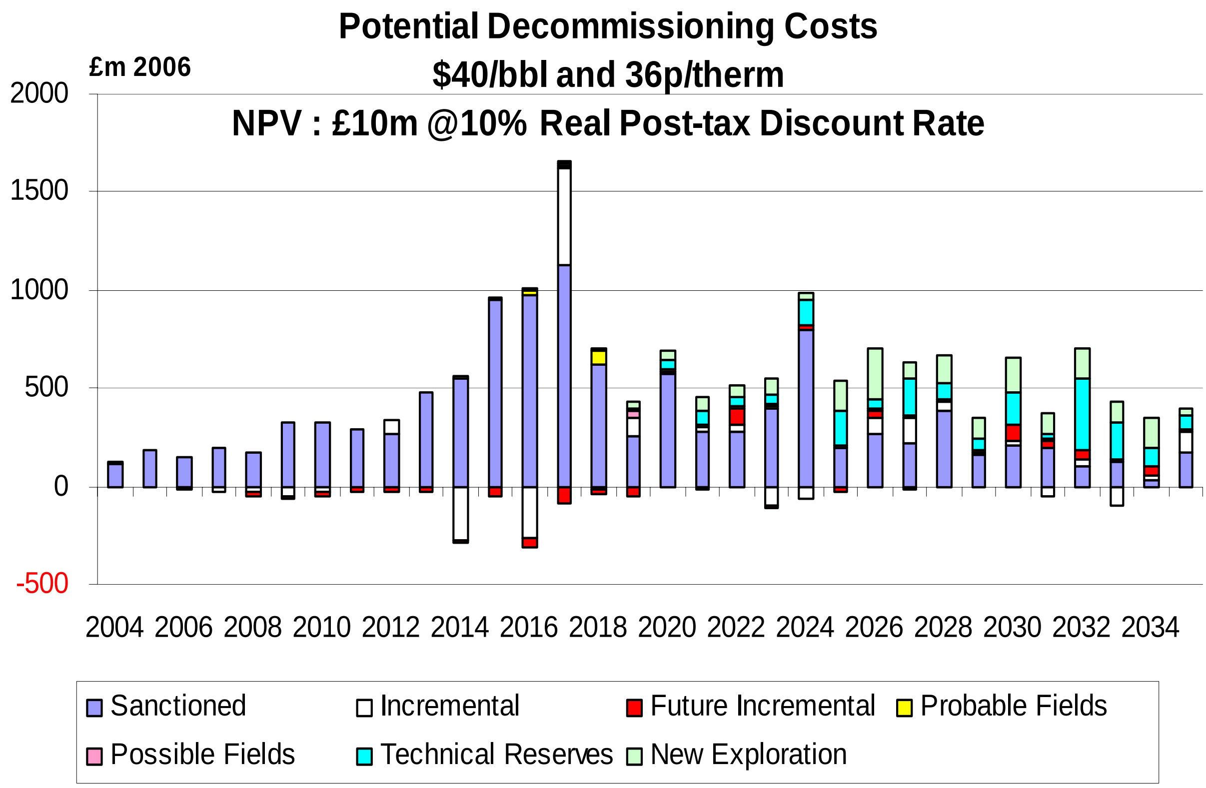
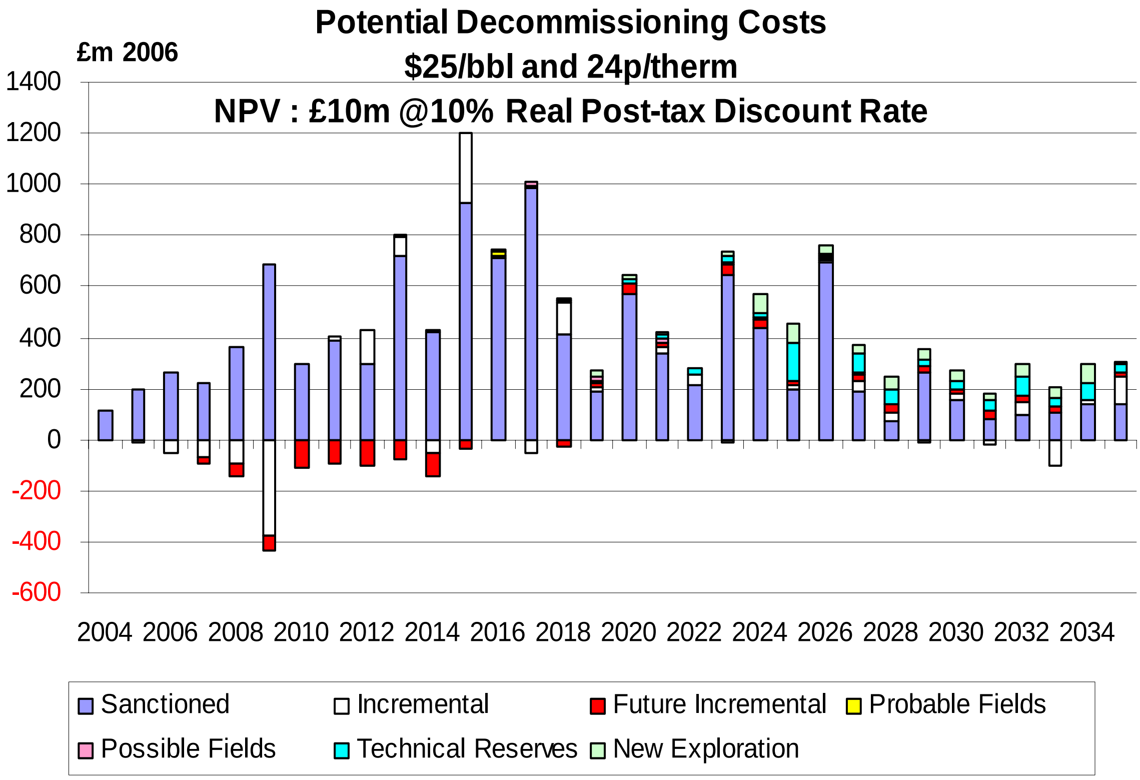


Chart 34



4. Effect of Tax Increase on Activity

From 1st January, 2006 the Supplementary Charge was increased from 40% to 50%. The rates of tax thus become 75% on fields and incremental projects subject to PRT and 50% on non-PRT-paying ones. As discussed in the early part of Section 3 it is clear that in present and prospective circumstances in the UKCS many projects offer returns with very modest expected NPVs. There are clearly concerns about the balance of the risks and rewards expected from new investments. Accordingly, in measuring the possible effect of the tax increase, it was felt that the most illuminating procedure was to examine the extent to which NPVs were brought below minimum acceptable levels. For this purpose minimum expected post-tax NPVs of £10 million and £5 million were considered necessary to justify investment. This part of the study thus calculates the NPVs (post-tax) before and after the Budget on the basis that the minimum values were required before the investment would proceed.

Under the $30, 28 pence case it was found that in the period to 2030 with discount rate of 10% in real terms and minimum NPV requirement of £10 million 16 fields would not go ahead as a consequence of the tax increase. The resulting effects on field investment, field operating expenditures and production are shown in Charts 35, 36 and 37. Cumulative investment is reduced by around £900 million, cumulative operating costs by around the same value, and cumulative production to 2035 is reduced by around 160 mmboe.

Investors may well use higher discount rates. The results of employing 15% rates in real terms are shown in Charts 38, 39 and 40. They reflect a reduction of 24 developments. Cumulative field investment now falls by around £1.75 billion, cumulative operating costs by around £1.2 billion, and cumulative production by around 225 mbboe.

Chart 35

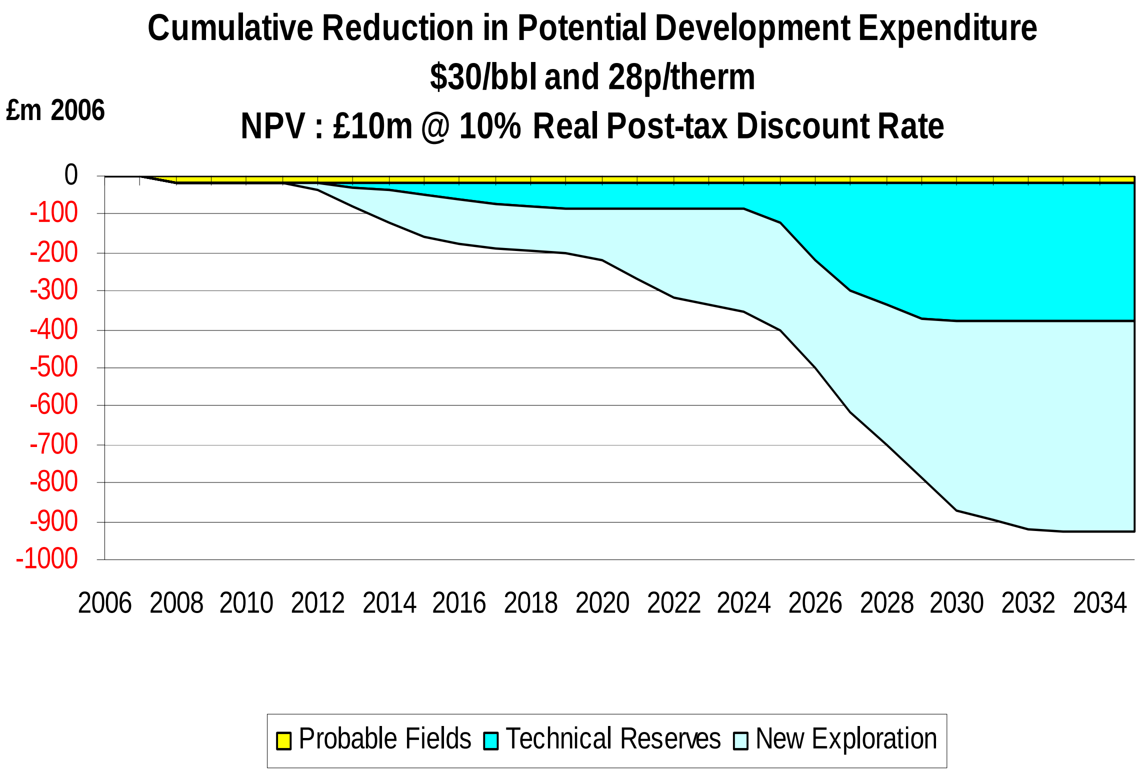


Chart 36

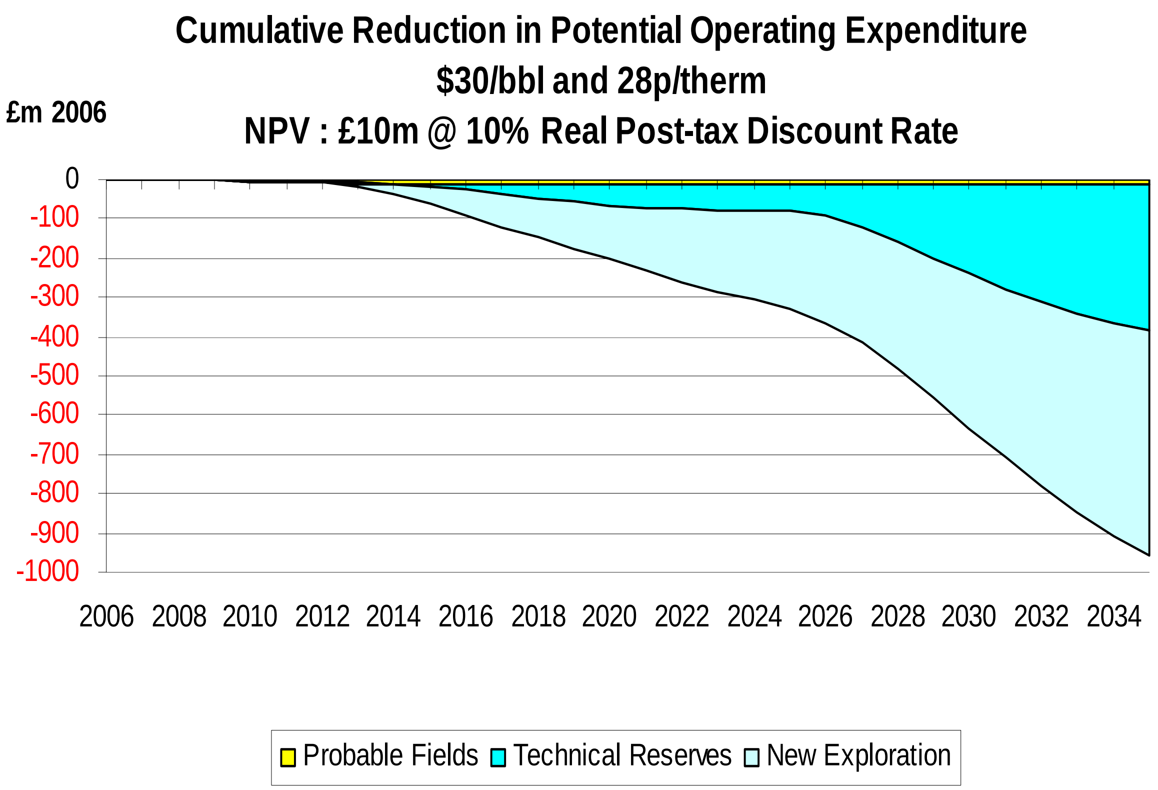


Chart 37

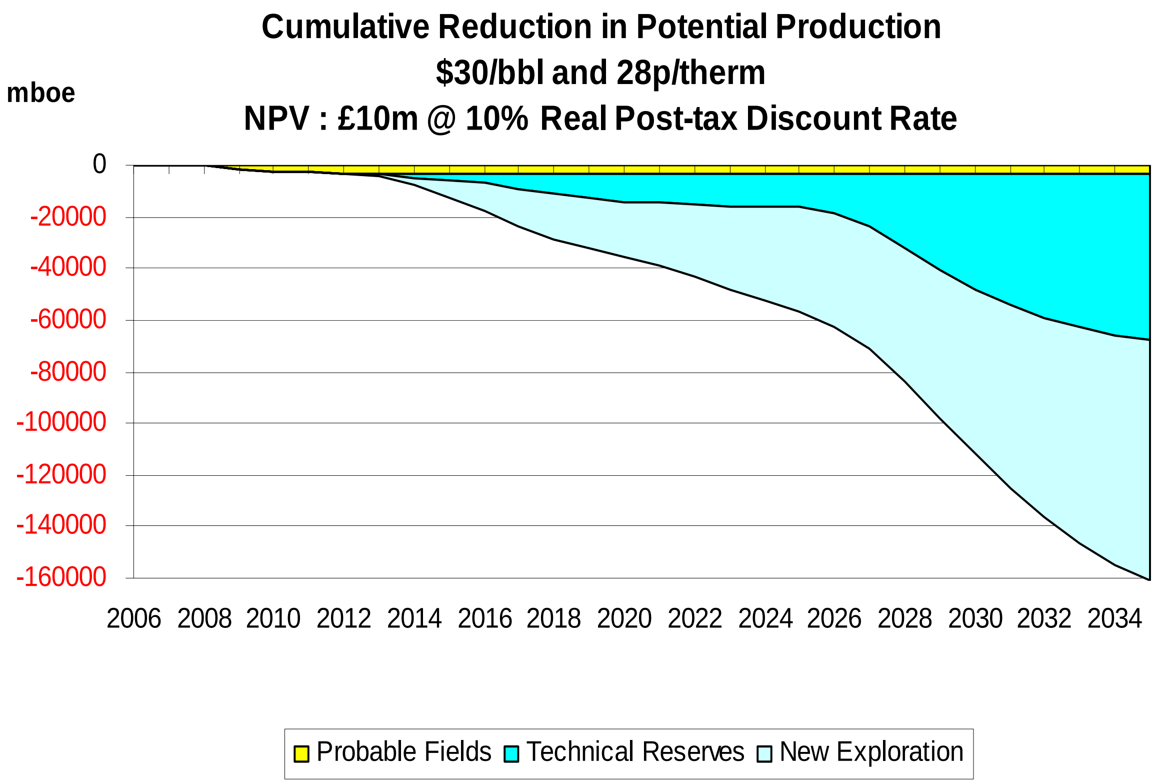


Chart 38

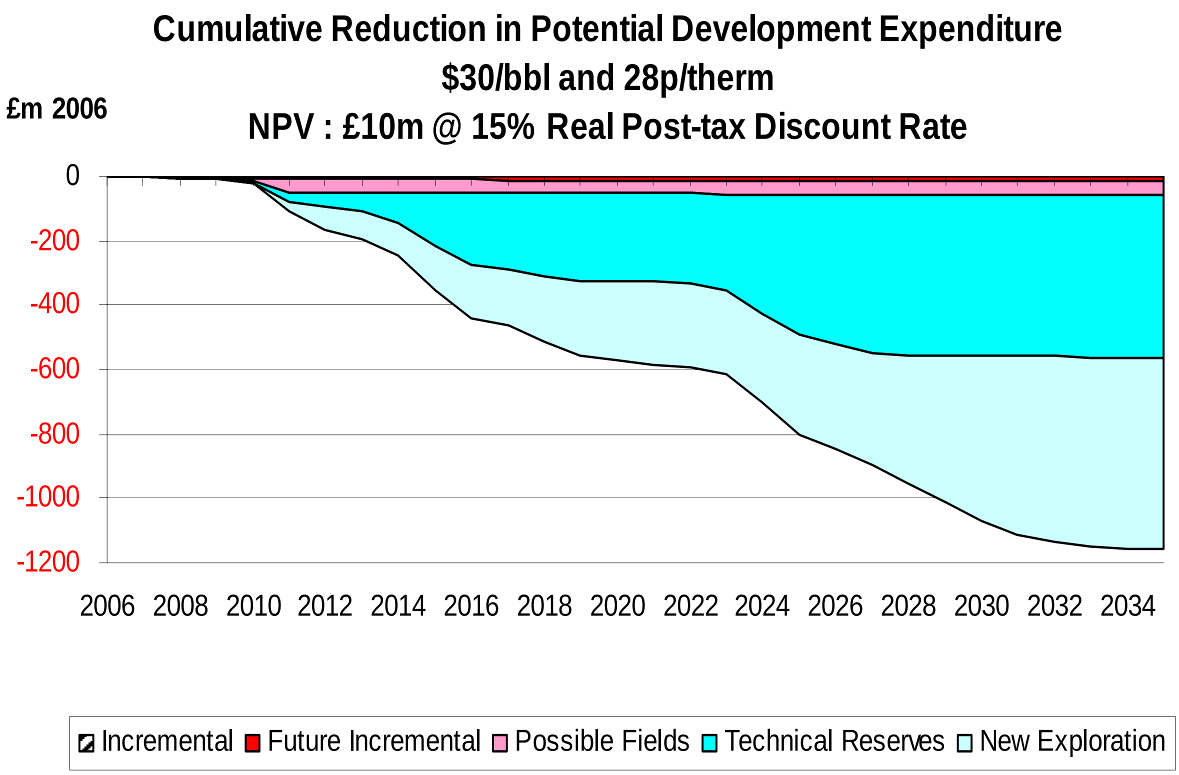


Chart 39

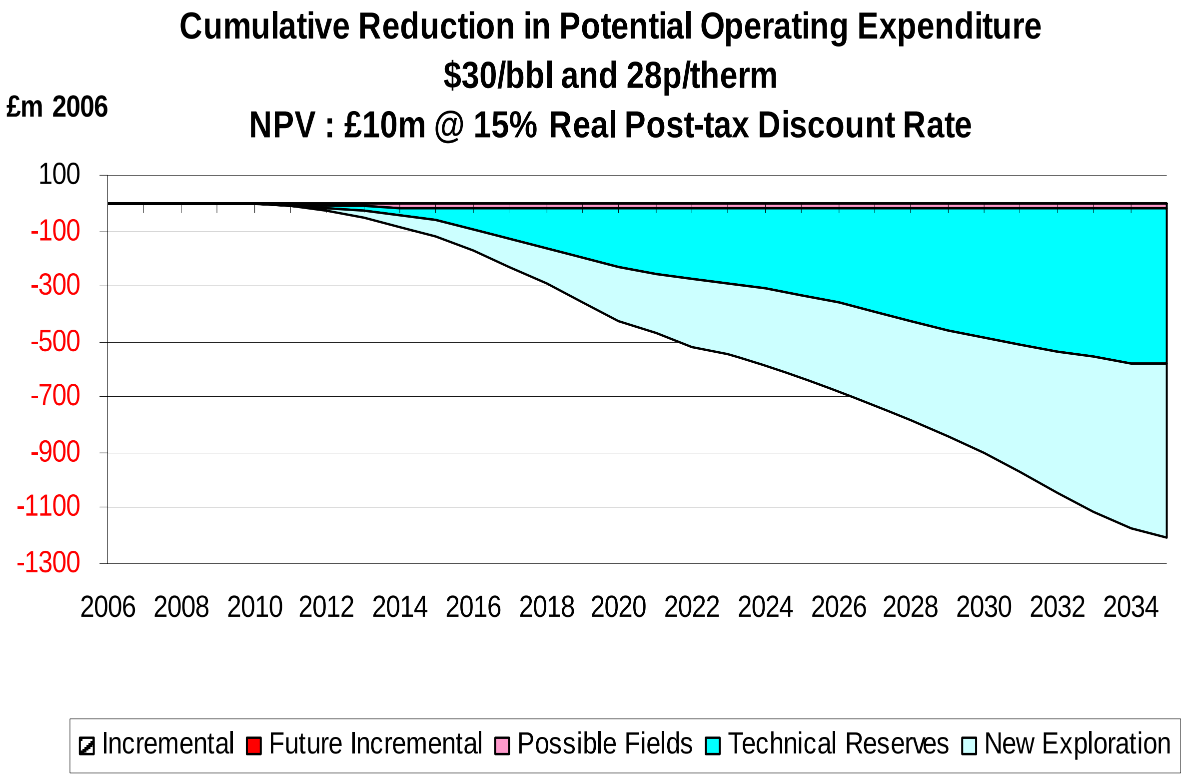
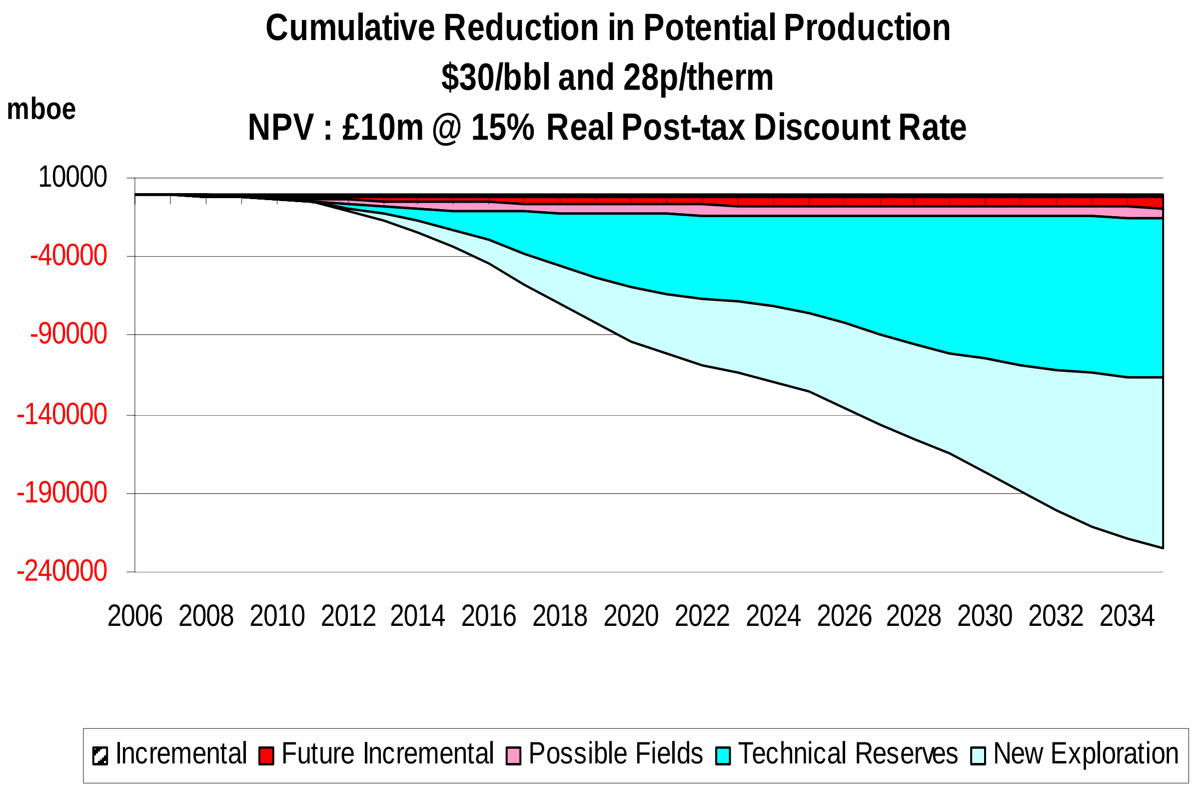


Chart 40



The results under the $40, 36 pence case with 10% real discount rate indicate that 12 developments would be deterred by the tax increase when £10 million was the minimum acceptable NPV. The resulting cumulative reduction in field investment (Chart 41) is around £600 million, operating costs around £500 million (Chart 42) and production around 90 mmboe (Chart 43).

If 15% real discount rate were employed 24 developments would be deterred. The resulting cumulative reduction in field investment is around £1.1 billion (Chart 44), field operating costs £1.5 billion (Chart 45), and production 175 mmboe (Chart 46).

Chart 41

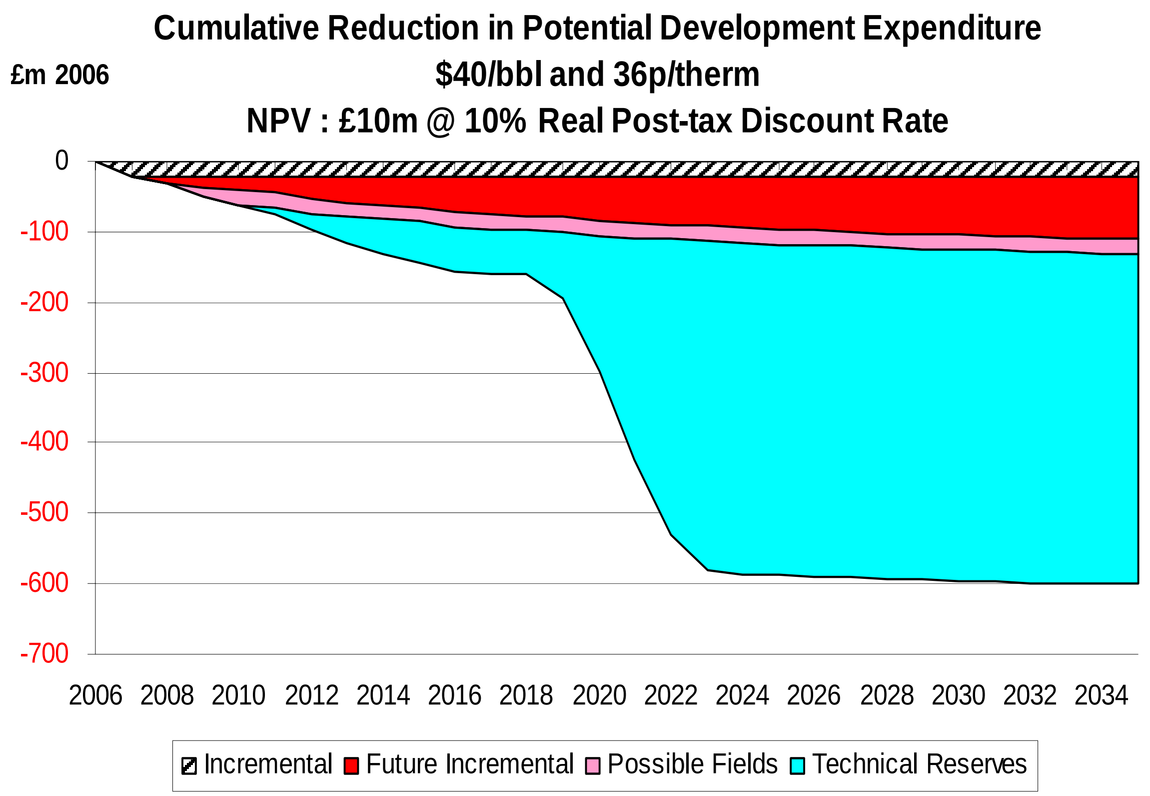


Chart 42

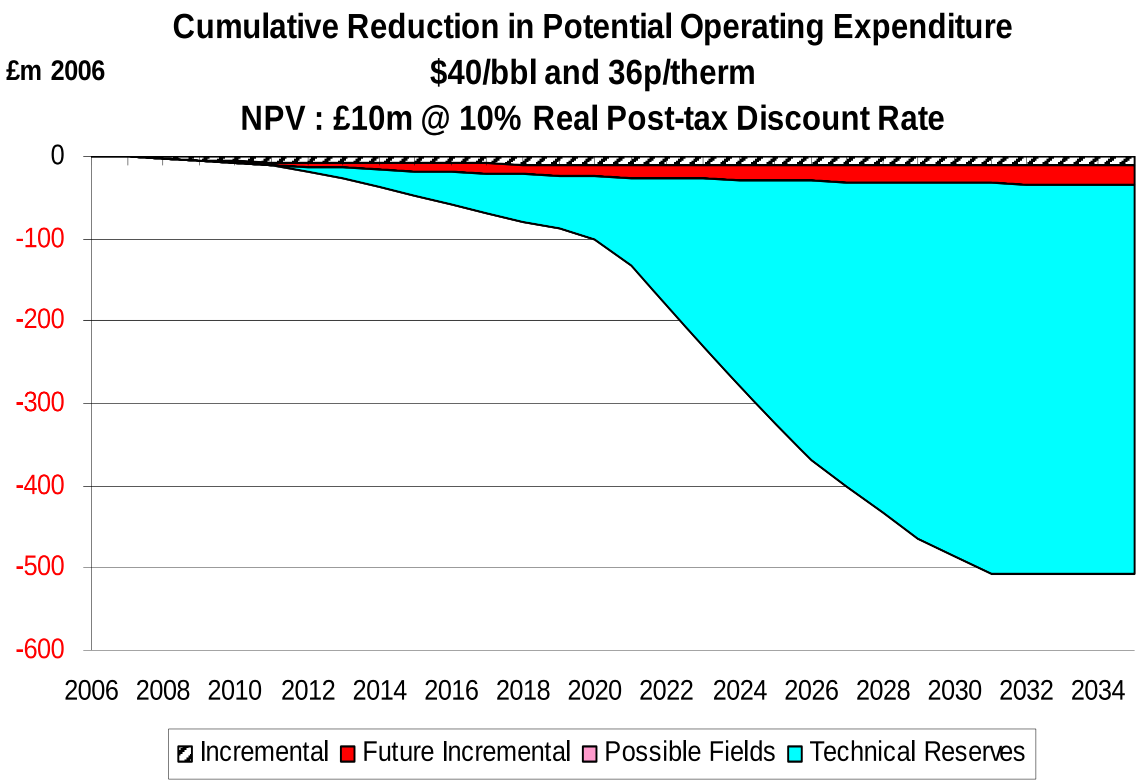


Chart 43

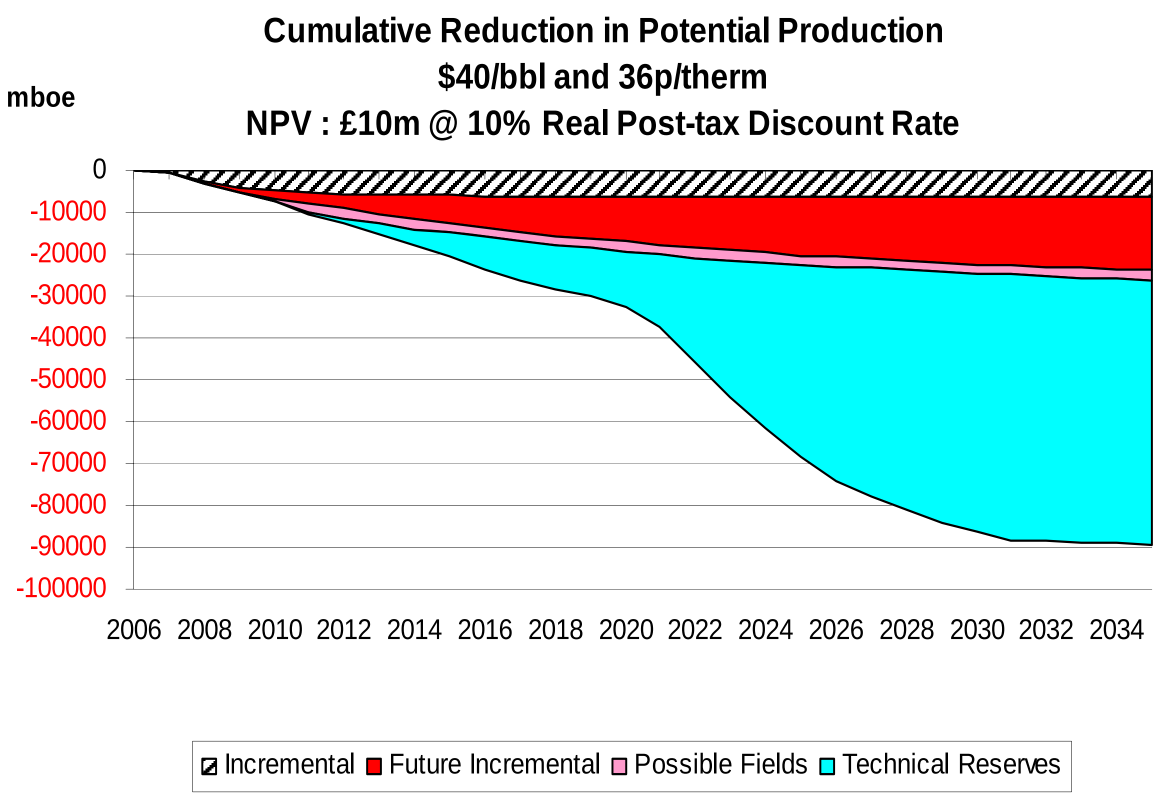


Chart 44

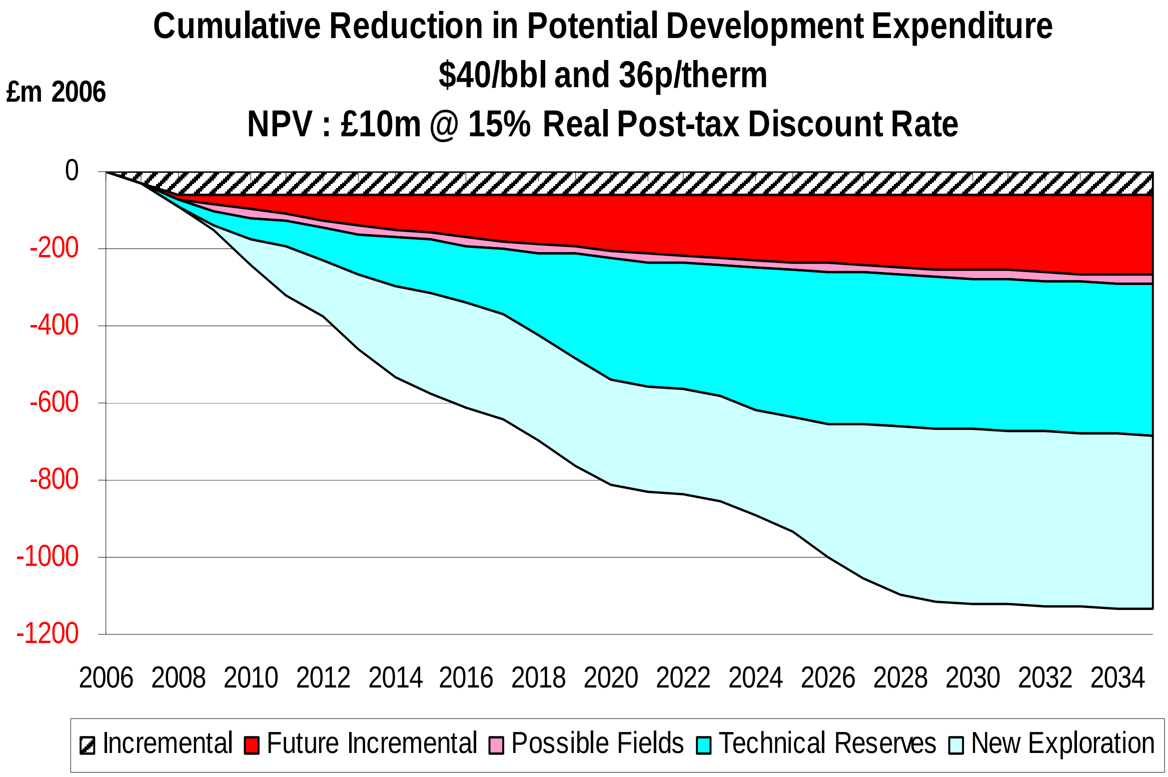


Chart 45

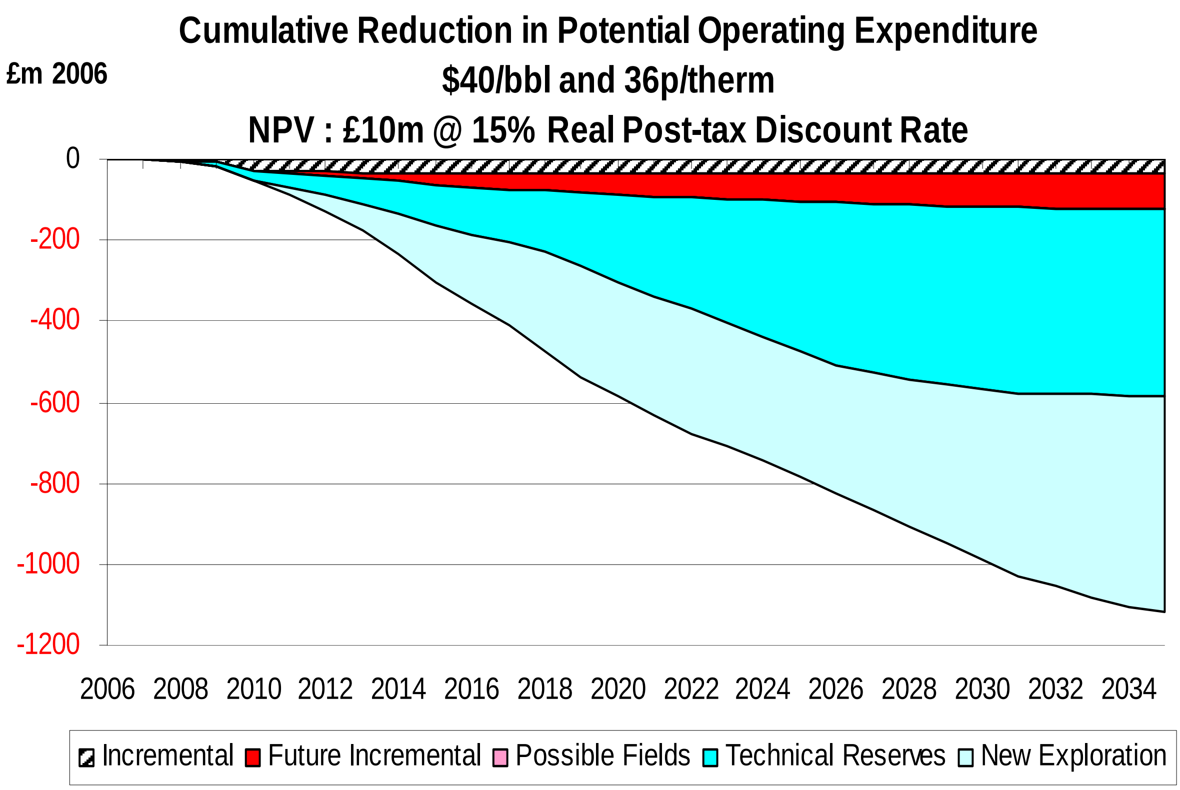
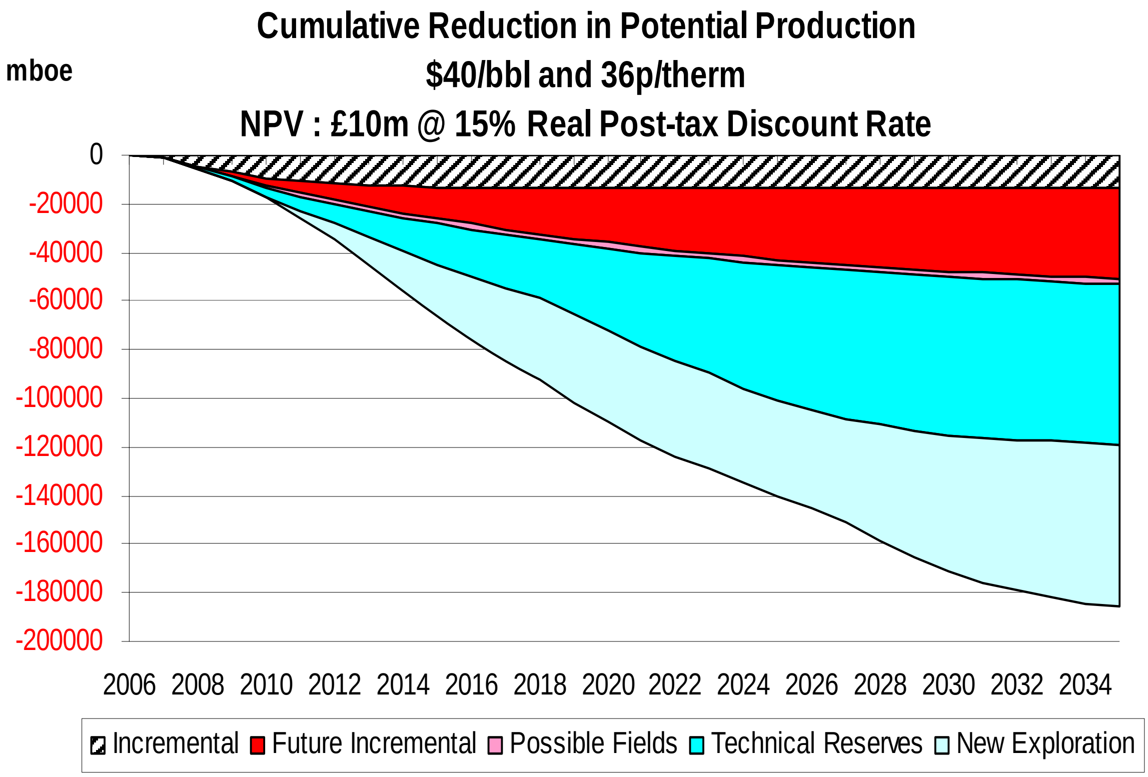


Chart 46



Under the $25, 24 pence case at 10% discount rate 22 developments would be deterred by the tax increase. The resulting cumulative reduction in field investment is around £2 billion (Chart 47), operating expenditures around £1.65 billion (Chart 48), and cumulative production around 370 mmboe (Chart 49).

If 15% real discount rate were employed 16 developments would be deterred. The resulting cumulative reduction in development expenditures is around £1.65 billion (Chart 50), operating expenditures £1.4 billion (Chart 51) and cumulative production 320 mmboe (Chart 52).

Chart 47

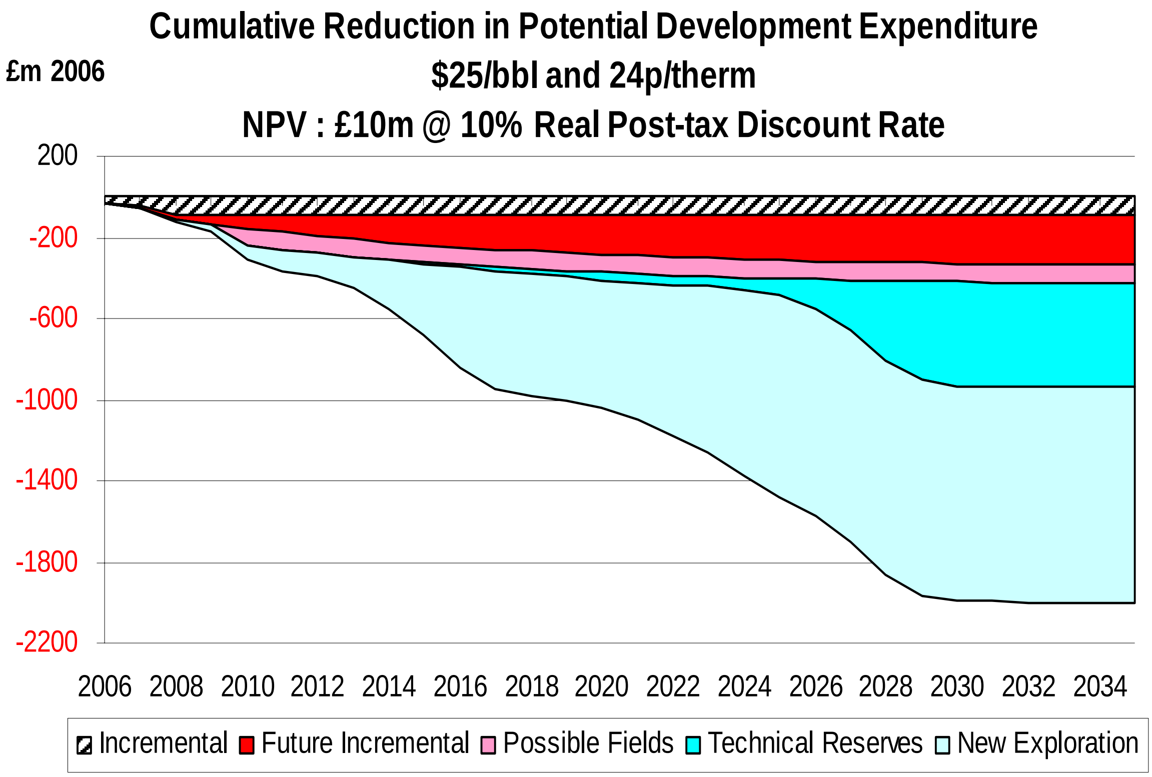


Chart 48

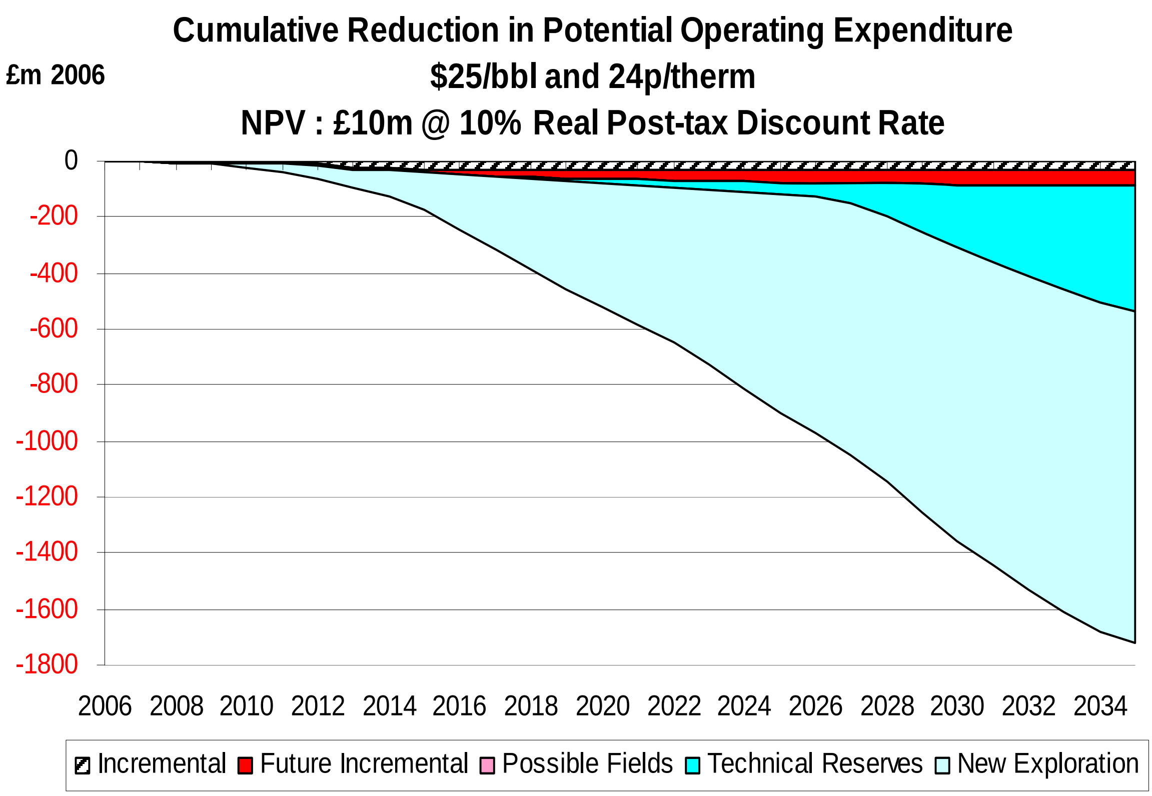


Chart 49

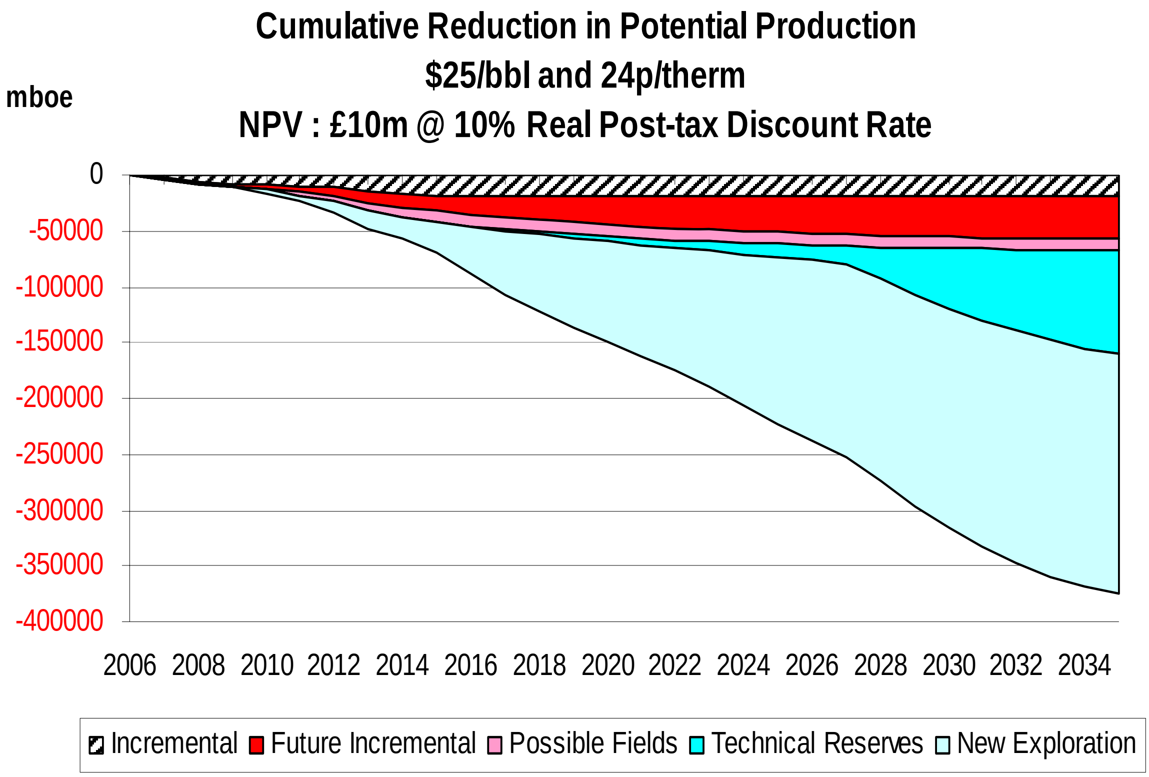


Chart 50

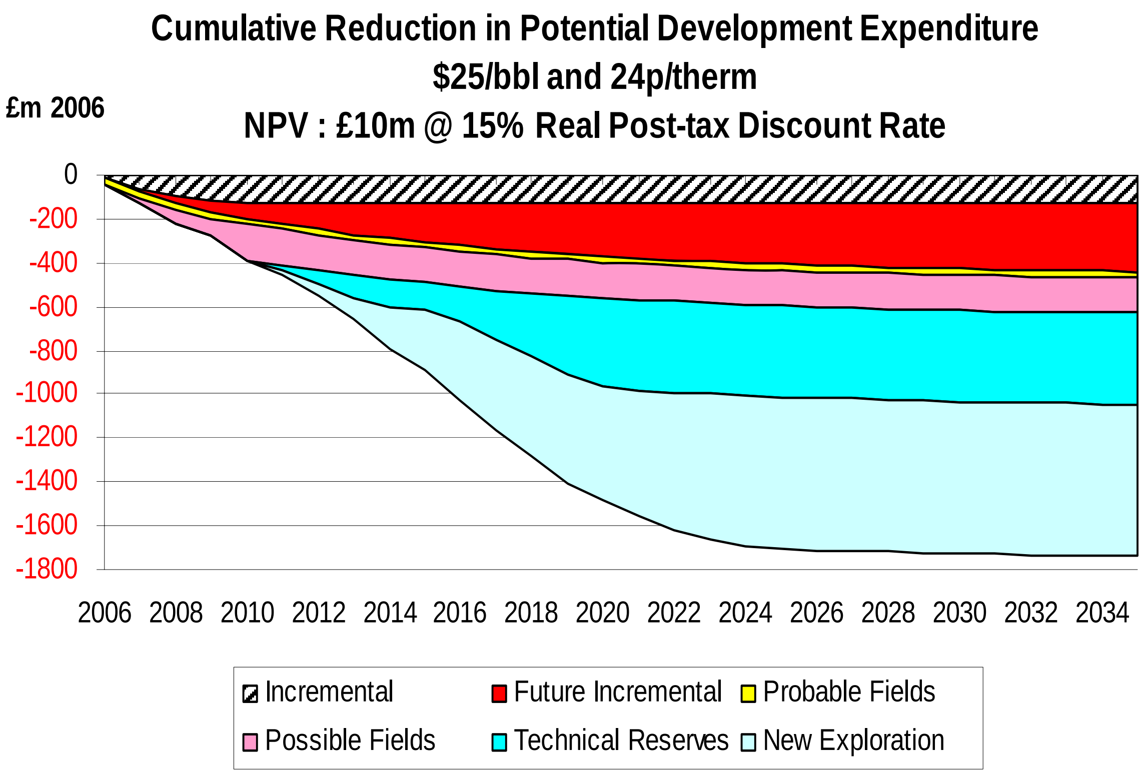


Chart 51

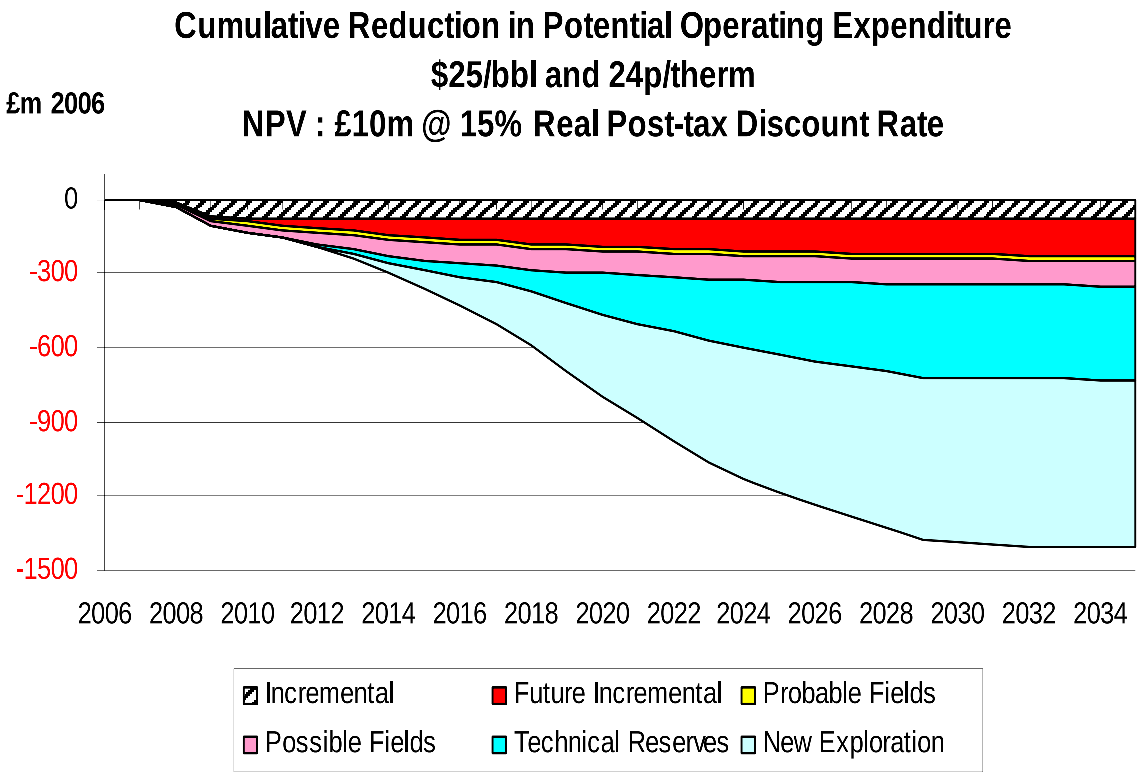
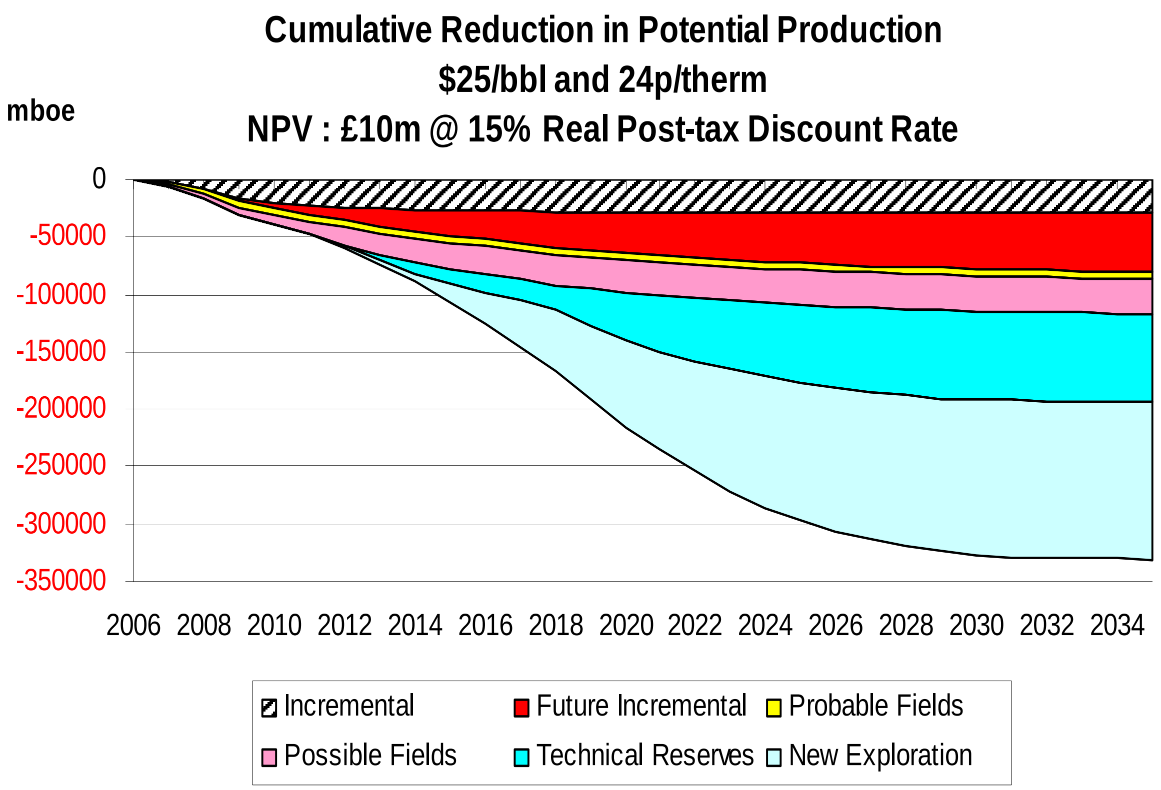


Chart 52



It is possible that investors would accept a minimum acceptable NPV lower than £10 million. Accordingly a case where the minimum was £5 million was also examined. Summary results are shown for the $30, 28 pence scenario in Charts 53, 54 and 55 along with the corresponding results for the £10 million case. It is seen that the choice of discount rate by investors could have a stronger effect on the resulting reduction in investment and production than the difference in minimum NPV.

Finally, the full values for all unsanctioned fields and projects relating to annual investment, operating expenditures and production are shown in Charts 56, 57 and 58 under the $30, 28 pence case. The range of annual investment under the different scenarios is seen to be significant in the period 2010-2017 in particular.

Chart 53

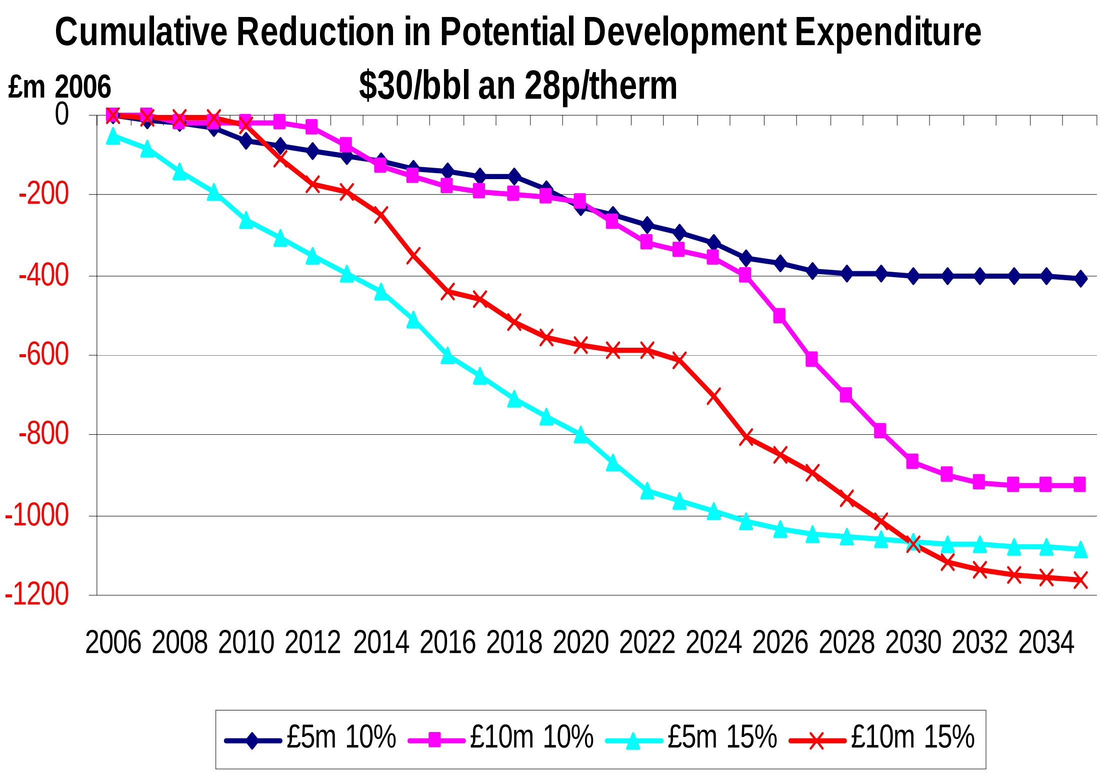


Chart 54

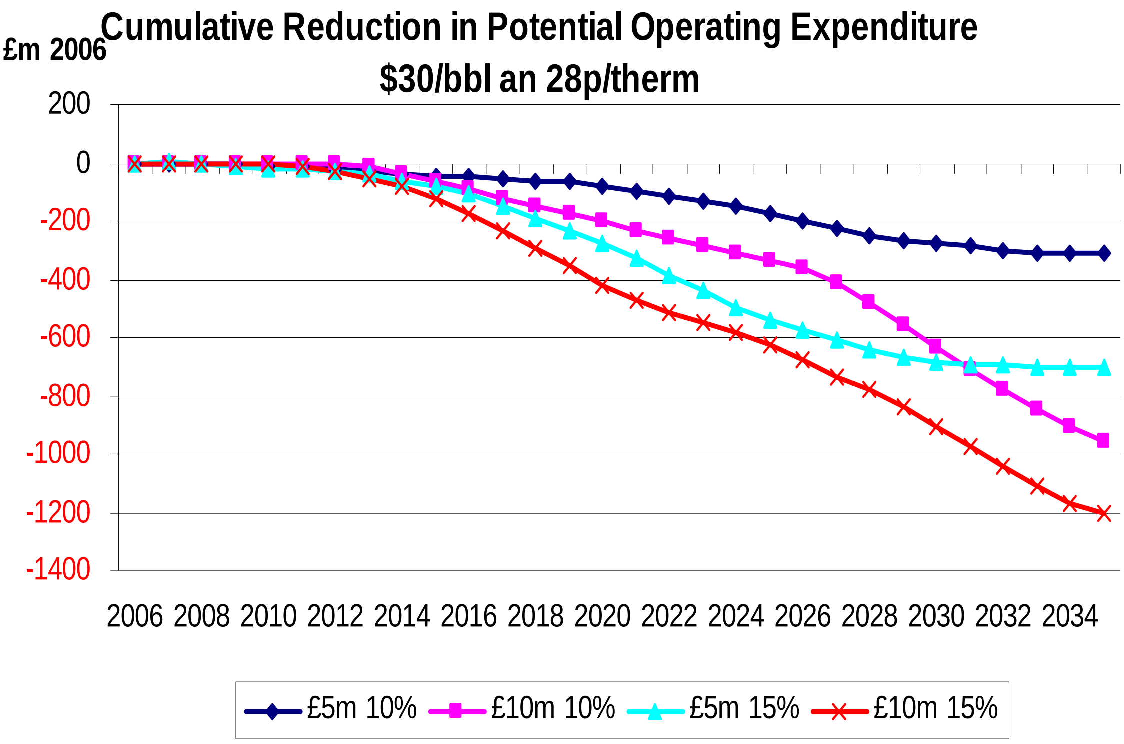


Chart 55

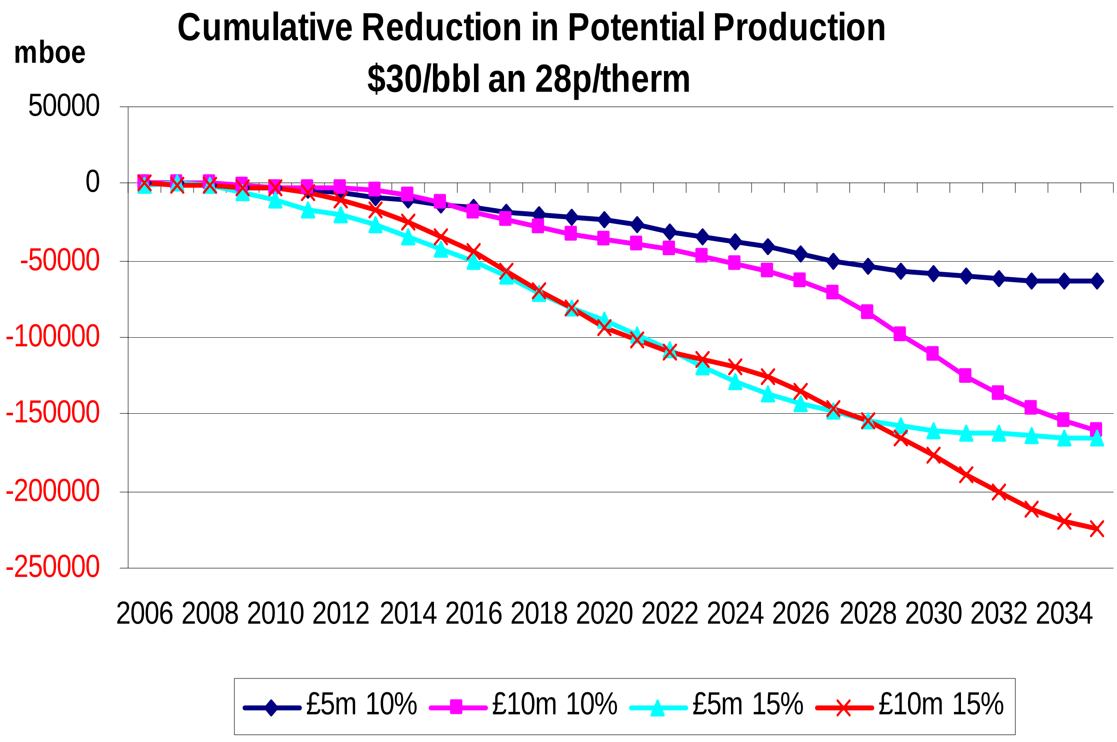


Chart 56

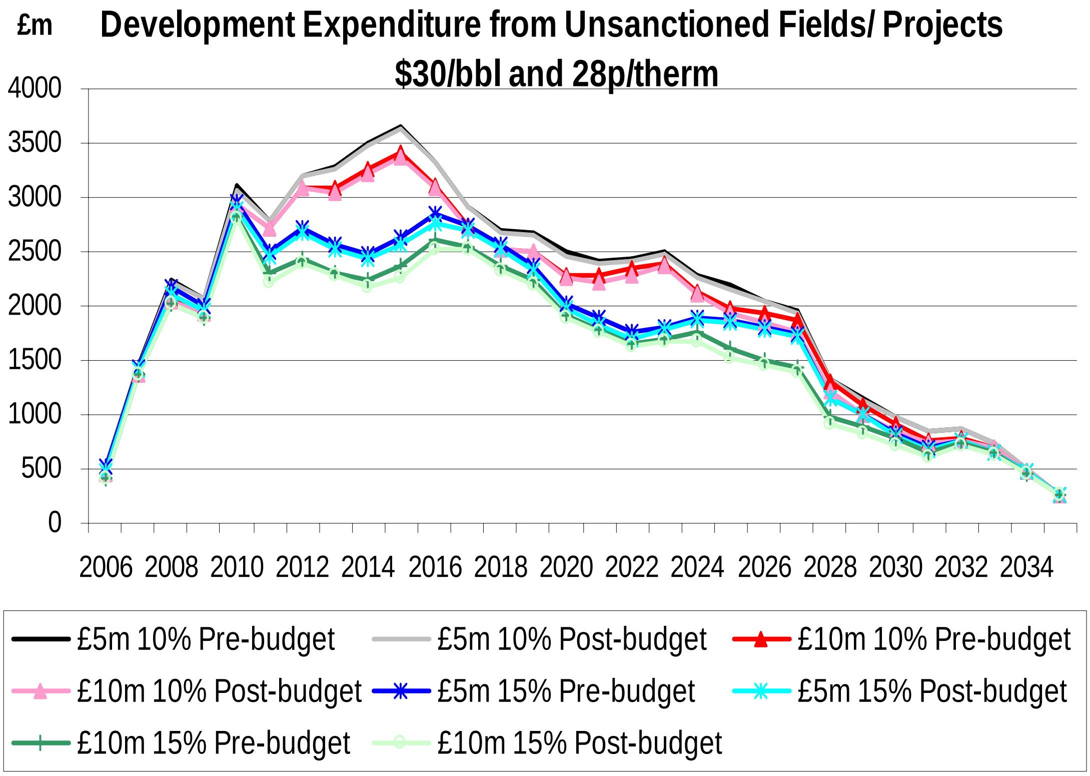


Chart 57

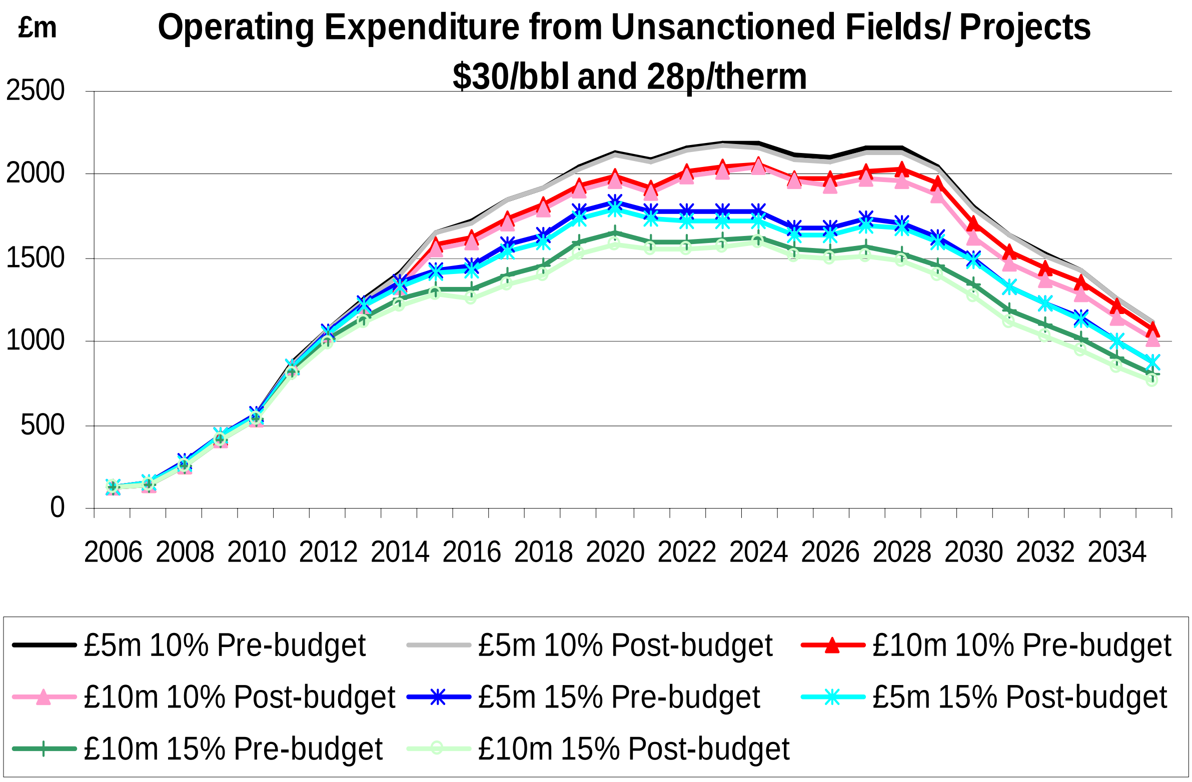
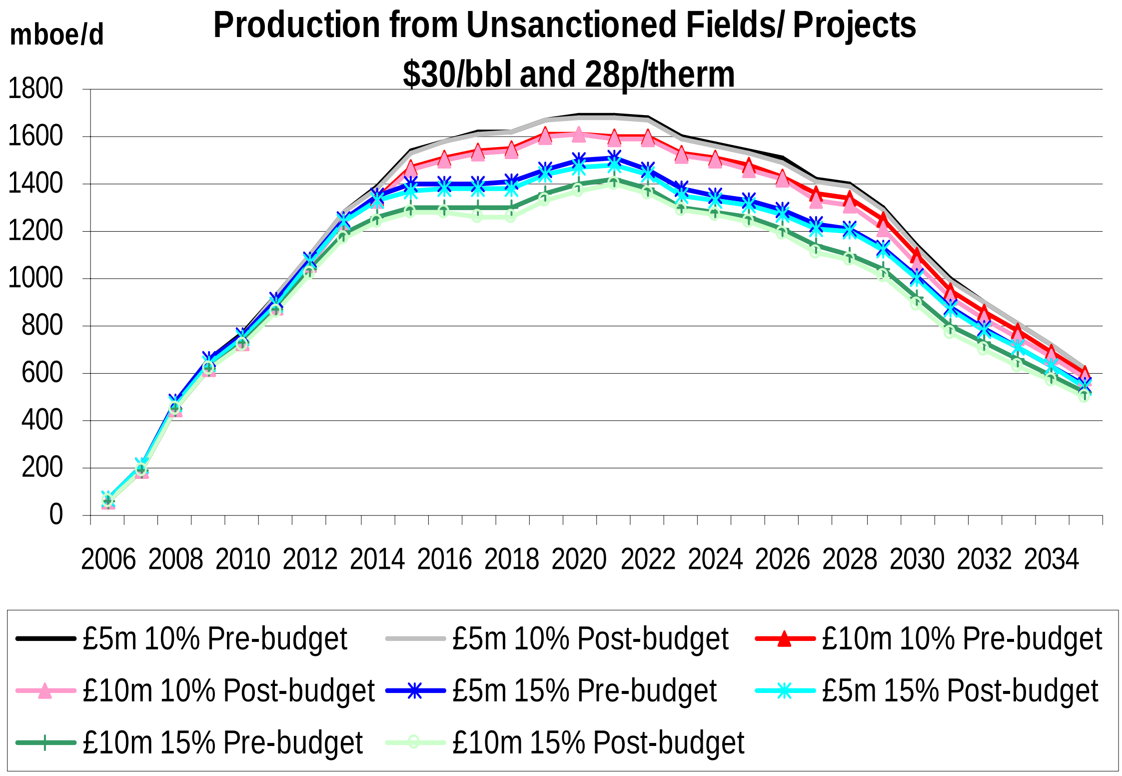


Chart 58



5. Structural and Incentive Aspects of Tax System

This study has concentrated on the impact of the tax increase on activity levels via the effect on the returns to new investment projects. For existing taxpayers the current system is essentially a cash flow tax with the characteristic that the post-tax internal rate of return (IRR) equals the pre-tax IRR irrespective of the tax rate. But the size of expected NPV from a project is of key importance to investors, and the finding that most future projects are relatively small with relatively high unit costs results in many of the post-tax NPVs becoming quite low. At the oil and gas prices likely to be employed by investors a general reduction in post-tax NPVs by 16.667% as a consequence of the budget results in the viability of some fields in the technical reserves category and some incremental projects being endangered.

The other characteristics of the cash flow tax are positive as far as the encouragement of investment is concerned. Thus all the key risks relating to exploration, development, and production are fully shared on 100% first year basis through the tax system. The UK petroleum tax system is unique from this viewpoint and these features are generally optimal form the viewpoint of encouraging investment activity.

Apart from the issue of the rate of tax there are some structural features which are less than optimal from the viewpoint of promoting investment in the context of the current operating environment in the UKCS. It is clear that the desired development of the large numbers of small fields and incremental projects is facilitated by ready access to infrastructure on reasonably competitive terms. The current Code of Practice is designed to promote this. The recent increase in the tax rate applies to tariff income as well as production income. This does not help to promote competitive terms as asset owners may well try to raise tariffs as a consequence, given the reduction in their prospective returns from the tax increase. There may be clauses in the indexation provisions relating to tariffs permitting adjustments in response to tax changes. In 2003 PRT was removed from the taxation of income from new tariff contracts on the understanding that the net economic benefit would be passed on to users. It is known that the outcome of negotiations of at least some tariff contracts was related to the outcome of this legislation. It is arguable in the present context that, consistent with the philosophy of the debate in 2003, the Supplementary Charge should not apply to tariff incomes.[1]

[1] An earlier study by the present authors demonstrated the national benefits of the PRT concession in 2003. See A G Kemp and L Stephen (April 2003), UK Oil and Gas Production Prospects, the Optimal Utilisation of UKCS Infrastructure, and the 2003 Budget Tax Changes, North Sea Study Occasional Paper No. 90, University of Aberdeen, Department of Economics, pp. 73.

The encouragement of the entry of new players to the UKCS is recognised as being desirable, but currently new players without tax cover are disadvantaged compared to existing ones. They have to wait until they have production income before their allowances relating to exploration, appraisal, and development can be utilised. The issue of the non-level playing field was recognised by the Government and the device of permitting allowances for E and A to be carried forward with compound interest was introduced. The 2006 budget extends the coverage to development allowances. It should be noted, however, that the increase in the tax rate from 40% to 50% also increases the extent of the non-level playing field as the rate of relief has been increased for tax-paying investors. The current rate of interest employed for compounding the allowances is 6% which is essentially a risk-free rate. This does not correspond to the cost of capital relating to risky E and A activities and it should be adjusted to reflect these risks. It is noteworthy that Norway had a similar device and risk-free rate to encourage E and A in their Continental Shelf. The device was not obviously having a worthwhile effect and has been replaced with a scheme of cash rebates for unrelieved E and A expenditures at the marginal rate of tax which is currently 78%. This is likely to be too revolutionary for adoption in the UKCS, but the experience indicates that a risk-free interest rate is inadequate to produce a worthwhile effect. It should be noted that the new player still bears the exploration risk since no relief will be given if no discovery is made. Only the cash refund scheme equalises the position between tax-paying and non-tax-paying players. Compounding the allowances at a rate reflecting the related cost of capital would at least reduce the disparity in treatment.

It is recognised that the encouragement of transactions in mature assets is desirable given their reduced attractions to some current licensees and their perceived greater attractions by other players whether existing or new. In this context the issue of financial liability for decommissioning and the associated security issue arises. Currently licensees may be required to provide guarantees for this purpose by the DTI or co-licensees. These take various forms with letters of credit currently being typical.[2] These are quite expensive and reduce the borrowing capacity of the licensee. They also cause fields to be prematurely decommissioned by accelerating the timing of cessation of production. The issue will become more important as more fields reach the time period when the requirement for security is triggered (typically when the remaining NPV reaches 150% of the expected decommissioning costs).

It is arguable that other forms of security are superior to the existing arrangements. Schemes involving decommissioning funds or escrow accounts have become more common around the world in both licences and production sharing contracts. Thus they exist in Namibia, Angola, Azerbaijan and Russia (Sakhalin). They involve the alienation of funds from the specified trigger point and tax relief or cost recovery status being given for the funds involved. Financial security is provided for all parties – co-licensees and Government. In the UK such schemes were examined in the early 1990's, but the Government resisted tax deductibility status being given to fund contributions. It was argued that tax relief should not be given for an activity until the expenditure in question was incurred, and that there would be an incentive to overprovide in order to obtain maximum tax relief. But mechanisms can be incorporated to safeguard the Government's position. Thus in the Netherlands provisions for decommissioning are deductible for both corporate income tax and State Profit Share on a unit of production basis, but independent, periodic estimates of decommissioning costs can be made with consequent adjustments to the permitted provisions. Further, if over provision does result it is fully subject to

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2 See A G Kemp and L Stephen (December 2004), Economic Aspects of Prospective Decommissioning Activity in the UKCS to 2030, North Sea Study Occasional Paper No. 97, University of Aberdeen, Department of Economics, pp. 61.

both corporate income tax and State Profit Share. In the UK the adoption of this scheme could require modifications to the application of Inheritance Tax. Other insurance-based schemes are also superior to the existing arrangements in the UK, but decommissioning funds/escrow account arrangements are generally more straight-forward and already in operation in several countries.

Given the prospective production decline rates in the UKCS with the associated small size of the great majority of the new fields the issue of enhancing recovery is of major importance. In this study it has been shown that the incremental projects relating to sanctioned fields currently being examined are likely to add far more to total production than that expected from all the probable and possible fields currently being assessed. The great majority of incremental projects are drilling-based, particularly infill and long-reach drilling. Most come under the umbrella of secondary recovery with very few coming under the category of tertiary recovery. It is arguable that, at the current stage of development of the UKCS, tertiary recovery techniques should be encouraged. These are generally significantly more expensive and require some R and D before they can be applied in the conditions of the North Sea. But the rewards in terms of enhanced recovery can be substantial as the experience of onshore USA has demonstrated. Technologies which offer substantial potential include (1) advanced chemical flood (surfactants/polymers), (2) air injection, (3) microbial EOR, (4) low salinity waterflood, (5) CO_2 injection, and (6) miscible gas injection. Other possibilities are hot water/thermal flooding.

It is arguable that targeted incentives could produce a worthwhile return to the nation in terms of enhanced output with associated tax revenues. An appropriate incentive in the framework of the current UK tax system would be an uplift against the Supplementary Charge on R and D on enhanced recovery schemes examples of which are shown above. It is noteworthy that loan interest is not deductible against the Supplementary Charge. There will be external benefits from the development and demonstration of these technologies in their more widespread use across fields in the UKCS. The case for the targeted incentive is appropriate because of the perceived caution among investors in introducing them in spite of the prevalence of relatively high oil prices. It is relevant that tax incentives for tertiary recovery schemes have for long featured in the USA.

Heavy oil projects suffer from very substantially lower product prices compared to average North Sea oil realisations. This raises the question of the price sensitivity of the tax system. Corporation tax (with the Supplementary Tax) is inherently not so price sensitive as PRT which is, however, now very less important in its application across the current fields in the UKCS and non-applicable for future ones. This study has highlighted the price sensitivity of medium/long run investment and production and shown how, if capital expenditure decisions were made at prices of $25/bbl in real terms, the result would be a rapid fall-off in these activities. In these circumstances a tax rate reduction would certainly help to sustain investment (though a cost-reduction initiative would also be required to have a really major effect on activity). Under current rules, a tax rate reduction would require a discretionary change by Government. This could certainly not be assumed to happen by a prudent investor. To reduce the investment uncertainty is certainly desirable and accordingly consideration should be given to the introduction of formula whereby the rate of Supplementary Charge is clearly and directly related to oil prices. This is not straight-forward in practice because of (a) the co-existence of gas and oil and (b) the volatility of prices in the short-term. These problems can be dealt with by the use of conversion factors and ranges of oil (and oil equivalent gas prices) over a specified period of time.

6. Conclusions

In this study the prospects for activity levels in the UKCS to 2035 have been modelled taking into account the up-to-date situation regarding field sizes, development and operating costs, prospectivity of exploration, and the recent tax increase. A striking feature of the prospects (undeveloped fields and incremental projects) is their relatively small size with the average size of the probable and possible fields being under 15 mmboe and that for the incremental investments being around 9 mmboe (ignoring one non-typical very large project). Another feature is the high unit cost with the average lifetime cost of the probable and possible fields exceeding \$15 per boe. The corresponding figures for the probable incremental projects is nearly \$11 per boe. These figures reflect the recent substantial cost increases and the relatively small size of the fields/projects.

These features are reflected in the size of the expected returns expressed in NPVs at real post-tax discount rates. Thus under a price scenario of \$30, 28 pence in the period to 2035 500 fields/projects had positive NPVs at 10% real discount rate but only 365 had NPVs in excess of £10 million. At \$40, 36 pence 578 fields/projects had positive returns and 519 had NPVs in excess of £10 million. Under the \$25, 24 pence price scenario 390 fields/projects had positive returns but only 221 had NPVs in excess of £10 million.

The consequences are that under the \$30, 28 pence case, with a £10 million or better NPV requirement, total hydrocarbon production could be nearly 3 mmboe/d in 2010 and over 1.9 mmboe/d in 2020. By 2035 total cumulative production from 2006 could be 21.6 bn boe. Under the \$40, 36 pence case production could be just over 3 mmboe/d in 2010 and 2.4 mmboe/d in 2020 with total recovery of 24.6 bn boe by 2035. Under the \$25, 24 pence case total production could be 2.8 mmboe/d in 2010, 1.3 mmboe/d in 2020 with total recovery of 17.5 bn boe. The long-term price sensitivity of production is clearly substantial.

This is reflected in the behaviour of field investment. Under the $40, 36 pence price case it holds up well for many years averaging over £4 billion per year for a considerable number of years. Under the $30, 28 pence scenario field investment falls below current levels but averages more than £3 billion per year for a considerable number of years. Under the $25, 24 pence case field investment falls at a sharp pace.

The effects of the 2006 Budget tax increase were measured in terms of its consequences on field investment, field operating costs and production in the long-term to 2035. Under the $30, 28 pence case with hurdle returns of NPV of £10 million or better at 10% discount rate 16 fields/projects which pass on a pre-budget basis fail after the budget. The resulting cumulative reduction in field investment to 2035 is £900 million (at 2006 prices) with the corresponding reduction in operating expenditures being around £950 million. The loss of production is around 165 mmboe. If a 15% discount rate were employed 24 fields/projects would be deterred and the reduction in investment would be £1.8 billion, the reduction in operating costs around £1.3 billion and the reduction in production around 230 mmboe.

Under the $40, 36 pence case the reduction in activity was quite modest when 10% discount rate was employed but with 15% rate 24 projects were deterred resulting in a reduction of field investment of £1.13 billion, operating costs of £1.1 billion and production of 189 mmboe. Under the $25, 24 pence case at 10% discount rate 22 projects are deterred resulting in a reduction in investment of £2 billion, a fall in operating costs of £1.75 billion and a reduction in production of 380 mmboe.

Given the clear need to encourage activity in the UKCS there is a case for some targeted tax changes to remove anomalies, level the playing field, and incentivise activities which could have a wide beneficial effect on output. The increase in tax on tariff income is anomalous given the acknowledged need to produce a régime with ready access to infrastructure on competitive terms. Removing the Supplementary Charge on tariff income is consistent with this desirable objective and also consistent with the decision in 2003 to remove PRT from new tariff contracts.

New players without tax cover are disadvantaged under the present tax system. They cannot obtain immediate tax relief on their E and A and development expenditures. The discrepancy in treatment has been increased with the increase in tax rate. The disadvantage of new players has been acknowledged through the introduction of the mechanism whereby unused allowances can be carried forward at 6% compound interest rate. This mechanism is conceptually sound but the rate is well below the cost of capital for E and A activities. A higher rate to reflect the appropriate cost of capital is necessary to produce a more level playing field to encourage new entrants which is acknowledged to be desirable.

To encourage (or at least not hinder) the transfer of assets (particularly mature fields) the taxation aspects relating to financial liability should be reformed. The typical current arrangements whereby letters of credit may be required when remaining NPV reaches 150% of decommissioning costs is expensive, reduces the borrowing capacity of the licensee concerned, and reduces field life. Decommissioning funds or escrow accounts with tax relief for the alienated funds, are more efficient mechanisms and are now in place in a number of countries such as Angola, Azerbaijan, Namibia, and Russia (Sakhalin). Provisions for decommissioning with tax relief are permitted in the Netherlands. Mechanisms can be included to prevent (and tax) overprovisions.

Examination of the prospects for the UKCS indicate the great importance of incremental investments. But most of these relate to drilling activities and secondary recovery. There is a need to encourage tertiary recovery techniques such as (1) advanced chemical flood (surfactants/polymers), (2) air injection, (3) microbial EOR, (4) low salinity waterflood, (5) CO_2 injection, and (6) miscible gas injection. Other possibilities are hot water/thermal flooding.

These generally require some R and D, especially to deal with North Sea conditions. There is a case for an uplift against the Supplementary Charge for approved R and D activities as discussed in Section 5. The incentive could produce considerable beneficial externalities through its wider application across the UKCS.

The present study has demonstrated that activity in the UKCS is quite price sensitive in the medium and long-term. If prices fell significantly a tax reduction could to some extent mitigate the fall in activity. The current system means that only discretionary changes in the rate can be made. There is merit in a schedule where the rate changes automatically with the oil price and this is known to investors. Such a schedule would reduce the investment uncertainty which is increased by frequent discretionary changes.

It should be stressed that the indicated activity levels, particularly those under the \$30, 28 pence case and \$40, 36 pence price scenarios are conditional on the success of the various PILOT/DTI initiatives currently in progress, including in particular the fallow fields/blocks initiative, the stewardship initiative, and the infrastructure Code of Practice. Further, the development of many small fields in the longer term depends on the prolongation of the life of the infrastructure of pipelines, terminals and processing platforms. This will be the subject of a forthcoming paper.