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Petroleum Taxation for the Maturing UK Continental Shelf (UKCS)

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NORTH SEA ECONOMICS

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

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

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

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

For 2013 the programme examines the following subjects:

a) Implications of Constitutional Change for the North Sea Oil and Gas Sector
b) Integrated Returns to Investment in CO_2 Capture, Transport and Storage
c) Full Cycle Returns to Exploration in the UKCS
d) Economics of CO_2 EOR Cluster Developments in the Central North Sea/ Outer Moray Firth

e) The Incidence of Field Allowances for Supplementary Charge
f) Future Activity Prospects for the UKCS
g) Economics of Third Party Access to Infrastructure
h) Tax Incentives for CO_2 EOR

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Petroleum Taxation for the Maturing UK Continental Shelf (UKCS)

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1. Context

The UK Continental Shelf (UKCS) is a mature petroleum province currently characterised by a combination of declining production and production efficiency, low levels of exploration, relatively small average size of discovery, and high investment and operating costs per barrel. Investment in field developments is at all-time record levels. This reflects the extremely high costs of developing a few very large fields, and also the substantial costs of incremental projects. A significant component of this is to maintain or enhance the integrity of the existing production infrastructure. Many assets are known to be on offer for sale.

There are other more positive indicators. The exploration success rate is generally high. It was 26% in 2013 and the average for 2008-2013 and 2000-2013 exceeded 28%. The 27th Licensing Round resulted in 410 blocks being offered to investors. This was an all-time record. Also, most licences (192 out of 224) are traditional, with only 25 being Promote. But the number of commitment wells was relatively low at only 18. DECC's most recent study of the remaining potential indicate their best estimate of the remaining recoverable potential to be in the range 11.1-21 billion barrels of oil equivalent (bnboe). There is a significant further upside potential, but with very high risks attached. Oil and Gas UK estimate the remaining potential within the range 15-24 bnboe.

The petroleum taxation system should reflect the above features of the current and prospective operating environment.

2. Conceptual Framework for Taxation System

The taxation system is intended to collect what is often termed a reasonable share of the revenues to the state. The preposition is that economic rents are generated by the exploitation of oil and gas in the UKCS and the state is entitled to a reasonable share of these. Economic rents may be defined as returns in excess of the supply price of the investment. To measure the supply price of the investment is not straight-forward. It requires an understanding of the investment hurdles of licensees, and thus how they perceive likely unit costs, production, and oil/gas prices. They will factor into their calculations the risks involved, including political risk, in making what are long term very capital intensive investments. In the current financial environment investors are in a capital rationing situation. This applies not only to smaller companies, who may have difficulty in accessing both debt and equity capital, but also to larger companies faced with restless institutional shareholders, some of whom have been vocal in stating that capital expenditure budgets should be curtailed.

In these circumstances investment hurdles are likely to be set in terms of NPV/I ratios which emphasise the productivity of every pound invested. Thus the materiality of the investment return is a key consideration. The decline in the average size of new field and the size of the remaining NPV in mature fields are relevant considerations here.

In making long term investment decisions investors generally use conservative values for screening purposes. In the present paper values of $90 per barrel and 58 pence per therm in constant real terms have been employed. It is acknowledged that, in decisions regarding loan finance, banks often use much lower screening prices of $70 or so.

Discount rates employed by investors generally reflect their weightted average cost of capital (WACC). This will vary from company to company depending, for example, on how well diversified is their portfolio of assets. A substantial portfolio means that the unsystematic risks are lower compared to a small portfolio. It should be noted that the WACC will always be significantly higher than a riskless rate. In the present paper the investment hurdle has been set at NPV@10%/I@10% > 0.3 in the base case, but attention is also given to a case where the hurdle is NPV@10%/I@10% > 0.5, indicating serious capital rationing.

3. <u>The Tax System in Context</u>

The present petroleum tax system has evolved in an ad hoc manner since 1975 in response to changes in the operating environment. Arguably it is not well-adjusted to the current and prospective position of the industry. On mature fields which received development consent prior to 16th March 1993 Petroleum Revenue Tax (PRT), Corporation Tax (CT) and Supplementary Charge (SC) apply, producing a headline rate of 81%. By international standards this is very high and not conducive to investment where the materiality of expected returns from incremental projects is a main consideration. The effective rate on incremental investments may be reduced by the Brownfield Allowance (BFA) for the SC, but, even if eligibility for this is confirmed, the effective rate is still high and arguably not consistent with the objective of maximising economic recovery. Because PRT paid is deductible for CT and SC a reduction in PRT paid leads to an increase in CT and SC. Thus to produce a worthwhile effect on post-tax returns a significant reduction in the PRT rate is needed.

For new fields developed since March 1993 CT at 30% and SC at 32% are payable. A plethora of field allowances against SC is available which, if eligibility is confirmed, can substantially reduce the overall effective rate from 62% to as low as 30% depending on the extent to which the allowance shelters income from SC. The allowances are based on physical features such as size of reserves, with water depth, location and whether the fields quality as heavy oil or high pressure/high temperature (HP/HT). The BFA is different, being based on investment costs per boe. The proposed new uHP/HT allowance is simply based on investment costs.

It is arguable that the system of field allowances should reflect economic rather than physical characteristics of the fields: investment decisions are based on economic features, and physical characteristics can only be imperfect substitutes for economic ones. Costs are directly linked to the returns from a project. The concept of uplift is employed in the design of PRT to reflect the absence of deductibility of loan interest and recognition of the need to obtain a return on the investment. Broadly, this concept has worked reasonably well in practice. It automatically accommodates changes in investment costs in the appropriate direction. The field allowances can only do this imperfectly, and there may well be cases where ineligibility for the allowance holds back an investment which is economic before tax. The field allowances are specified in monetary terms. Conceptually this is certainly an improvement over the volume allowance for PRT, the effect of which is to increase the benefit of the allowance when oil prices rise and to decrease its value when oil prices fall. It is regressive in relation to oil price changes. The field allowance for SC is progressive in relation to oil price changes. But its

value does not automatically react to changes in costs which is arguably a desirable feature in the current investment environment.

In considering the appropriate structure of the tax system the headline rate is always discussed, but often without presentation of arguments for what constitutes an appropriate rate. The statement that the UK tax system has to be internationally competitive is certainly correct as far as the oil sector is concerned. Allowances such as investment uplift and field allowances help because in effect they increase the return on the investment. The headline rate is relevant here because it directly affects the materiality of returns which is a necessary element in determining the international competitiveness of the UKCS. Thus for some time there existed what was in effect a cash flow tax with 100% first year allowances and a single tax rate. The post-tax internal rate of return then equalled the pre-tax rate of return. But the headline rate determined the materiality of returns expressed in terms of NPV or NPV/I ratio. In the current situation in the UKCS the materiality of returns is a main issue in attracting investment and it is necessary to consider variations in headline rates in that context. In modelling undertaken it was found that, the greater the capital rationing constraint, realistic rate reductions could enhance investment to a greater degree than realistic increases in uplift or field allowances. This subject is developed further below.

Currently many investors in the UKCS are not in a tax-paying position. They carry forward their losses under the Ring Fence Expenditure Supplement (RFES) provisions at 10% interest rate for a total of 6 accounting periods. After an initial year for purposes of the RFES has been established losses in later years are accumulated with interest for progressively shorter periods. The mechanism of compounding forward

losses is conceptually sound and consistent with the resource rent tax concept, but the restrictions on the time period can reduce its effectiveness. Thus if the E and A period is quite long there may be only very limited opportunities for accumulating losses at the field development stage where the expenditures are much larger. The current RFES disadvantages an investor without tax cover compared to one in a full tax-paying position not only because of this time limitation but also because the risks and costs of making no discovery at all are fully borne by the investor, whereas they are fully shared through the tax system if the investor is currently paying tax. In general there is merit in a tax system which is neutral and thus does not discriminate against new entrants. It is arguable that they should be encouraged to invest in the UK and should not be placed at a competitive disadvantage. The <u>Wood Review</u> has, of course, emphasised the need to raise exploration from the present low levels.

The <u>Wood Review</u> also highlighted the need to encourage third party use of the infrastructure of pipeline, hub platforms and terminals in order to reduce the development costs of new fields, to encourage further infrastructure investment, and thus to maximise economic recovery. Currently SC as well as CT apply to tariffing activities in the UKCS, though PRT no longer applies to new tariffing contracts. Recently investors with no production-related activities in the UKCS have purchased interests in offshore pipeline activities. This is an encouraging development. It is arguable that, given the objective of optimising the use of the offshore infrastructure tariffs should reflect the costs of providing the service rather than any local economic rents. This still leaves room for debate on the comparative merits of marginal or average cost pricing, multi-part schemes with separate charges for (a) access and (b) usage. But, with tariffs reflecting costs of provision, there should not be a tax additional to corporation tax such as SC. Of

course, the tax deductions for the costs relating to the third party service should reflect this.

The substantial decline in production efficiency over the last decade is a major concern. There are major national gains to be obtained from reversing this trend in terms of enhanced output, tax receipts, and industry net cash flow. The new Regulator has a key role here. The industry is currently examining how production efficiency can be improved and significant investment is being made to effect this. The tax system can only play a secondary role in this area, but a reduction in the effective rate clearly improves the return to investment or operating expenditures on measures which improve production efficiency.

The Wood Review also highlighted the merits of encouraging enhanced oil recovery (EOR) schemes. Relevant technologies are Low Salinity Waterflood, Polymer Flood, Miscible Gas Injection, and CO_2 EOR. All of these are relatively high cost activities when conducted offshore and with very significant risks. But the potential long term national benefits are also significant. It is likely that in the longer term costs may be reduced through the learning by doing process. A feature of the Polymer Flood, Miscible Gas and CO_2 EOR technologies is the high operating costs consequent upon the need to purchase large quantities of polymer, gas and CO_2. This means that tax incentives based on investment costs only do not properly reflect the cost structure. Thus there is a case for including operating costs in any targeted allowance. This may cause practical problem in tax implementation. This potential difficulty could be overcome by limiting the eligible operating costs to the purchase costs of the necessary primary material for the EOR process, namely the polymer, gas and CO_2.

4. <u>Modelling Procedures</u>

In order to assess the implications of various taxation arrangements a large financial model of the UKCS developed in the University of Aberdeen was employed to project activity levels over the period 2014-2050. The financial model incorporates all the complex taxation arrangements as they have evolved since the 1960's. The model is applied to a very large field database incorporating key data on the sanctioned fields and future possible developments from incremental projects, probable fields, possible fields, technical reserves and new discoveries made over the period to 2045[1]. The fields in the category of technical reserves are not yet at the planning stage. Most are economically and/or technically challenging. To reflect this the average development costs was set at $5 per boe above the average for those fields in the probable/possible categories. Monte Carlo modelling was employed separately for each of the 5 main regions of the UKCS to calculate the numbers of new discoveries and their size distribution based on trends in the exploration effort and success rates over the past decade. Monte Carlo modelling was also employed to determine the distribution of investment and operating costs for new discoveries and fields in the technical reserves category.

The model operates by calculating the pre-tax and post-tax returns to all the future fields and incremental projects. There are investment hurdles to be overcome. They are NPV@10%/I@10% > 0.3 in the base case and NPV@10%/I@10% > 0.5 in a second case reflecting very substantial capital rationing. There is a second constraint on the numbers of new field developments in any one year reflecting both the financial and

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[1] Full details can be obtained from the authors.

physical capacity of the industry including the supply chain. In the case highlighted in this paper the investment screening prices are $90 per barrel and 58 pence per therm both in constant real terms.

The extent to which the Wood Review proposals are implemented was also considered in the modelling assumptions. Two cases were examined reflecting high and moderate degrees of success in implementing the proposals. The case of moderate success is reported here. With respect to the tax-paying position of investors two cases were considered. In the first the investors are all assumed to be in a tax-paying position. In the second case they are not currently in a tax-paying position. The base case in this paper reflects the current tax-paying investor.

5. Results of Modelling

(a) Base Case with Current Tax System

In Chart 1 total hydrocarbon production over the period 2014-2050 is shown. The cumulative total from all fields and projects is 14.1 bn boe. Cumulative production from sanctioned fields is 6 bn boe, probable fields is 0.9 bn boe, from possible fields 0.4 bn boe, from current incremental projects 0.9 bn boe, from future incremental projects 1.7 bn boe, from technical reserves 2.4 bn boe and from future discoveries 1.9 bn boe.

Chart 1

Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
Production efficiency problem partly resolved

Tboe/d

Sanctioned Incremental Future Incremental Probable Possible Technical Reserves New Exploration

Chart 2

Potential Total Field Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
Production efficiency problem partly resolved

Real 2014 £m

Sanctioned Incremental Future Incremental Probable Possible Technical Reserves New Exploration

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Chart 3

Potential Total Field Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
Production efficiency problem partly resolved

Real 2014 £m

In Charts 2 and 3 the total field expenditures (investment, operating
and decommissioning) are shown. Over the period to 2050
development expenditures amount to over £122 bn at 2014 prices,
operating expenditures are £175 bn and decommissioning
expenditures £45 bn. Altogether there are 271 new field
developments over the period (out of a total of 454). Incremental
projects are in addition to these.

(b) Difference when Investor Currently not in Tax-paying Position

The change in activity when the investor is not in a tax-paying
position is now illustrated. There are 27 fewer new field
developments over the period. Oil and gas production are reduced by
similar volumes, namely 156 mmboe for oil and 149 mmboe for gas.
The profile for the decrease in total hydrocarbon production is shown
in Chart 4.

Chart 4

Change in Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Tboe/d

Legend: ▢ Probable ▢ Possible ▢ Technical Reserves ▢ New Exploration
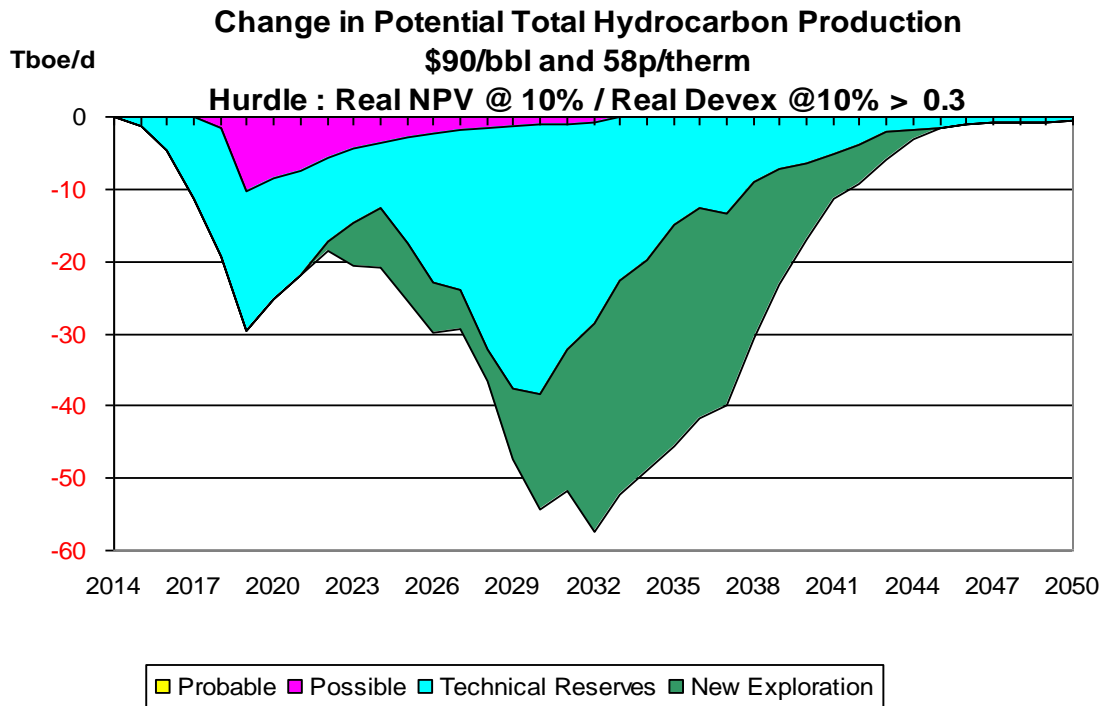
The geographic locations of the reduction are shown in Chart 5.

Chart 5

Change in Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Tboe/d

Legend: ▢ Cns / MF ▢ Irish ▢ Nns ▢ SNS ▢ WoS
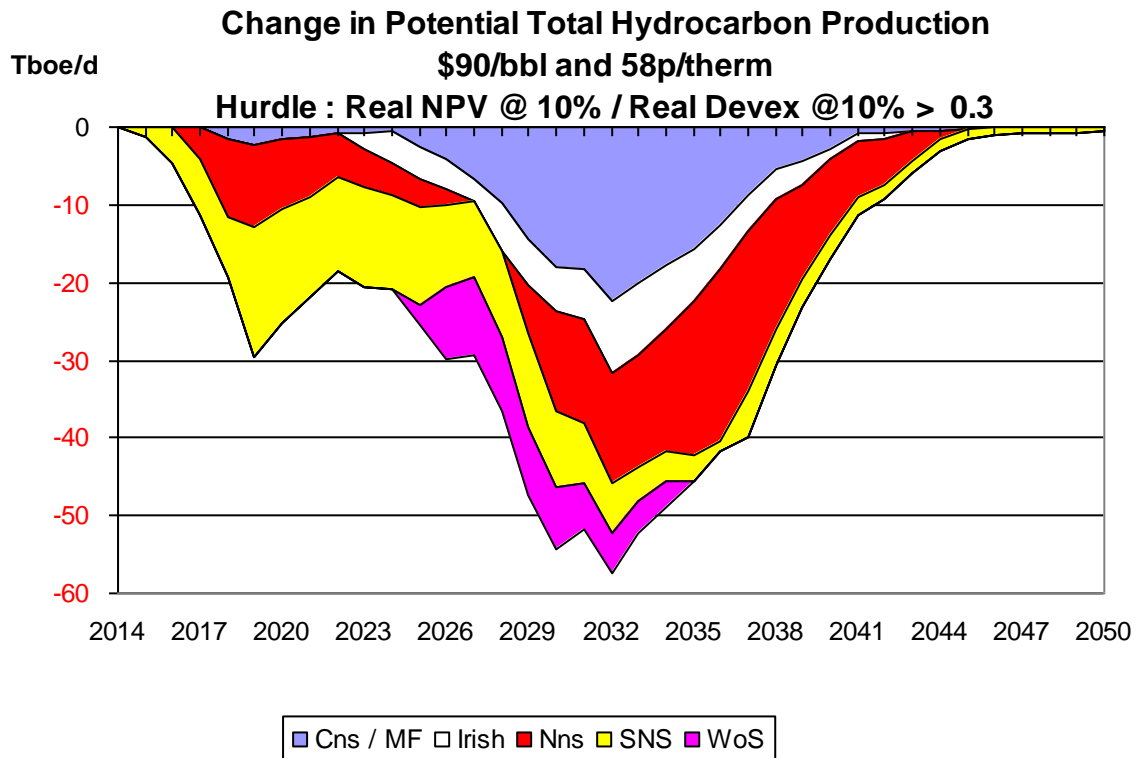
In Chart 6 the reduction in development expenditure is shown. Over the period it amounts to £4.5 bn at 2014 prices. The fall starts in the near future.

Chart 6

Change in Potential Development Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Real 2014 £m

Probable Possible Technical Reserves New Exploration
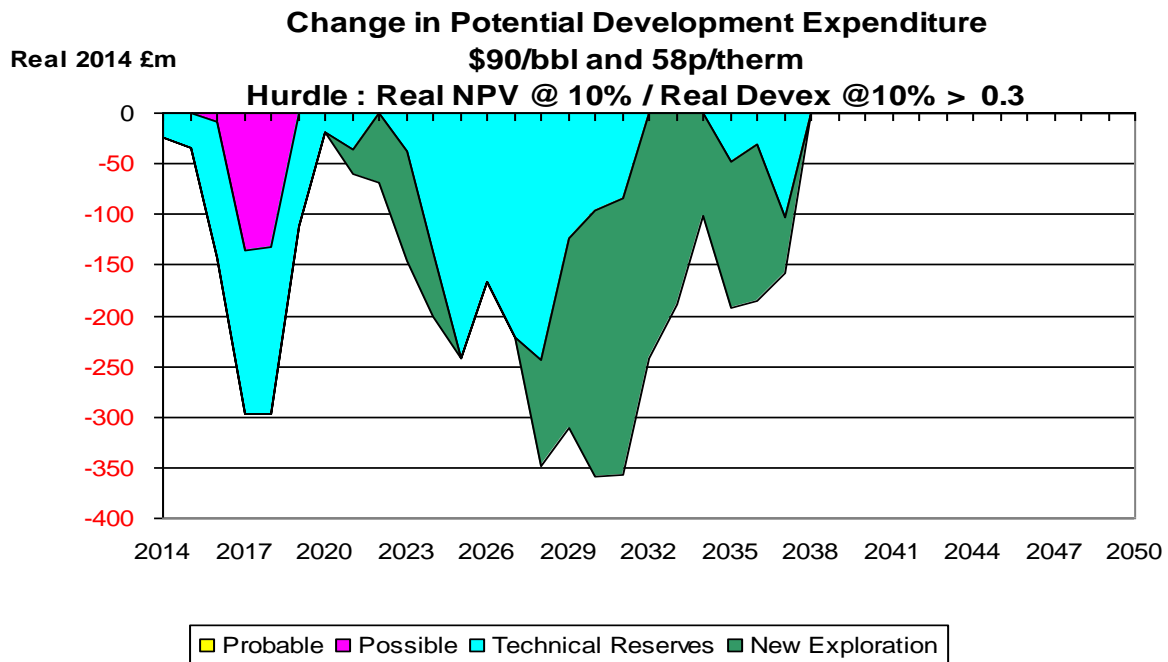
In Chart 7 the reduction in operating expenditures is shown. Over the period it amounts to £4.2 bn.

Chart 7

Change in Potential Operating Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Real 2014 £m

Probable Possible Technical Reserves New Exploration

13
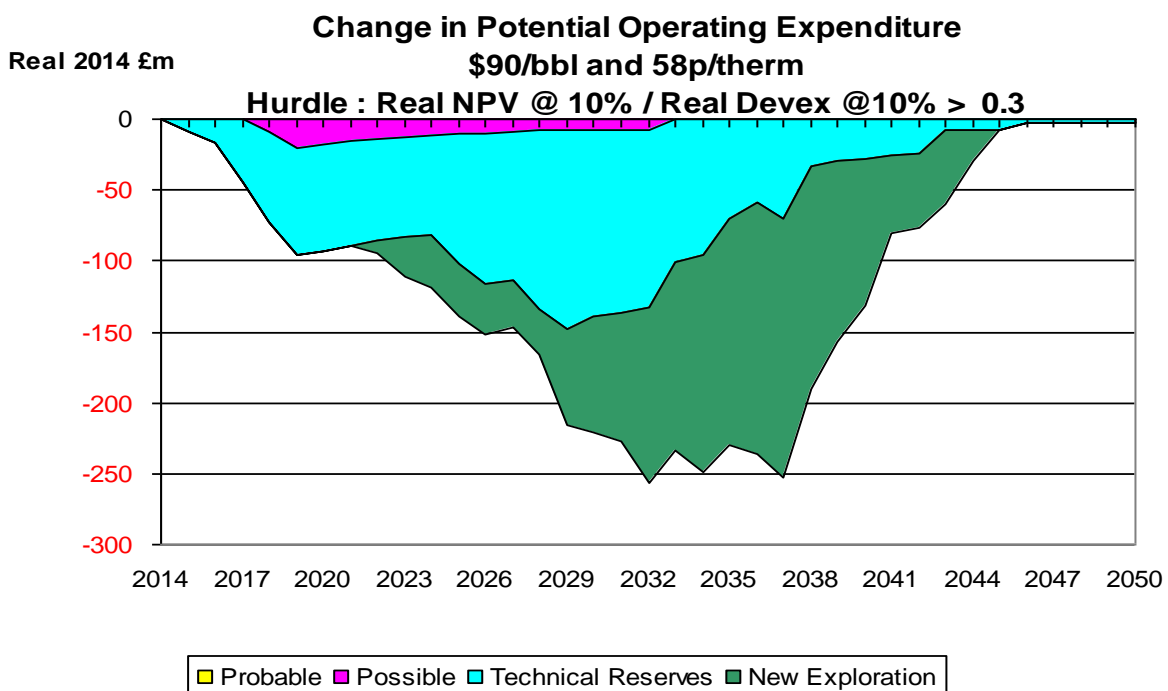
In Chart 8 the cumulative decrease in decommissioning expenditures is shown. It amounts to £443 million by 2050.

Chart 8

Change in Potential Cumulative Decommissioning Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Real 2014 £m

Legend: Probable ■ Possible ■ Technical Reserves ■ New Exploration

Chart 9

Change in Potential Tax Revenue
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.3

Real 2014 £m

Legend: Probable ■ Possible ■ Technical Reserves ■ New Exploration

14
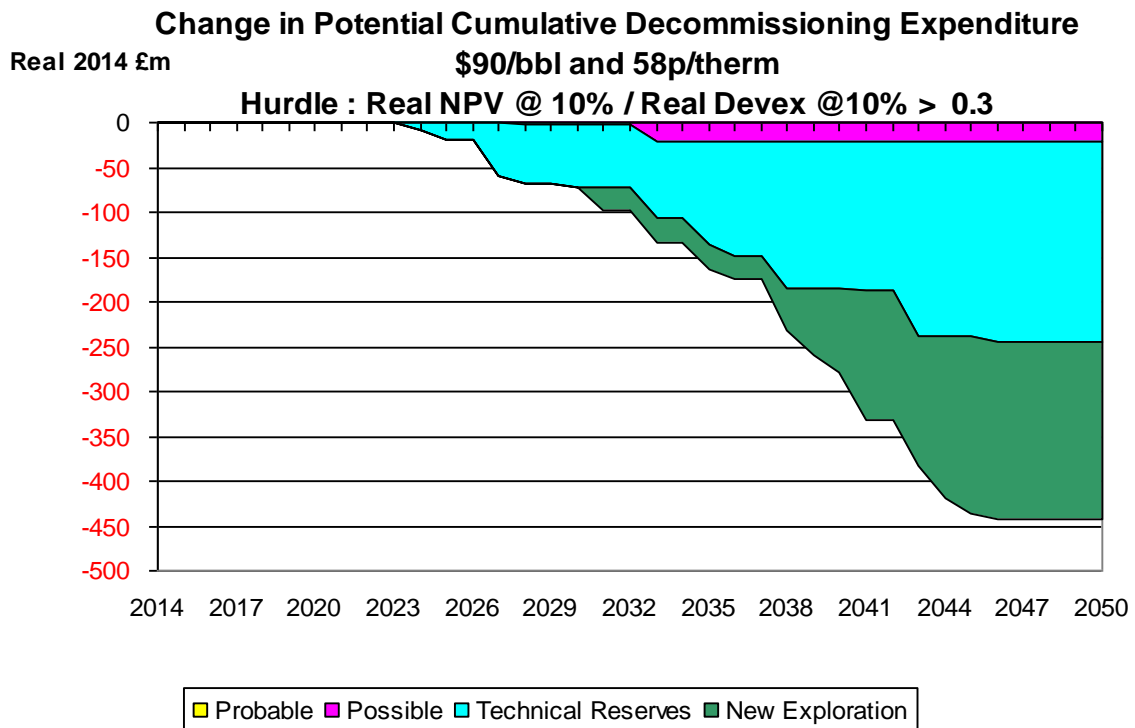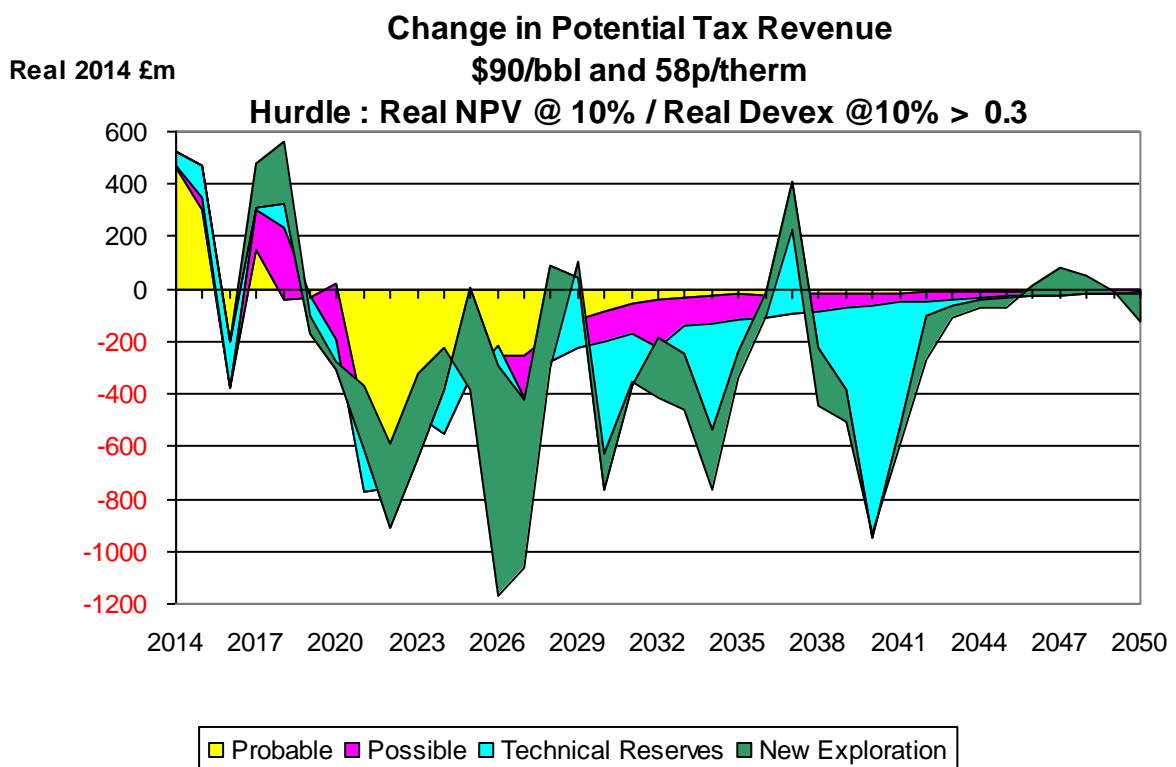
(c) Difference when Investment Hurdle is NPV/I > 0.5

When the investment hurdle is NPV/I > 0.5 new activity becomes significantly less than with NPV/I > 0.3. If investors are in a full tax-paying position cumulative production to 2050 becomes 11.7 bnboe with 6 bnboe coming from sanctioned fields, 0.7 bn from current incremental projects, 1.5 bn from future incremental projects, 0.5 bn from probable fields, 0.4 bn from possible fields, 1.5 bn from technical reserves, and 1.1 bn from new discoveries. Total development expenditure becomes £87.8 bn, total operating expenditures become £147 bn and total decommissioning costs £42 bn.

If investors are not in a tax-paying position there are 21 fewer new field developments. The resulting reduced production is shown in Chart 10.

Chart 10

Change in Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.5
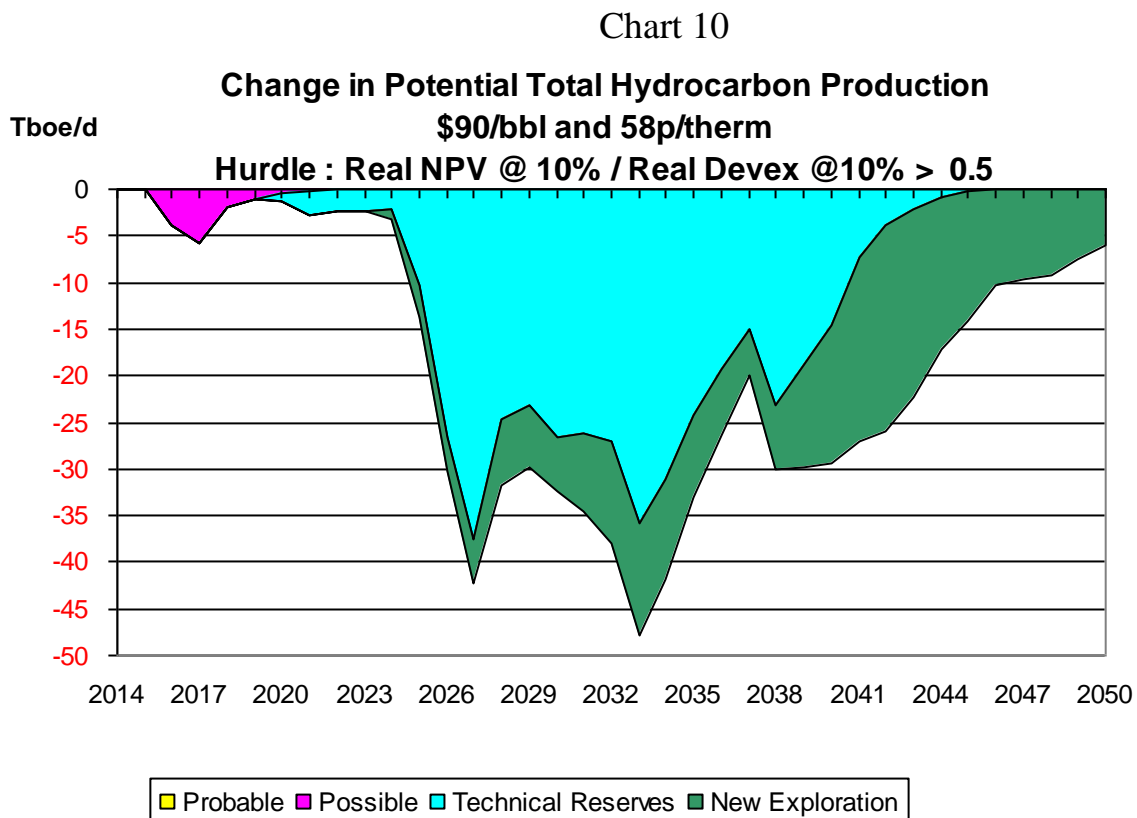
The total is 250 mmboe. The reduction in development costs is shown in Chart 11.

Chart 11

Change in Potential Development Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.5

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
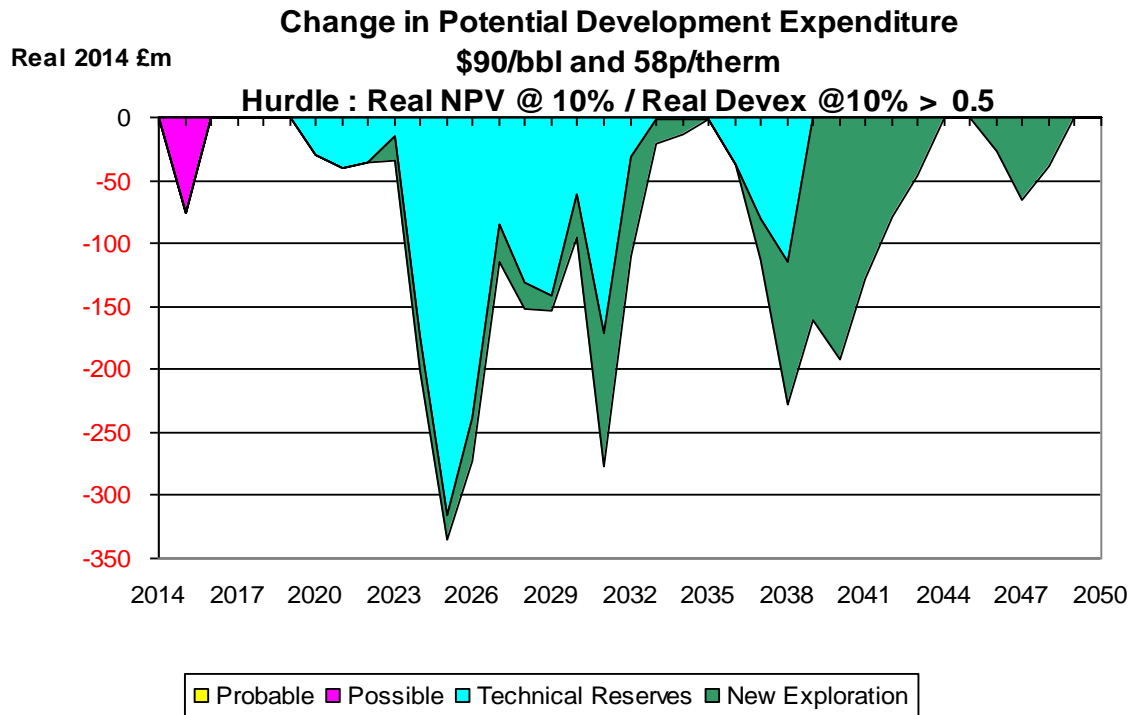
The total is £3.1 bn. The reduction in operating costs is shown in Chart 12. The total is £2.7 bn.

Chart 12

Change in Potential Operating Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.5

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
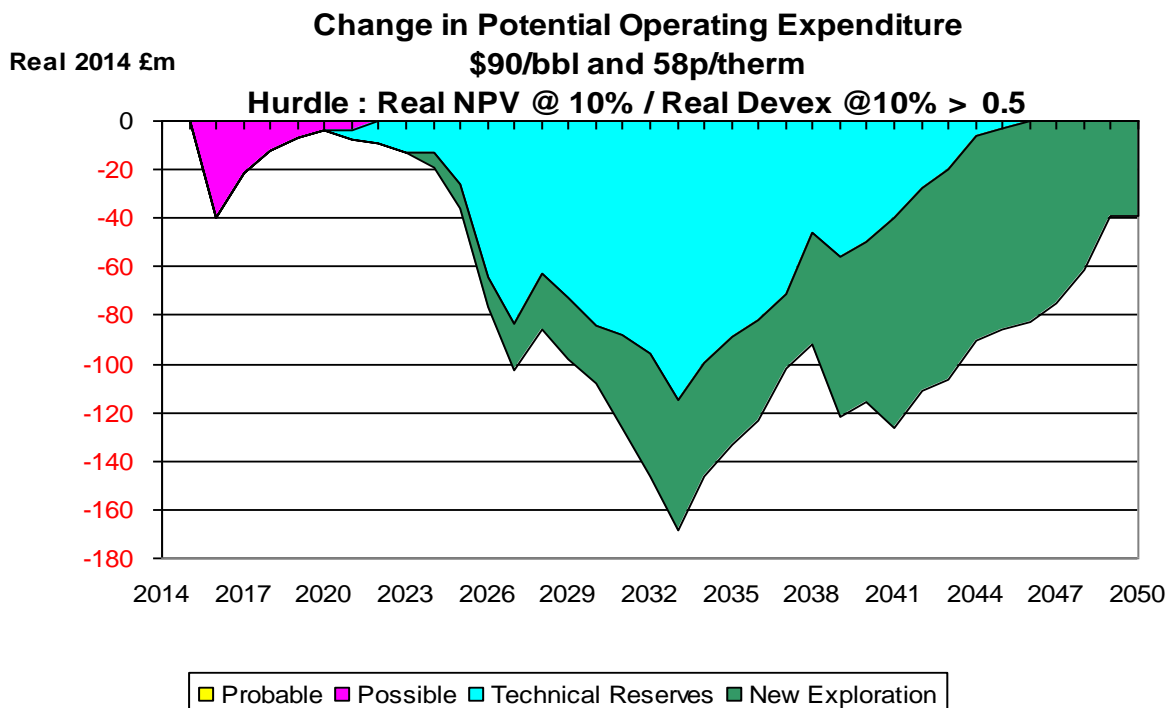
The cumulative reduction in decommissioning costs is shown in Chart 13. The total becomes £253 million.

Chart 13

Change in Potential Cumulative Decommissioning Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.5

Real 2014 £m

Legend: Probable, Possible, Technical Reserves, New Exploration
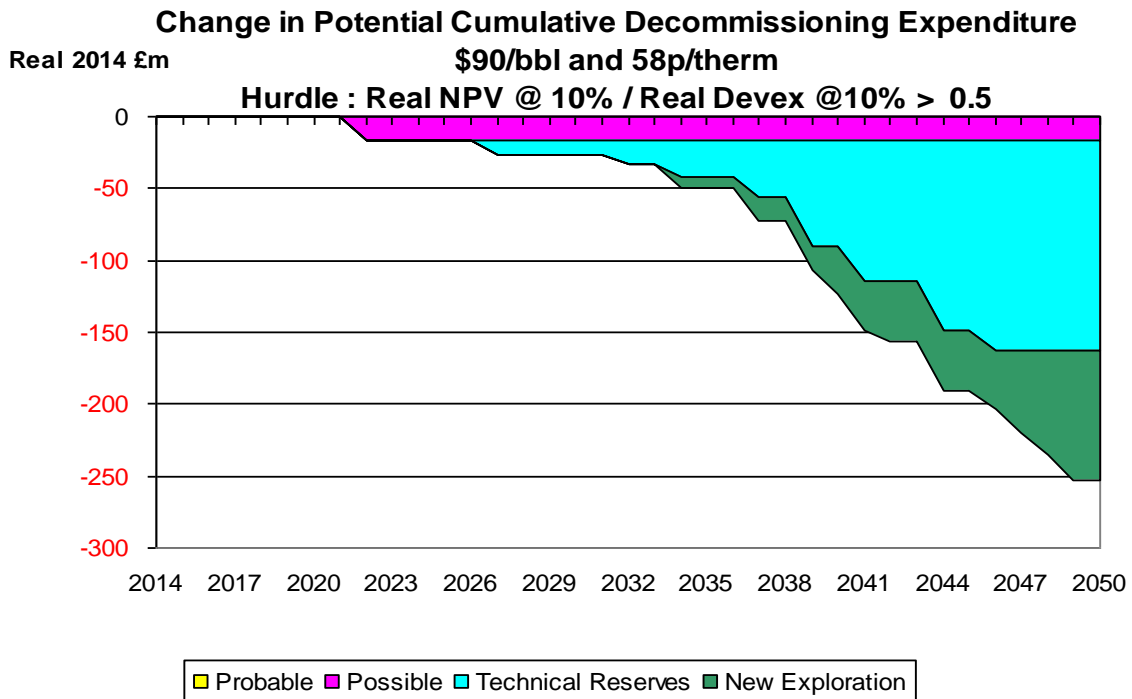
The reduction in tax revenues is shown in Chart 14. The total becomes £6.9 bn.

It is emphasised that the results may understate the difference in returns and activity. If long E and A periods are involves the benefits of the RFES will be less.

Chart 14

Change in Potential Tax Revenue
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @10% > 0.5

Real 2014 £m

Probable Possible Technical Reserves New Exploration
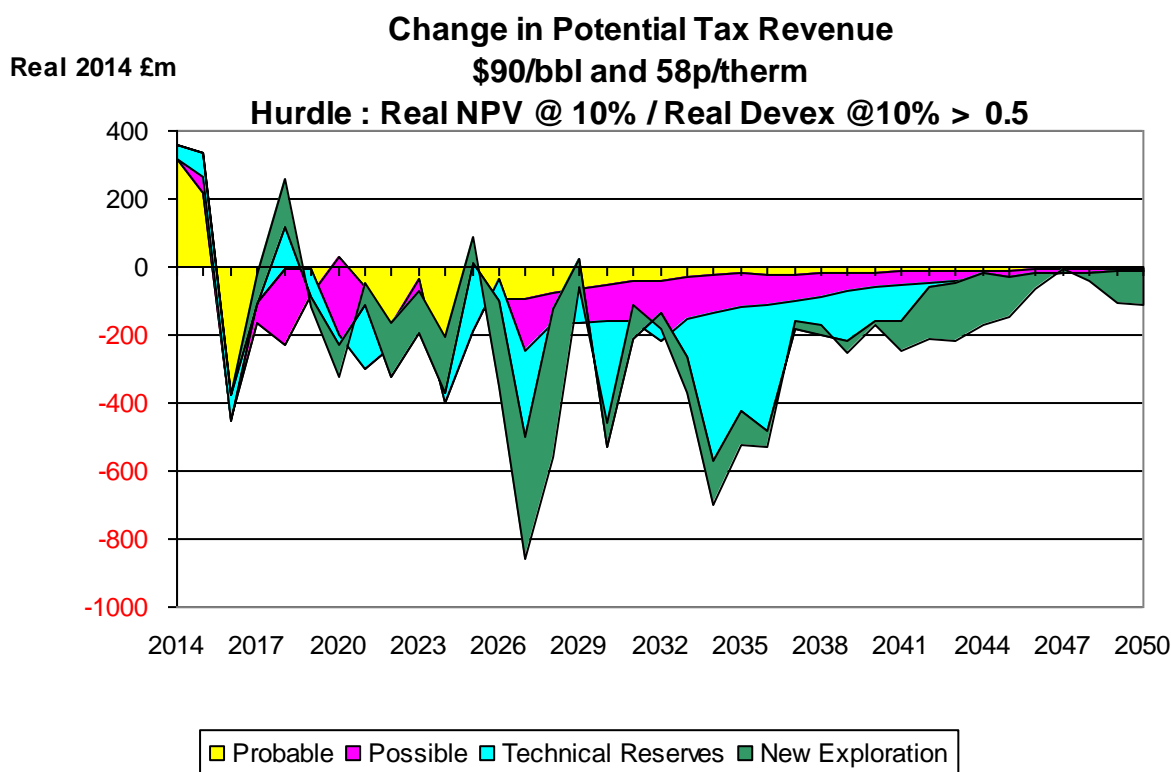
(d) **Effects of Replacing Field Allowances on Unsanctioned Fields**
with Current BFA, Hurdle NPV/I > 0.3, Investor in Full Tax-
paying Position

The effects on activity of the replacement of the current field
allowances by the current BFA on unsanctioned fields was examined.
The results for an investor in a full tax-paying position was a
reduction of 30 in the number of new fields being triggered over the
period. Total net hydrocarbon production falls by a relatively small
amount (84 mmboe). The result is shown in Chart 15. In some years
there is an increase. This occurs in circumstances where the small
field allowance is worth less than the cost-based BFA.

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Chart 15

**Change in Potential Total Hydrocarbon Production
with Brown Field type allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Tboe/d

Probable ▪ Possible ▪ Technical Reserves ▪ New Exploration
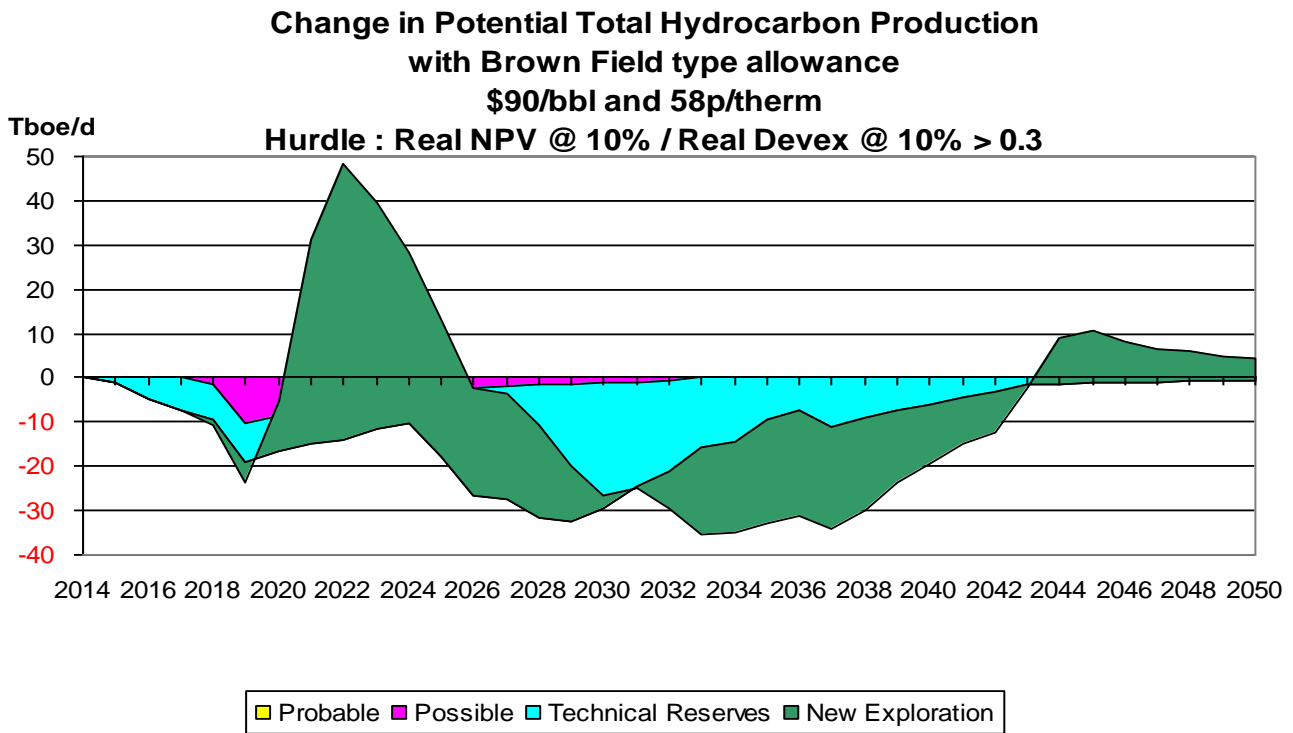
In Chart 16 the change in development costs is shown. There is a net decrease of £998 million.

Chart 16

**Change in Potential Development Expenditure
with Brown Field type allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable ▪ Possible ▪ Technical Reserves ▪ New Exploration
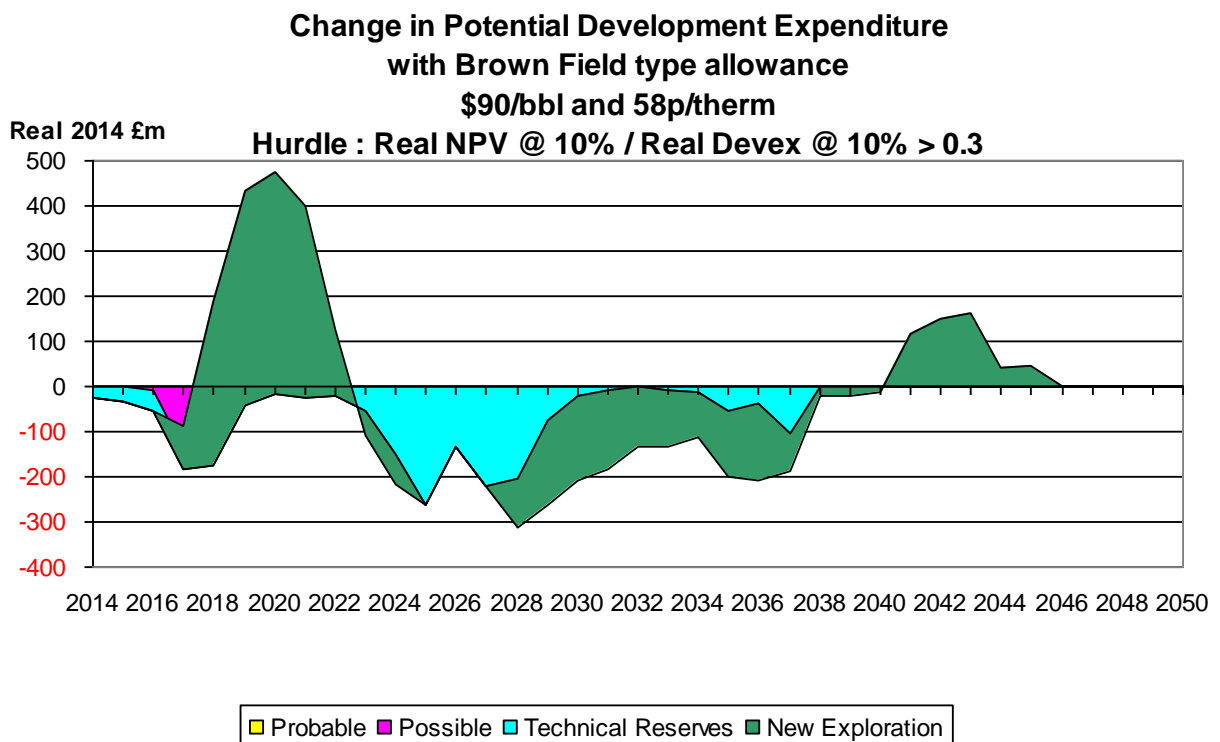
In Chart 17 the change in operating costs are shown. There is a net reduction of £1.2 bn.

Chart 17

**Change in Potential Operating Expenditure
with Brown Field type allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable ▪ Possible ▪ Technical Reserves ▪ New Exploration
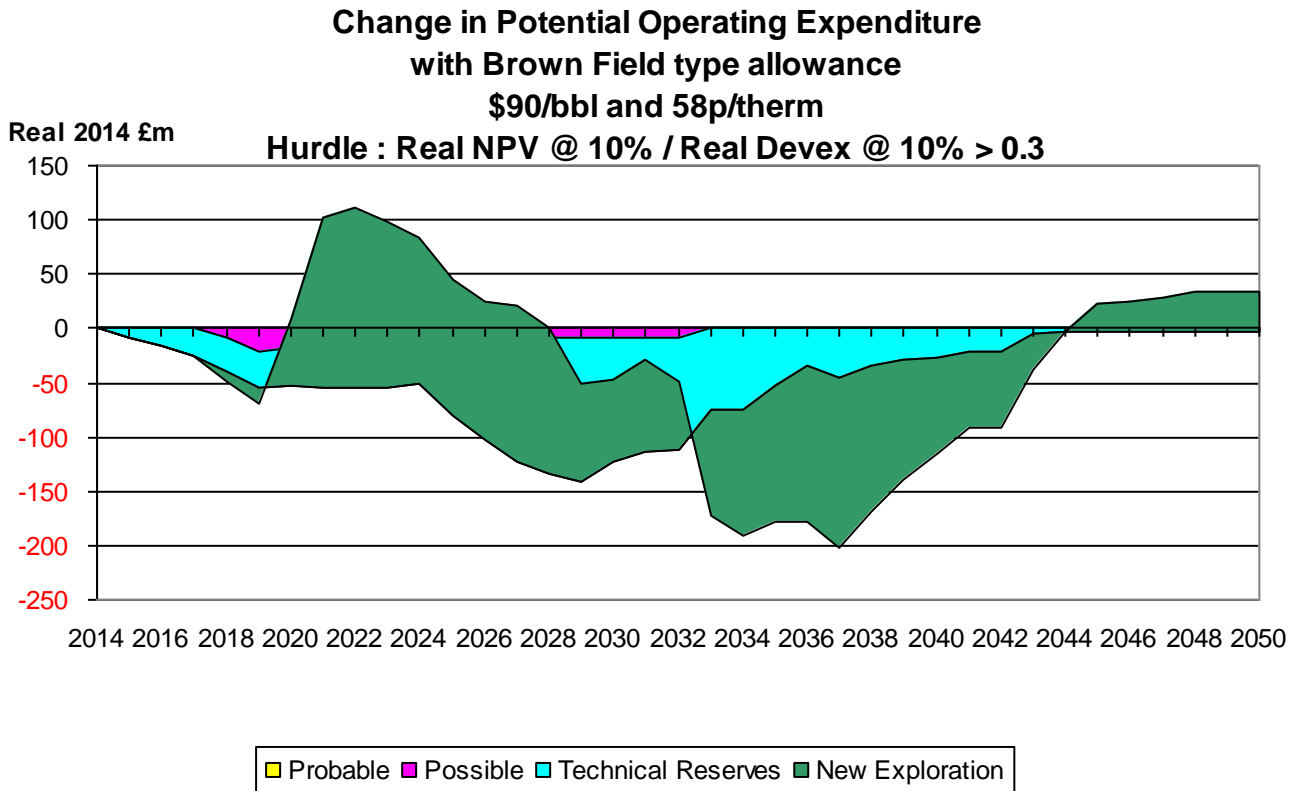
The change in tax revenues is shown in Chart 18. There is a net increase of £5.2 bn. But activity levels are lower and maximum economic recovery is not being achieved. There is a decrease in the value of the allowances of £4.6 bn which is not countered by the increase of £2.97 bn.

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Chart 18

**Change in Potential Tax Revenue
with Brown Field type allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
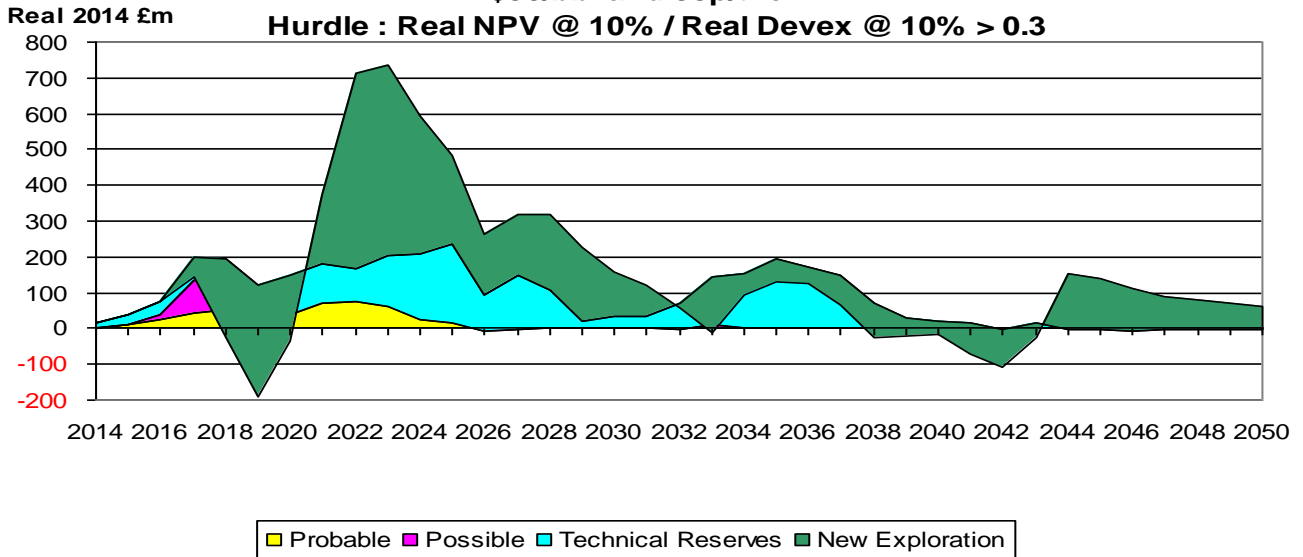
(e) Effects of Replacing Fields Allowances with Current BFA, Hurdle NPV/I > 0.5, Investor in Full Tax-paying Position

When the hurdle becomes NPV/I > 0.5 it was found that 54 fewer fields were developed over the period. Total hydrocarbon production falls by 492 mmboe (See Chart 19).

Chart 19

**Change in Potential Total Hydrocarbon Production
with Brown Field type allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration

21
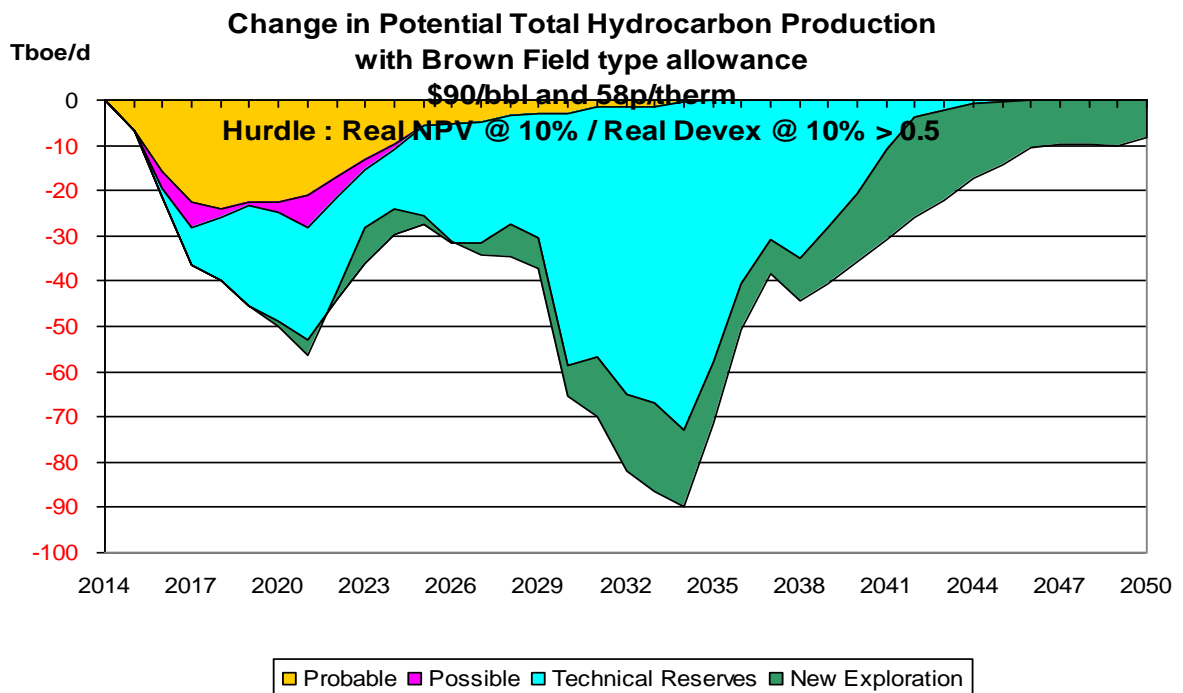
Development expenditure falls by £5.6 bn (See Chart 20).

Chart 20

**Change in Potential Development Expenditure
with Brown Field type allowance
$90/bbl and 58p/therm**

Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

□ Probable ■ Possible □ Technical Reserves ■ New Exploration
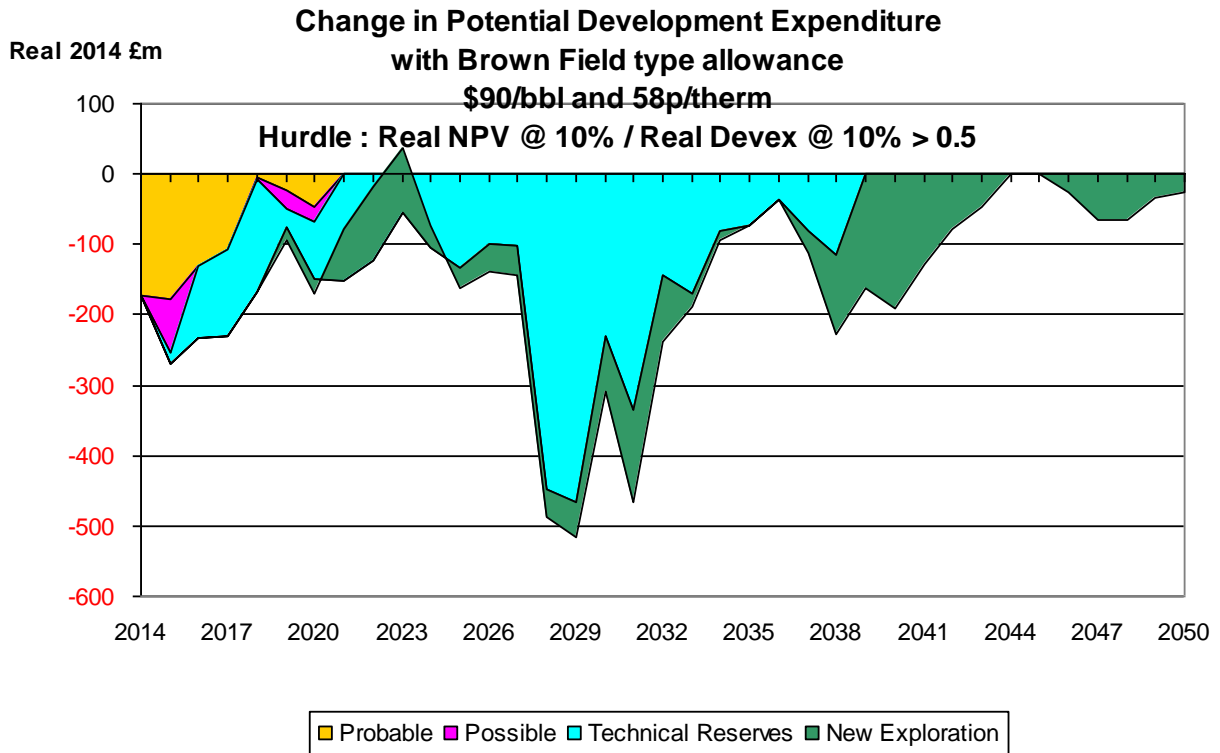
Operating expenditures fall by £5.6 bn (See Chart 21).

Chart 21

**Change in Potential Operating Expenditure
with Brown Field type allowance
$90/bbl and 58p/therm**

Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

□ Probable ■ Possible □ Technical Reserves ■ New Exploration

22
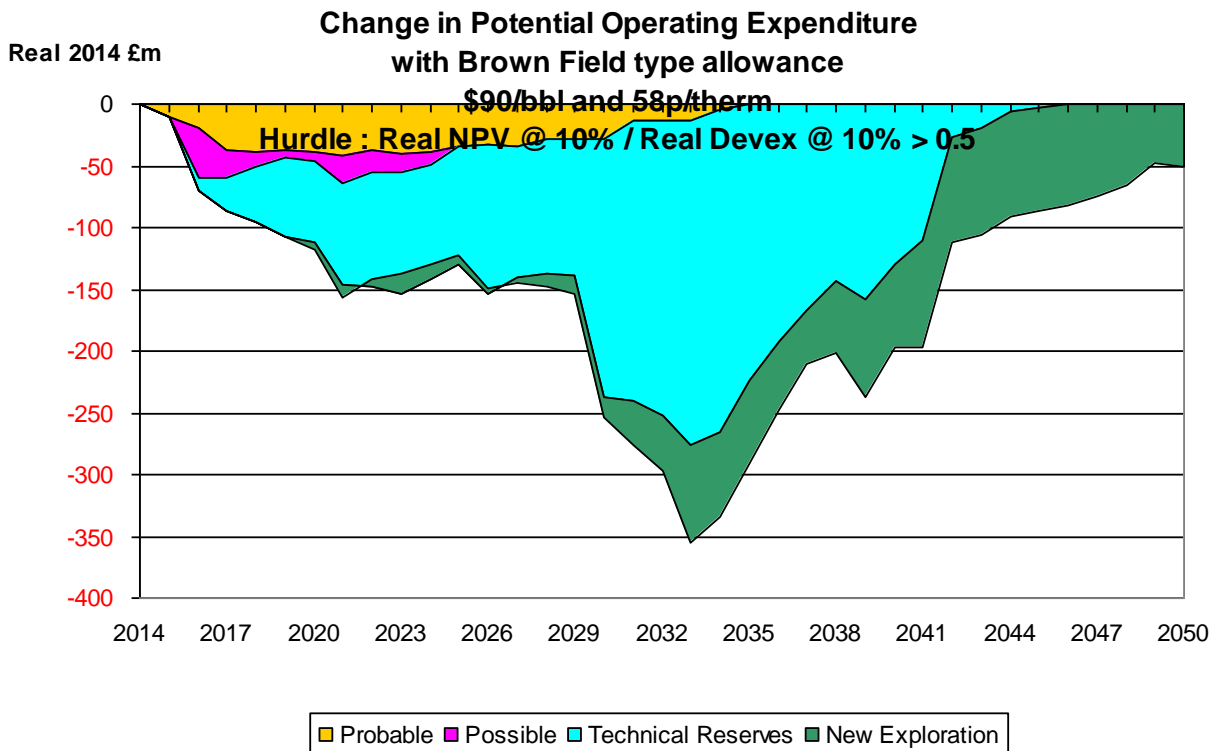
Tax revenues fall by £1.5bn (See Chart 22). While there is an increase in allowances of £1.3 bn there is also a decrease of £2.5 bn.

Chart 22

**Change in Potential Tax Revenue
Brown Field type allowance
$90/bbl and 58p/therm**

Real 2014 £m

Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
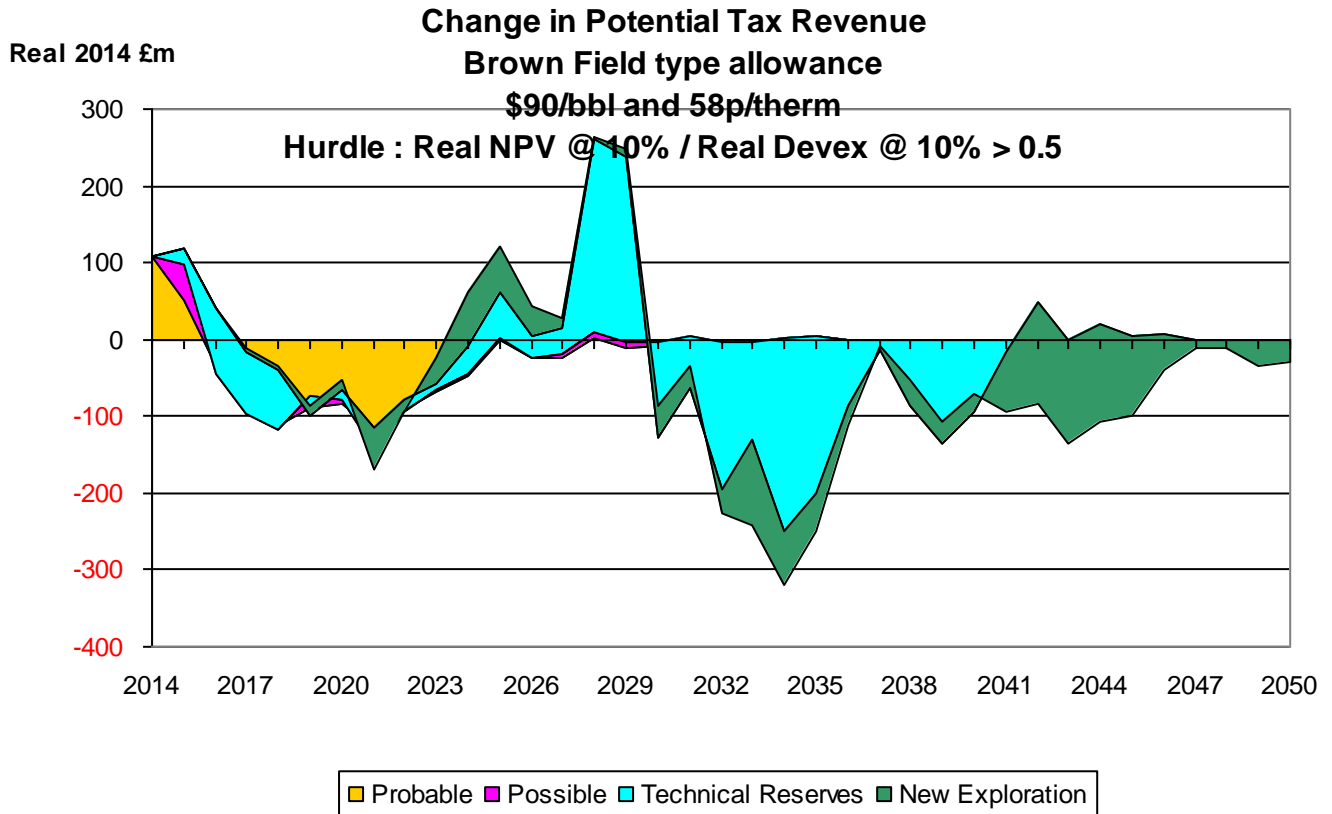
(f) Effects of Increasing BFA to £75 per tonne and Removing Caps to Replace Existing Field Allowances for SC, Hurdle NPV/I > 0.3, Full Tax-paying Investor

The effects of increasing the BFA to a maximum of £75 per tonne, removing the caps, and replacing the existing field allowances with the enhanced BFA are now examined. There is still a reduction (10) in the numbers of new field developments triggered over the period. But this is the net effect of some increases as well as decreases. The increases emanate principally from the removal of the cap. There are also differences in the impact on oil developments compared to gas. Oil production increases by 767 mmboe (See Chart 23).

Chart 23

**Change in Potential Oil Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

tb/d

□ Probable ■ Possible □ Technical Reserves ■ New Exploration
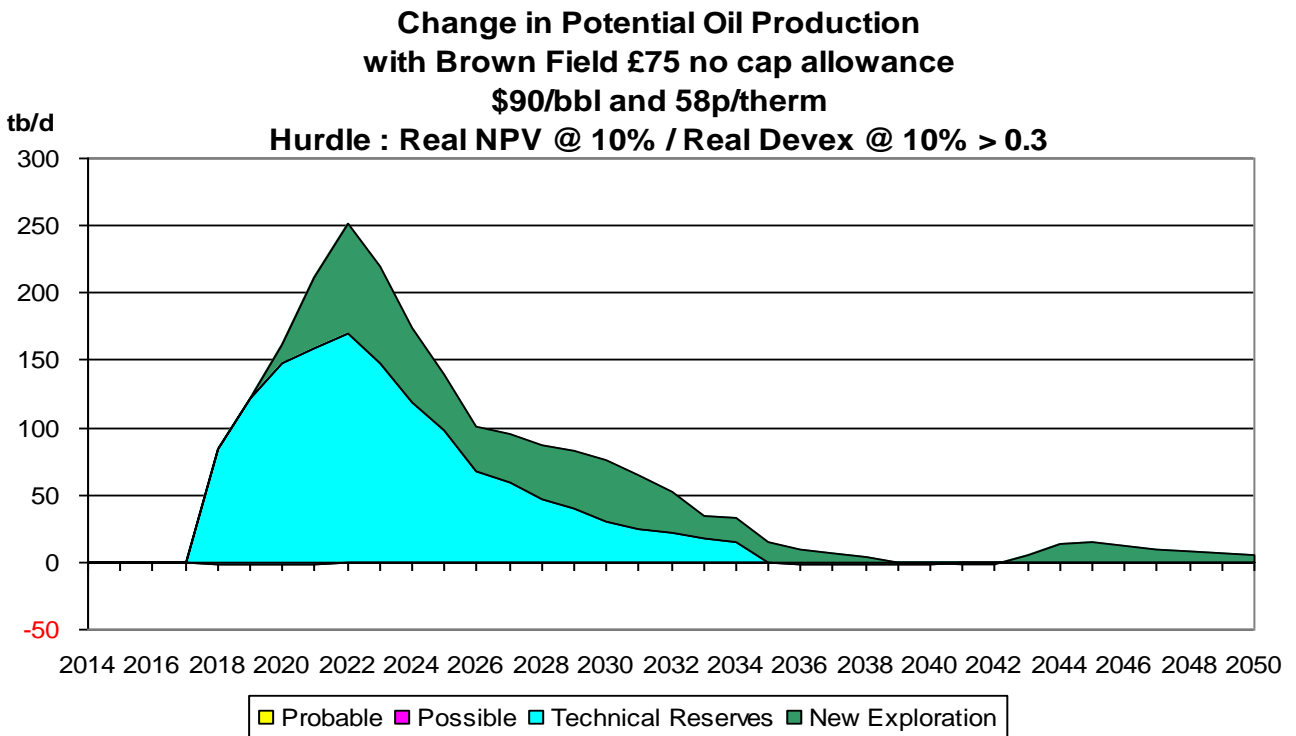
Gas production shows a net increase of 37 mmboe (See Chart 24).

But it is seen that this includes cases of reductions due to the value of

the BFA being less than the value of the current field allowances.

This happens in gas fields in the SNS.

Chart 24

**Change in Potential Gas Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

mmcf/d

□ Probable ■ Possible □ Technical Reserves ■ New Exploration
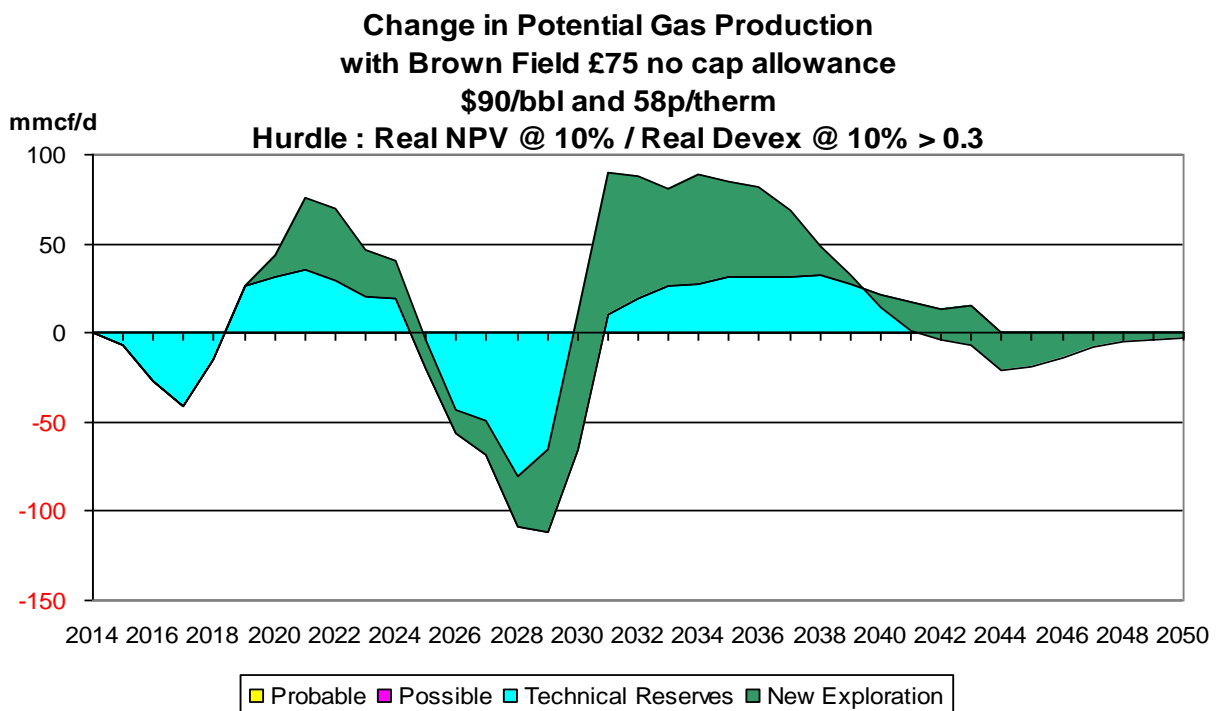
The net effect on total hydrocarbon production is an increase of 804 mmboe (See Chart 25).

Chart 25

**Change in Potential Total Hydrocarbon Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**
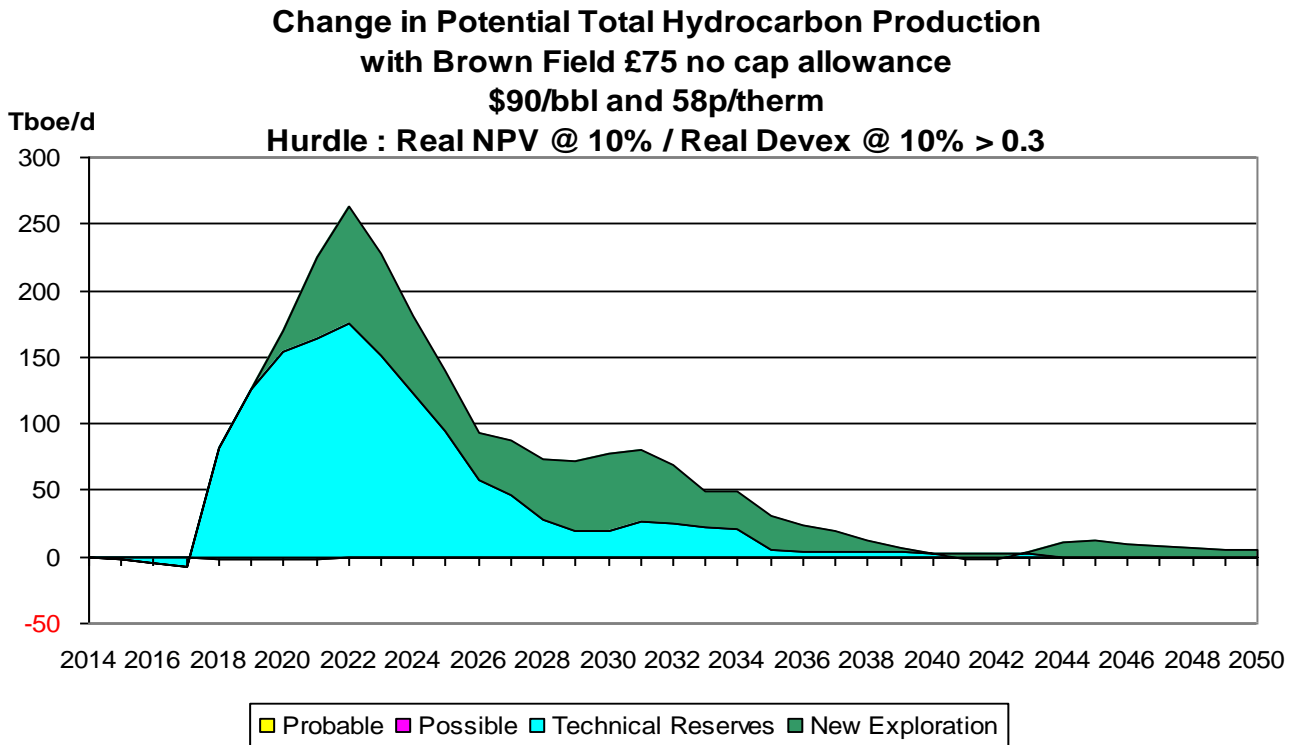
Development expenditures increase by £13 bn in this scenario (See Chart 26). It is noteworthy that the increase is greatest over the next few years when investment is in danger of falling off sharply.

Chart 26

**Change in Potential Development Expenditure
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

25
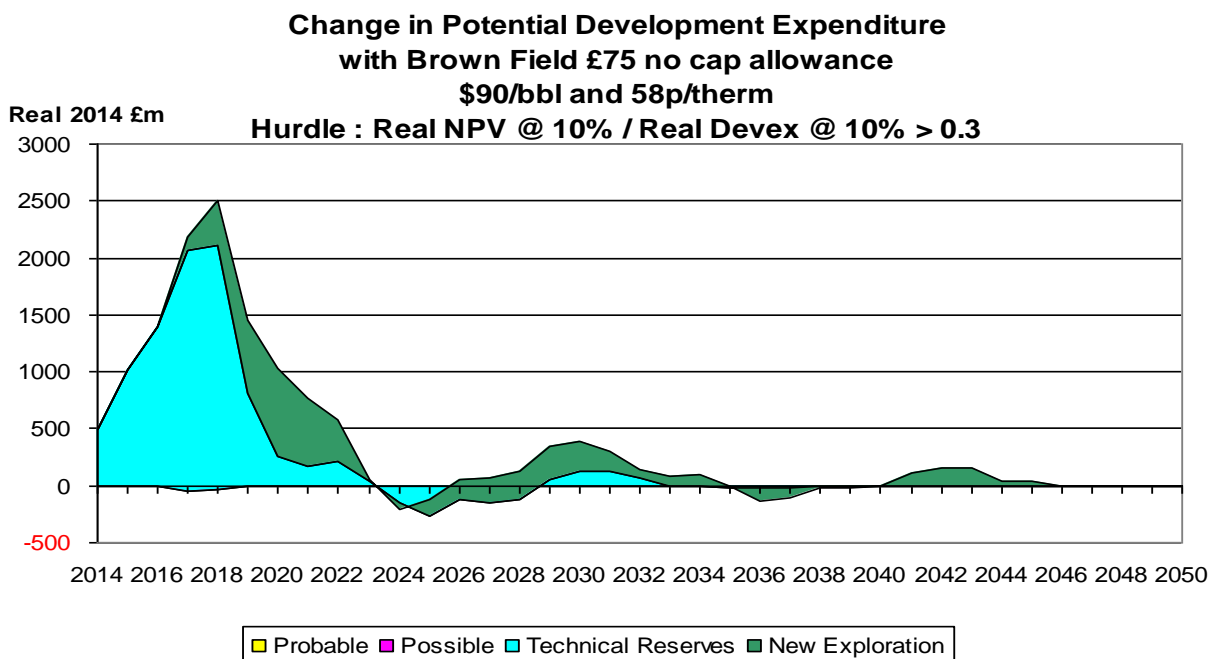
Operating costs increase by £10.2 bn in this scenario (See Chart 27).

Chart 27

**Change in Potential Operating Expenditure
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
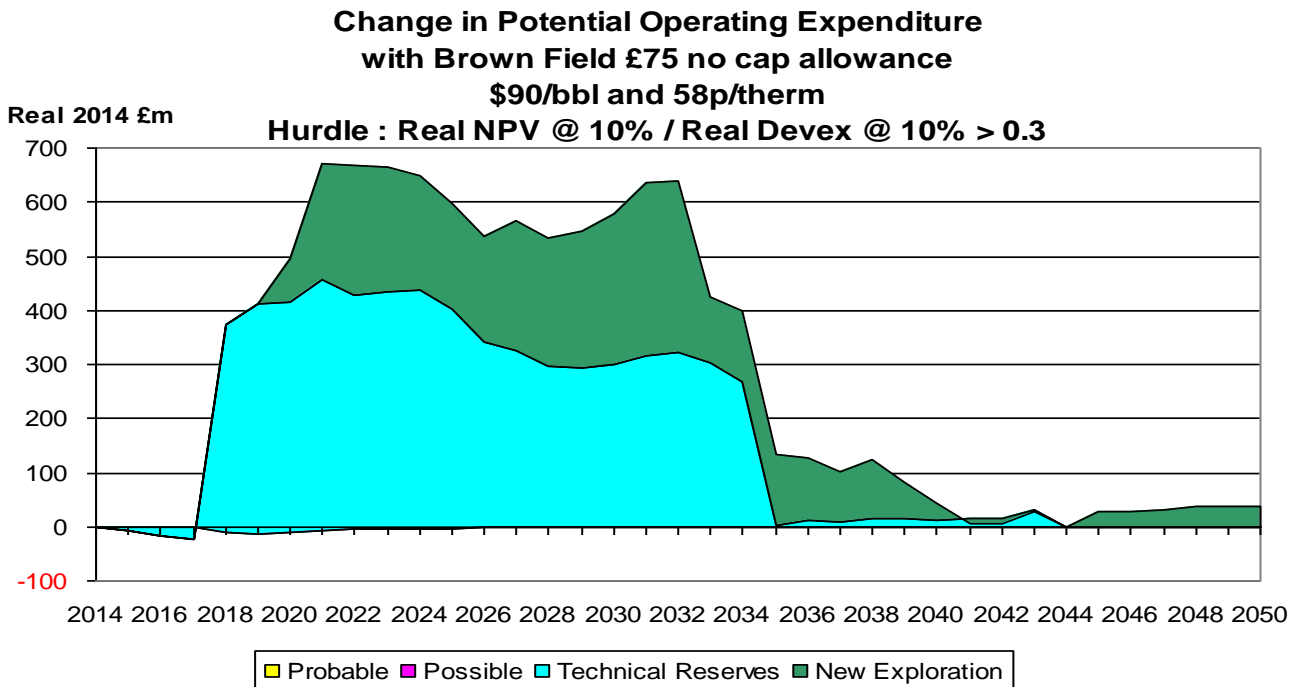
Tax revenues exhibit a net increase of £10.9 bn over the period (See Chart 28). It should be noted that, while the increase in allowances is nearly £10.8 bn, there is also a decrease of £3.3 bn. Thus some fields do not gain from the change.

Chart 28

**Change in Potential Tax Revenue
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration

26
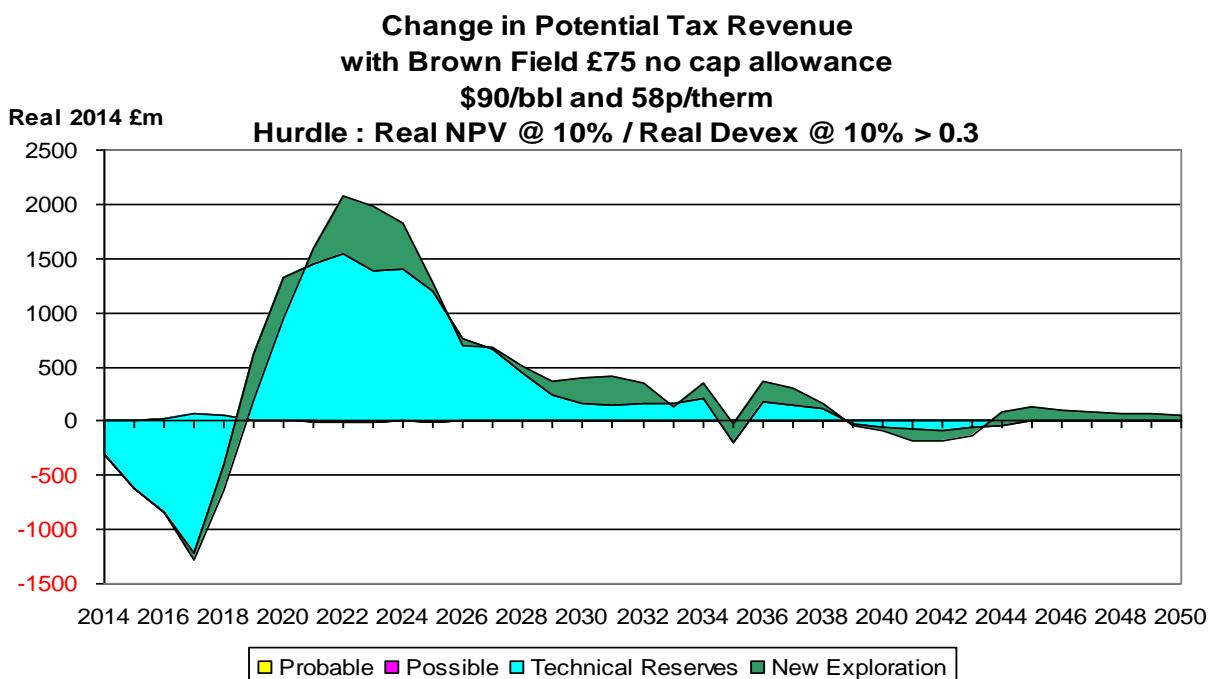
(g) Effects of Increasing BFA to £75 per tonne and Removing Caps to Replace Existing Field Allowances for SC, Hurdle Rate NPV/I > 0.5, Full Tax-paying Investor

If the investment hurdle were NPV/I > 0.5 it was found that 39 fewer fields would be developed over the period to 2050. Oil production could increase by 406 mmboe (See Chart 29).

Chart 29

**Change in Potential Oil Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**
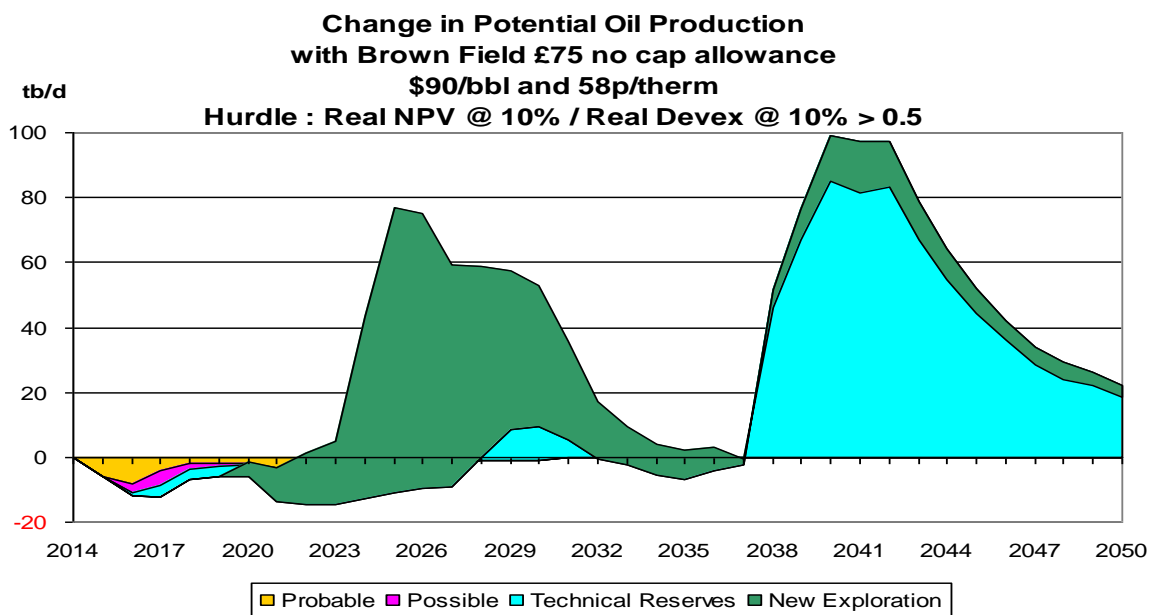
But gas production could fall by 213 mmboe (See Chart 30). The value of the BFA is sometimes less than the current field allowance.

Chart 30

**Change in Potential Gas Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

27
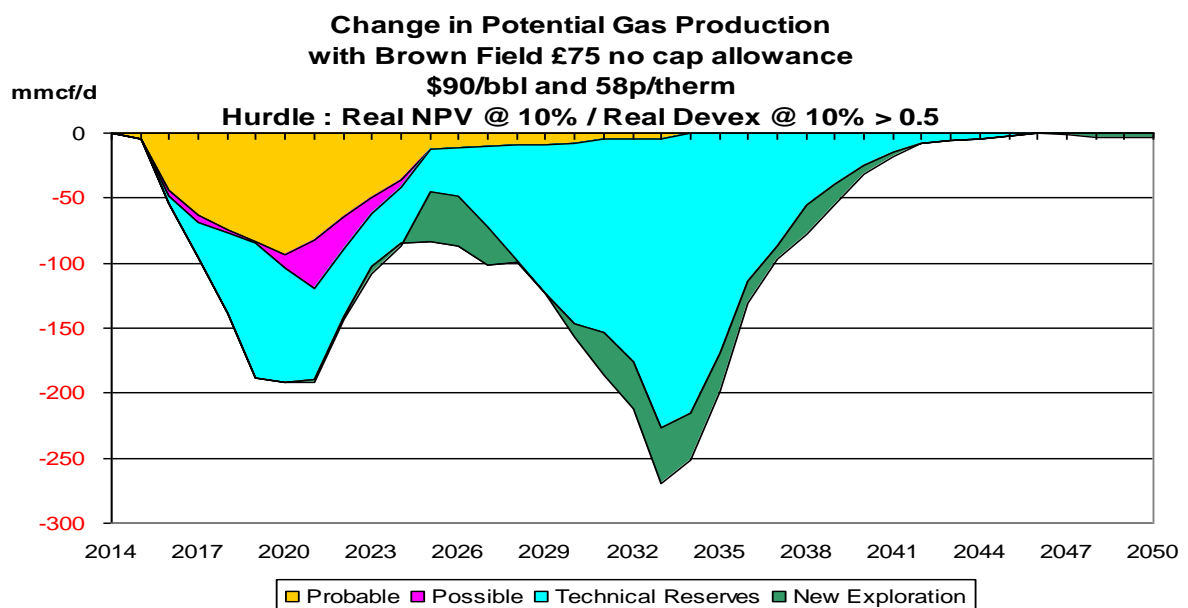
Total hydrocarbon production (including NGLs) increases by 198 mmboe (See Chart 31).

Chart 31

**Change in Potential Total Hydrocarbon Production
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Tboe/d

Probable | Possible | Technical Reserves | New Exploration
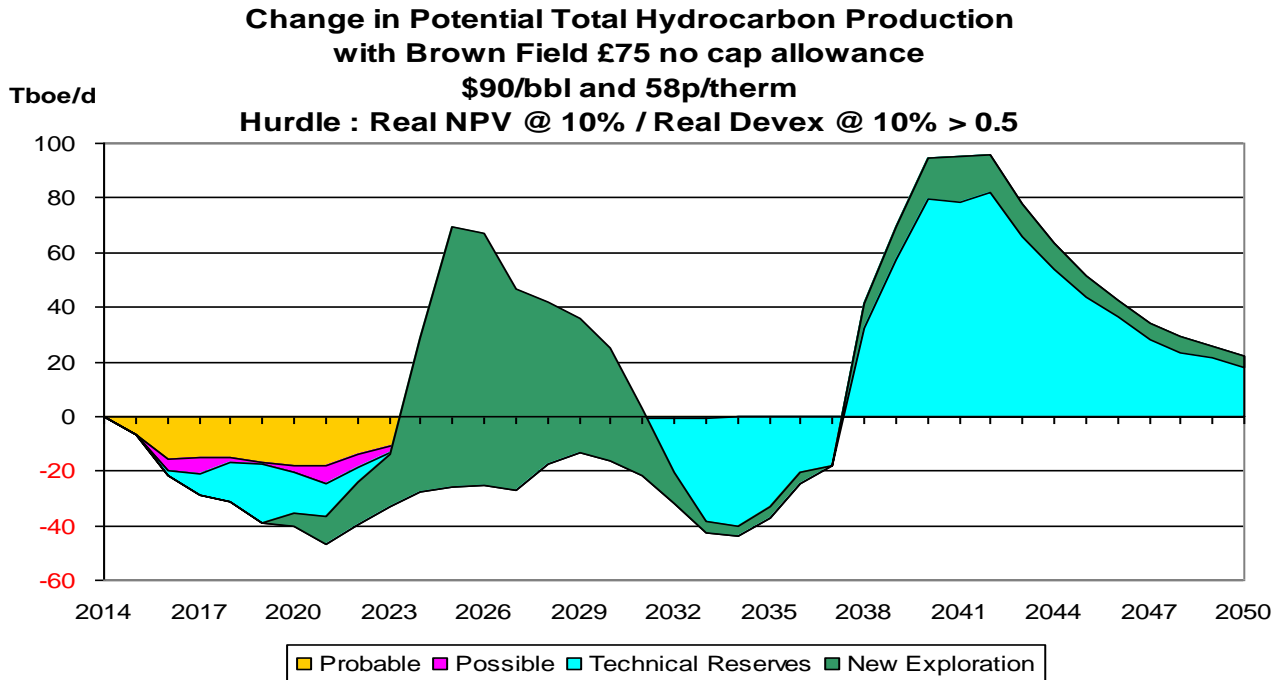
Field development expenditures increase by £3.6 bn (See Chart 32). The fields which are incentivised are more important than those which are disincentivised.

Chart 32

**Change in Potential Development Expenditure
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Real 2014 £m

Probable | Possible | Technical Reserves | New Exploration
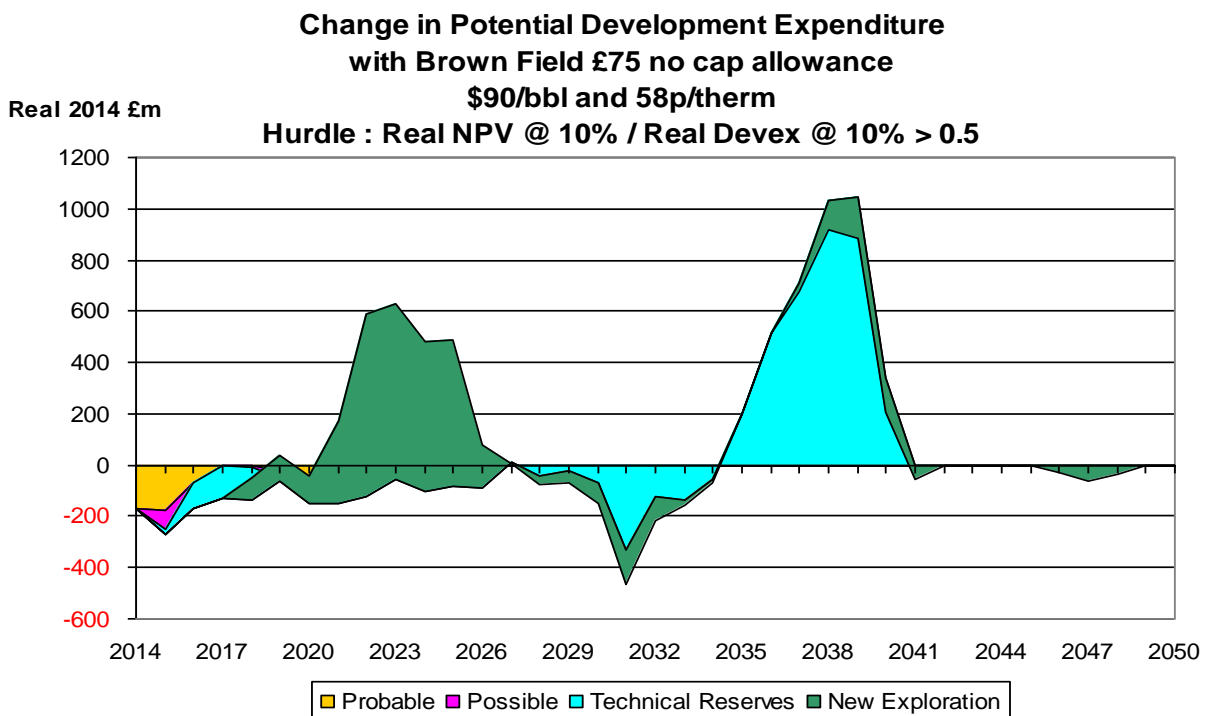
Operating expenditures increase by a net amount of £2.25 billion (See Chart 33). It is noticeable, however, that there is a decrease for much of the period.

Chart 33

**Change in Potential Operating Expenditure
with Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Real 2014 £m

Legend: Probable, Possible, Technical Reserves, New Exploration
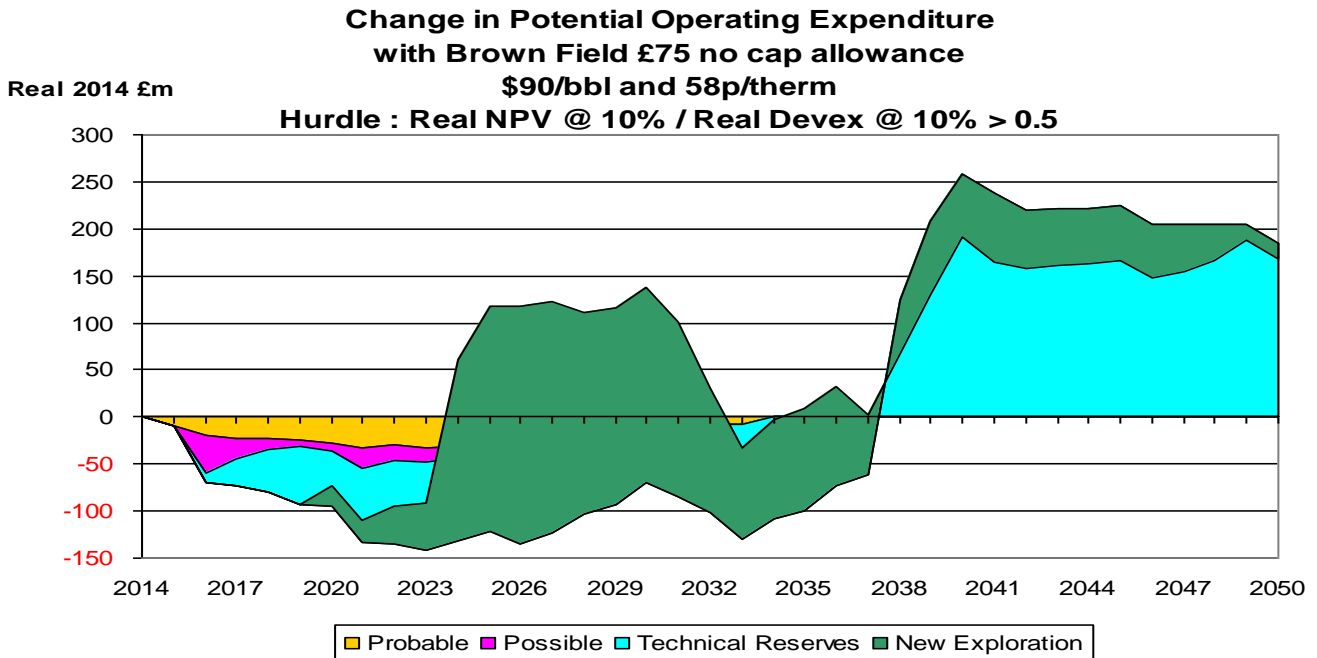
There is a net increase in tax revenues of £7.5 billion (See Chart 34). There are many losses as well as gains from the tax change. The increase in allowances exceeds £6 billion but there is also a decrease of nearly £2 billion.

Chart 34

**Change in Potential Tax Revenue
Brown Field £75 no cap allowance
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Real 2014 £m

Legend: Probable, Possible, Technical Reserves, New Exploration

29
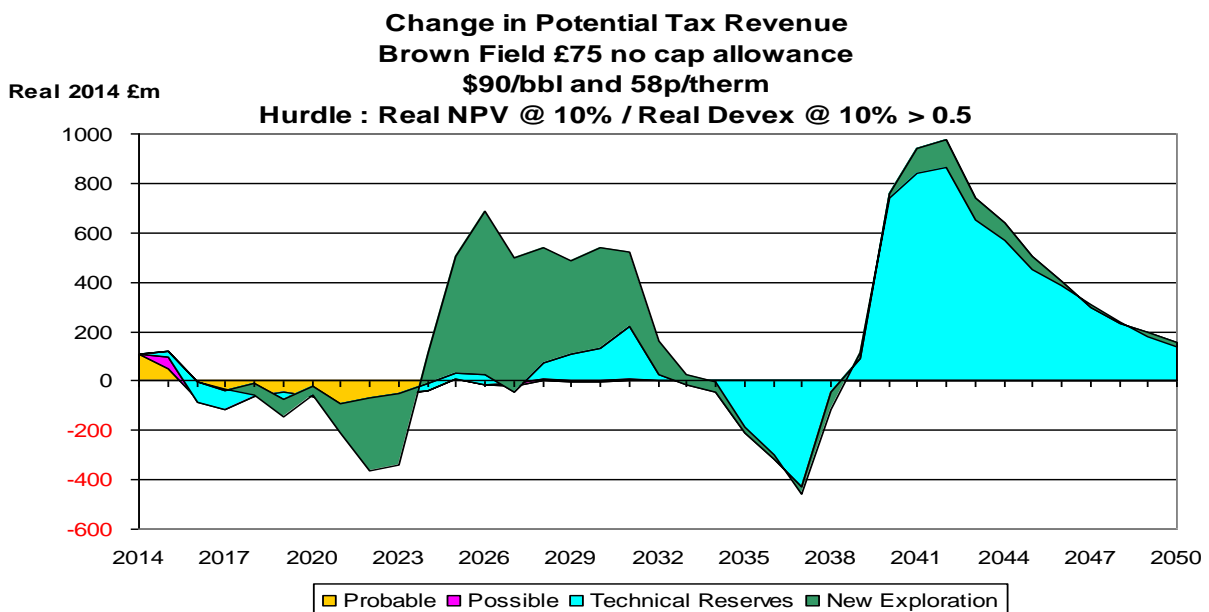
(h) Replacement of Field Allowances on Unsanctioned Fields by Investment Uplift of 62.5%, Hurdle Rate NPV/I > 0.3, Full Tax-paying Investor

The effects of replacing the current plethora of field allowances with an investment uplift of 62.5% on unsanctioned fields were examined. In the case with the hurdle of NPV/I > 0.3 it was found that 26 extra field developments were triggered. The resulting increase in oil production was 1.4 bnboe (See Chart 35).

Chart 35

Change in Potential Oil Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
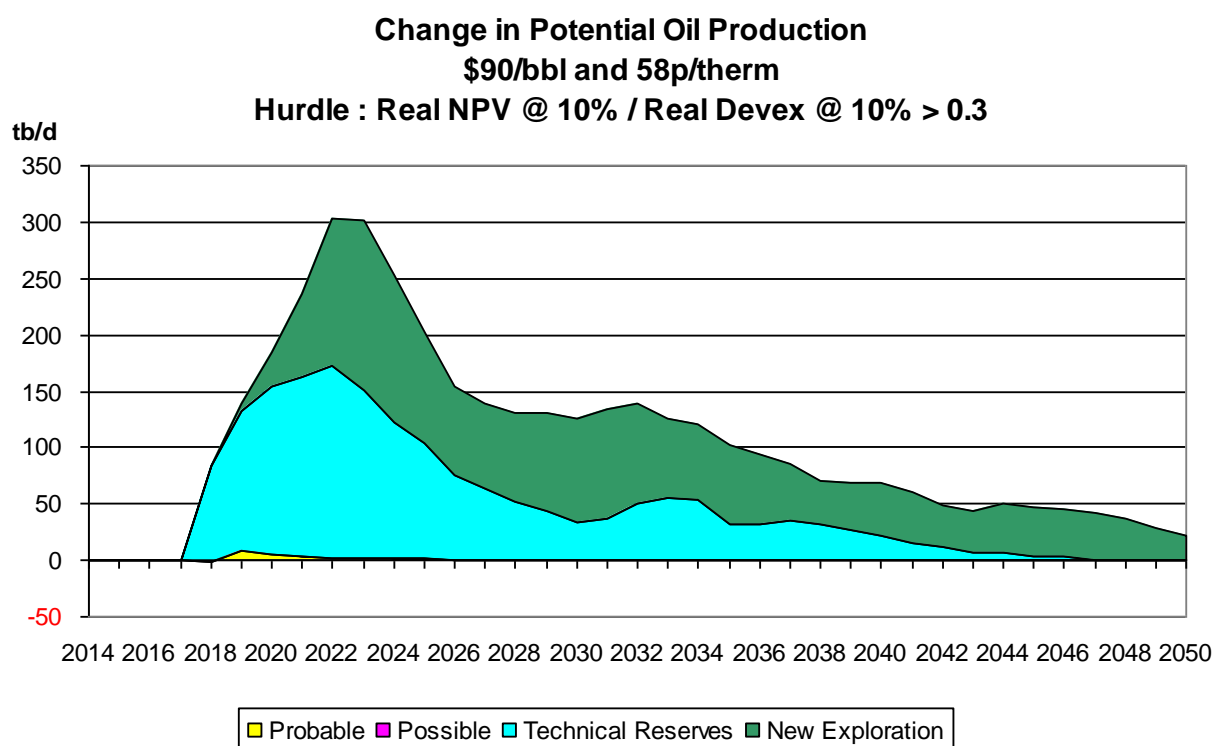
The increase in gas production was only 172 mmboe (See Chart 36). For some gas fields the uplift was worth less than the existing field allowances.

Chart 36

Change in Potential Gas Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
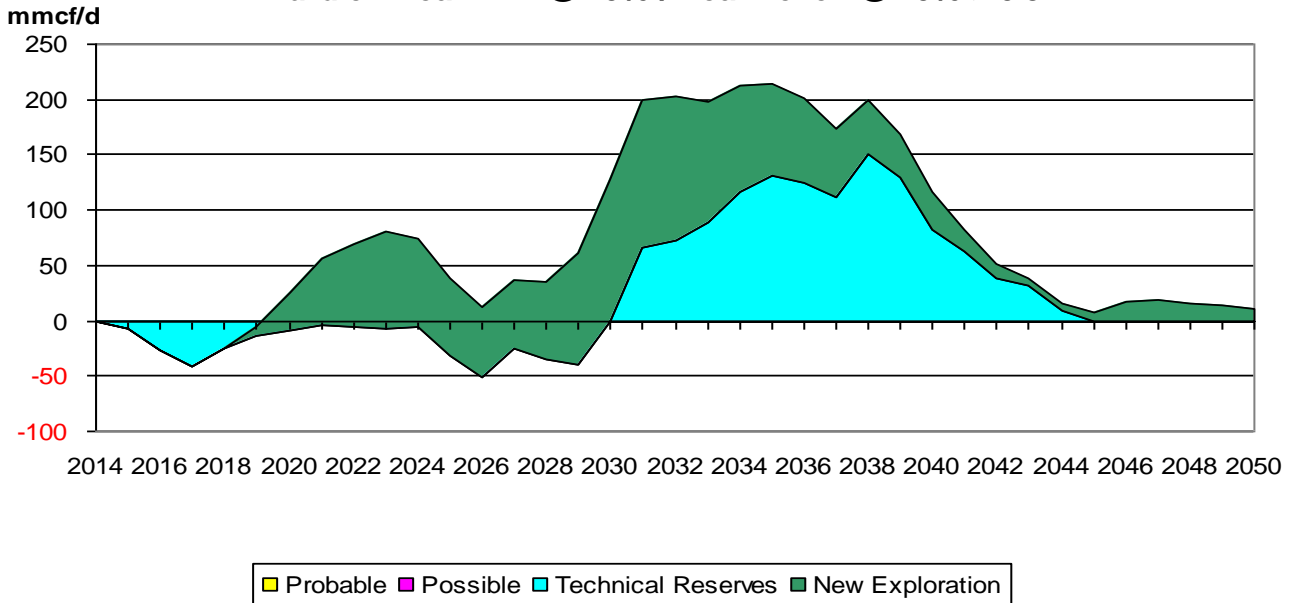
The increase in total hydrocarbon production is 1.57 bnboe (See Chart 37).

Chart 37

Change in Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
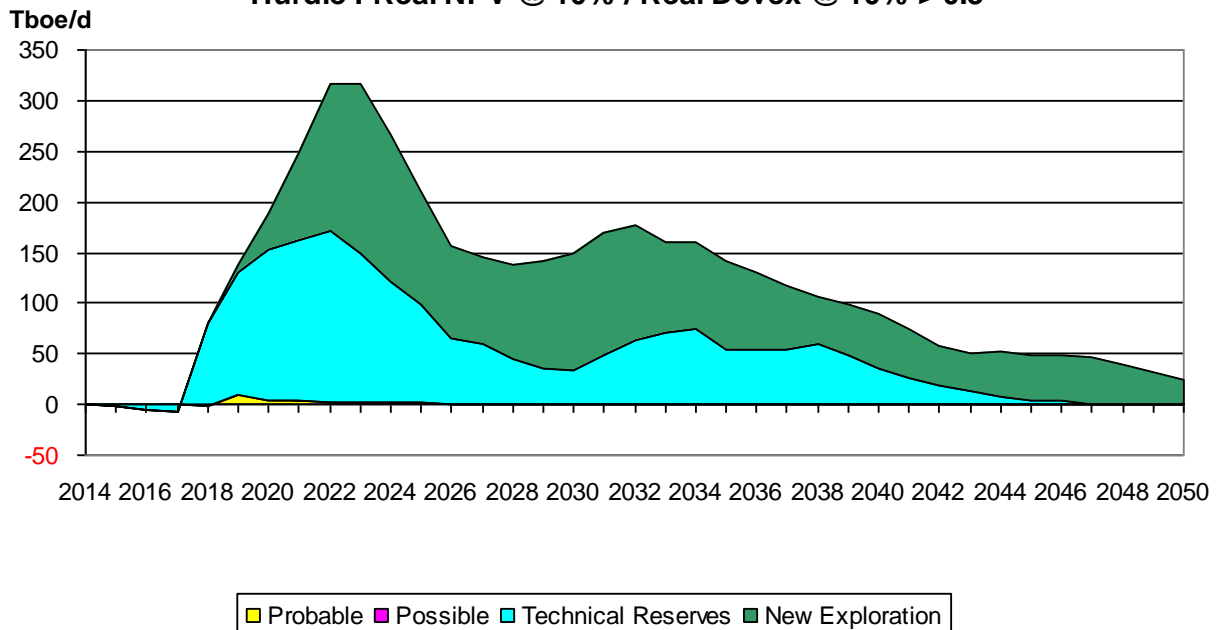
The increase in field development expenditures is a massive £26.8 bn (See Chart 38). It is noteworthy that there is a major increase in the near term future when investment is otherwise expected to fall sharply.

Chart 38

Change in Potential Development Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Legend: □ Probable ■ Possible ■ Technical Reserves ■ New Exploration
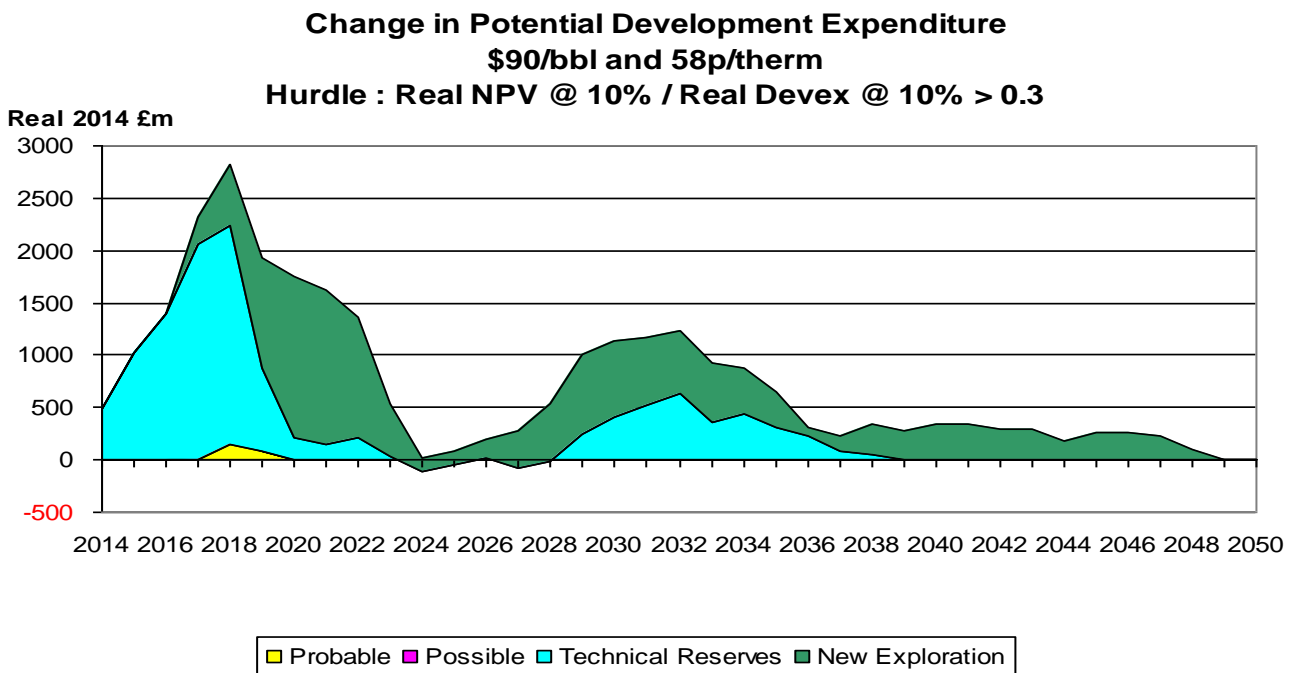
Operating expenditures increase by £21.4 billion (See Chart 39). The increase in decommissioning costs is nearly £2.5 bn over the period.

Chart 39

Change in Potential Operating Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Legend: □ Probable ■ Possible ■ Technical Reserves ■ New Exploration

32

The increase in tax revenues is £12.3 bn over the period (See Chart 40). There is a reduction over the next few years followed by major increases. While there are clearly very large net benefits it should be noted that some gas fields obtain lower allowances with the uplift scheme.

Chart 40

Change in Potential Tax Revenue
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Real 2014 £m

Legend: Probable | Possible | Technical Reserves | New Exploration
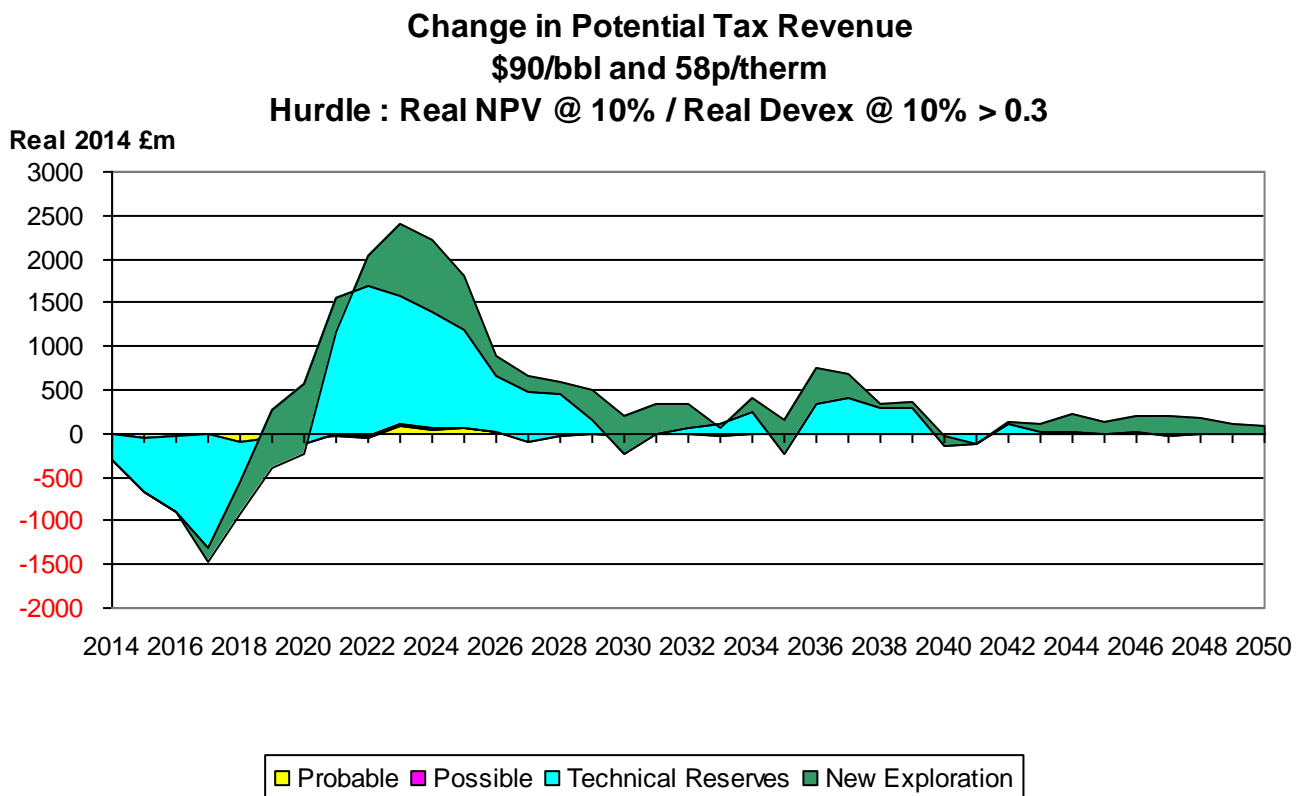
(i) Replacement of Field Allowances by Investment Uplift of 62.5%, Hurdle NPV/I > 0.5, Full Tax-paying Investor

In the case where the investment hurdle is NPV/I > 0.5 it was found that there was a net increase of 3 fields triggered by the change. But this conceals a large change in the composition of the fields with 21 being triggered and 18 being disincentivised. The increase in total hydrocarbon production is 1.1 bnboe (See Chart 41). Of this 287 mmboe comes from gas fields. This is the net effect of increases and decreases.

33

Chart 41

Change in Potential Total Hydrocarbon Production
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Tboe/d

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
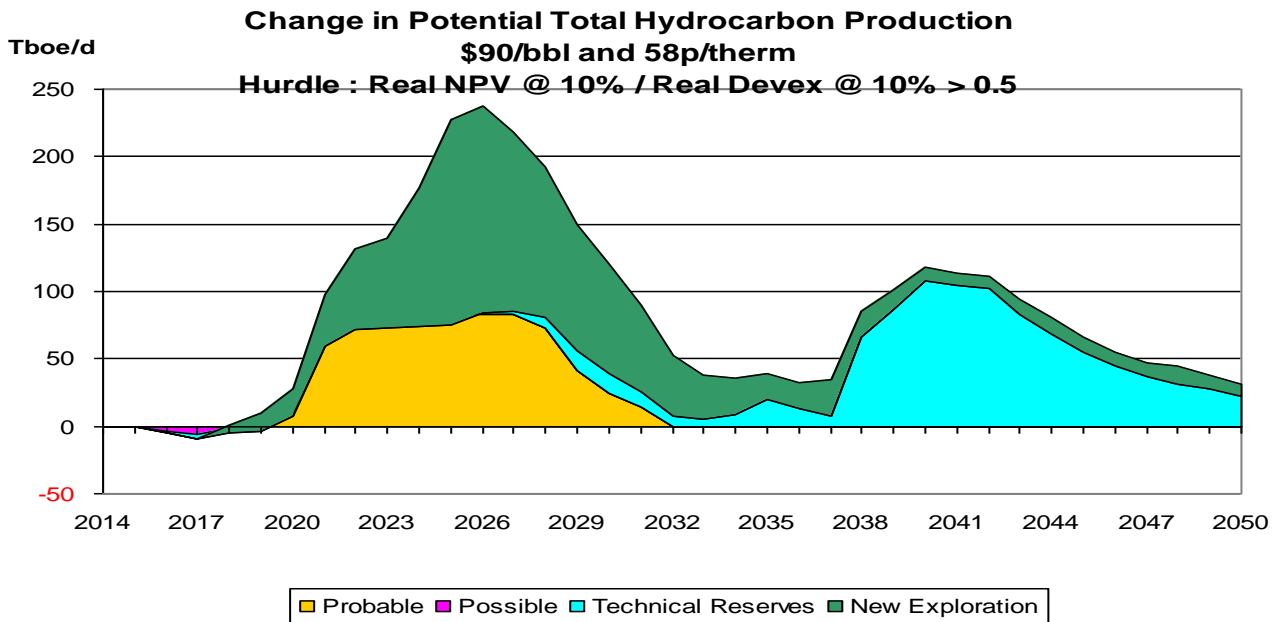
There is an increase in development expenditures of £14.3 bn (See Chart 42). There is a major increase from 2017 for some years.

Chart 42

Change in Potential Development Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration

34
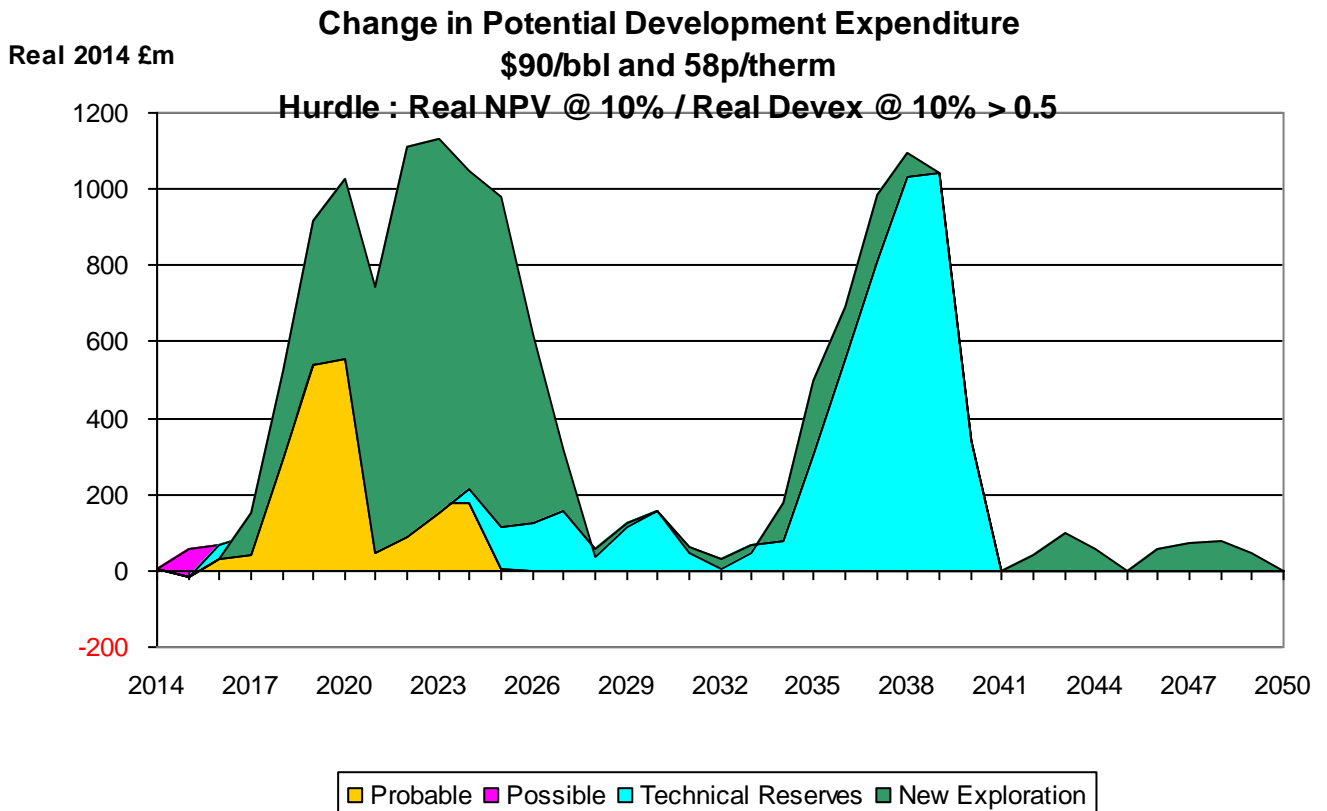
Operating expenditures increase by £11.4 bn (See Chart 43).

Decommissioning expenditures increase by £1 billion.

Chart 43

Change in Potential Operating Expenditure
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Legend: Probable Possible Technical Reserves New Exploration
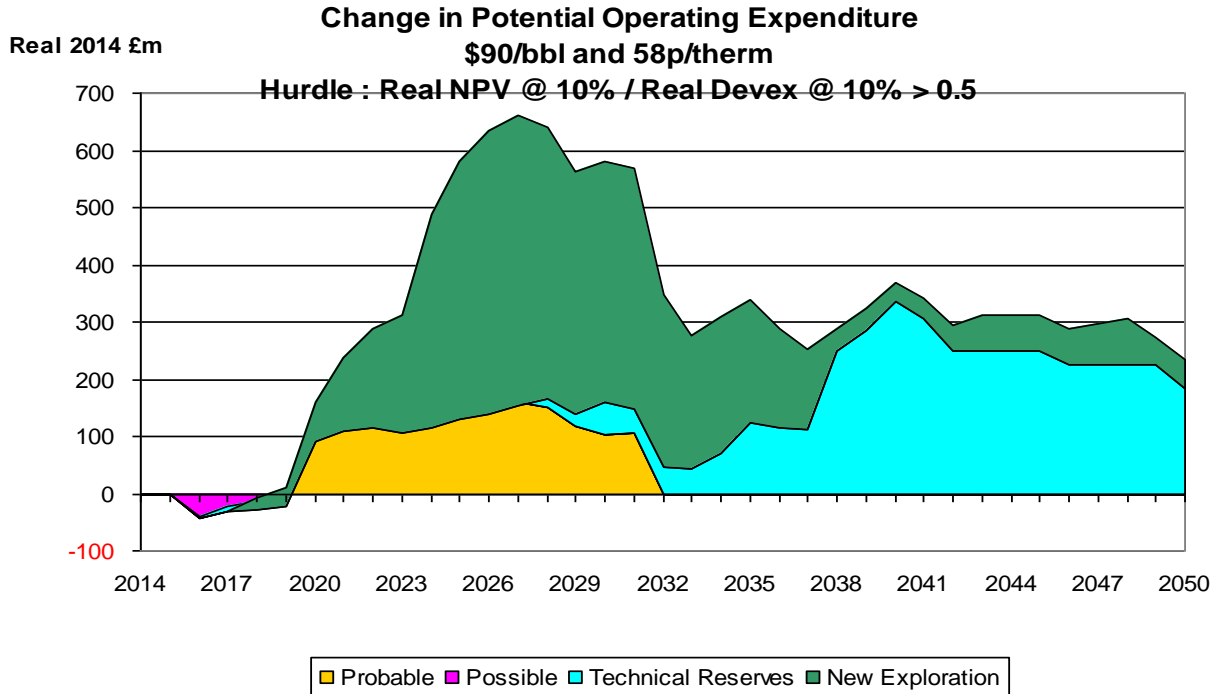
Tax revenues increase by £14.7 bn (See Chart 44). A key feature is

the major increase from 2020 for over a decade.

Chart 44

Change in Potential Tax Revenue
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Legend: Probable Possible Technical Reserves New Exploration
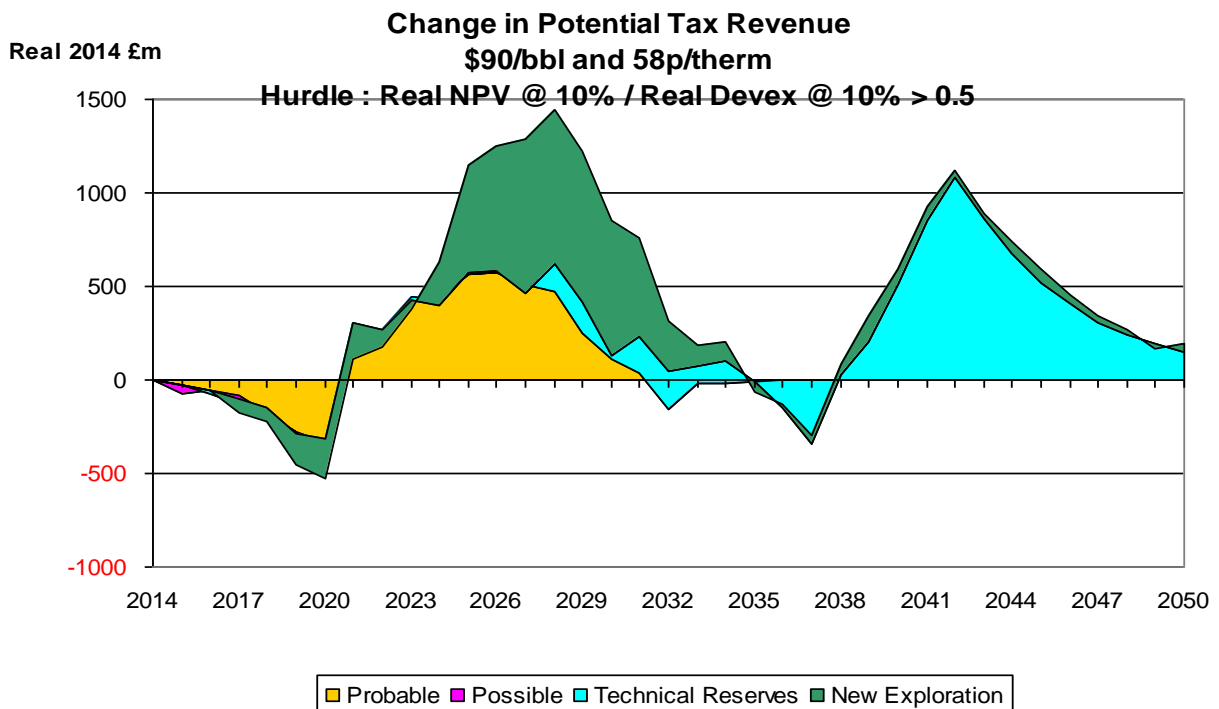
(j) Replacement of Field Allowances by Investment Uplift of 50%, Hurdle NPV/I > 0.3, Full Tax-paying Investor

When the investment uplift is at 50% there is a net increase (9) in the number of new field developments. But this conceals a significant reduction (16) as well as significant increase. The increase in oil production is 1.1 bnboe (See Chart 45).

Chart 45

**Change in Potential Oil Production
50% Uplift
$90/bbl and 58p/therm
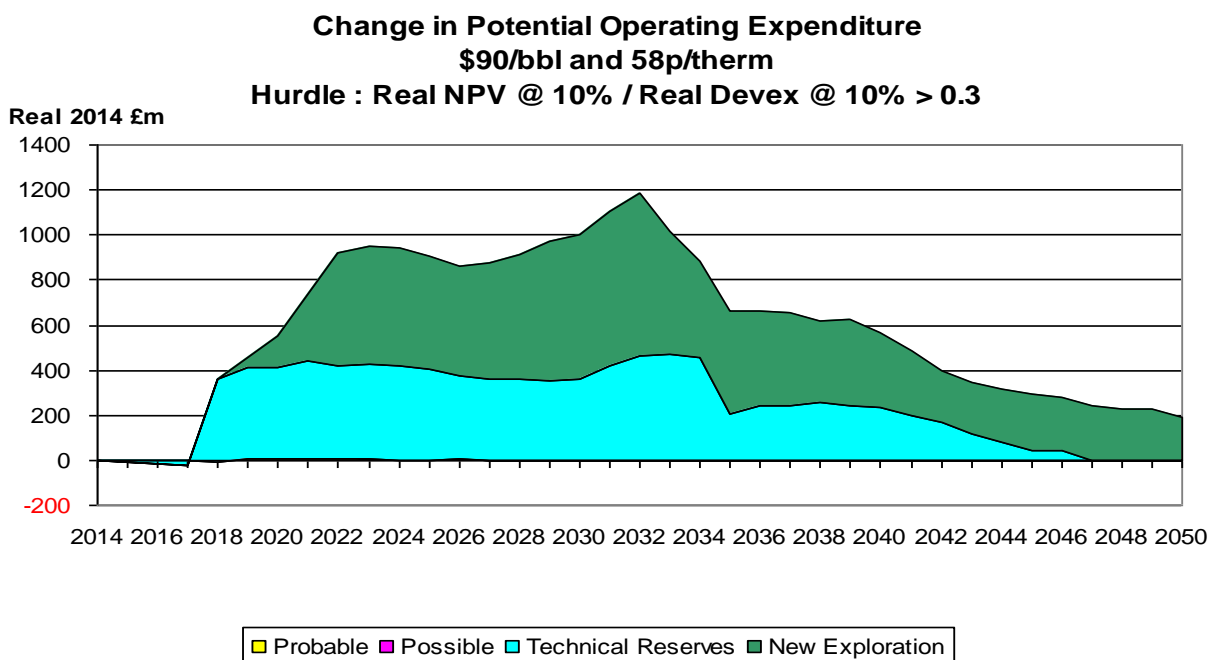Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

tb/d

Legend: Probable ▪ Possible ▪ Technical Reserves ▪ New Exploration

There is a net increase of 77 mmboe in gas production (See Chart 46). It is seen that there is a reduction in some years from the tax change.

36

Chart 46

Change in Potential Gas Production
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

mmcf/d

Legend: □ Probable ■ Possible ■ Technical Reserves ■ New Exploration
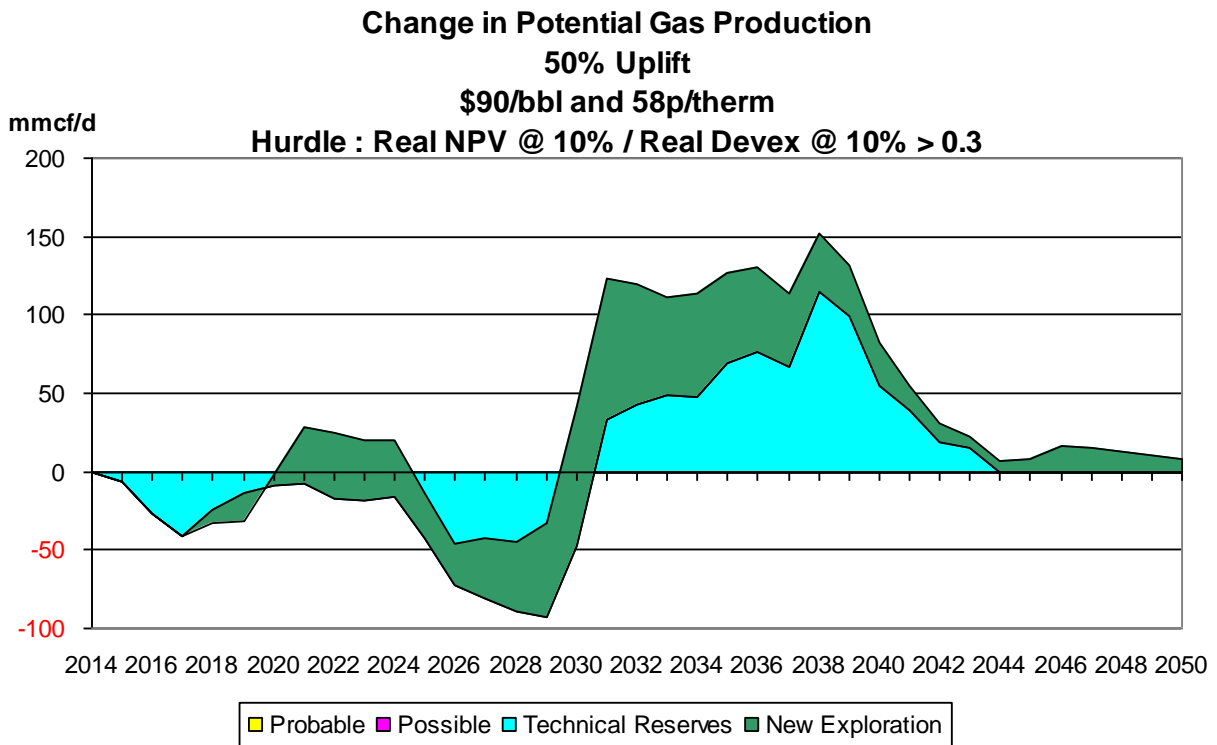
Total hydrocarbon production increases by 1.2 bnboe (See Chart 47).

The large increase in the decade from 2018 onwards is noticeable.

Chart 47

Change in Potential Total Hydrocarbon Production
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Tboe/d

Legend: □ Probable ■ Possible ■ Technical Reserves ■ New Exploration
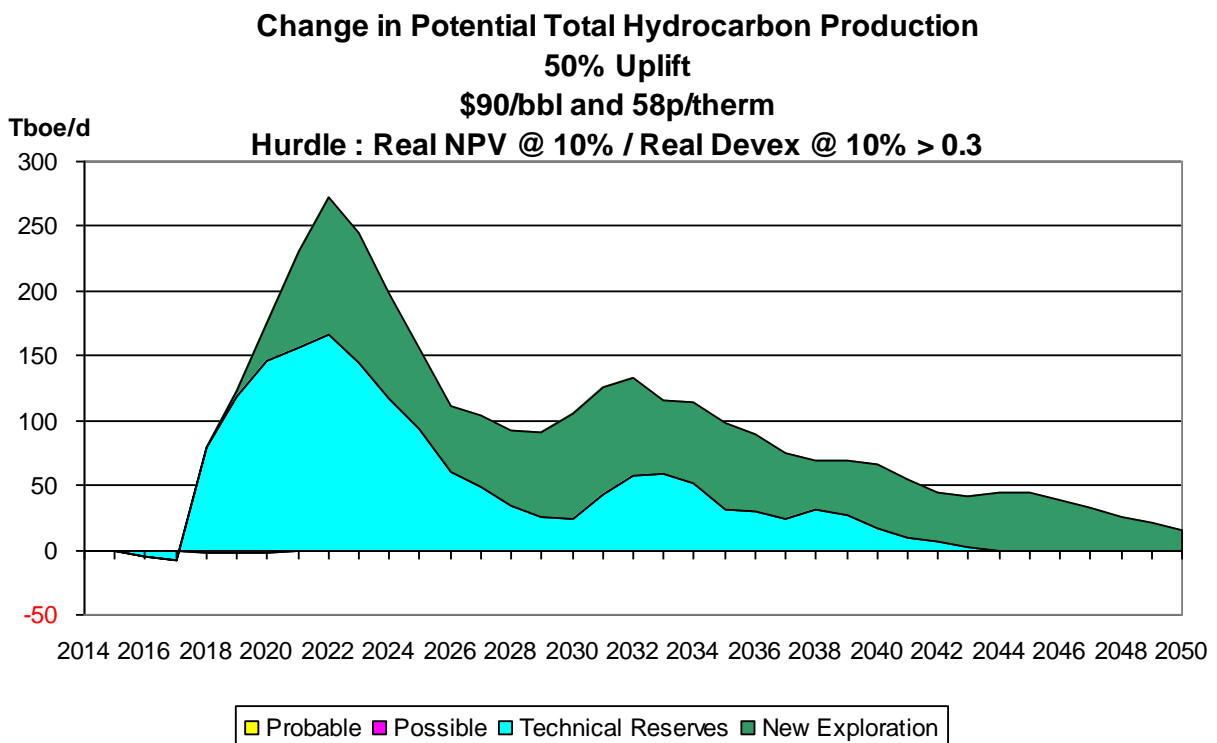
The total increase in development expenditures in the period is £20.2 billion (See Chart 48). The large increase over the next few years is a noticeable feature.

Chart 48

Change in Potential Development Expenditure
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
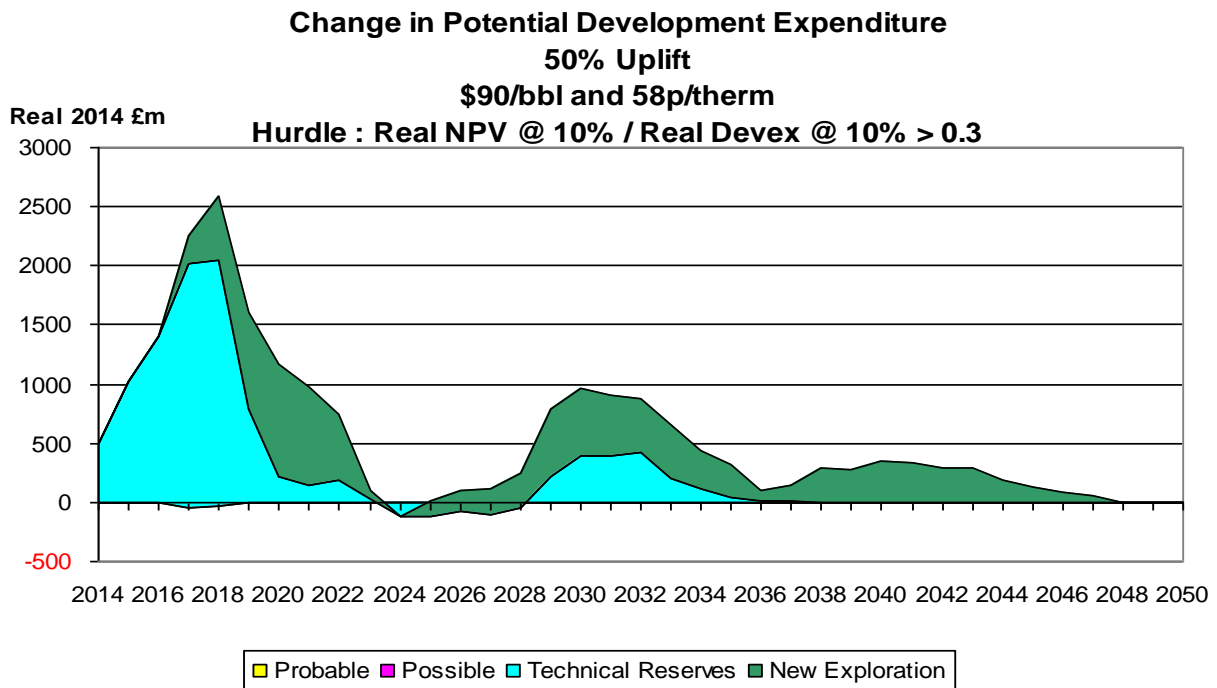
The increase in operating expenditures over the period is £16.1 billion (See Chart 49).

Chart 49

Change in Potential Operating Expenditure
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

38
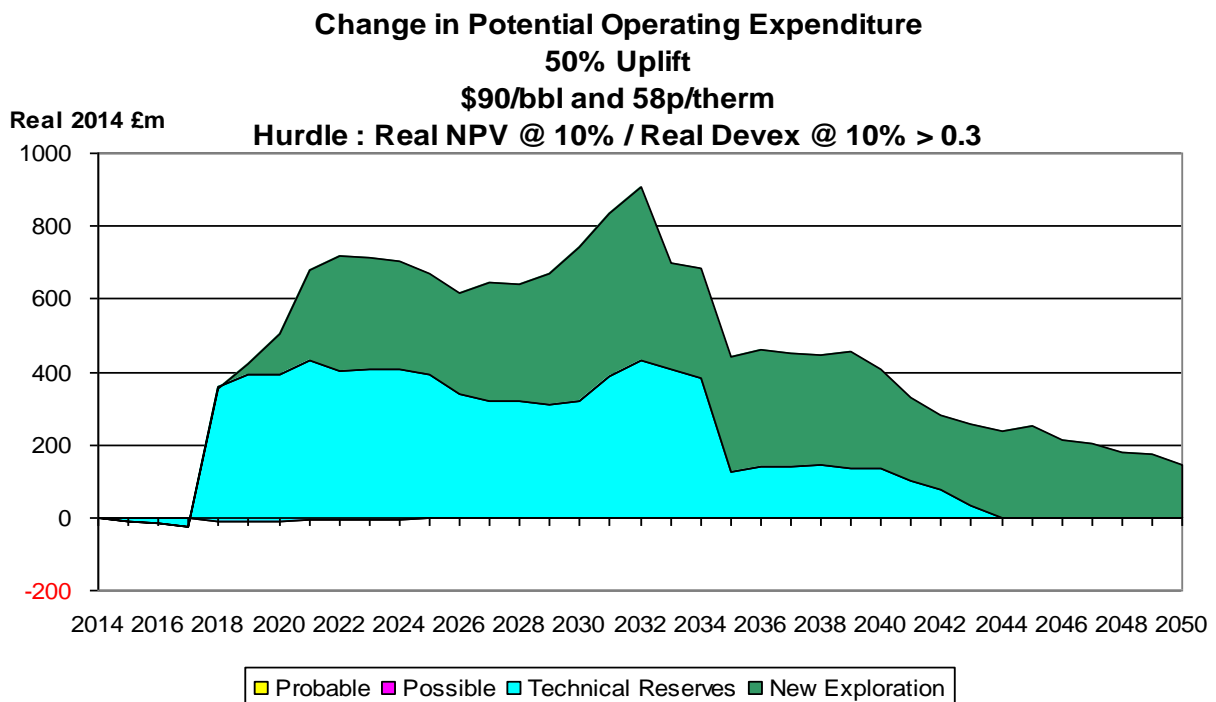
The net increase in tax revenues over the period is £12.9 billion (See Chart 50). There is a reduction over the next few years followed by a major increase from 2018 for several years.

Chart 50

Change in Potential Tax Revenue
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Real 2014 £m

Probable   Possible   Technical Reserves   New Exploration
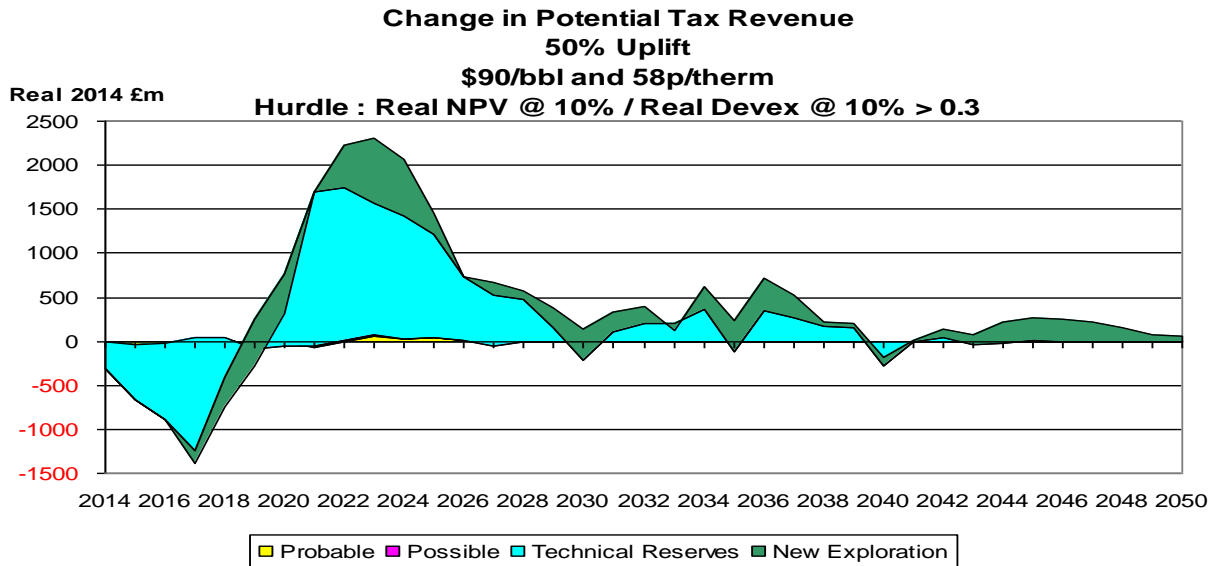
(k) Replacement of Field Allowances by Investment Uplift of 50%, Hurdle NPV/I > 0.5, Full Tax-paying Investor

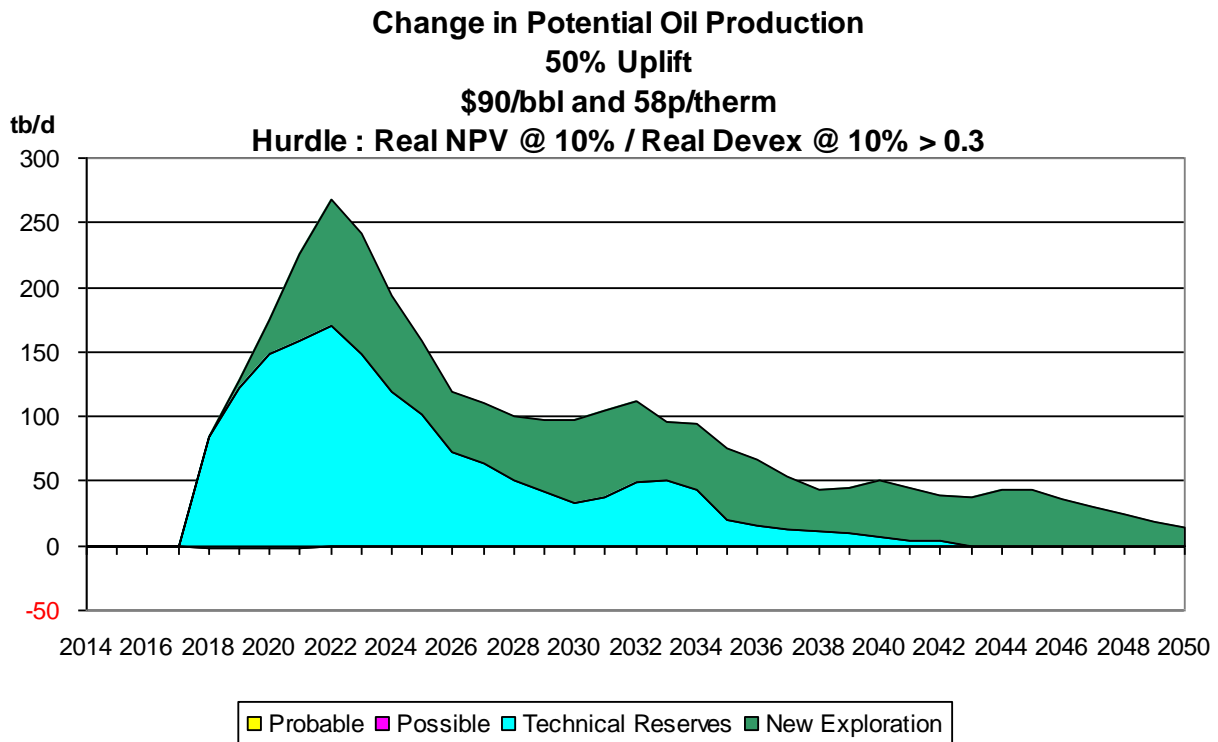When the investment hurdle is NPV/I > 0.5 there are 15 fewer fields whose development is triggered over the period. But this conceals a significant number whose development is triggered. The result is a net increase in oil production of 522 mmboe over the period (See Chart 51.   Chart 51

Change in Potential Oil Production
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

tb/d

Cns / MF   Irish   Nns   SNS   WoS

But there is a small reduction in gas production (See Chart 52).

Chart 52

**Change in Potential Gas Production
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

mmcf/d

[Chart showing change in potential gas production from 2014 to 2050, with categories: Probable, Possible, Technical Reserves, New Exploration]

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
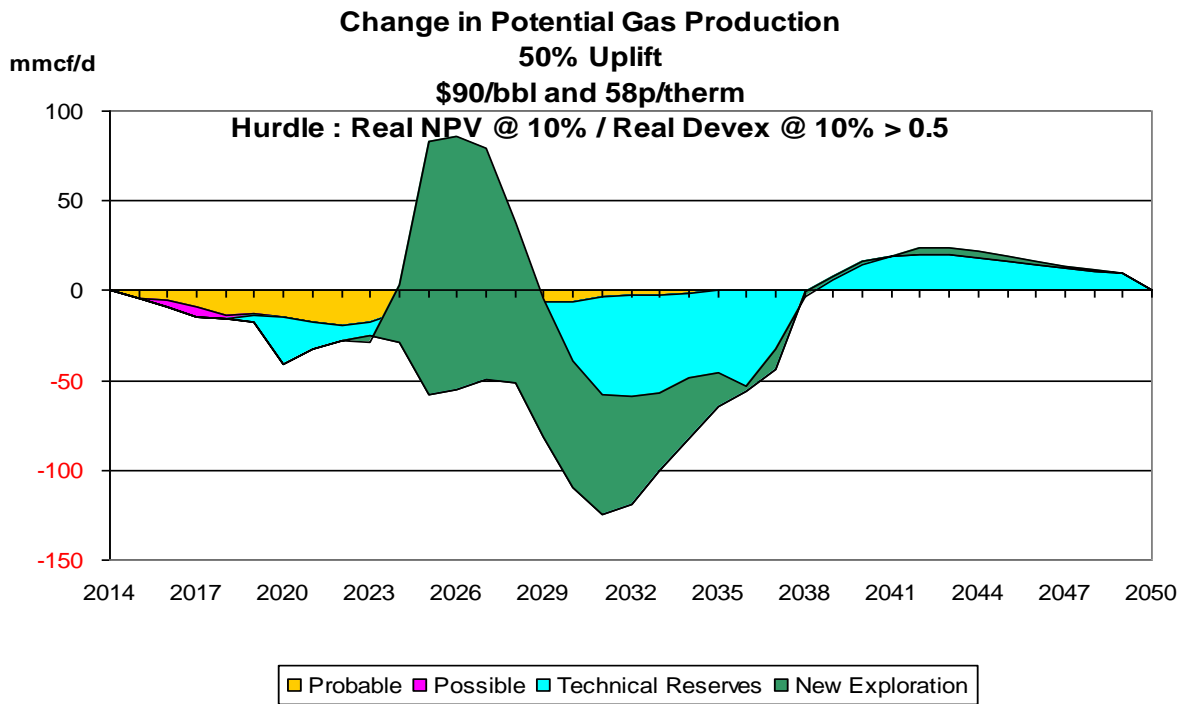
There is a net increase in total hydrocarbon production of 515 mmboe (See Chart 53).

Chart 53

**Change in Potential Total Hydrocarbon Production
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Tboe/d

[Chart showing change in potential total hydrocarbon production from 2014 to 2050, with categories: Probable, Possible, Technical Reserves, New Exploration]

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration

40
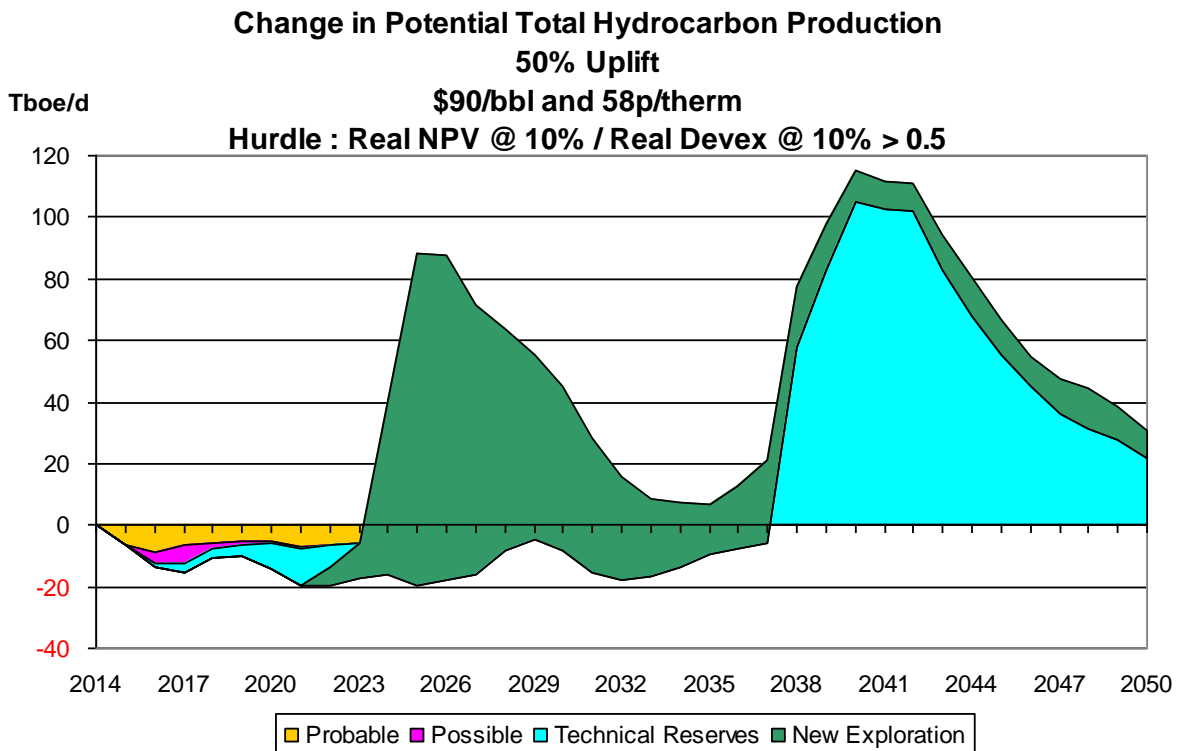
Total development expenditure increases by £7.1 billion (See Chart 54). In the short term there is a decrease.

Chart 54

Change in Potential Development Expenditure
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Probable ■ Possible □ Technical Reserves ■ New Exploration
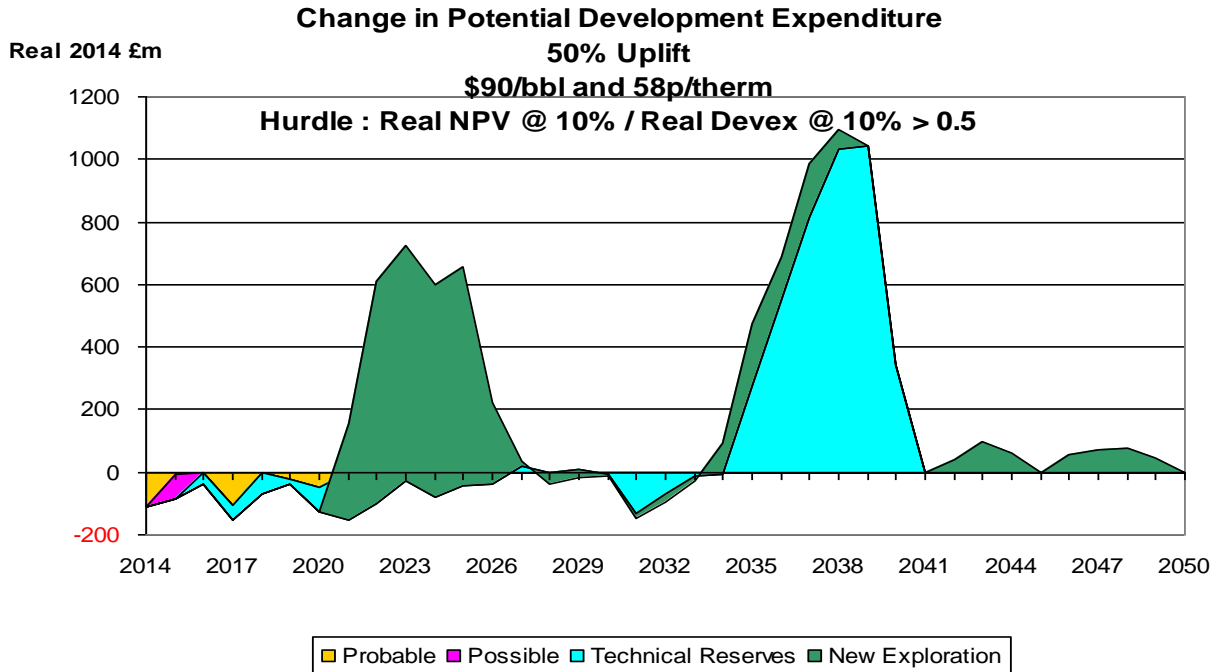
Total operating expenditures increase by £5.5 billion (See Chart 55). There are net decreases in the short term.

Chart 55

Change in Potential Operating Expenditure
50% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Probable ■ Possible □ Technical Reserves ■ New Exploration
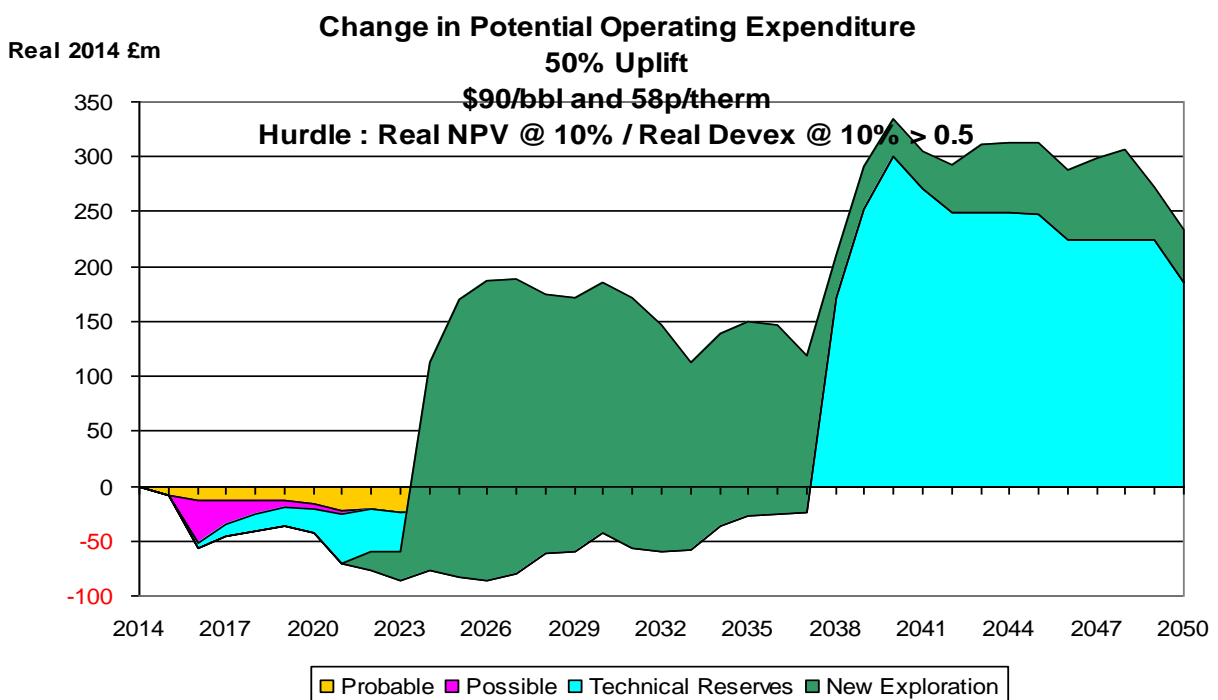
Tax revenues show a net increase of £9.8 bn over the period (See Chart 56). There is a decrease in the period to 2024 followed by a significant increase and later decreases and increases.

Chart 56

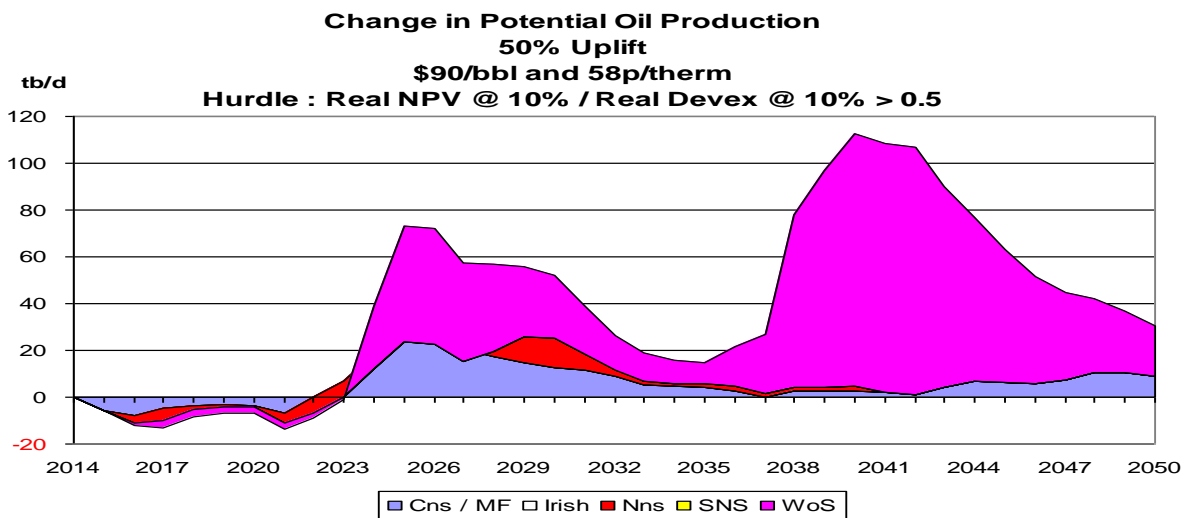**Change in Potential Tax Revenue**
50% Uplift
$90/bbl and 58p/therm
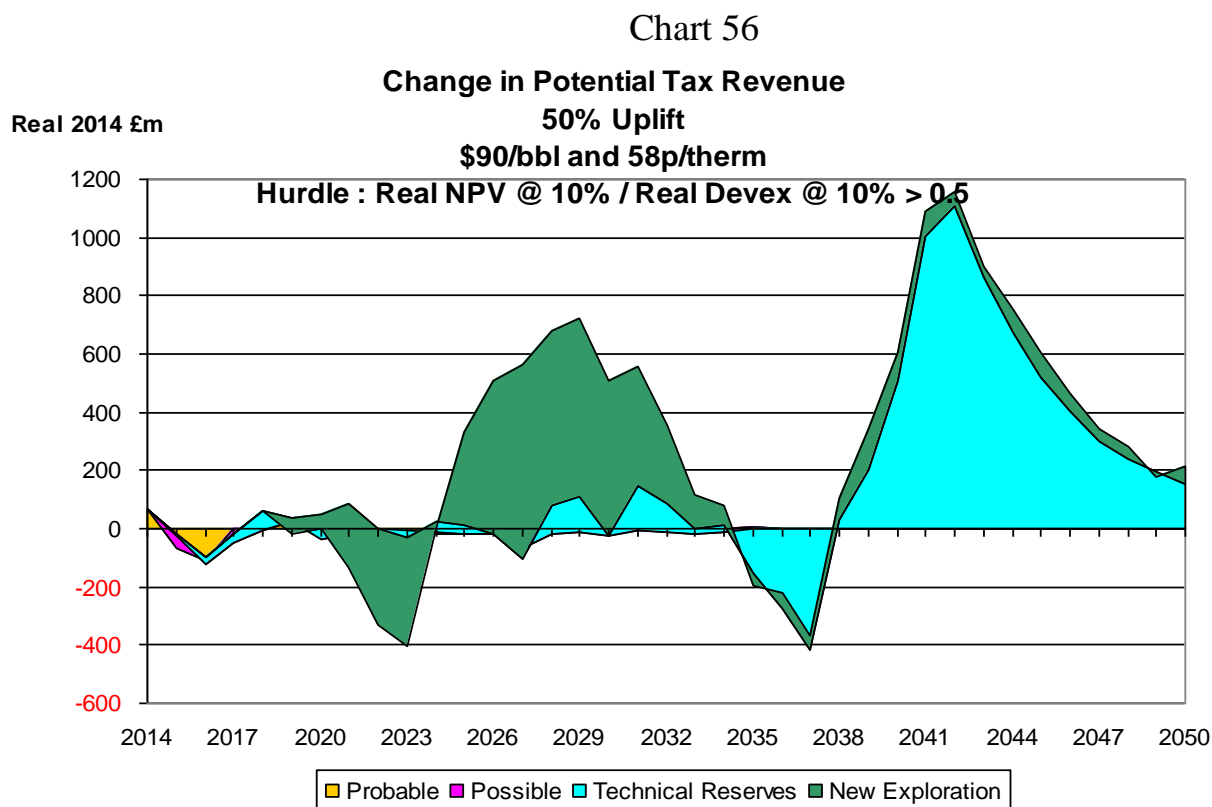
(l) Replacement of Field Allowances with Investment Uplift of 75%, Hurdle NPV/I > 0.3, Full Tax-paying Investor

When the investment uplift is 75% and the hurdle is NPV/I > 0.3 there are 47 net further new field developments. There are still 7 developments which are disincentivised by the change. The net increase in oil production is 1.86 bnboe and the net increase in gas production 304 mmboe. The increase in total hydrocarbon production including NGLs is 2.17 bnboe (See Chart 57). The increase is very strong in the period from 2017 onwards.

Chart 57

**Change in Potential Total Hydrocarbon Production
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Tboe/d

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration
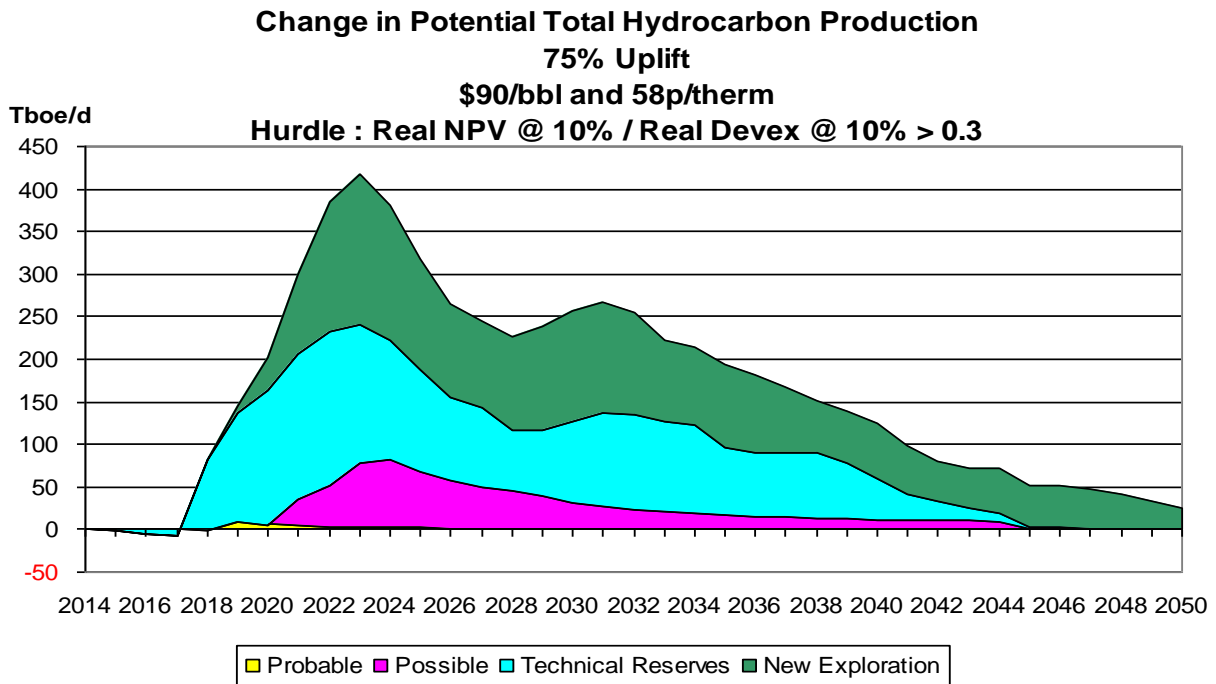
The increase in field development expenditure is a massive £36.6 bn in this scenario (See Chart 58). There is very strong growth from now until 2020.

Chart 58

**Change in Potential Development Expenditure
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

☐ Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration

43
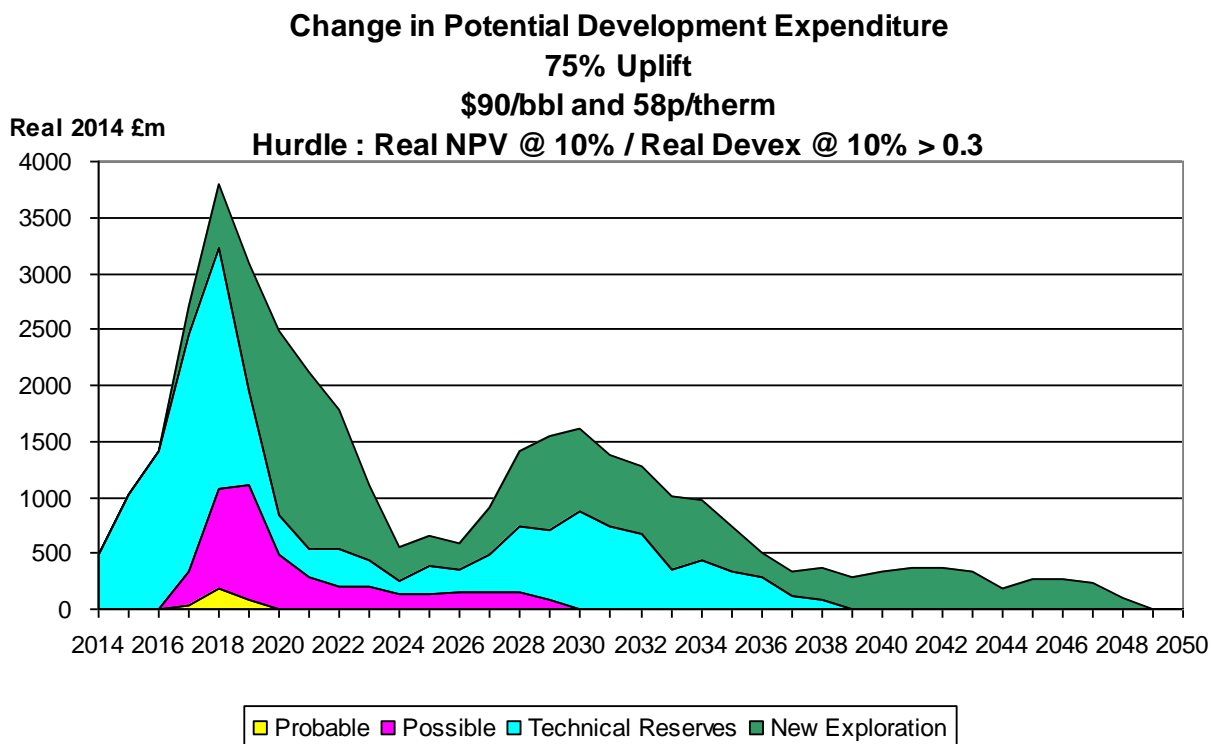
Operating expenditures increase by over £30 bn in the period (See
Chart 59).

Chart 59

**Change in Potential Operating Expenditure
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable Possible Technical Reserves New Exploration
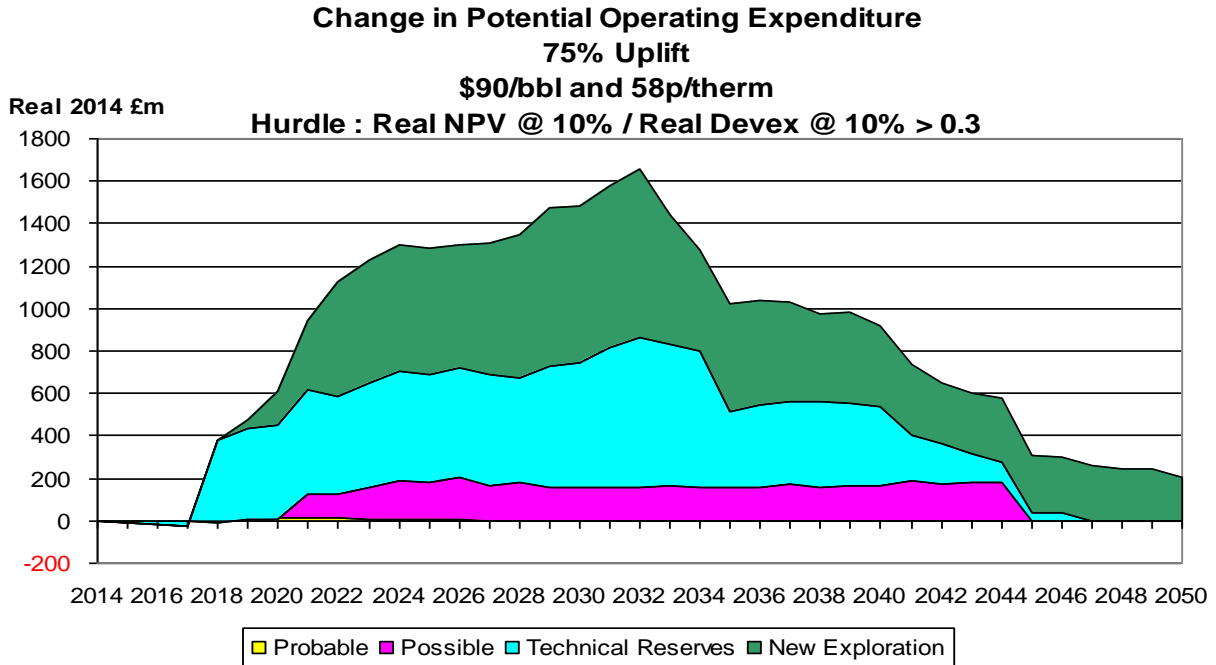
Tax revenues increase by over £13 bn over the period (See Chart 60).
There is a significant decrease in the period to 2020 followed by a
major increase.

Chart 60

**Change in Potential Tax Revenue
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable Possible Technical Reserves New Exploration

44
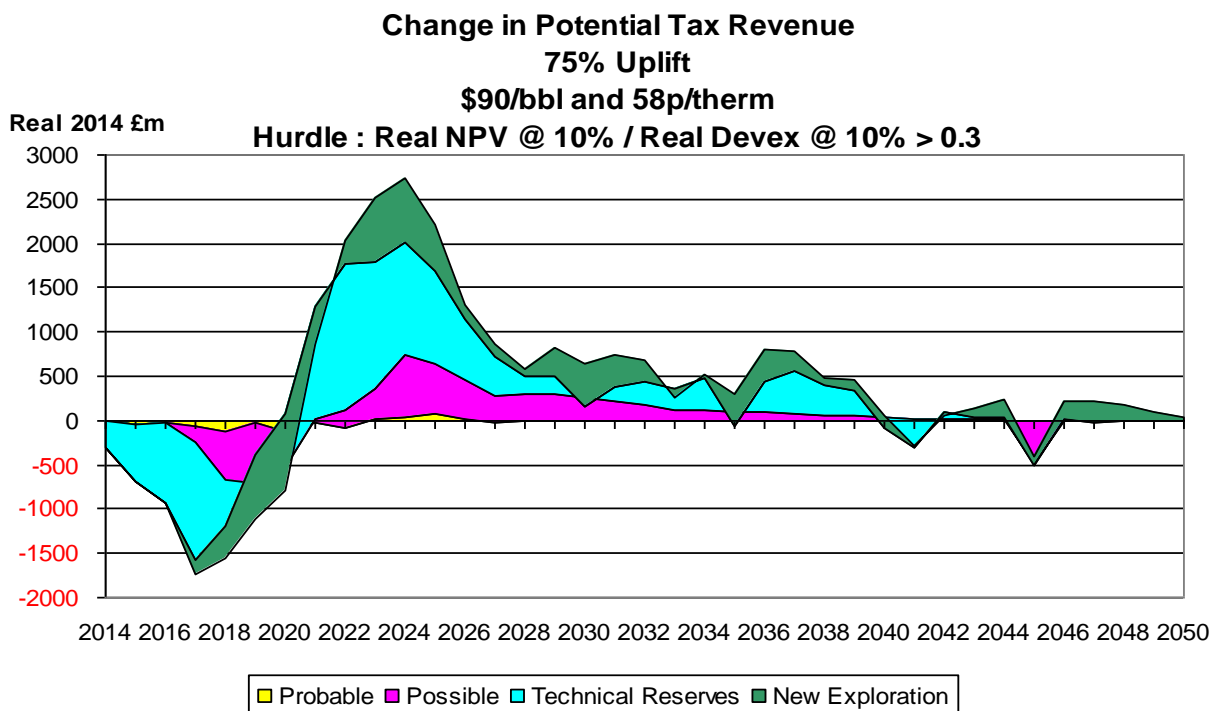
(m) Replacement of Field Allowances with Investment Uplift of 75%, Hurdle NPV/I > 0.5, Full Tax-paying Investor

When the investment hurdle is NPV/I > 0.5 there is a net increase of 16 new field developments triggered. But 14 new fields are disincentivised by the change. The increase in total hydrocarbon production is 1.3 bnboe over the period (See Chart 61). The increase is very noticeable in the period 2020-2030.

Chart 61

Change in Potential Total Hydrocarbon Production
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
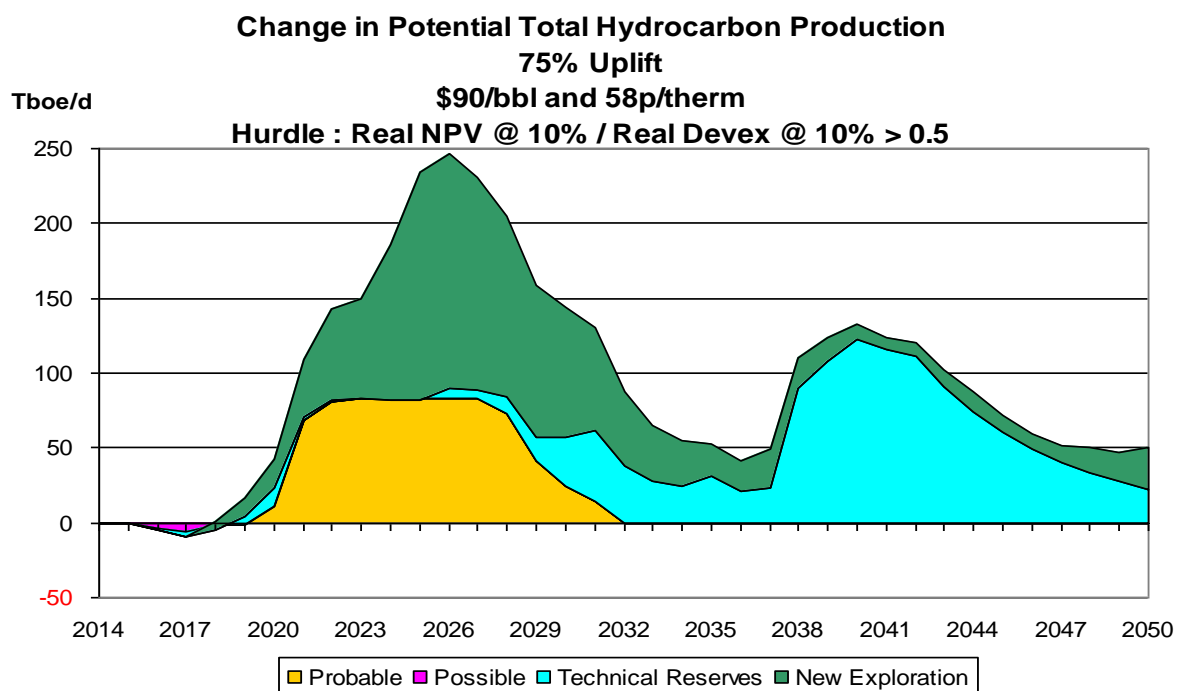
Field development expenditures increase by over £17 bn through the period (See Chart 62). It is very large in the period from 2017 to 2030.

Chart 62

Change in Potential Development Expenditure
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Probable ■ Possible ■ Technical Reserves ■ New Exploration
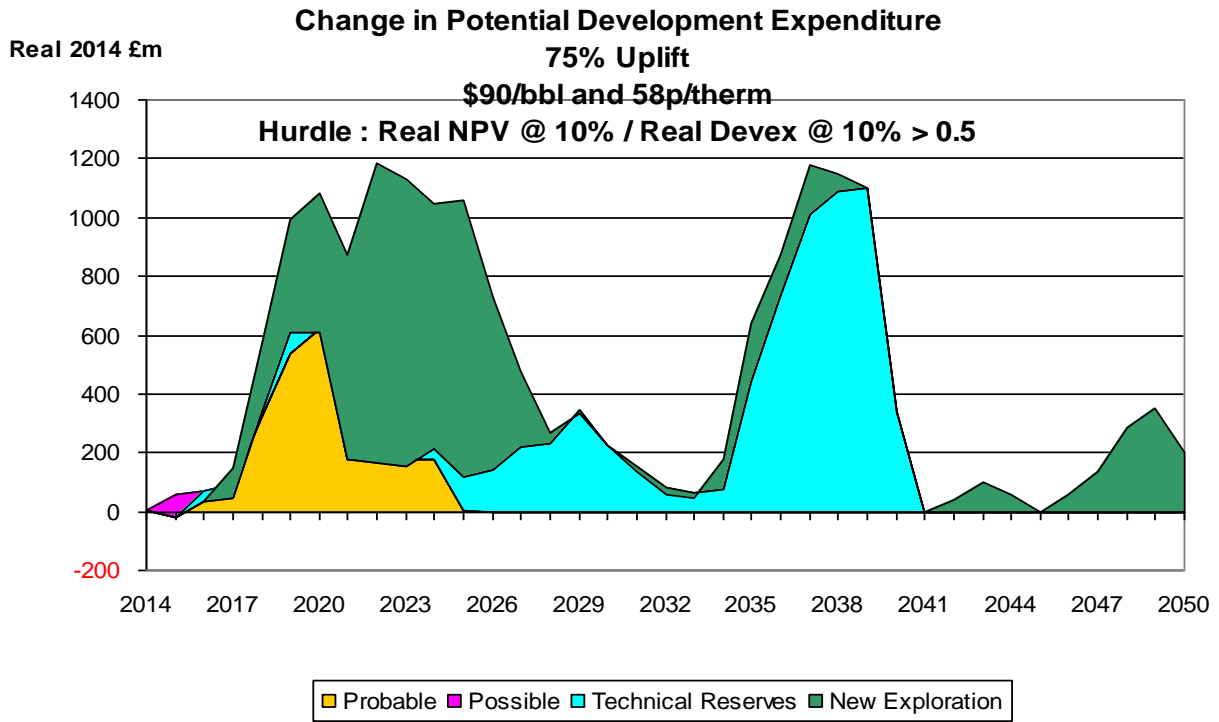
Operating expenditures increase by £13.2 bn over the period (See Chart 63).

Chart 63

Change in Potential Operating Expenditure
75% Uplift
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Probable ■ Possible ■ Technical Reserves ■ New Exploration
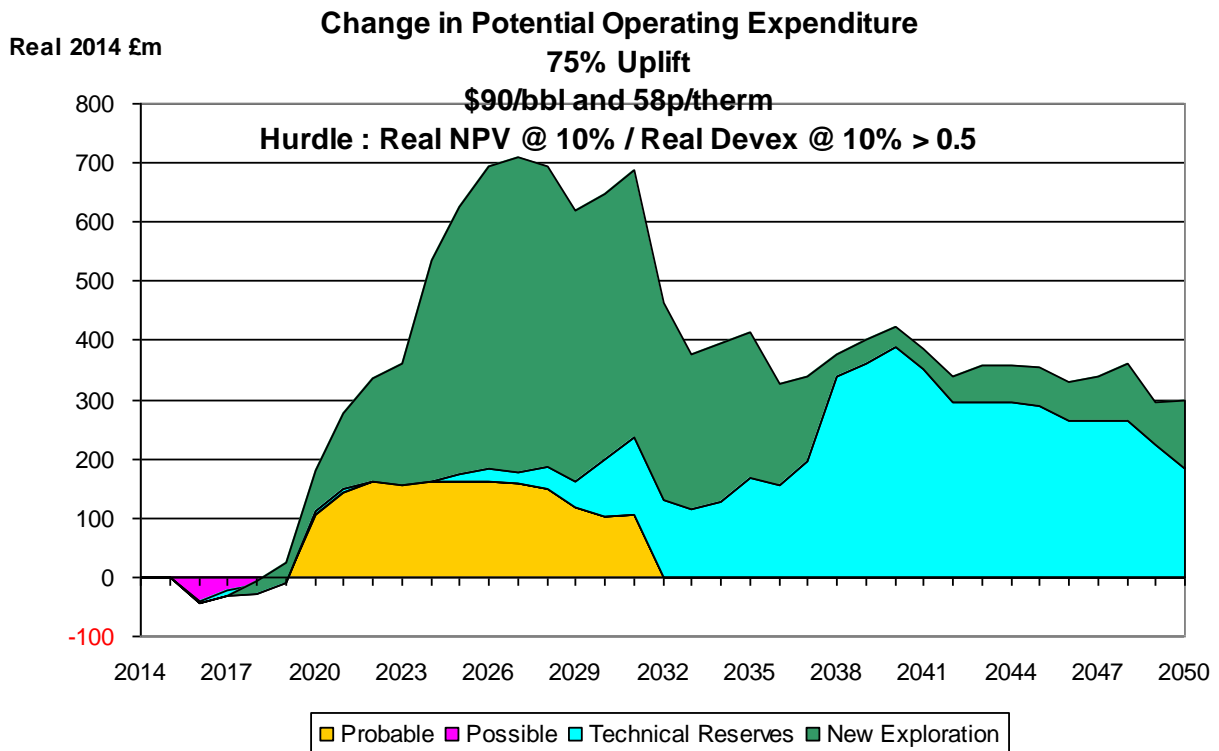
Tax revenues increase by £14.3 bn over the period (See Chart 64). There is a reduction to 2020 followed by a major increase for more than a decade.

Chart 64

Change in Potential Tax Revenue
75% Uplift
$90/bbl and 58p/therm
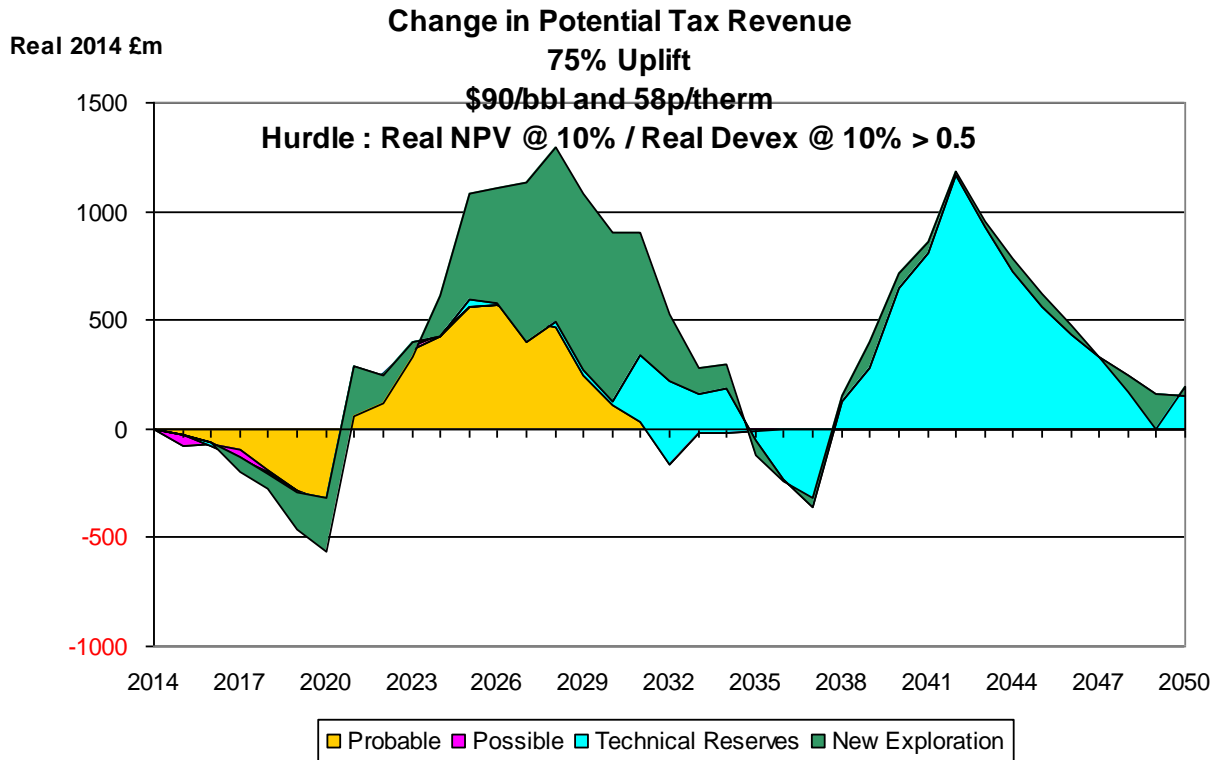
(n) Effects of SC at 20% with Existing Field Allowances, Hurdle NPV/I > 0.3, Full Tax-paying Investor

The effects on activity of a reduction in the rate of SC to 20% with no other changes are now discussed. There is a net increase of 7 new field developments plus 5 more incremental projects which pass the hurdle. Interestingly there are 5 new fields and 1 incremental project which now fail the hurdle. This is because of the reduction in the rate of relief for the investment expenditure in situations where the field allowance already shelters most if not all of the income from SC.

There is an increase in total hydrocarbon production from incremental projects of 111 mmboe over the period (See Chart 65).

47

Chart 65

**Change in Potential Total Hydrocarbon Production
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Tboe/d

Sanctioned ■ Incremental □ Future Incremental
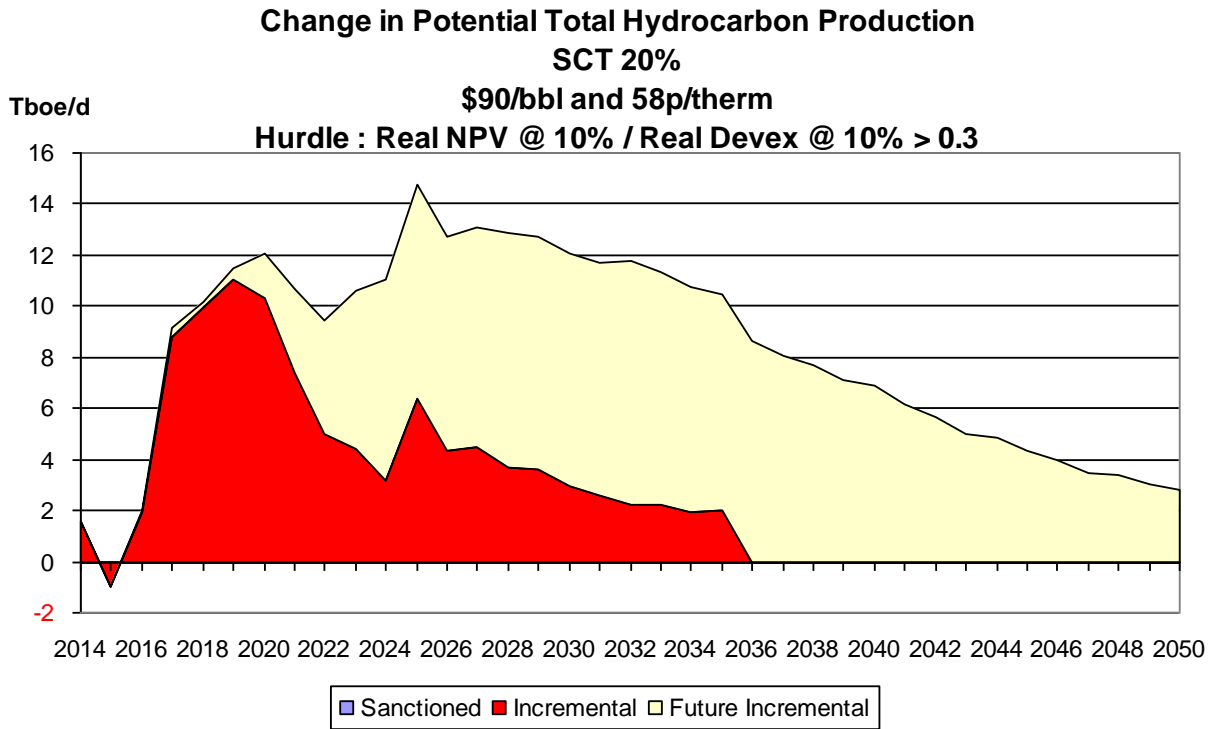
From new fields there is an increase of 394 mmboe (See Chart 66).

The total increase is thus 505 mmboe.

Chart 66

**Change in Potential Total Hydrocarbon Production
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Tboe/d

□ Probable ■ Possible ■ Technical Reserves ■ New Exploration

48
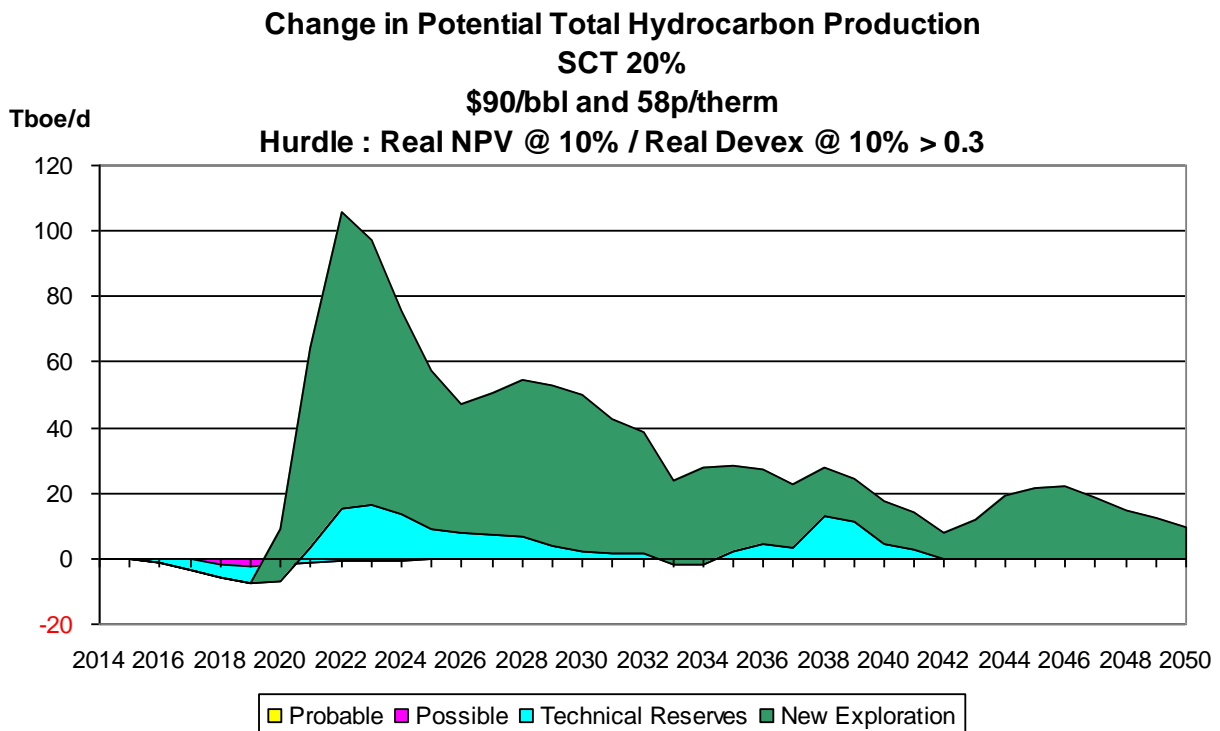
There is an increase of £854 million on investment in incremental projects (See Chart 67).

Chart 67

**Change in Potential Develoment Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

☐ Sanctioned ■ Incremental ☐ Future Incremental
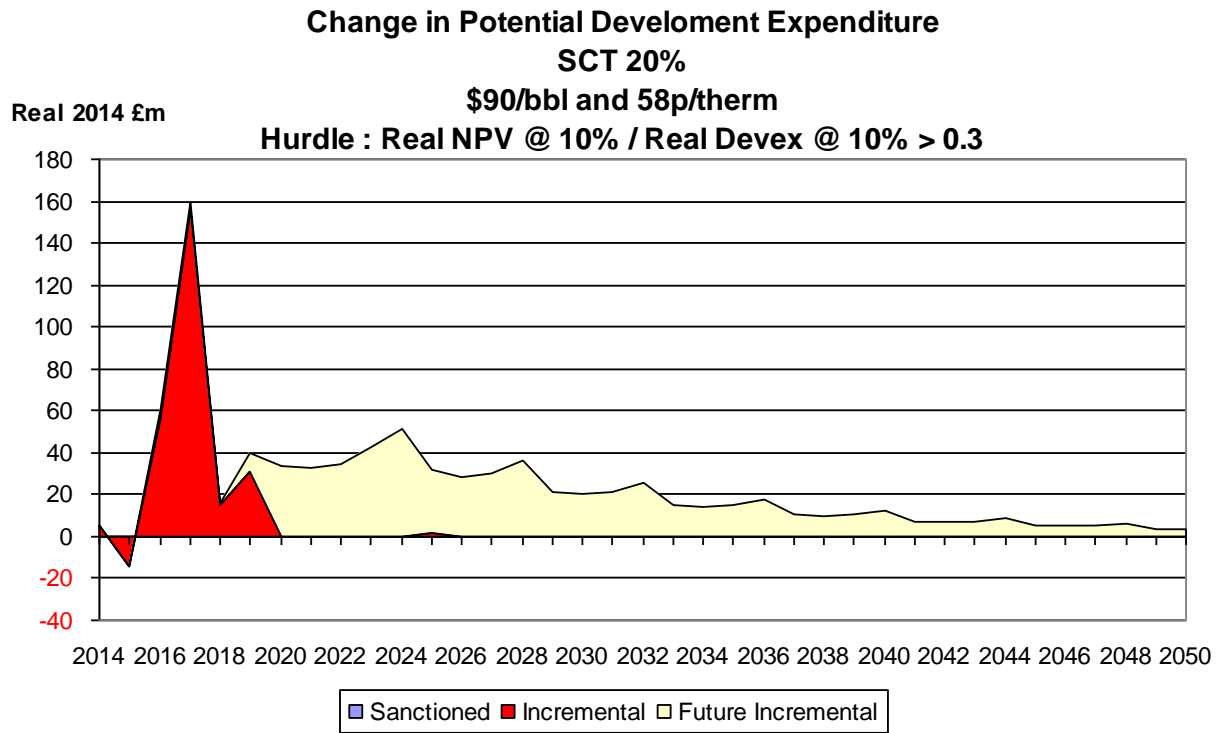
On new fields there is an increase in investment of £6.5 bn (See Chart 68).

Chart 68

**Change in Potential Develoment Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

☐ Probable ■ Possible ☐ Technical Reserves ■ New Exploration

49
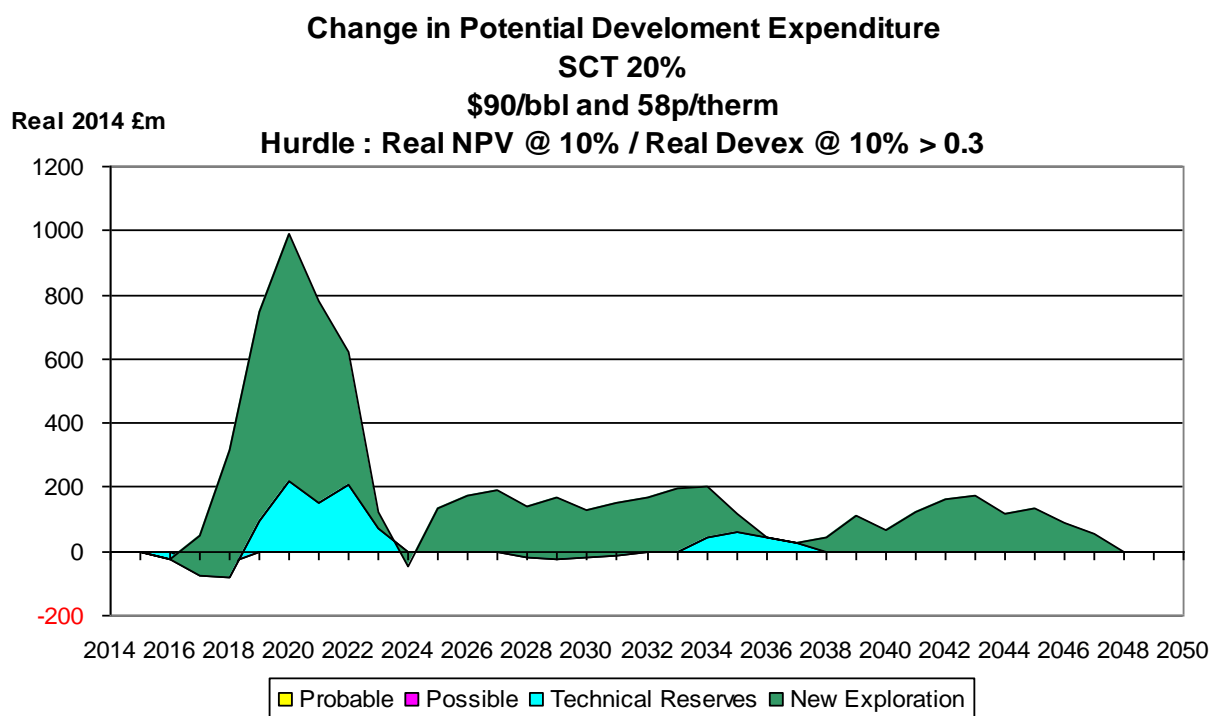
The increase is very noticeable over the next few years. Operating expenditures on incremental projects increase by £1.9 billion (See Chart 69).

Chart 69

**Change in Potential Operating Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Sanctioned Incremental Future Incremental
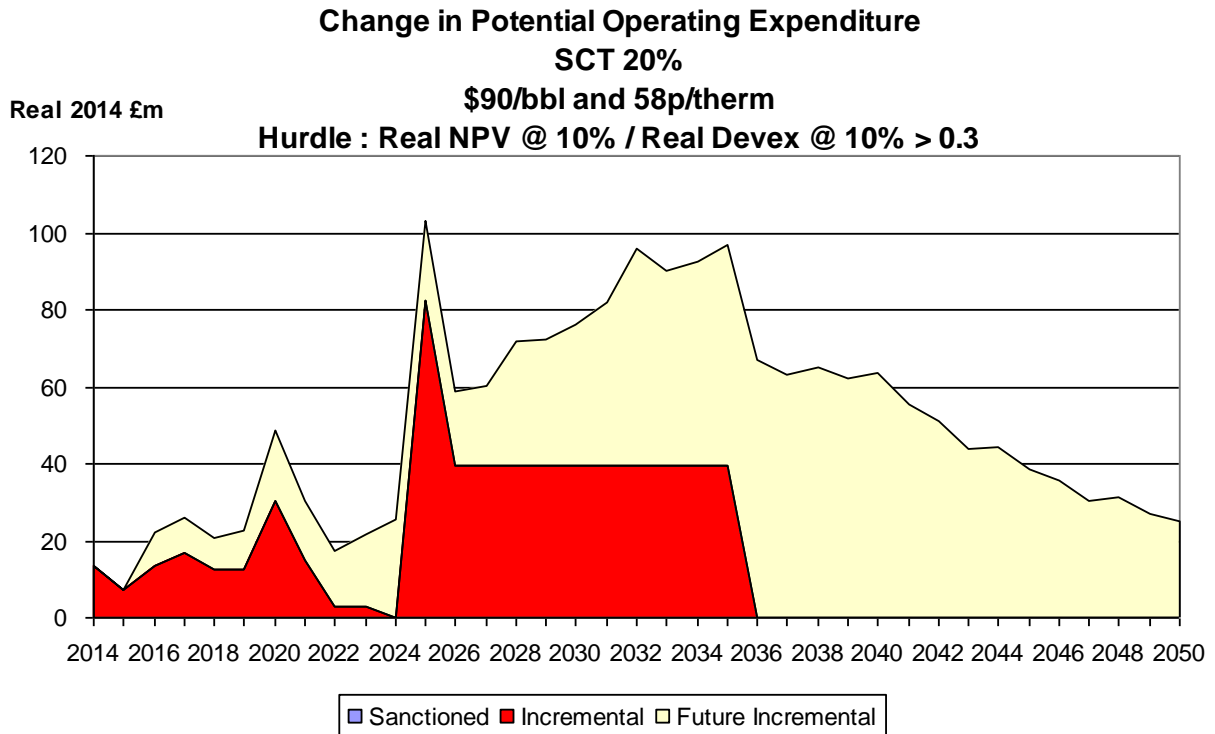
On new fields they increase by £5.3 billion (See Chart 70).

Chart 70

**Change in Potential Operating Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable Possible Technical Reserves New Exploration

50
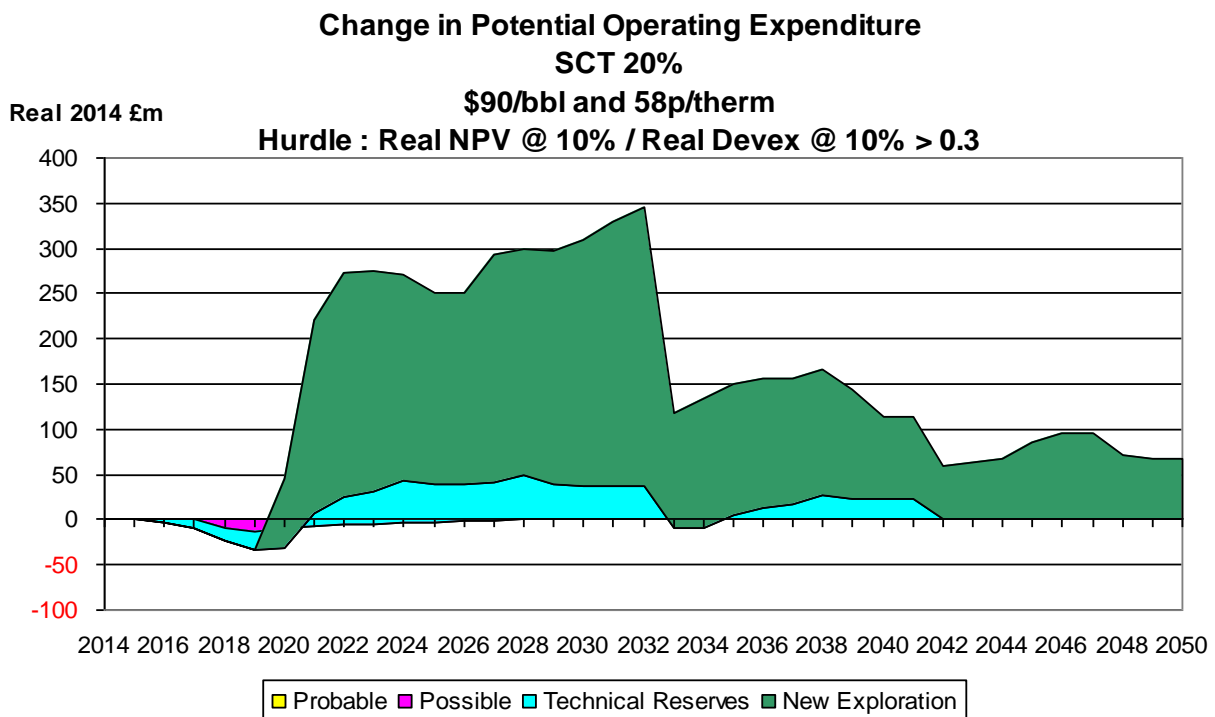
The change in tax revenues attributable to future fields is shown in Chart 71.

Chart 71

**Change in Potential Tax Revenue
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Probable ☐ Possible ☐ Technical Reserves ☐ New Exploration ☐
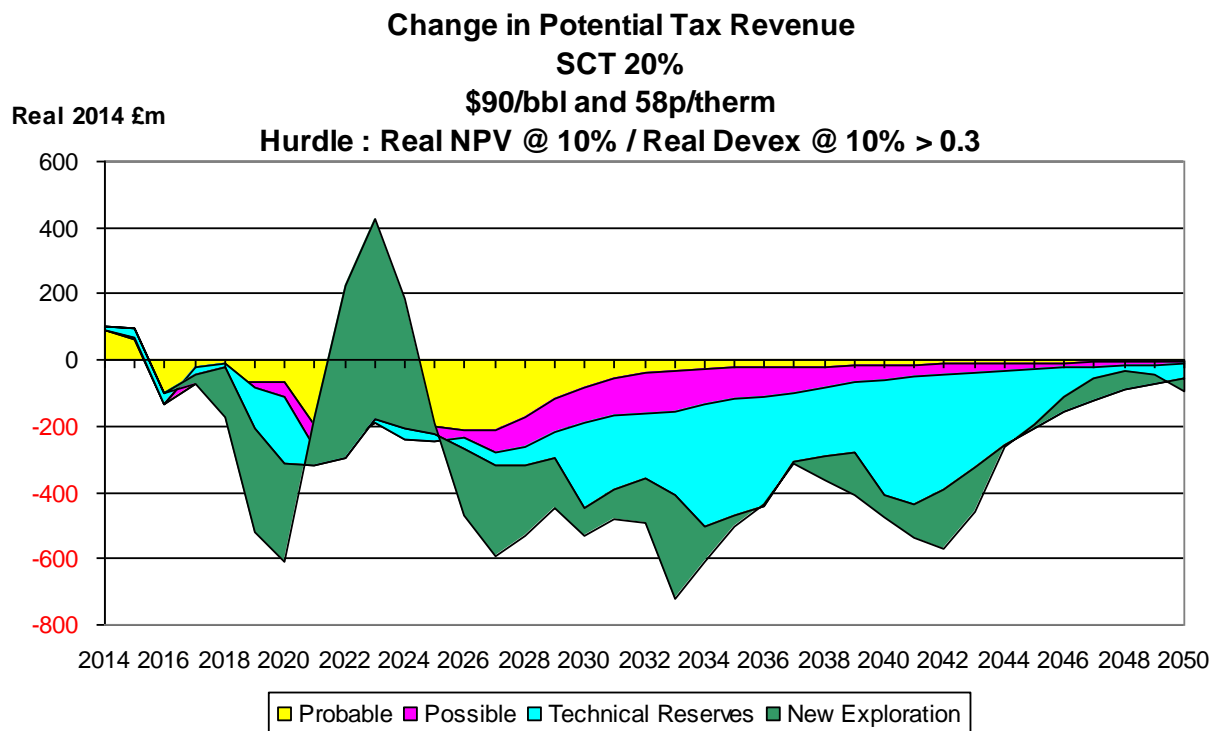
There is a net reduction of £10.5 bn. While more fields do pass the hurdle and pay tax many fields already pass the hurdle and pay less tax as a result of the rate reduction. It is emphasised that these results are based on the assumption that investors are all in a tax-paying position. It is recognised that many are not currently in a full tax-paying situation.

(o) Effects of SC at 20% with Existing Field Allowances, Hurdle NPV/I > 0.5, Full Tax-paying Investor

Where the investment hurdle is NPV/I > 0.5 it was found that a net increase of 16 new field developments plus 5 extra incremental projects were triggered. There is an increase in production from incremental projects of 223 mmboe (See Chart 72).

Chart 72

Change in Potential Total Hydrocarbon Production
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
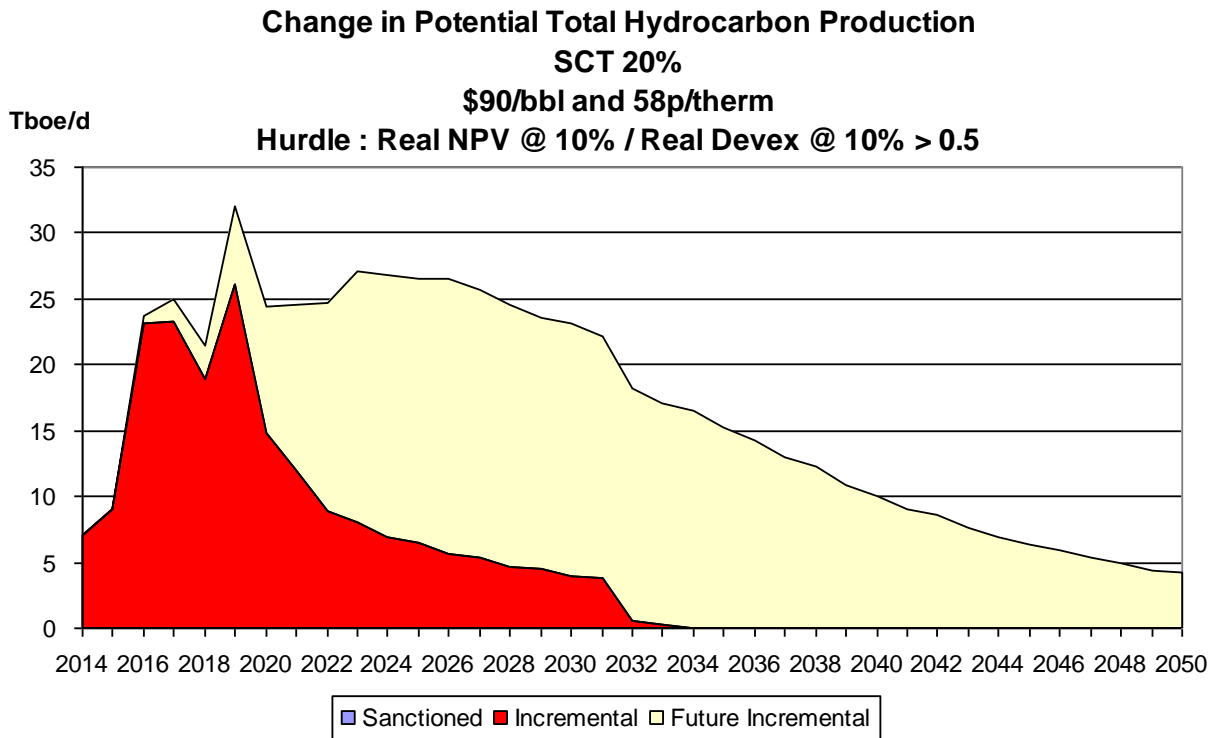
From new fields there is an increase of 1.1 bnboe (See Chart 73). The increase in production from incremental projects comes in the near future while much of the increase from new fields comes in the period 2020-2032.

Chart 73

Change in Potential Total Hydrocarbon Production
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
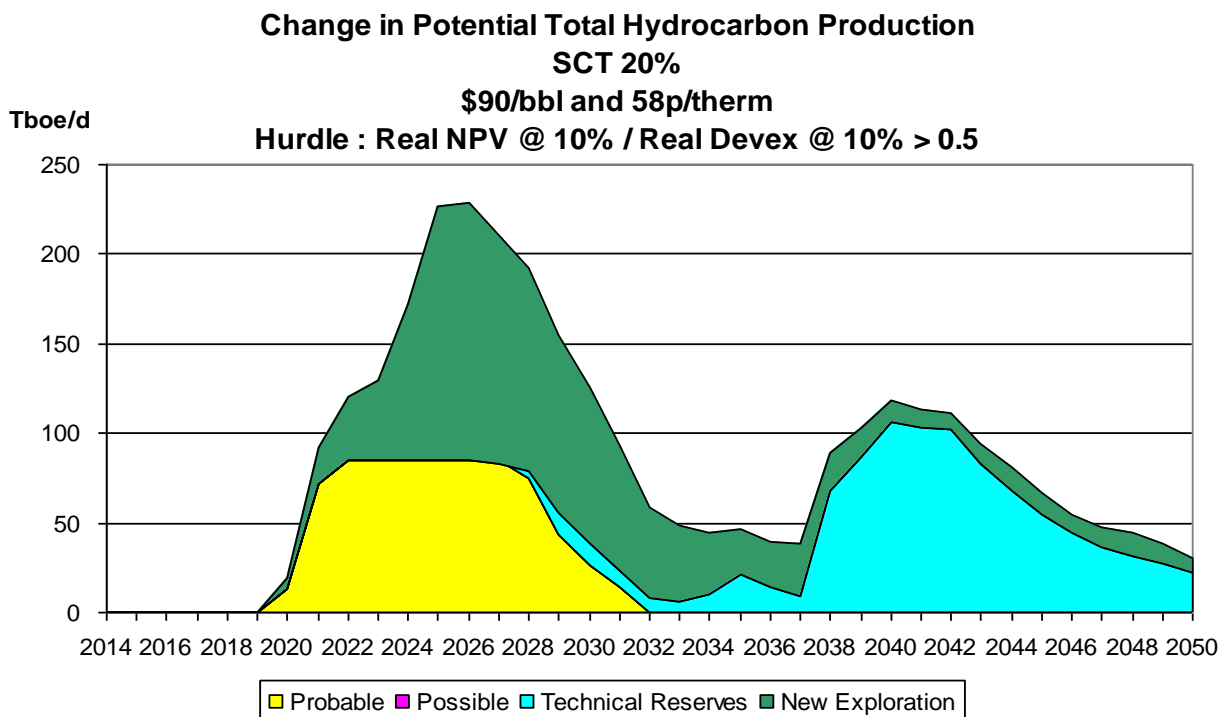
There is an increase of £2.8 bn in development expenditures on incremental projects (See Chart 74).

Chart 74

Change in Potential Develoment Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

☐ Sanctioned ■ Incremental ☐ Future Incremental
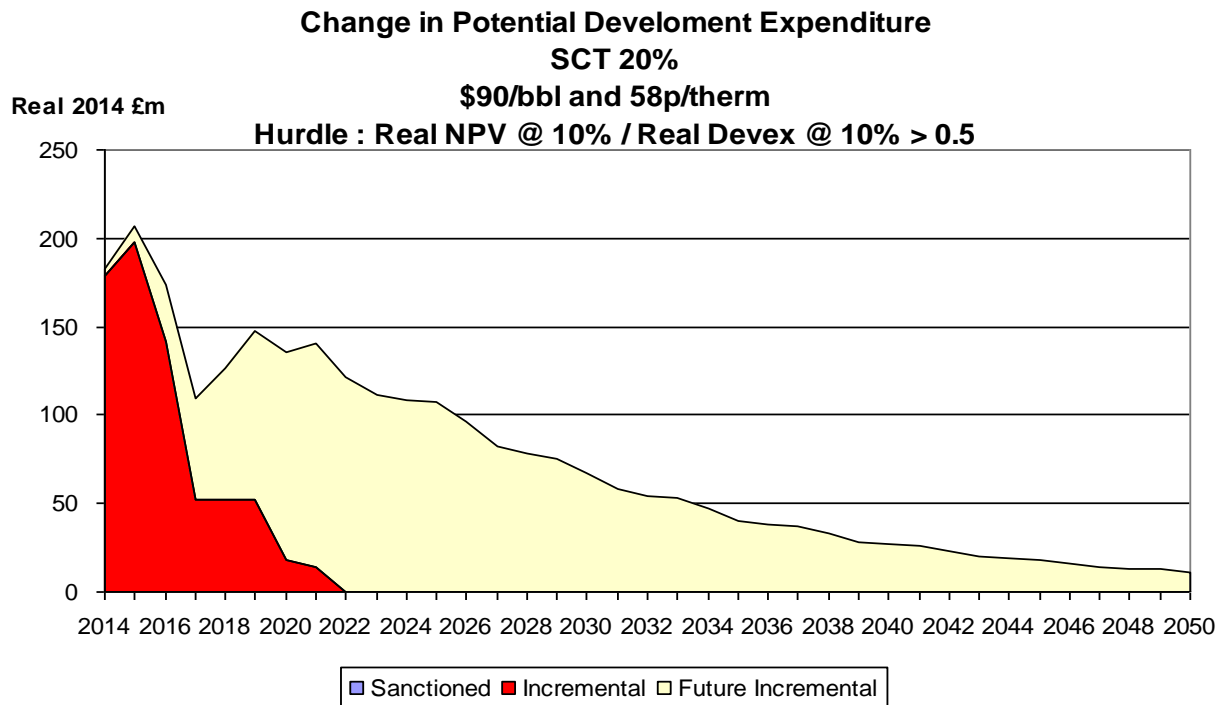
On new fields the increase is £13.8 bn. The resulting total change in development expenditures are shown in Chart 75. There is a major increase in the period 2018-2028.

Chart 75

Change in Potential Development Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

☐ Cns / MF ☐ Irish ■ Nns ☐ SNS ■ WoS

53
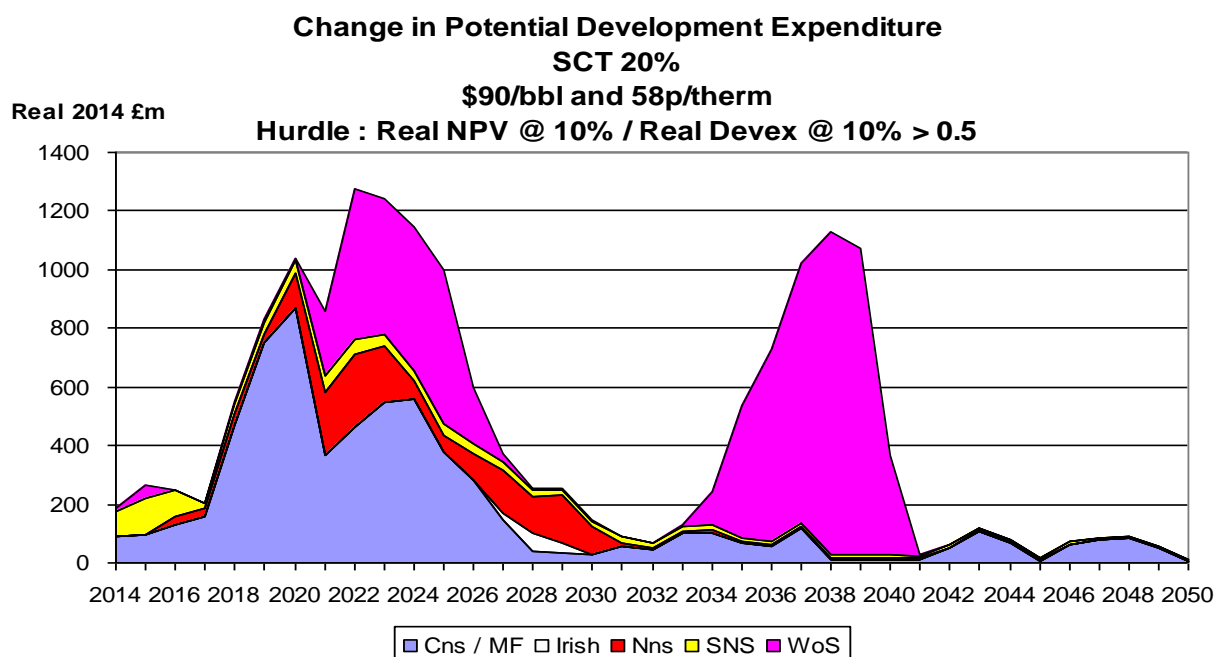
Operating costs on incremental projects increase by over £900 million (See Chart 76).

Chart 76

Change in Potential Operating Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
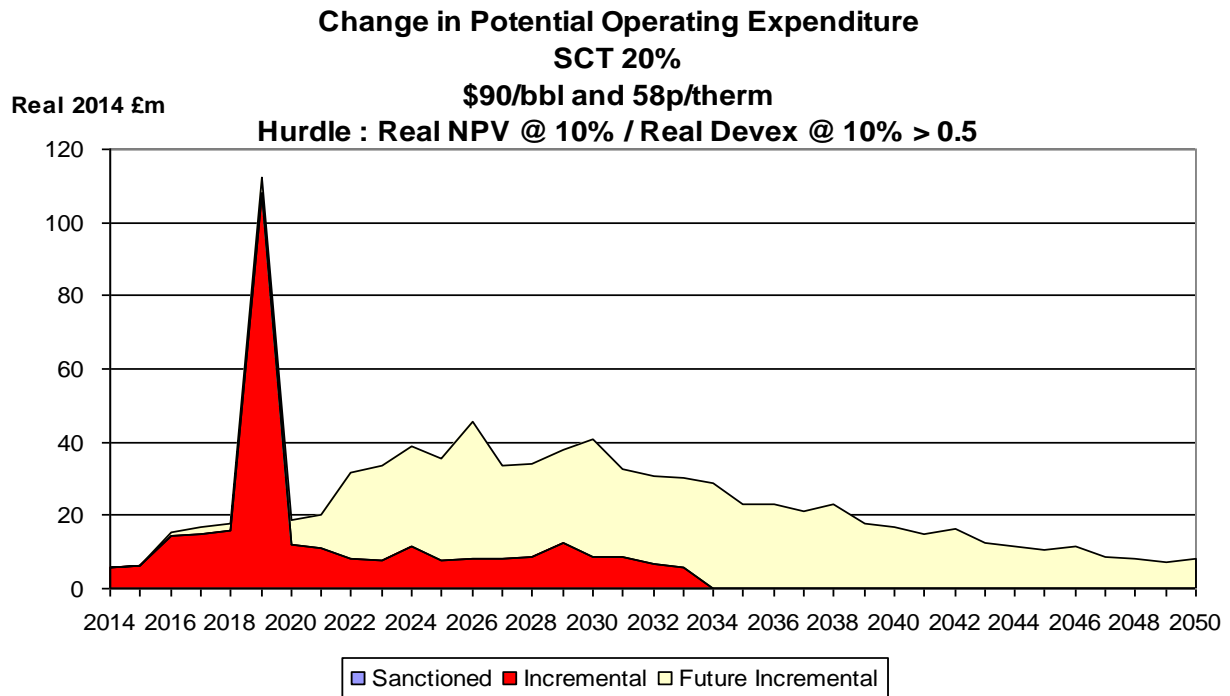
On future new fields the increase is £11.3 bn (See Chart 77).

Chart 77

Change in Potential Operating Expenditure
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

54
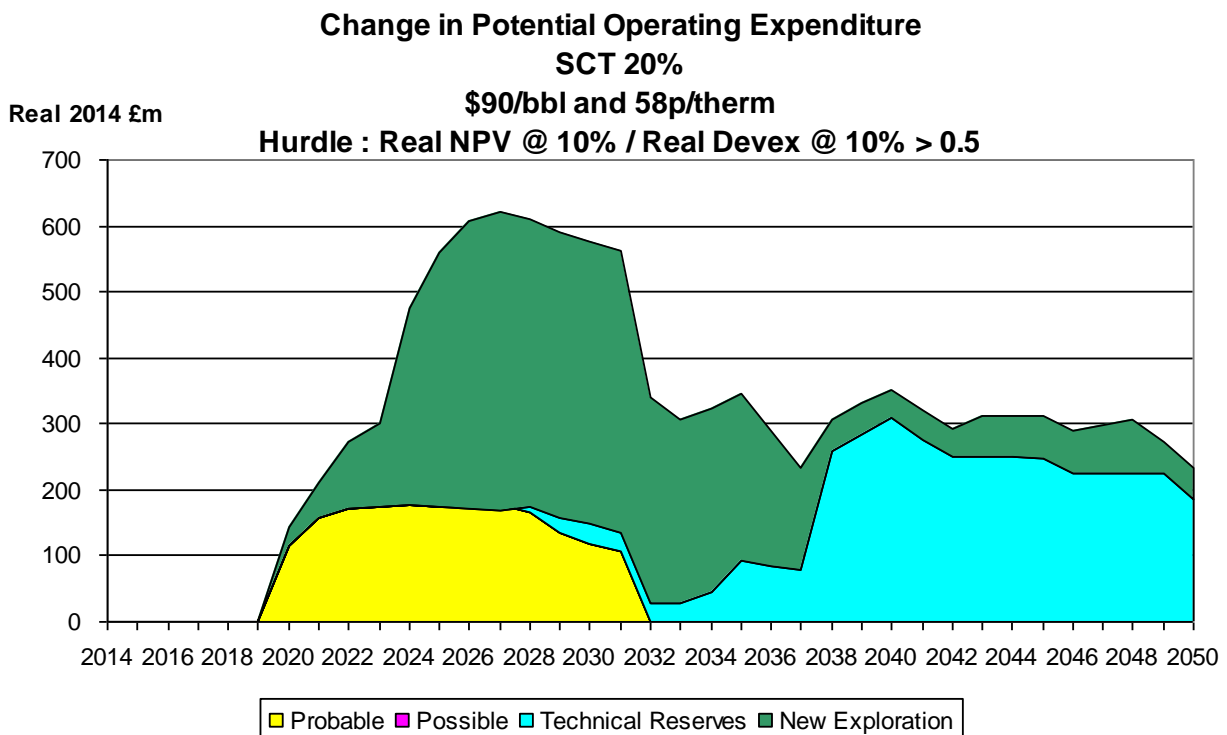
Tax revenues attributable to new field developments increase by £2.9 bn over the period (See Chart 78).

Chart 78

Change in Potential Tax Revenue
SCT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

[Area chart with y-axis from -1000 to 1000 (Real 2014 £m) and x-axis years from 2014 to 2050. Legend: Probable (yellow), Possible (magenta), Technical Reserves (cyan), New Exploration (dark green).]
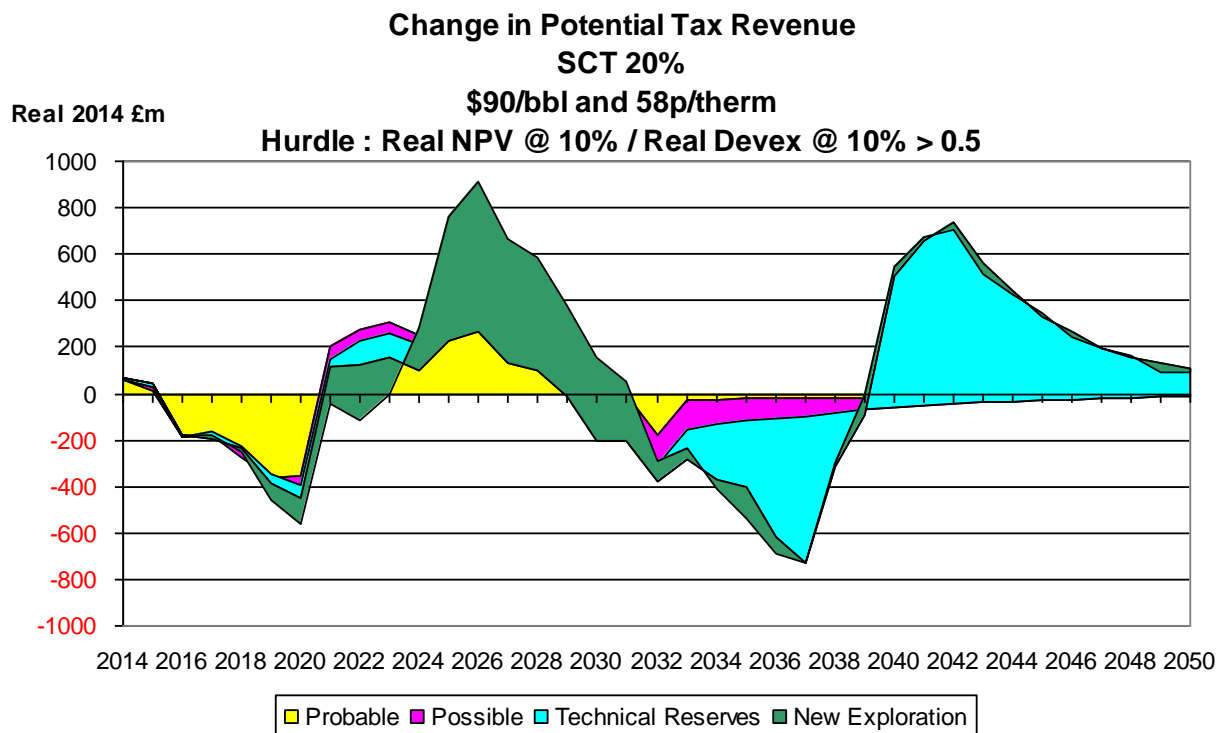
(p)Effects with SC at 20% but No Field Allowances, Hurdle NPV/I > 0.3, Full Tax-Paying Investor

If the SC rate were reduced to 20% but all field allowances were removed from unsanctioned fields and projects there would be a net reduction of 23 future fields which passed the hurdle. But this disguises an increase of 7 fields. The tax change would also lead to 3 further incremental projects being triggered. The change in oil production from incremental projects is shown in Chart 79 and from new fields in Chart 80.

Chart 79

Change in Potential Oil Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Chart 80

Change in Potential Oil Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3
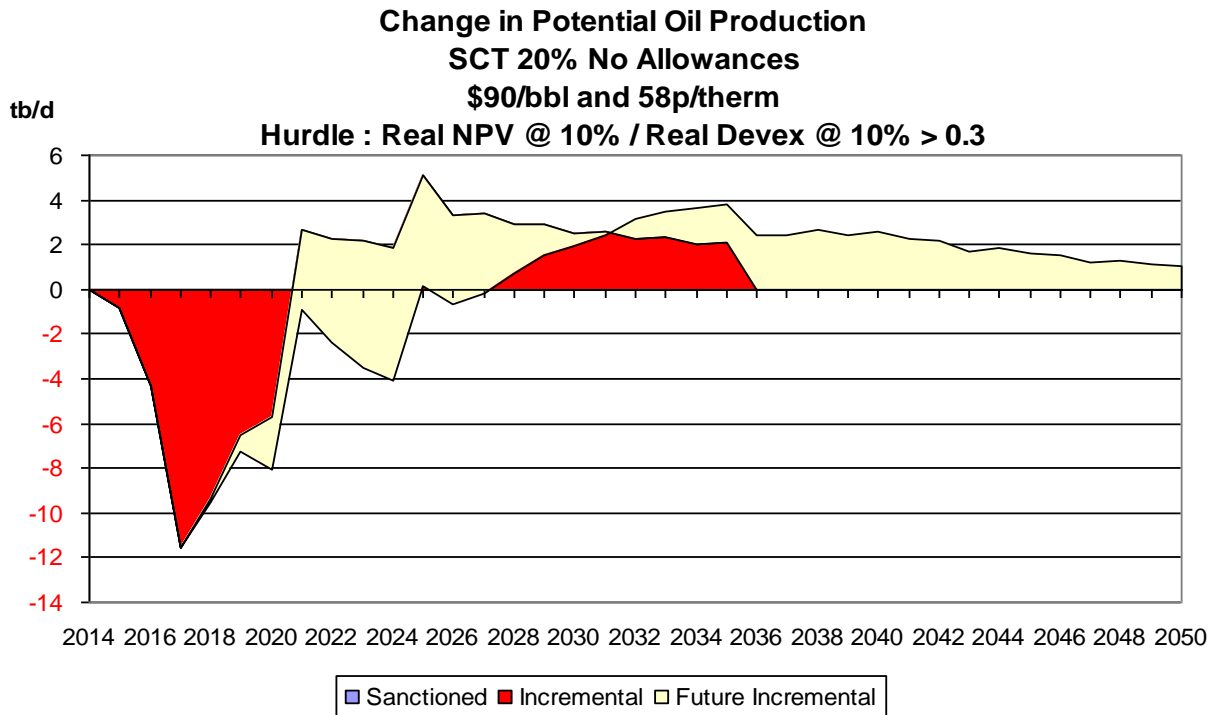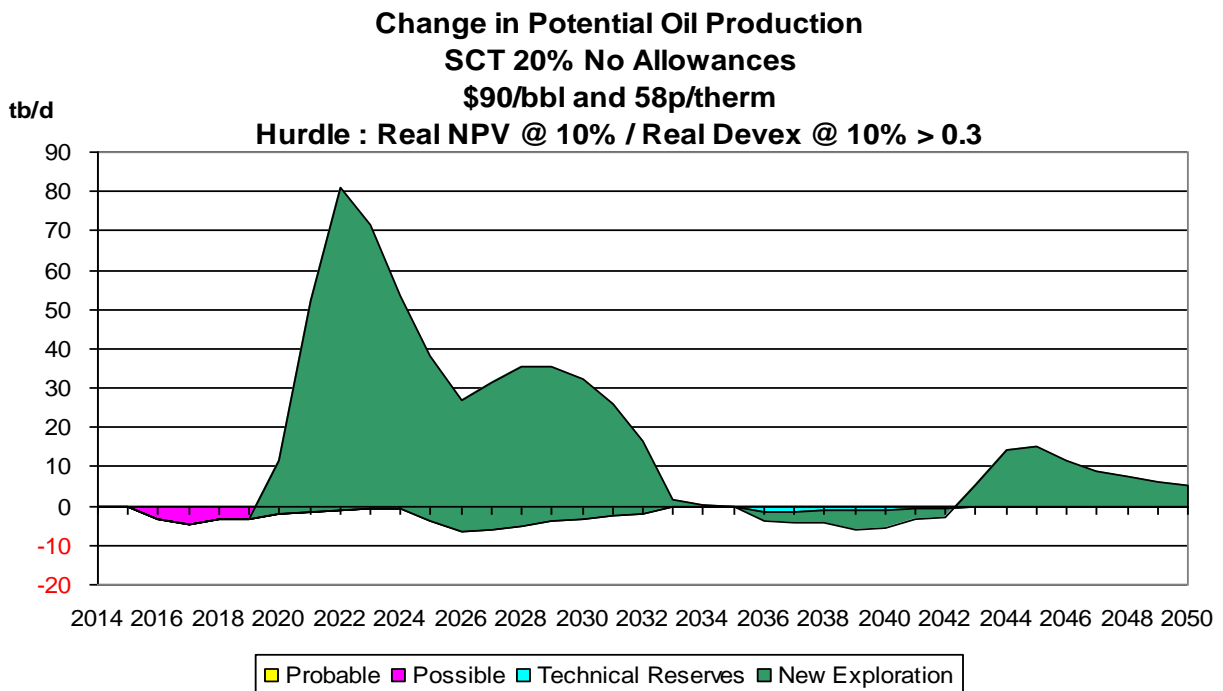
There is an increase in gas production of 40 mmboe from incremental projects (See Chart 81).

56

Chart 81

**Change in Potential Gas Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

mmcf/d

Sanctioned ■ Incremental □ Future Incremental
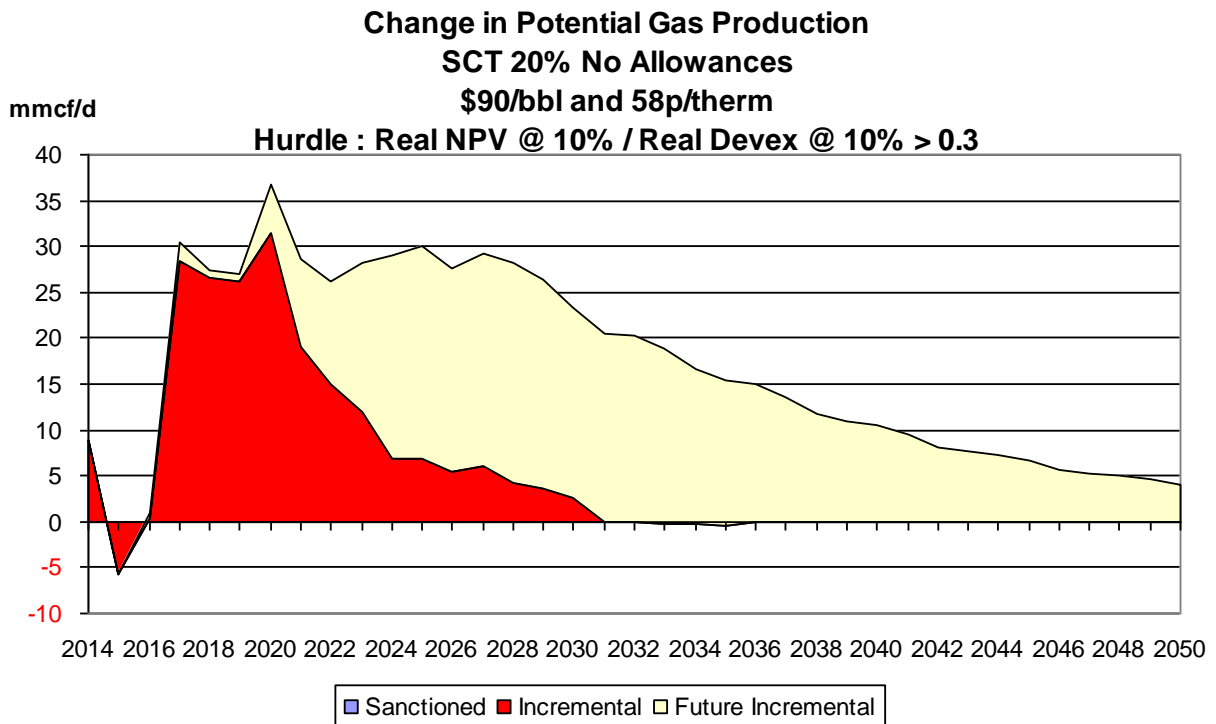
But there is a decrease in gas production from new fields of 103 mmboe (See Chart 82).

Chart 82

**Change in Potential Gas Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

mmcf/d

□ Probable ■ Possible □ Technical Reserves ■ New Exploration

57
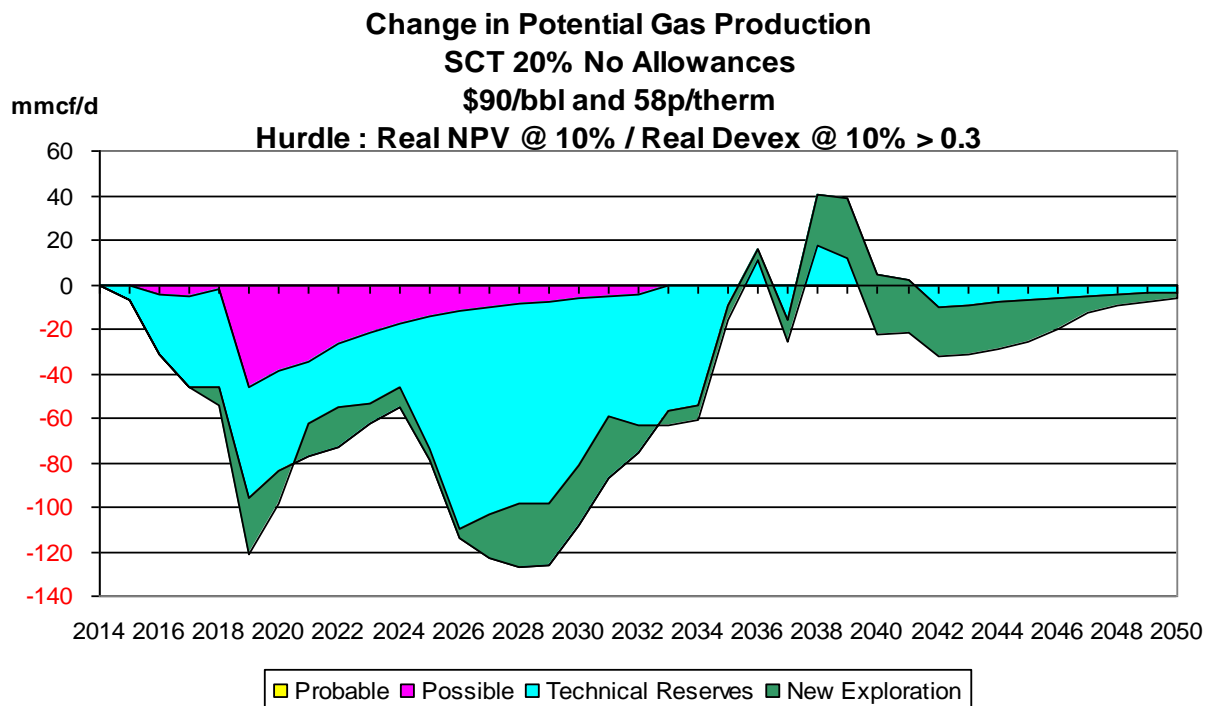
There is an increase in total hydrocarbon production of 139 mmboe
(See Chart 83).

Chart 83

**Change in Potential Total Hydrocarbon Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Tboe/d
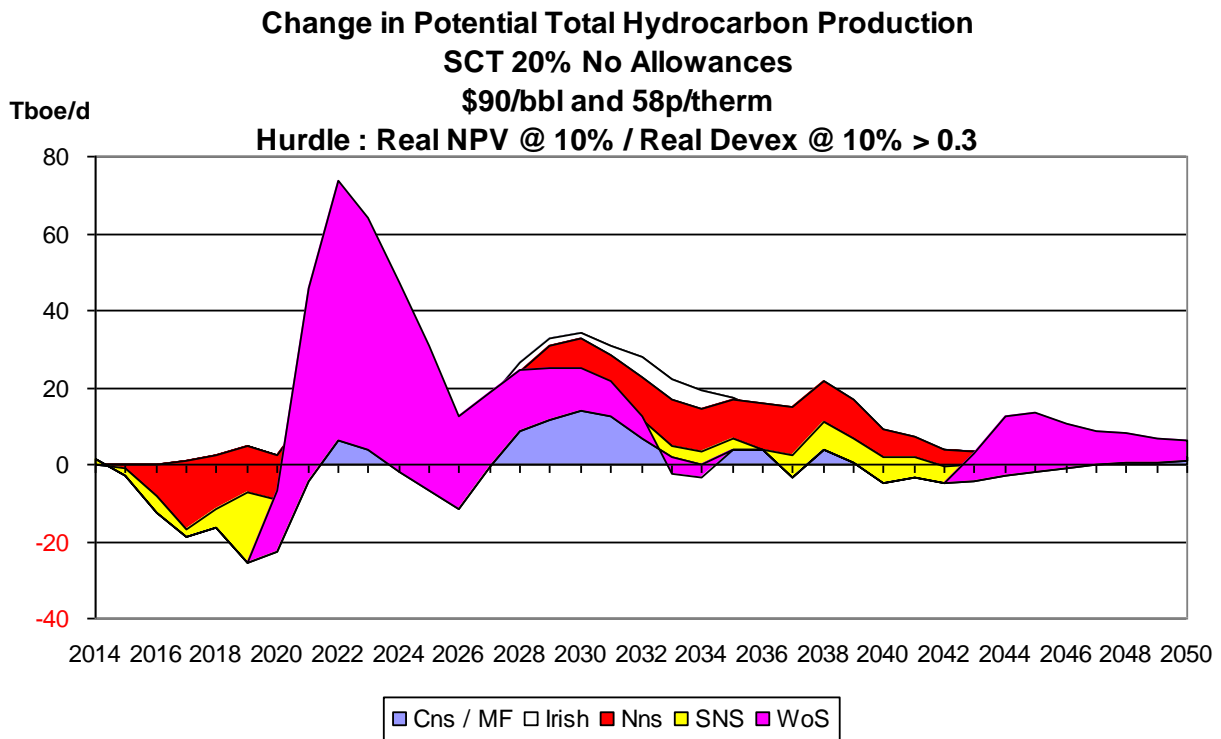
Development expenditures on all fields and projects increase by £2.15
bn (See Chart 84).

Chart 84

**Change in Potential Development Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

58
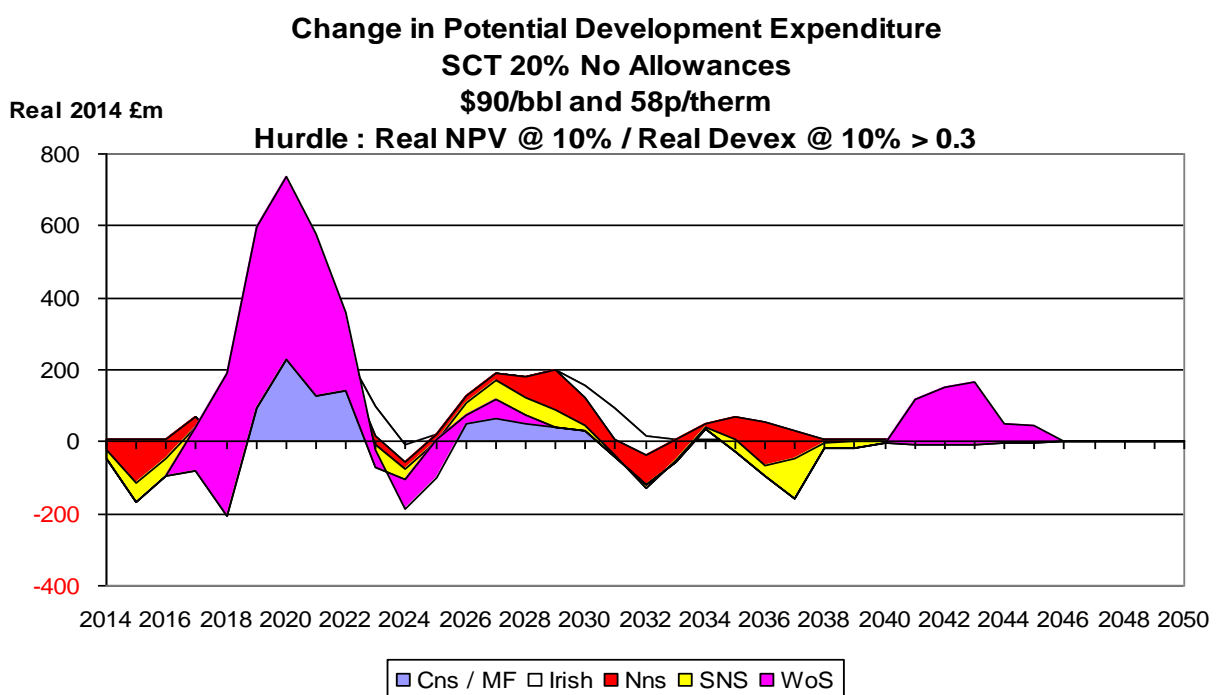
Field operating expenditures increase by £772 million (See Chart 85).

Chart 85

**Change in Potential Operating Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Legend: Cns / MF · Irish · Nns · SNS · WoS
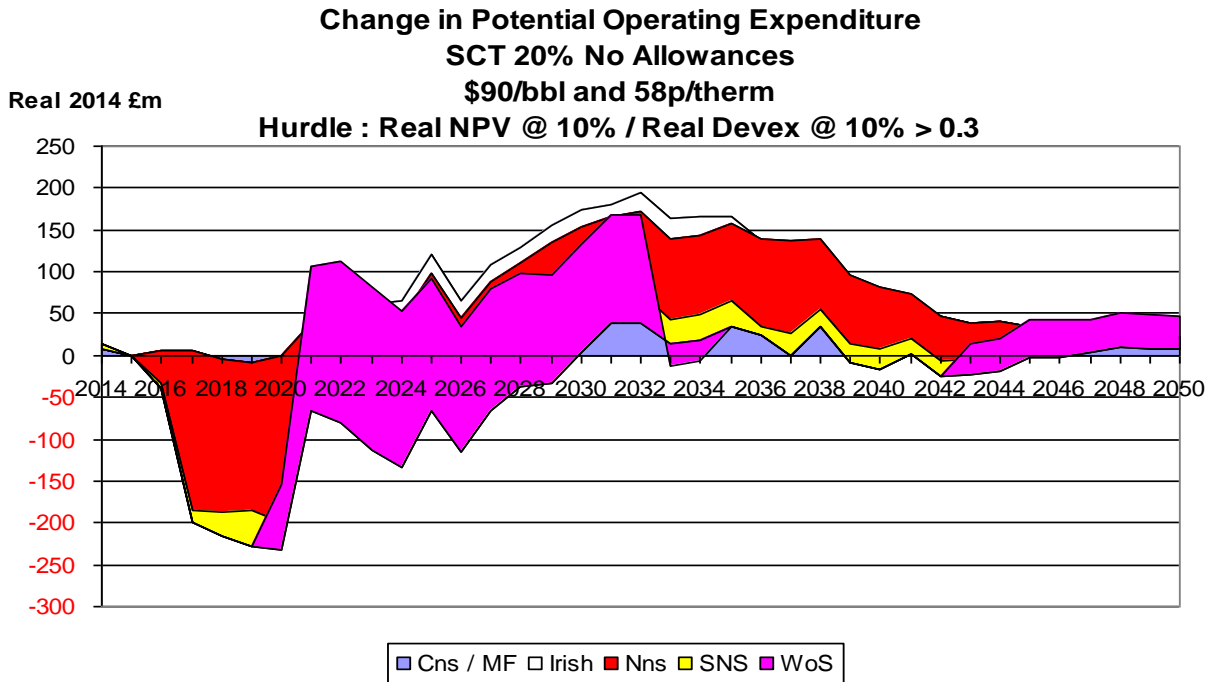
Tax revenues from future fields decrease by £7.26 billion (See Chart 86). The modelling is based on all investors being in a full tax-paying position.

Chart 86

**Change in Potential Tax Revenue
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3**

Real 2014 £m

Legend: Probable · Possible · Technical Reserves · New Exploration

59
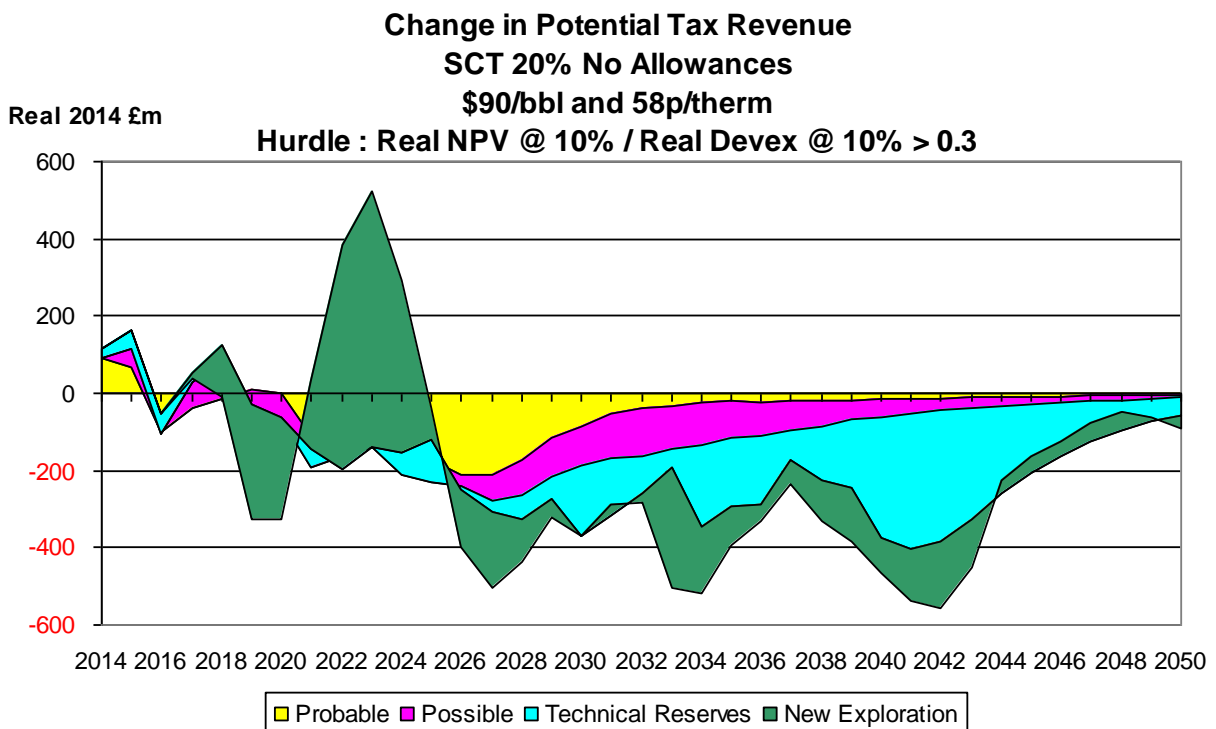
(q) Effects with SC at 20%, No Field Allowances, Hurdle NPV/I > 0.5, Full Tax-Paying Investor

If the investment hurdle were NPV/I > 0.5 there is a net decrease of 19 new field developments and a net increase of 3 incremental projects. It should be noted that there are 9 additional new field developments. There is an increase in total oil production of 582 mmboe (See Chart 87).

Chart 87

**Change in Potential Oil Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Legend: Cns / MF, Irish, Nns, SNS, WoS
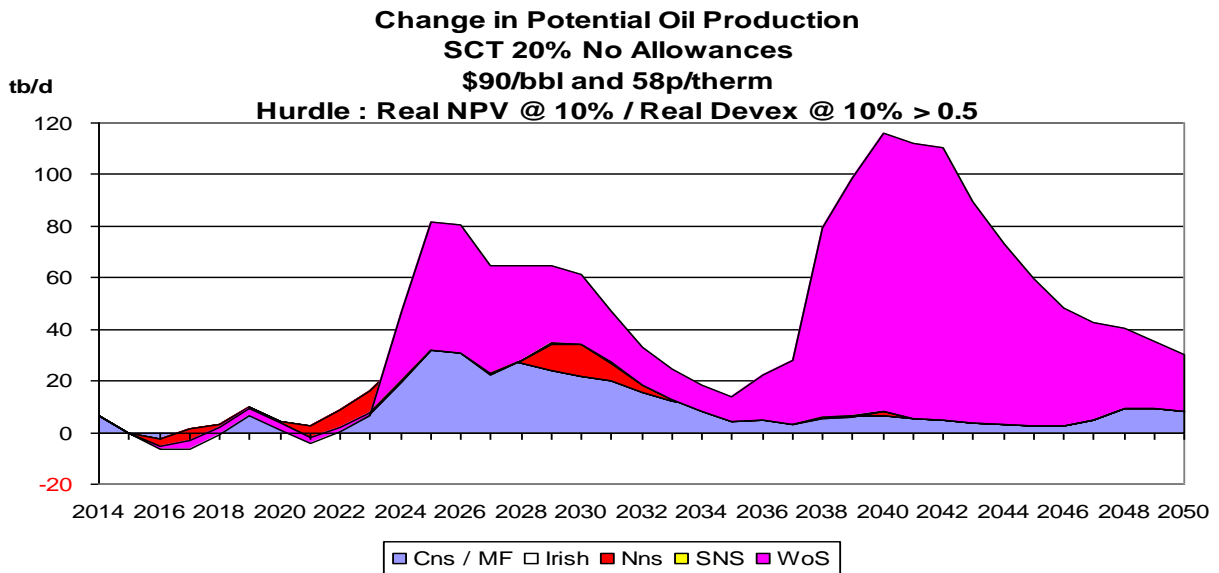
There is a net increase of 105 mmboe in gas production, but this involves reductions from some fields (See Chart 88).

Chart 88

**Change in Gas Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Legend: Cns / MF, Irish, Nns, SNS, WoS
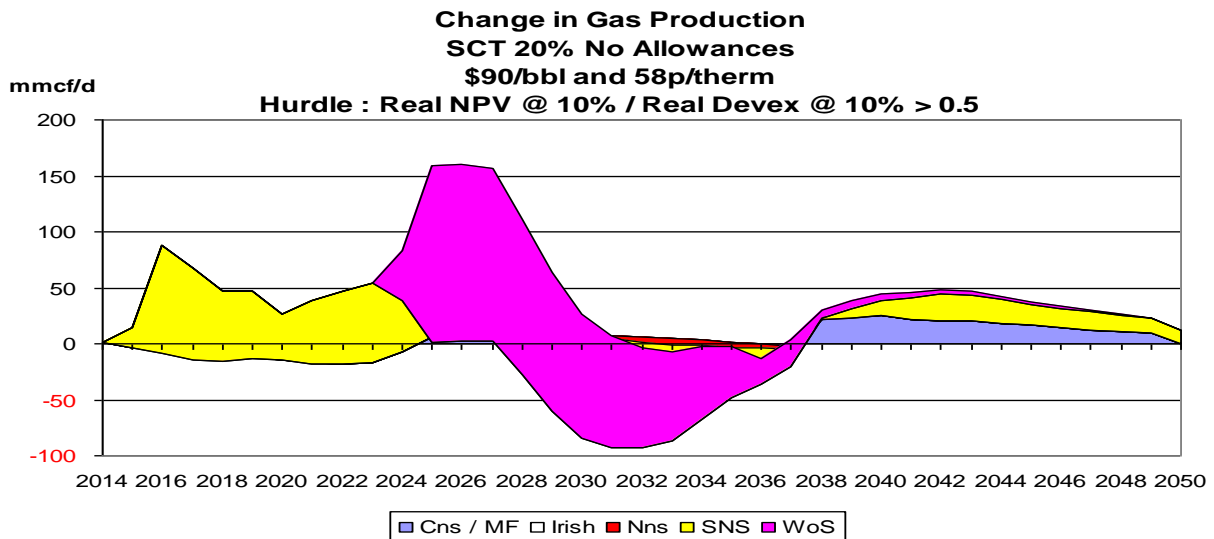
The overall net increase in total hydrocarbon production is 687 mmboe (See chart 89).

Chart 89

Change in Potential Total Hydrocarbon Production
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Tboe/d

Cns / MF   Irish   Nns   SNS   WoS
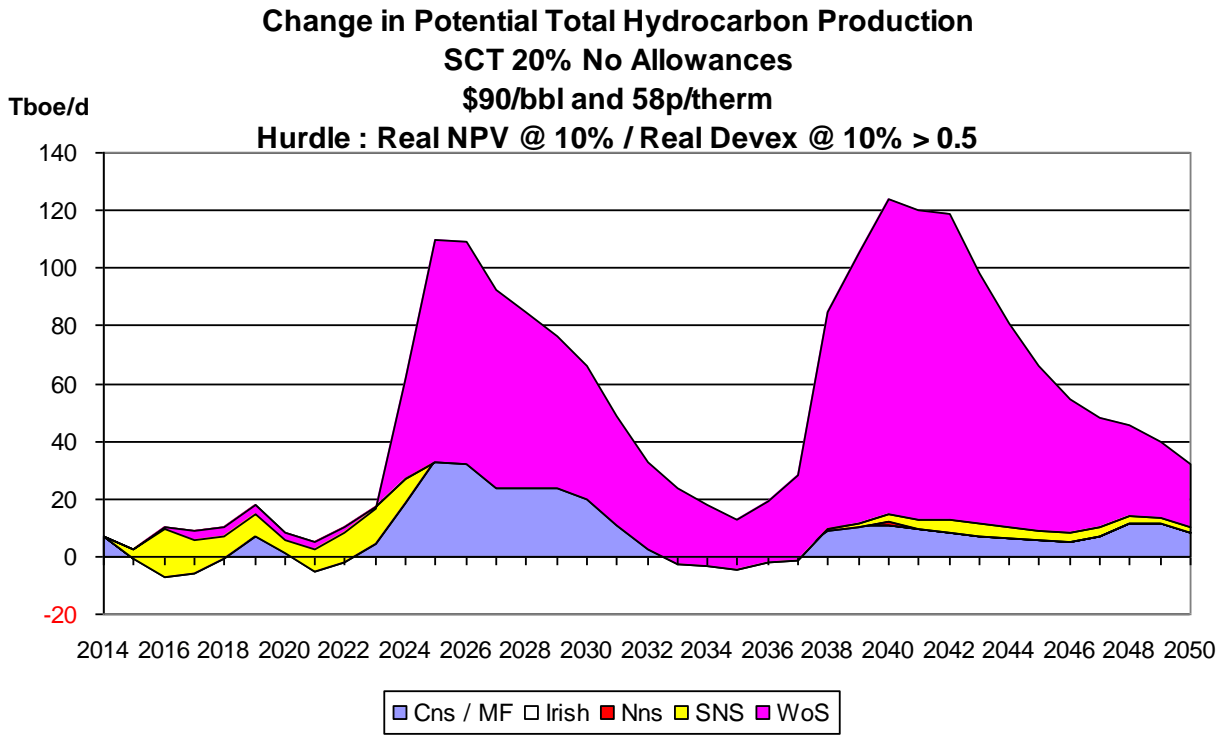
Development expenditure on incremental projects increases by £2.2 bn (See Chart 90).

Chart 90

Change in Potential Develoment Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m

Sanctioned   Incremental   Future Incremental
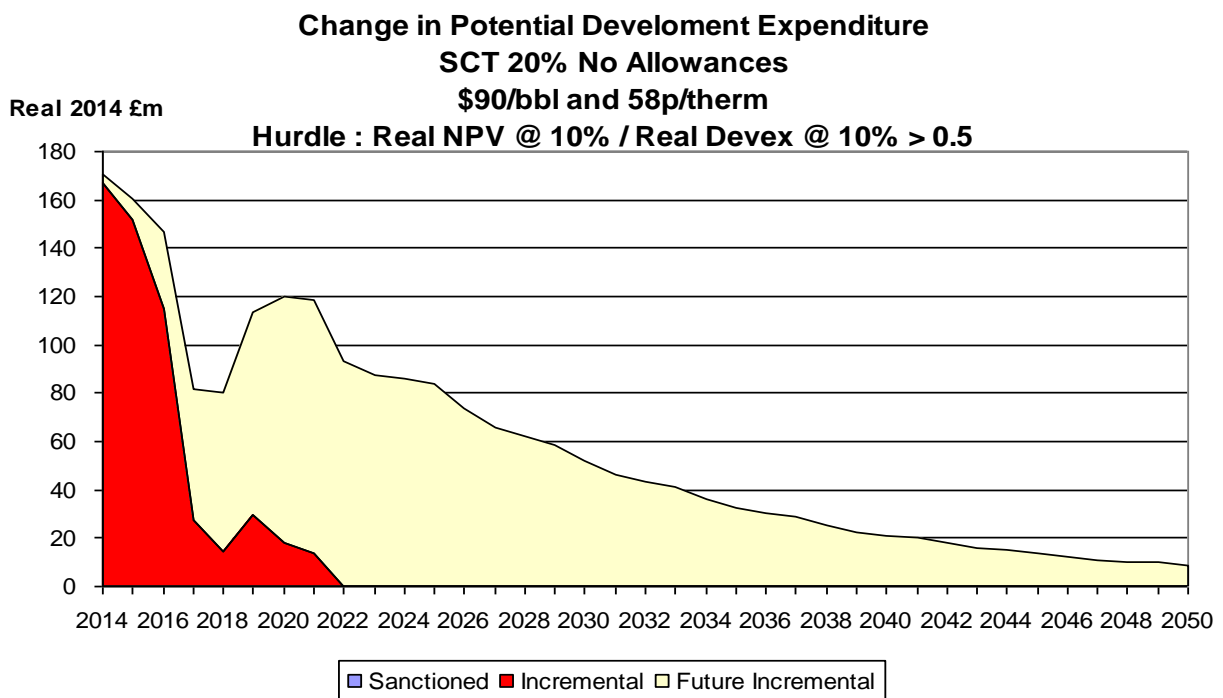
On new field developments the increase is over £6.6 billion (See Chart 91).

Chart 91

**Change in Potential Develoment Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Real 2014 £m
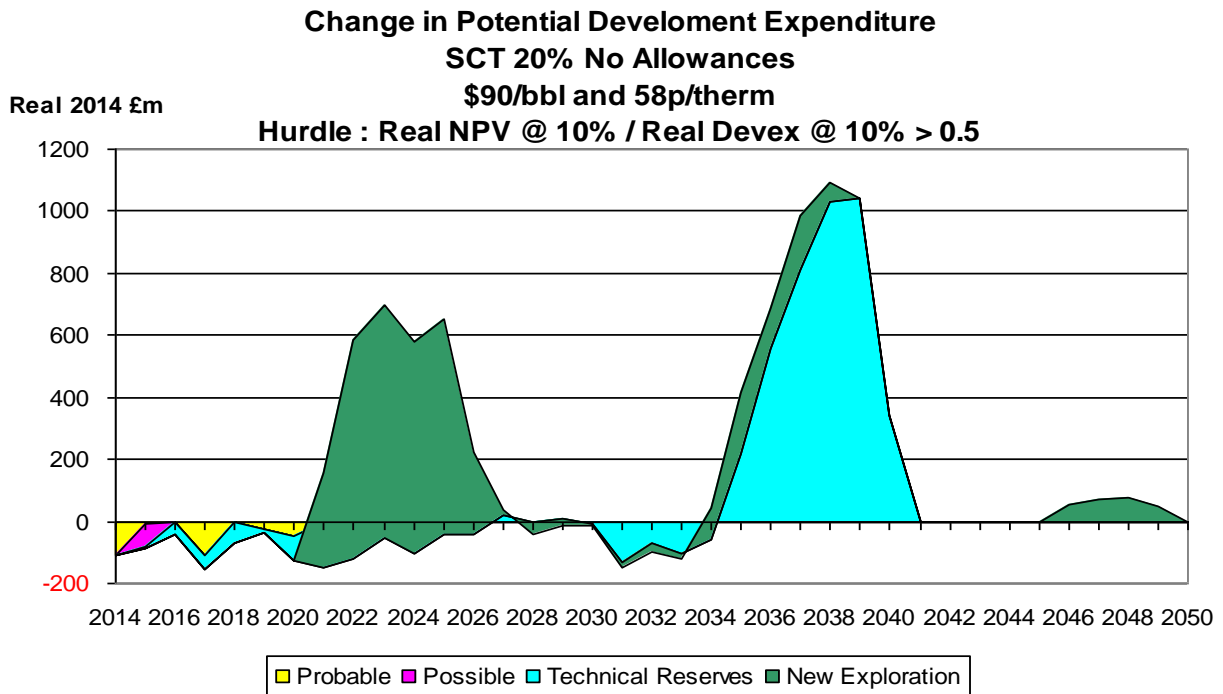
The increase on incremental projects is followed by a substantial increase on new fields. Operating costs increase by £894 million on incremental projects (See Chart 92).

Chart 92

**Change in Potential Operating Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5**

Real 2014 £m

62
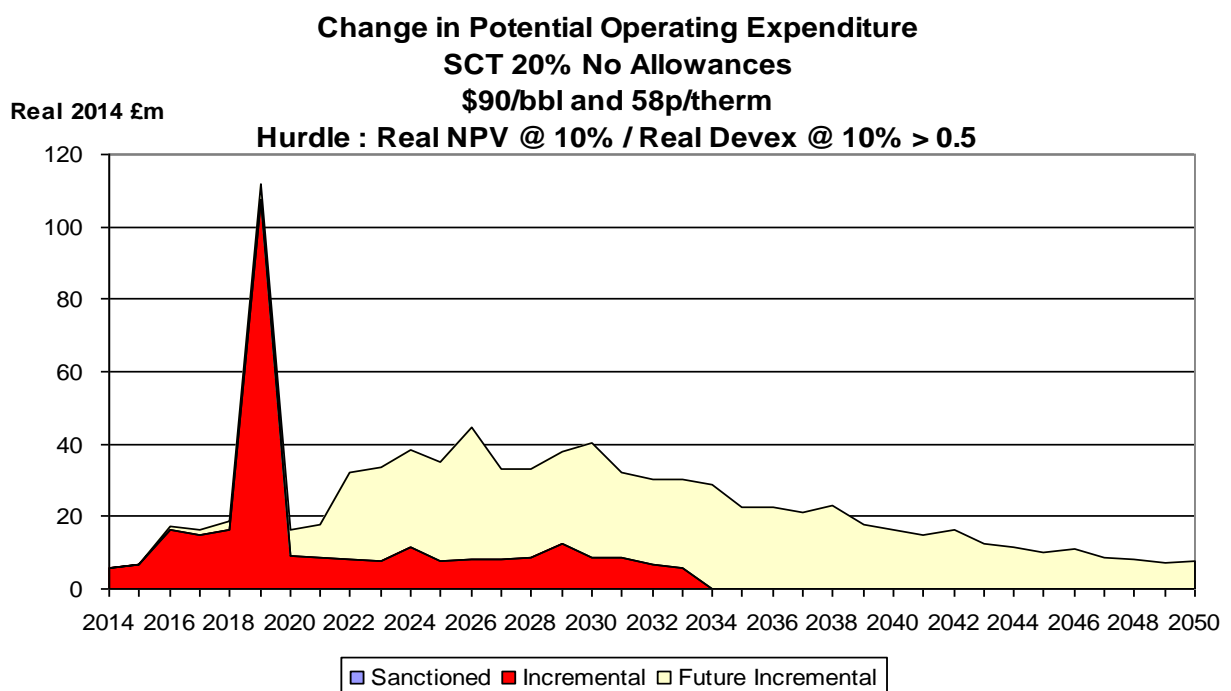
On new fields they increase by £5.2 billion (See Chart 93).

Chart 93

Change in Potential Operating Expenditure
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
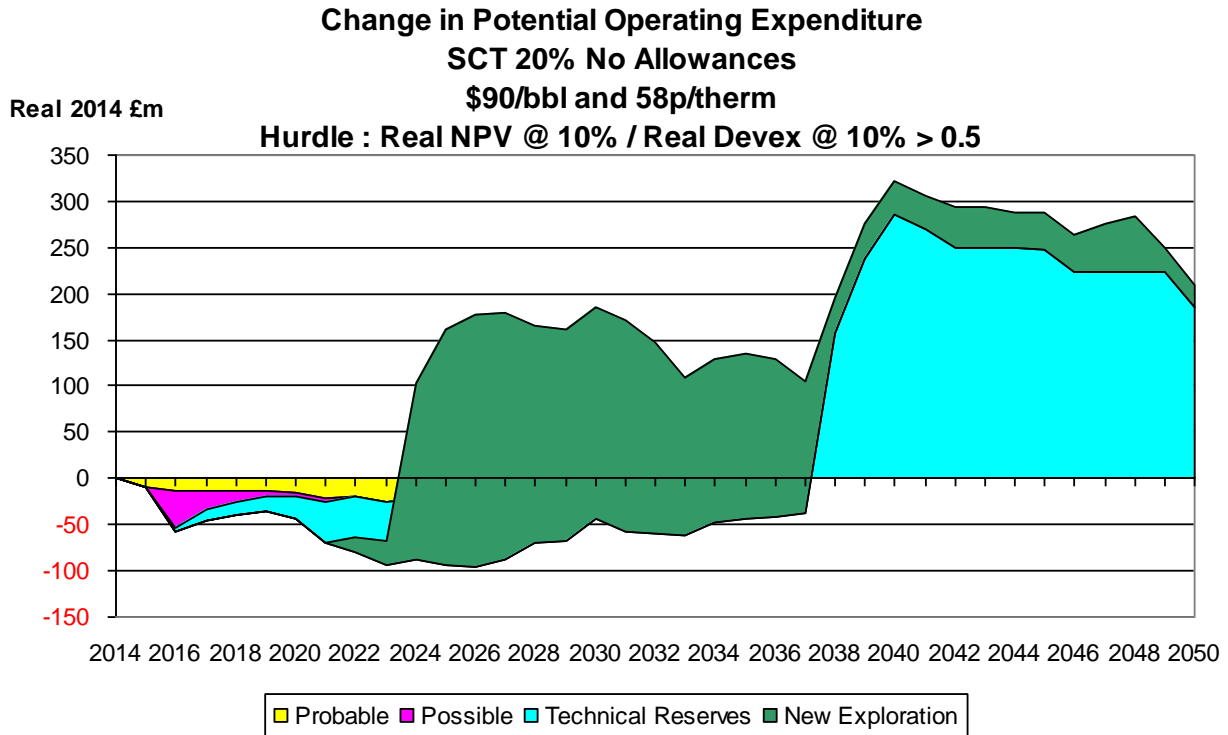
Tax revenues from new fields increase by £894 million (See Chart 94).

Chart 94

Change in Potential Tax Revenue
SCT 20% No Allowances
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

63
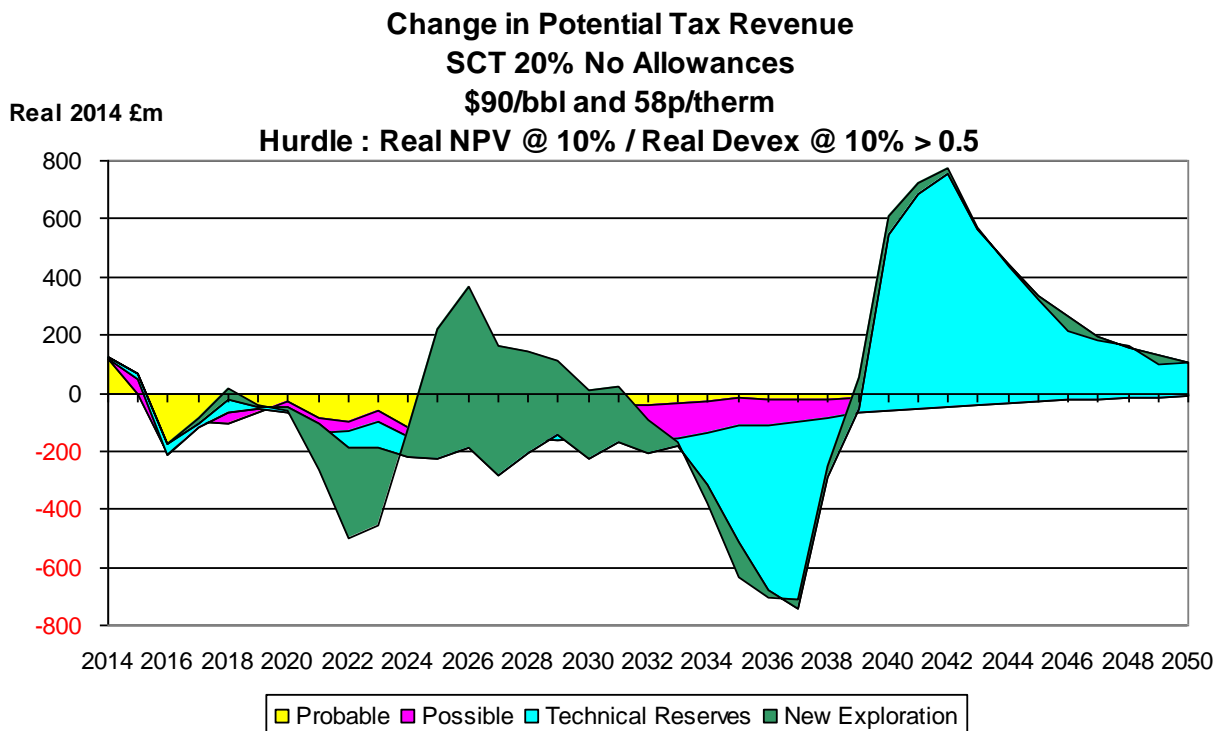
There are net reductions for a substantial period.

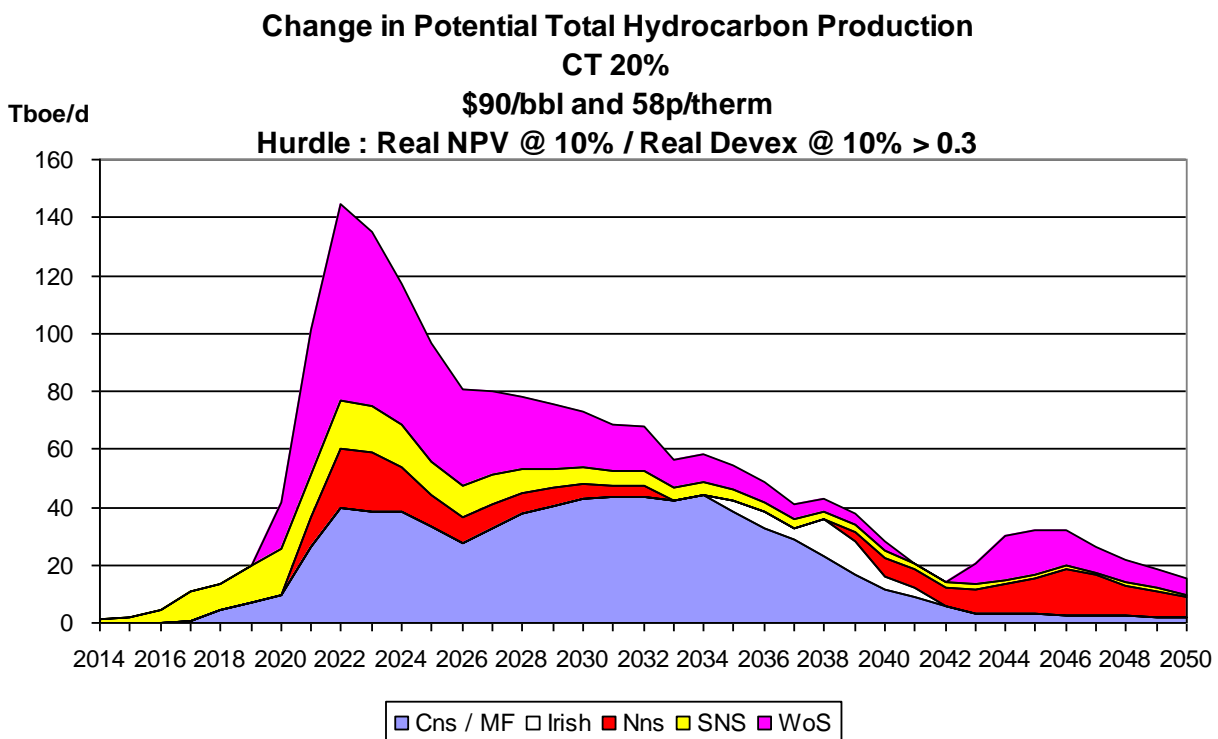**(r) Effects with CT at 20% and SC at 32% with Current Allowances, Hurdle NPV/I > 0.3, Investor in Full Tax-Paying Position**

With CT reduced to 20% but all other tax arrangements as at present, and with the hurdle at NPV/I > 0.3 there is an increase in the number of new field developments of 20 plus 6 extra incremental projects. A reduction in the CT rate obviously reduces the effective rate but the changed structure of the system increases the relative value of field allowances. Oil production increases by 506 mmboe and gas production by 149 mmboe. The overall increase in total hydrocarbon production is 661 mmboe (See Chart 95).

Chart 95

Change in Potential Total Hydrocarbon Production
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Tboe/d

Cns / MF   Irish   Nns   SNS   WoS

Development expenditure increases by £966 million on incremental projects (See Chart 96) and by £8.9 billion a few fields (See Chart 97).

Chart 96

Change in Potential Develoment Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Real 2014 £m

Sanctioned ■ Incremental □ Future Incremental

Chart 97

Change in Potential Develoment Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

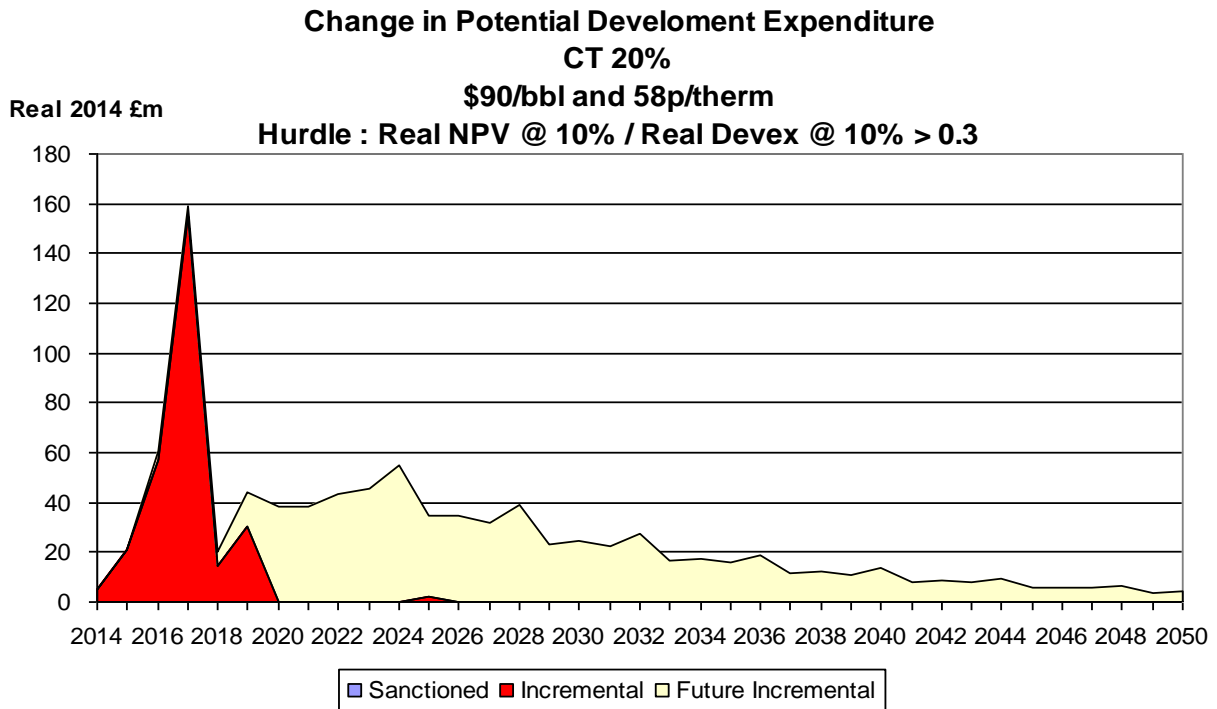Real 2014 £m

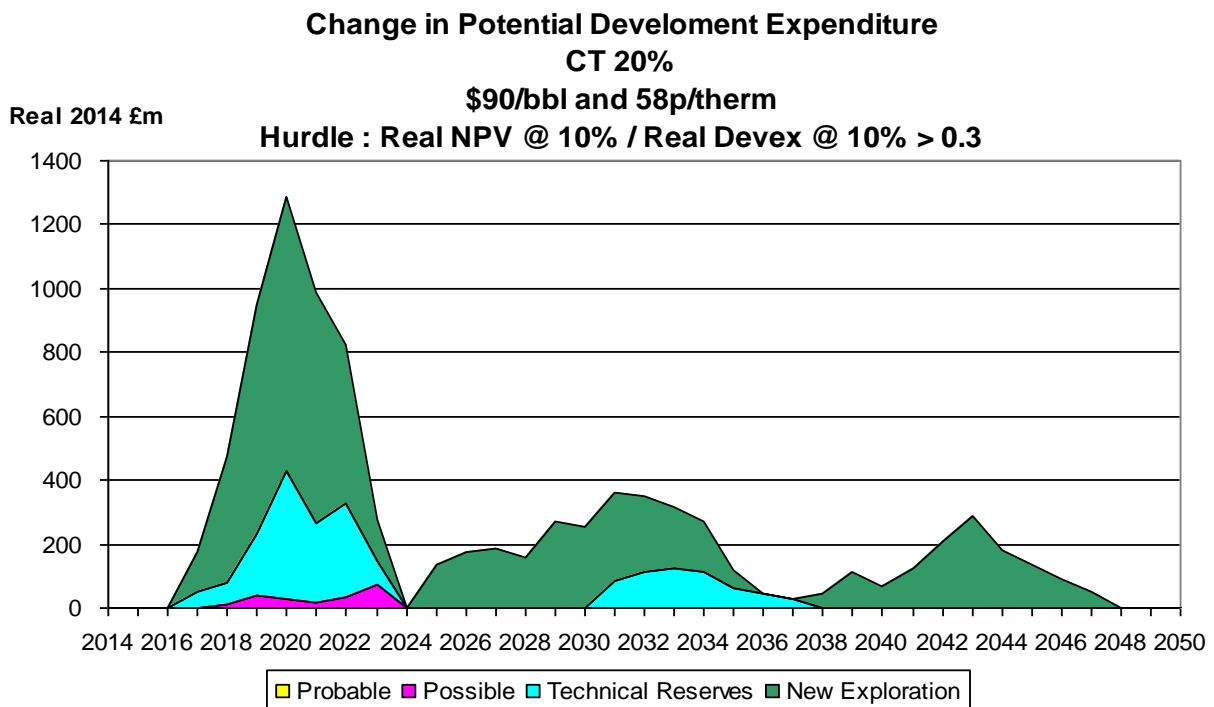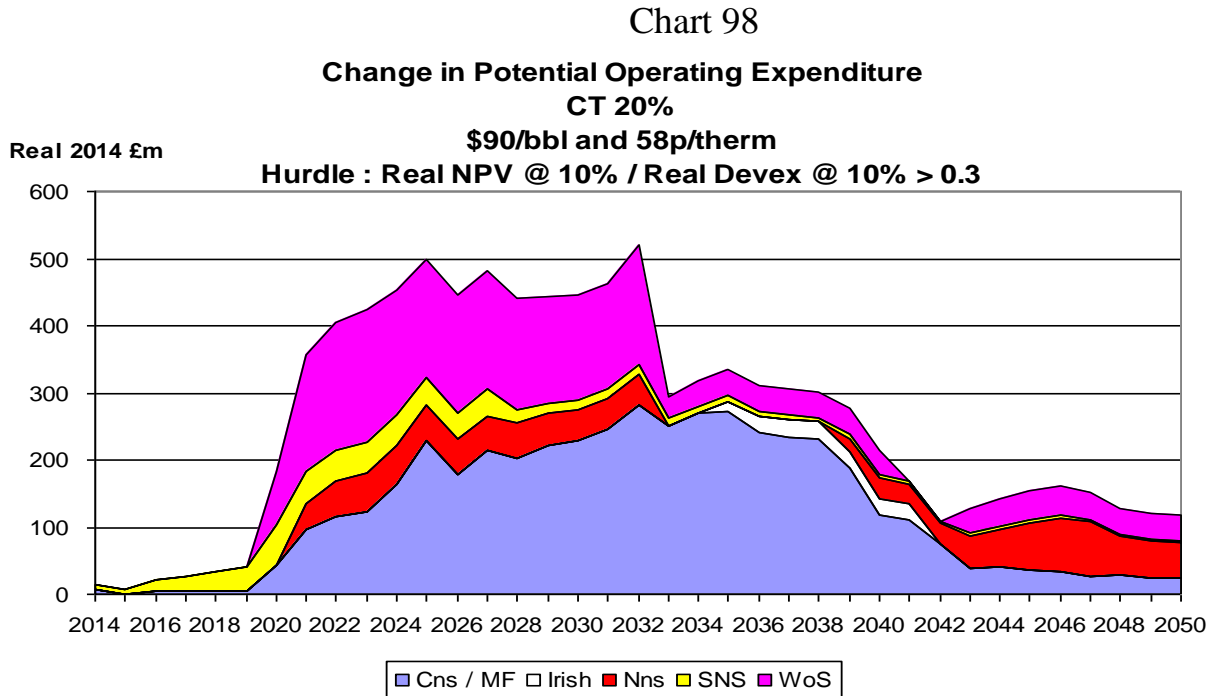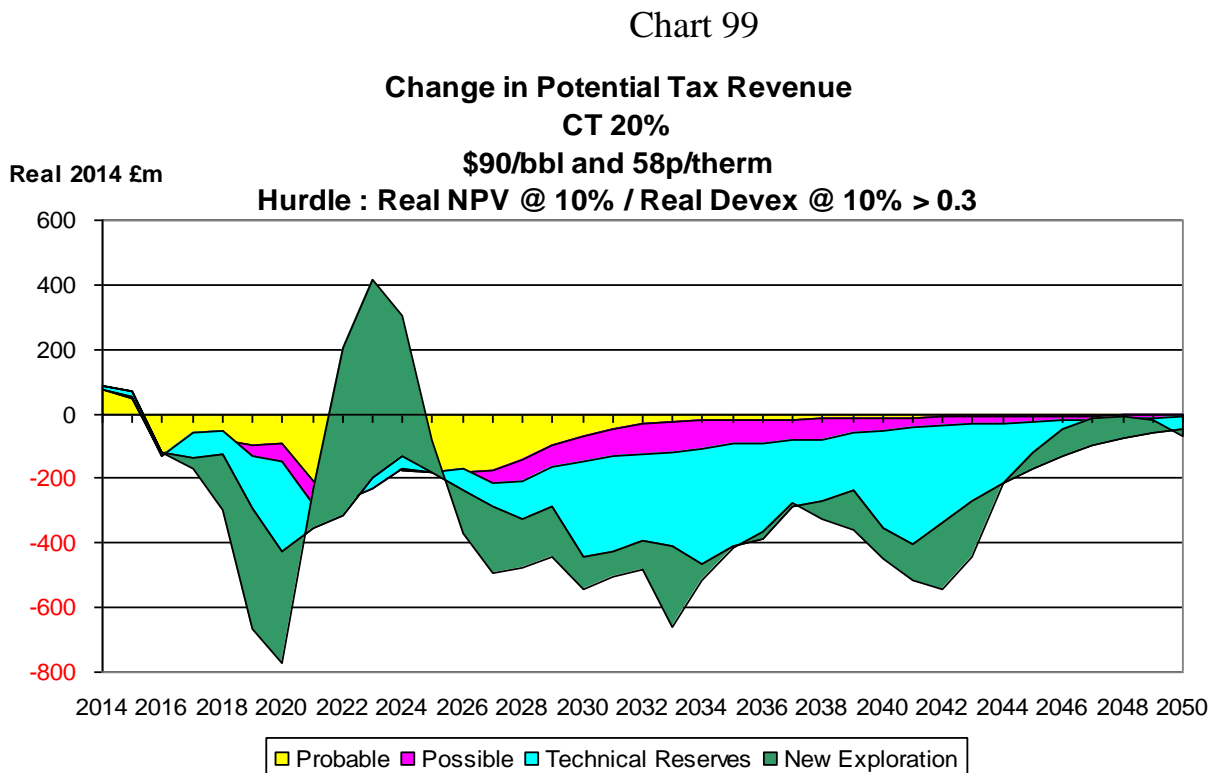

□ Probable ■ Possible □ Technical Reserves ■ New Exploration

65

Operating expenditures increase by £1.9 billion on incremental projects and by £5.85 billion on new fields. The total increase is shown in Chart 98.

Chart 98

Change in Potential Operating Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Real 2014 £m

Legend: Cns / MF, Irish, Nns, SNS, WoS

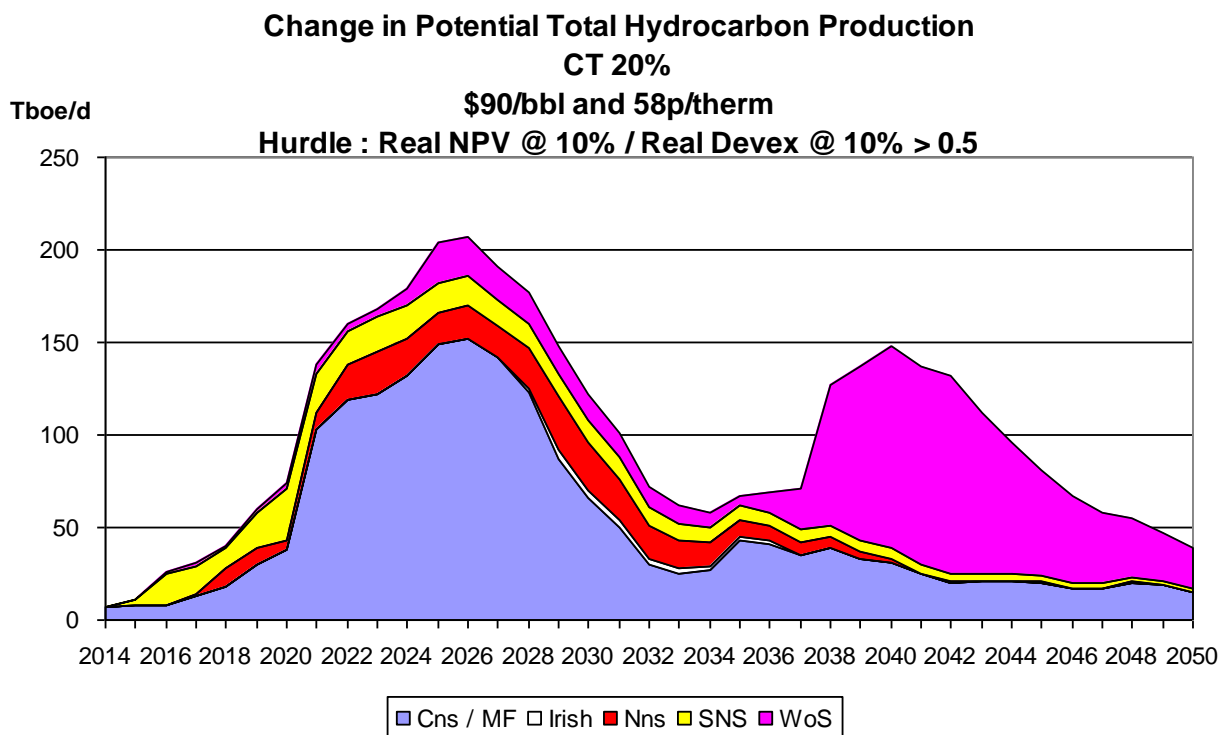On future fields there is a net decrease in tax receipts from future fields of £9.9 billion, despite the increase from fields triggered by the rate reduction. The results are shown in Chart 99.

Chart 99

Change in Potential Tax Revenue
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.3

Real 2014 £m

Legend: Probable, Possible, Technical Reserves, New Exploration

(s) Effects with CT at 20% and SC at 32% with Current Field Allowances, Hurdle NPV/I > 0.5, Investor in Full Tax-Paying Position

If the investment hurdle is NPV/I > 0.5 the tax reduction triggered the development of 27 extra new fields plus 6 extra incremental projects. There is an increase in production of 1.34 bnboe from all new fields and projects (See Chart 100).

Chart 100

Change in Potential Total Hydrocarbon Production
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

There is an increase in development expenditure of £3 bn on incremental projects (See Chart 101).

Chart 101

Change in Potential Develement Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m
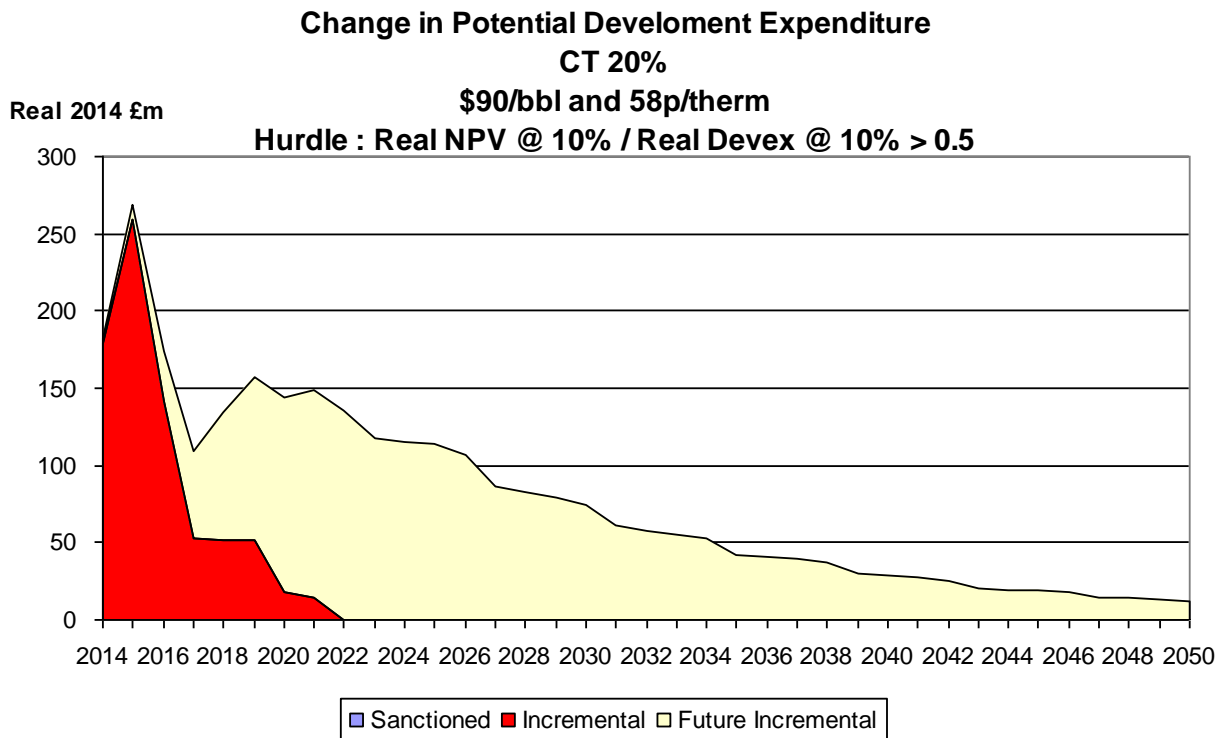
On new fields there is an increase in development expenditure of £14.6 bn (See Chart 102).

Chart 102

Change in Potential Develement Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

Real 2014 £m
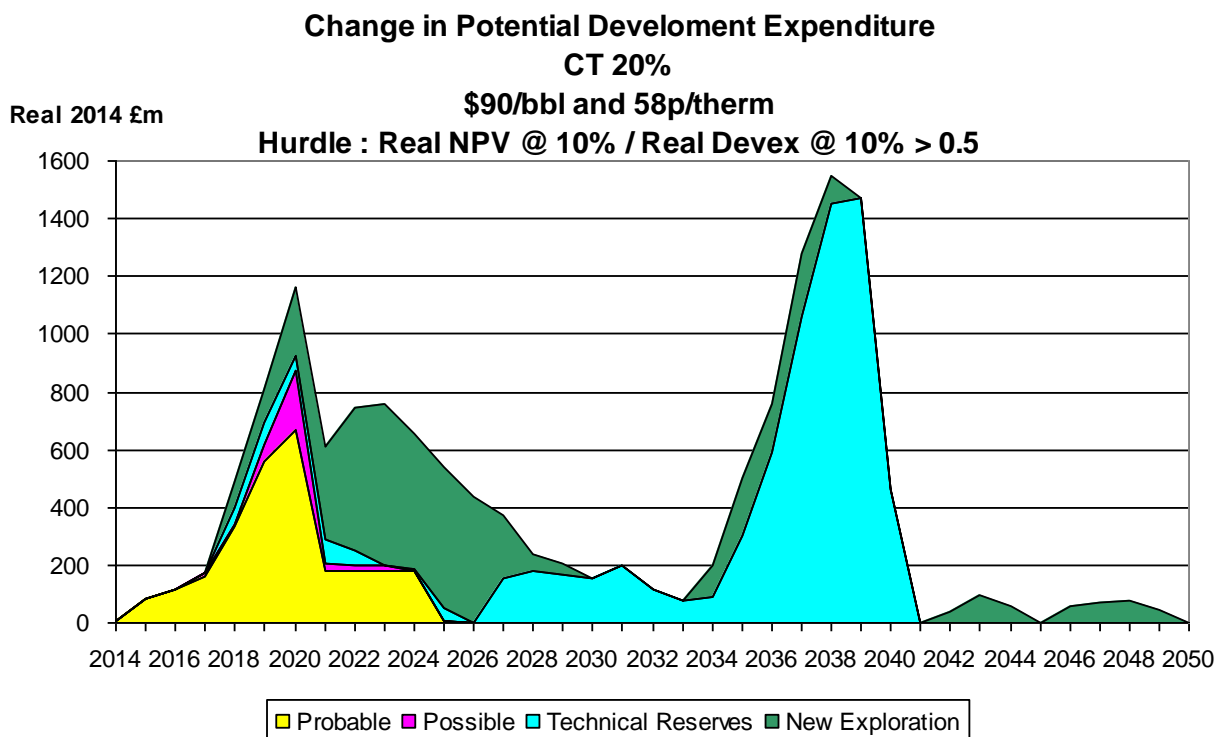
Aggregate operating expenditures increase by £11.8 billion (See Chart 103).

Chart 103

Change in Potential Operating Expenditure
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5
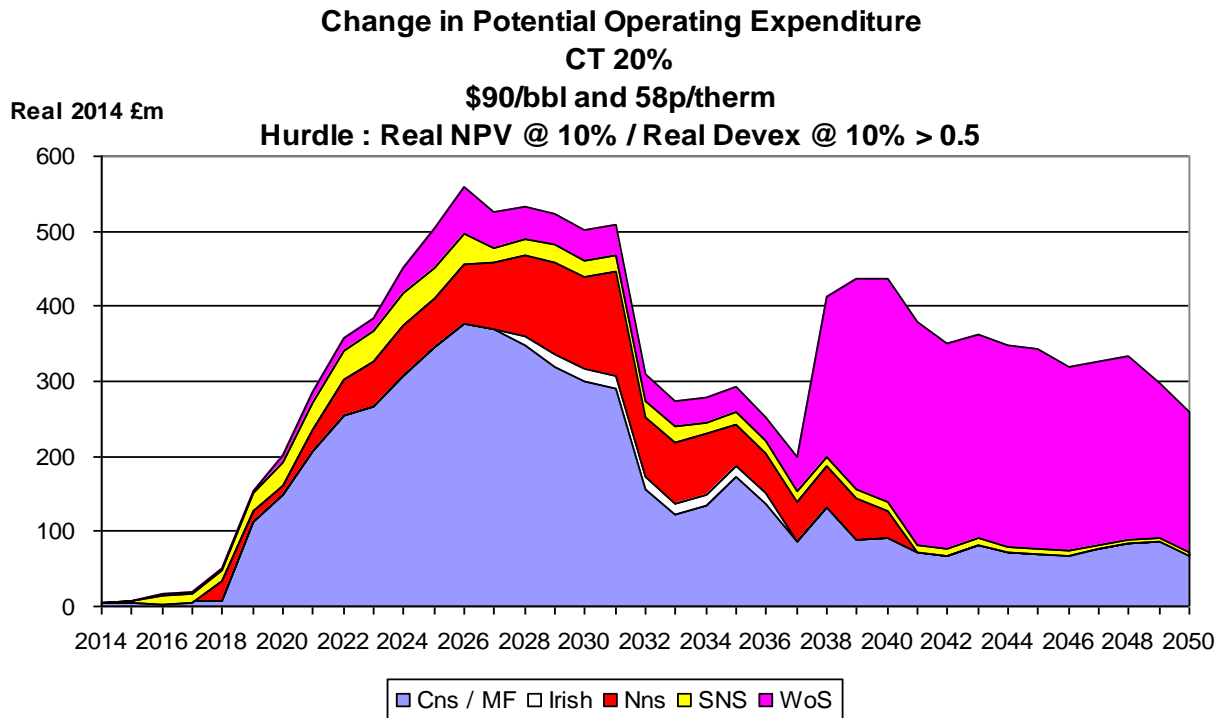
Tax revenues from new fields increase by £2.2 billion (See Chart 104).

Chart 104

Change in Potential Tax Revenue
CT 20%
$90/bbl and 58p/therm
Hurdle : Real NPV @ 10% / Real Devex @ 10% > 0.5

69
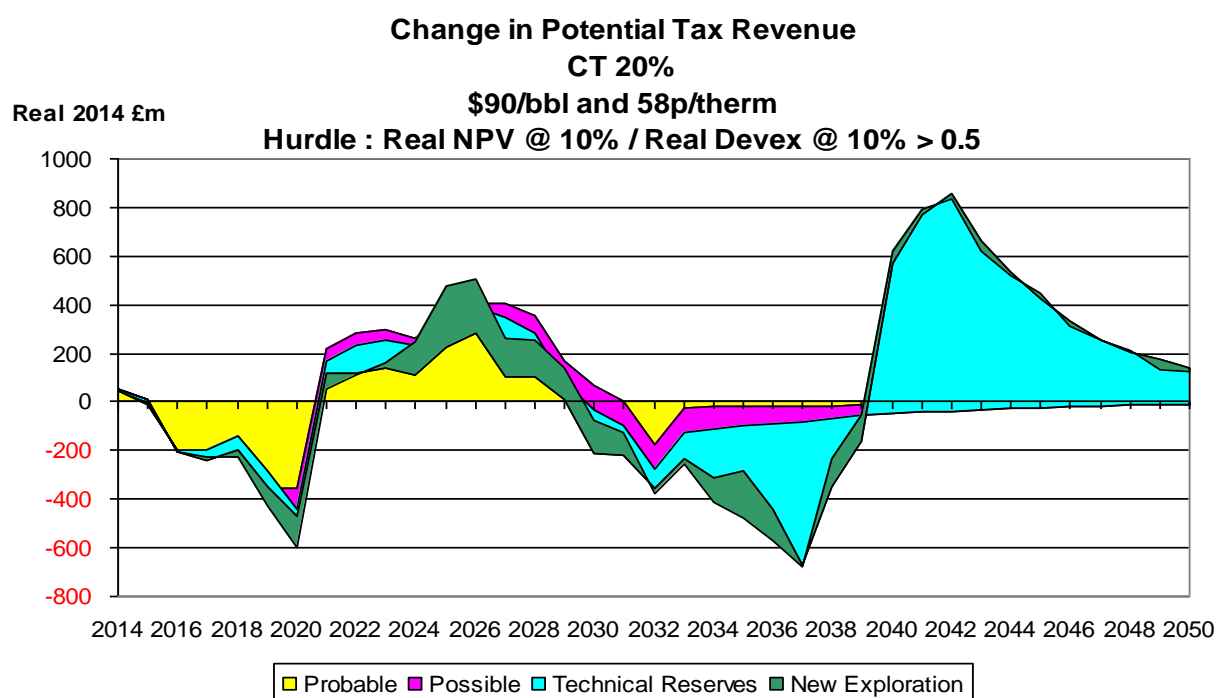
(t) EOR Schemes

There is a consensus among all stakeholders that efforts should be made to enhance the (economic) recovery factor on oil fields in particular from its present average of 45% or so. To date there has been only a limited amount of investment in tertiary recovery schemes. The costs pertaining to these activities in offshore situations are very high compared to onshore. For purposes of the Tax Review several EOR projects which are relevant to the present situation in the UKCS were examined. These are (1) Low Salinity Waterflood, (2) Polymer Flood (risked) (3) Polymer Flood (unrisked), and (4) Miscible Gas Injection. All have relatively high costs and risks and long payback periods. But the cost structures vary. While all have substantial capital costs the polymer flood schemes (particularly the risked case) and the miscible gas injection scheme have very high operating costs. The purchase of the polymers and the gas are included in the definition of operating costs. It is arguable that, fundamentally, these product purchases are akin to capital investment. The 4 projects were modelled on the assumption that the investor is in a full tax-paying position but the projects are not subject to PRT. The modelling results presented here emphasise pre-tax and post-tax NPVs at various real discount rates. This is to highlight the challenging nature of the investments. The post-tax returns are shown under the various tax arrangements already discussed in this paper.

In Charts 105-108 inclusive the returns to the 4 projects are shown pre-tax and post-tax under the present tax system and with the present BFA increased to a maximum of £75/tonne and the cap removed. In addition the effects are shown of including operating costs in the definition eligible expenditure for BFA purposes.
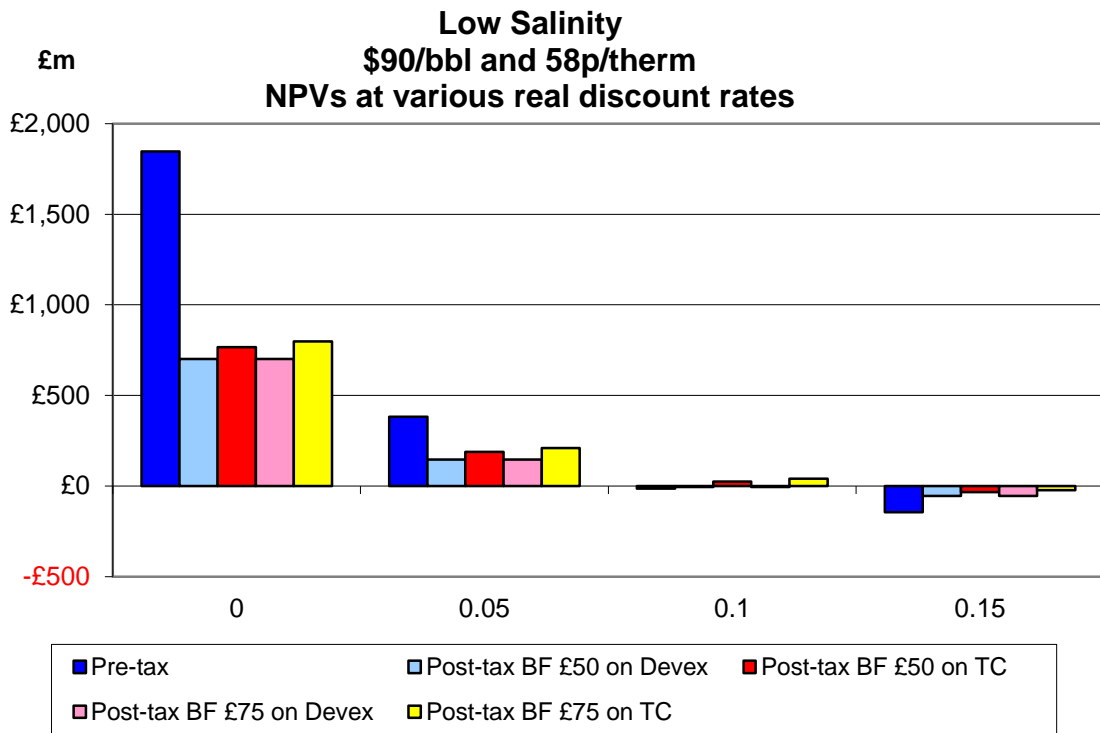
Chart 105

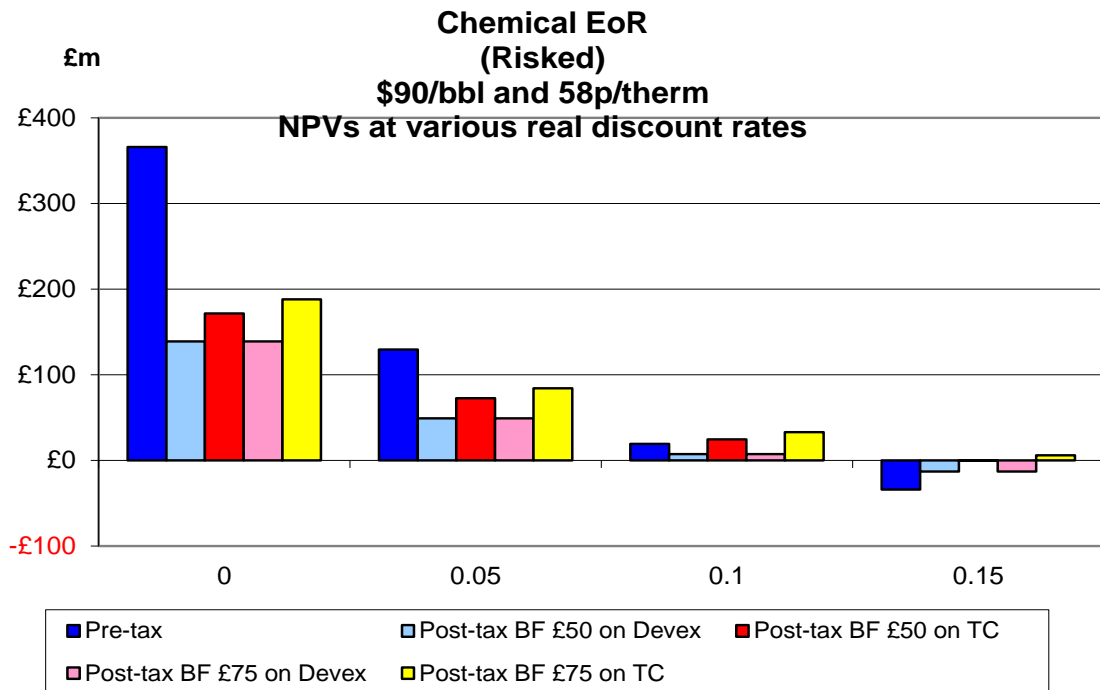**Low Salinity**
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 106

Chemical EoR
(Risked)
$90/bbl and 58p/therm
NPVs at various real discount rates

71

Chart 107

Miscible Gas EoR
$90/bbl and 58p/therm
NPVs at various real discount rates

£m

| Pre-tax | Post-tax BF £50 on Devex | Post-tax BF £50 on TC |
| Post-tax BF £75 on Devex | Post-tax BF £75 on TC | |

Chart 108

Chemical EoR
(Unrisked)
$90/bbl and 58p/therm
NPVs at various real discount rates

£m

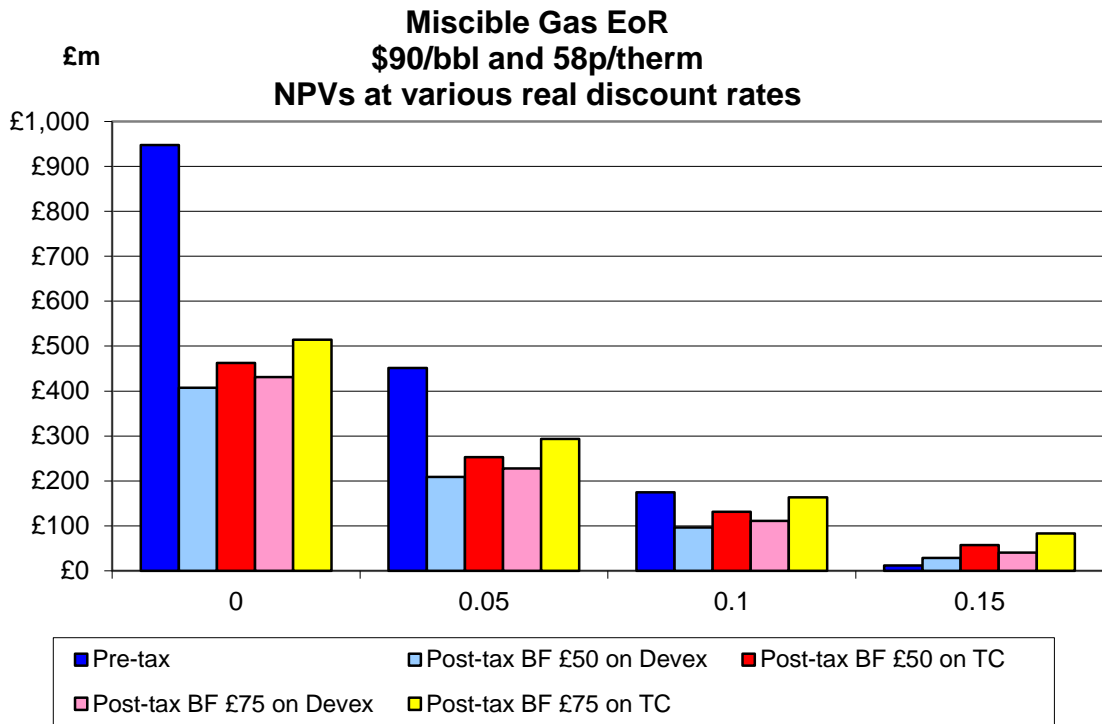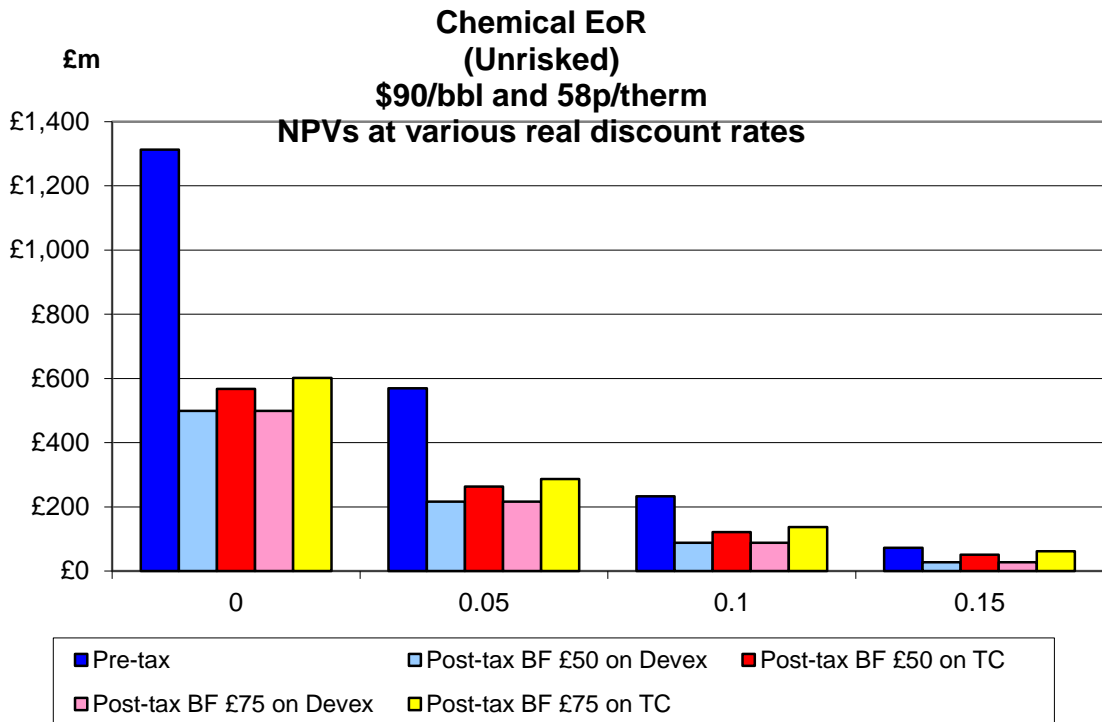| Pre-tax | Post-tax BF £50 on Devex | Post-tax BF £50 on TC |
| Post-tax BF £75 on Devex | Post-tax BF £75 on TC | |

The Low Sal project exhibits very modest returns before tax. The (real) IRR is close to 10%. At 5% discount rate (c. 7.5% in MOD terms) the pre-tax NPV is significantly reduced under all the tax arrangements. The BFA at maximum of 75% based on total costs is the strongest incentive shown.

The returns to the risked Polymer Flood scheme are very modest at 5% real discount rate. The BFA at 75% based on total costs is again the strongest incentive. These remarks also apply to the Miscible Gas Injection project. The unrisked Polymer Flood project broadly exhibits the same pattern of results.

In Charts 109-112 inclusive the returns to the projects are shown when the incentive is an investment uplift based solely on the incremental project's costs and revenues. It is seen that increasing the size of the investment uplift has only a modest impact on post-tax NPVs. At 5% real discount rate the difference between pre-tax and post-tax NPVs remains substantial. At 10% real discount rate there is much less difference.
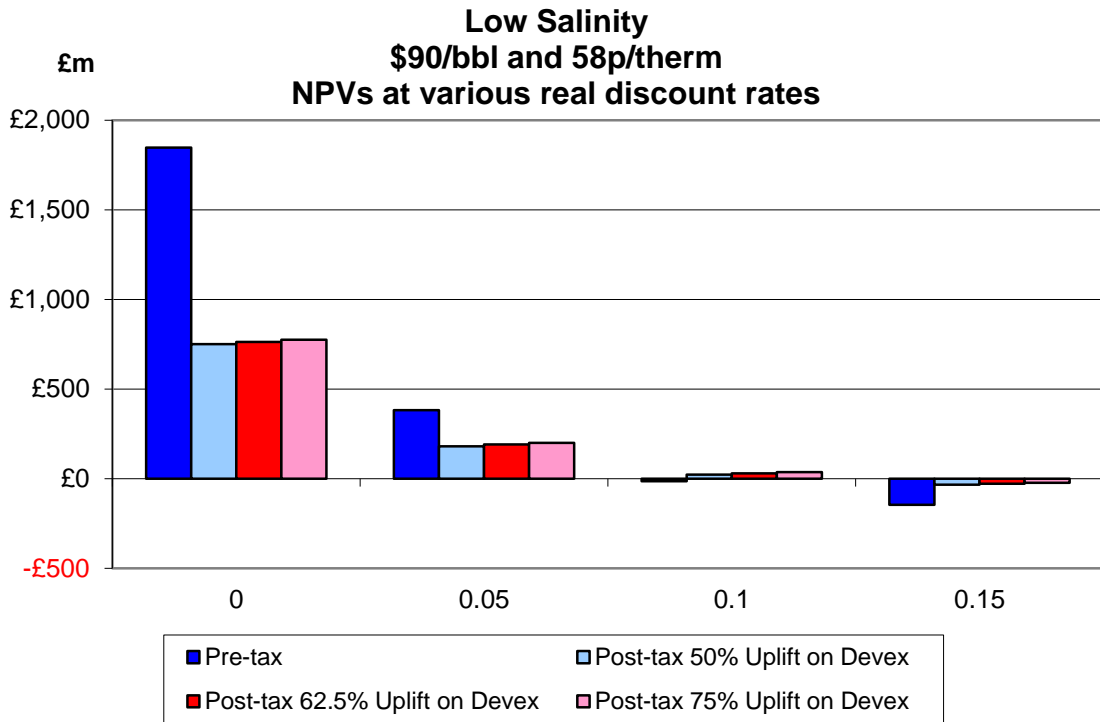
Chart 109

Low Salinity
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 110

Chemical EoR
(Risked)
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 111

Miscible Gas EoR
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 112

Chemical EoR
(Unrisked)
$90/bbl and 58p/therm
NPVs at various real discount rates
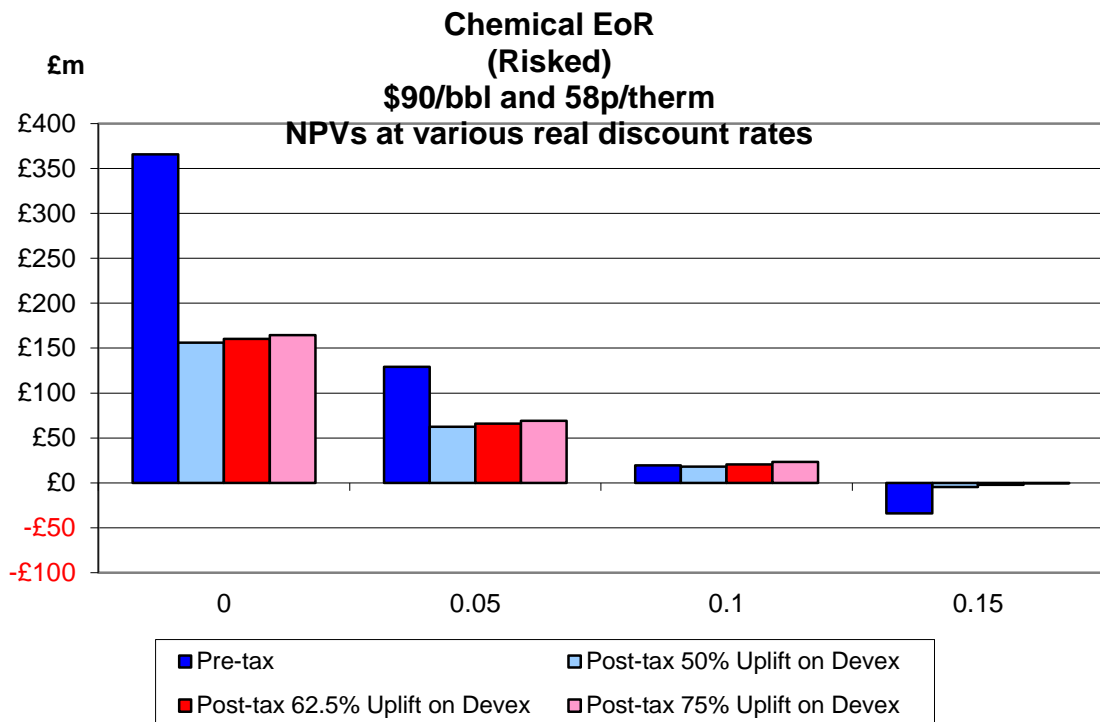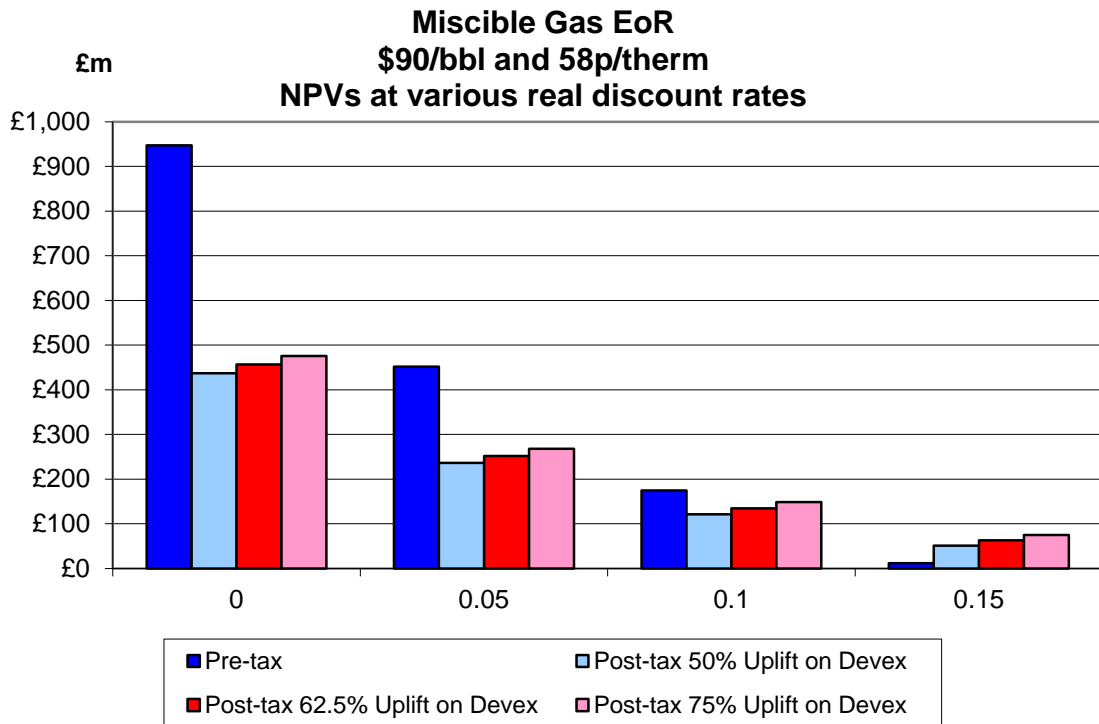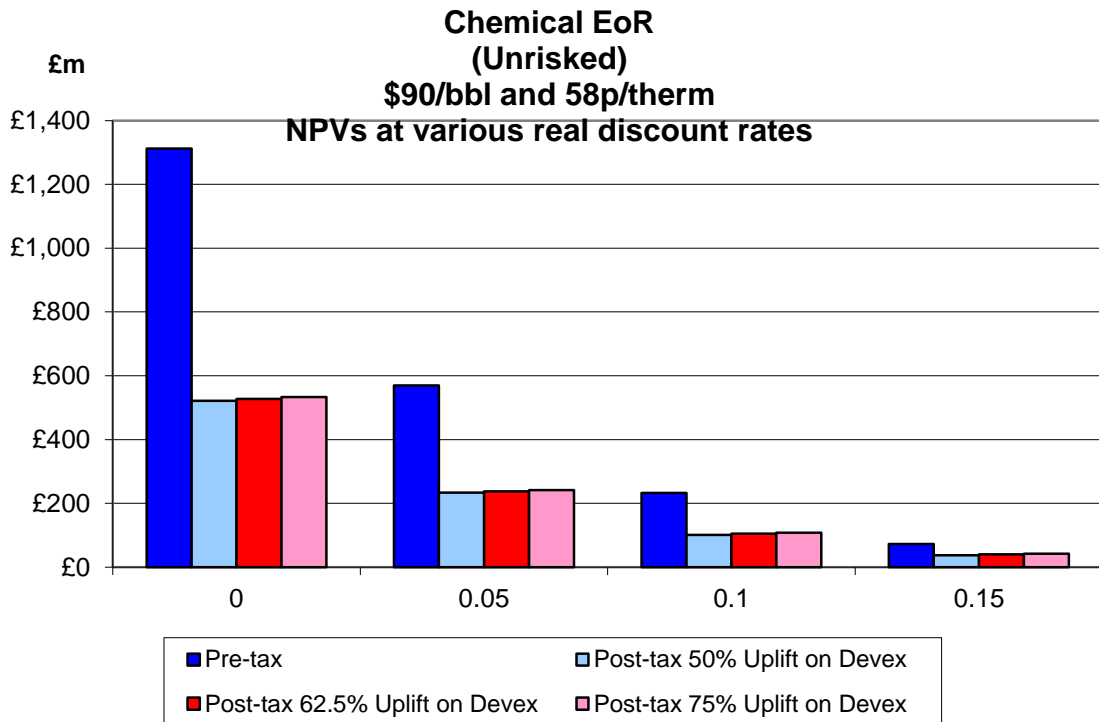
In Charts 113-116 inclusive the returns to the projects are shown where the uplift is based on total costs. This clearly helps the Polymer Flood and Miscible Gas Injection projects in particular. At low rates of discount the pre-tax NPV generally exceeds the post-tax value but at 10% real discount rates the reverse is the case.

Chart 113

Low Salinity
$90/bbl and 58p/therm
NPVs at various real discount rates

Legend: ■ Pre-tax □ Post-tax 50% Uplift on TC ■ Post-tax 62.5% Uplift on TC □ Post-tax 75% Uplift on TC

Chart 114

Chemical EoR
(Risked)
$90/bbl and 58p/therm
NPVs at various real discount rates

Legend: ■ Pre-tax □ Post-tax 50% Uplift on TC ■ Post-tax 62.5% Uplift on TC □ Post-tax 75% Uplift on TC

Chart 115

Miscible Gas EoR
$90/bbl and 58p/therm
NPVs at various real discount rates

£m

Legend: ■ Pre-tax ■ Post-tax 50% Uplift on TC ■ Post-tax 62.5% Uplift on TC ■ Post-tax 75% Uplift on TC

Chart 116

Chemical EoR
(Unrisked)
$90/bbl and 58p/therm
NPVs at various real discount rates

£m

Legend: ■ Pre-tax ■ Post-tax 50% Uplift on TC ■ Post-tax 62.5% Uplift on TC ■ Post-tax 75% Uplift on TC
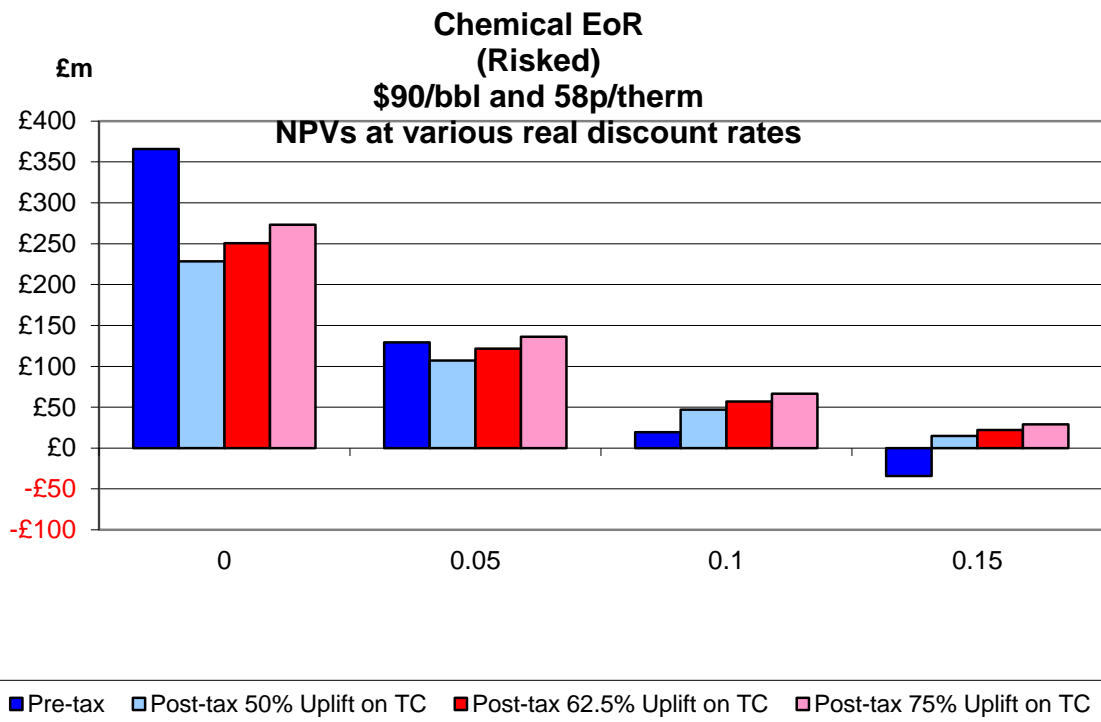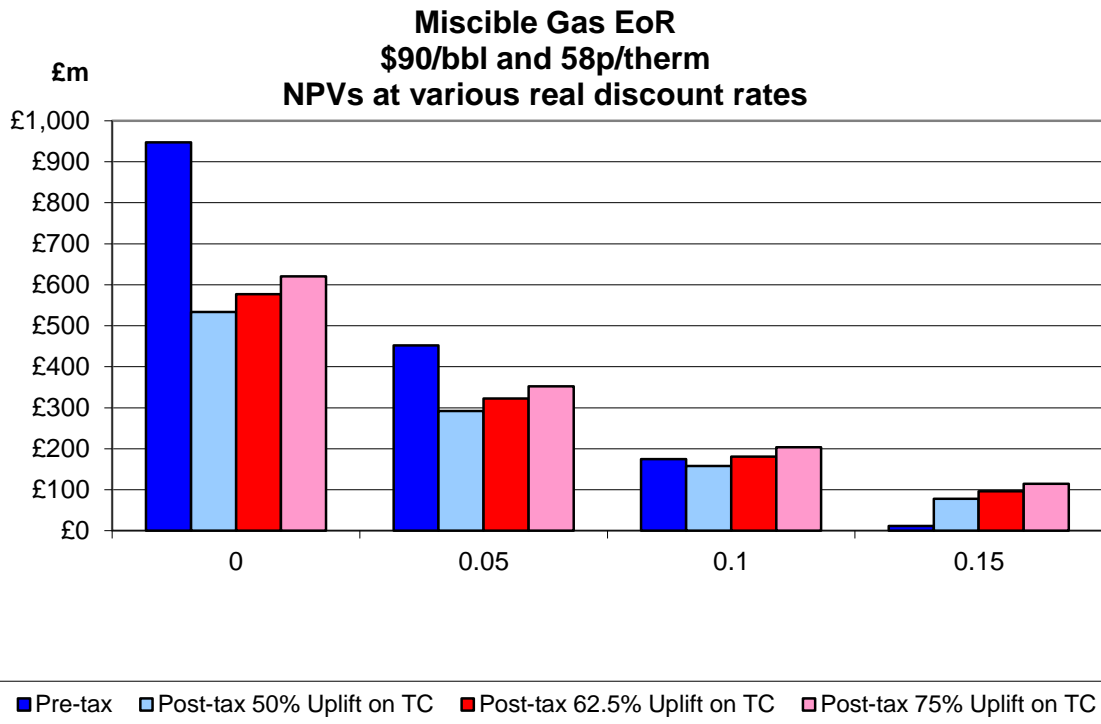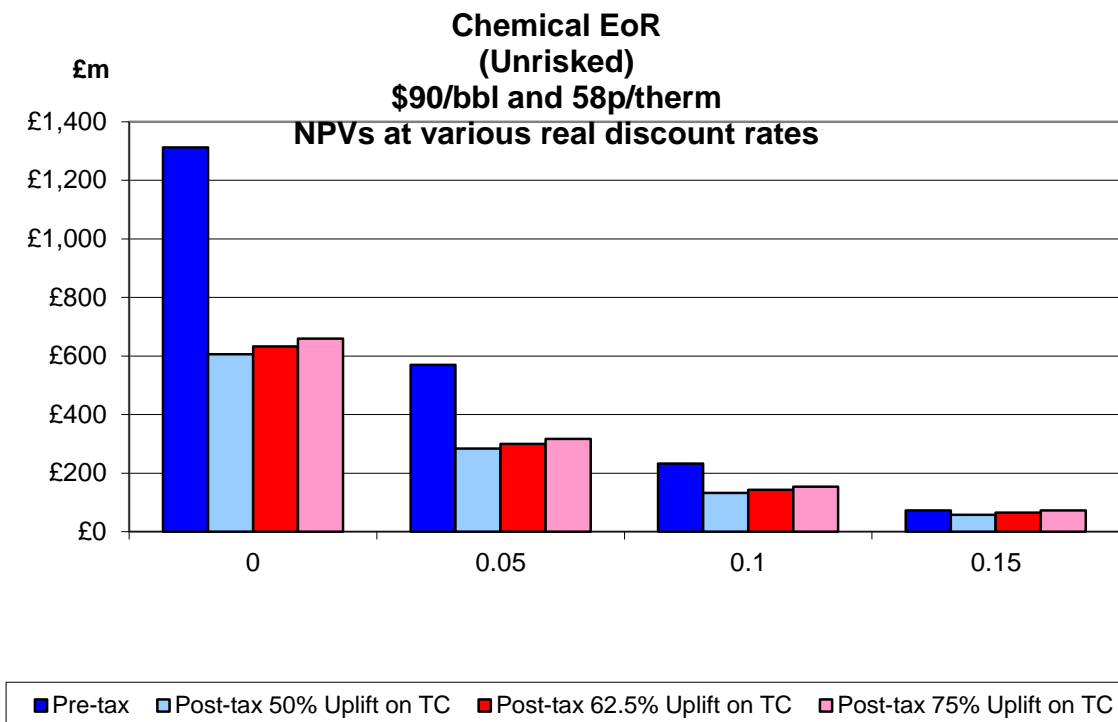
In Charts 117-120 inclusive the pre-tax returns and post-tax returns are shown with no SC being applicable. Though the structure of the incentive is very different there is not very much difference in the resulting pattern of NPVs compared to the uplift based on total costs.
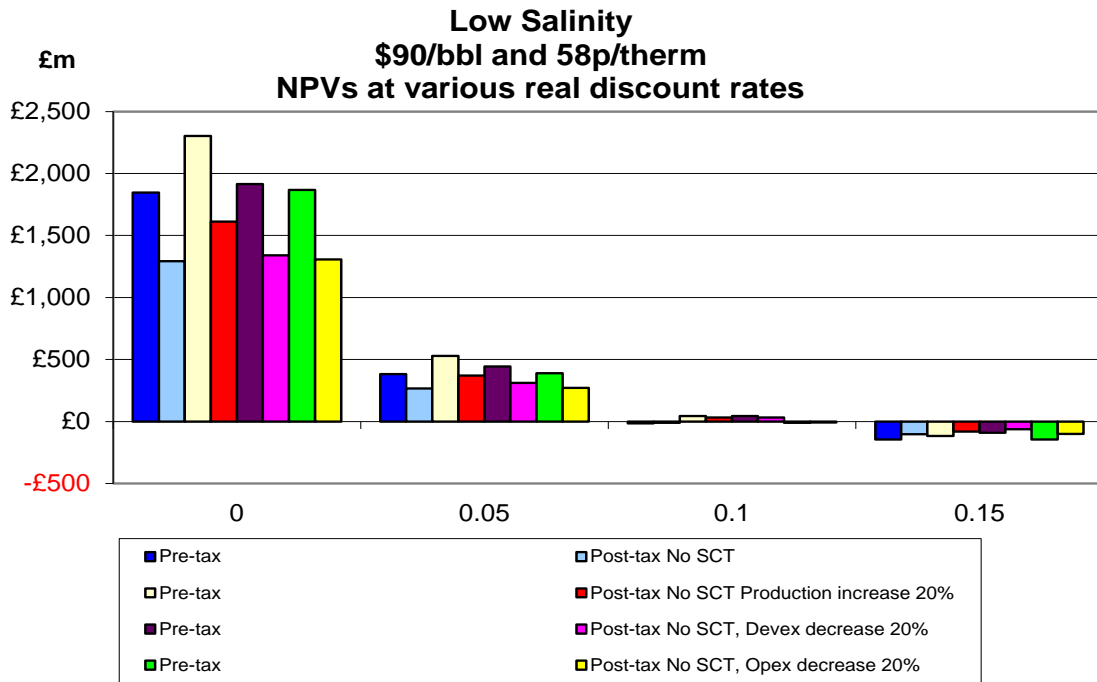
Chart 117

Low Salinity
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 118

Chemical EoR
(Risked)
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 119

Miscible Gas EoR
$90/bbl and 58p/therm
NPVs at various real discount rates

Chart 120

Chemical EoR
(Unrisked)
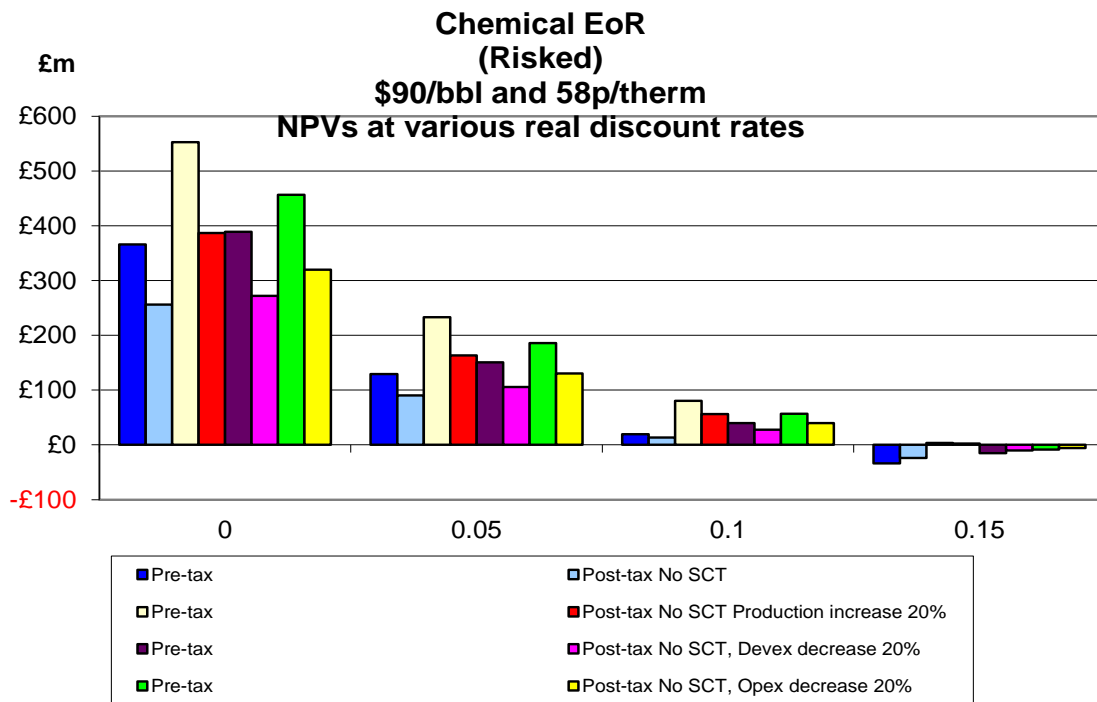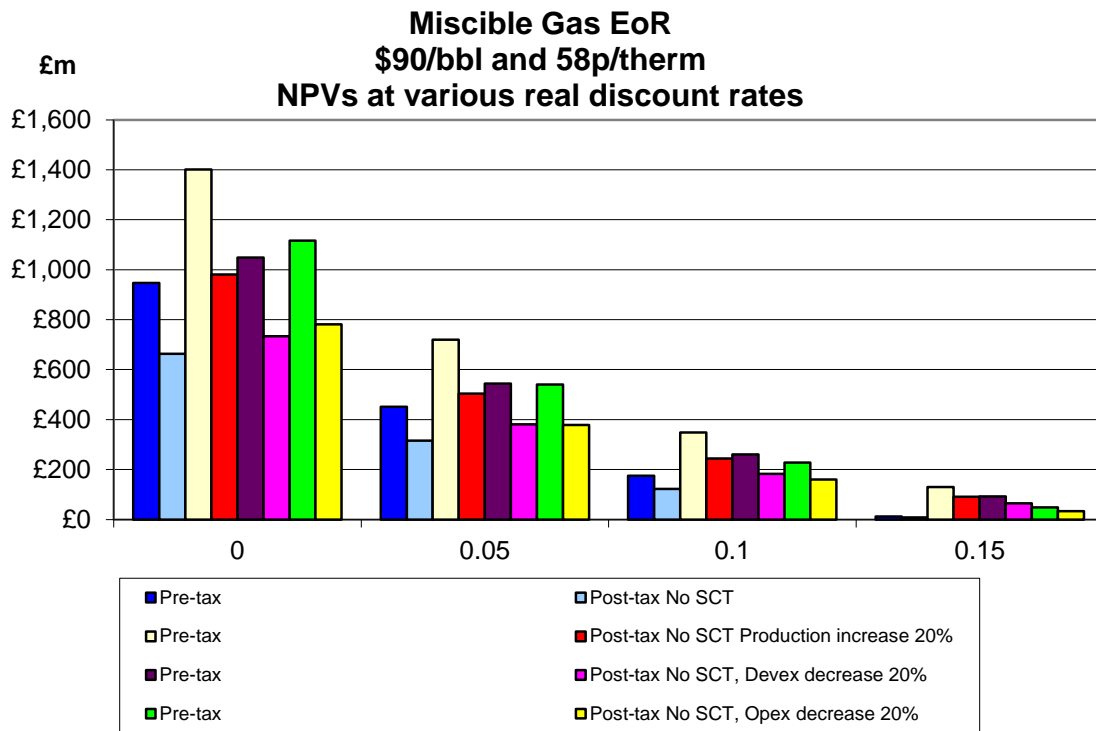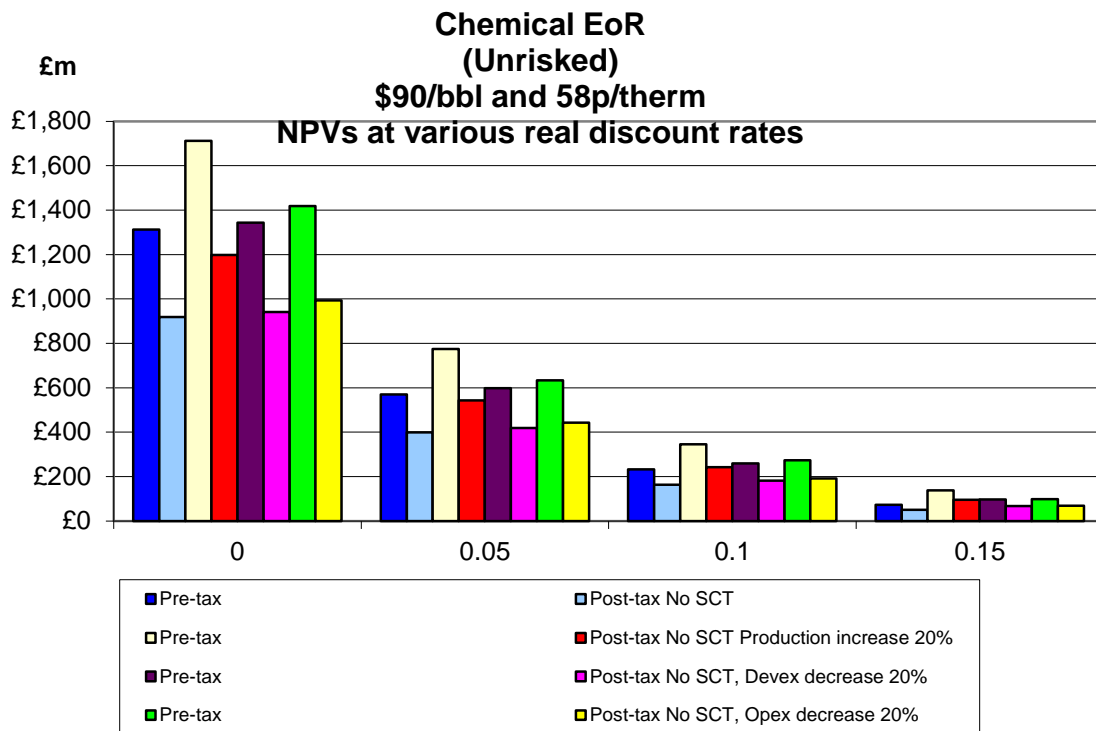**$90/bbl and 58p/therm**
NPVs at various real discount rates

(u) PRT and EOR Schemes: a Case Study of a CO_2 EOR Project

Many incremental projects are undertaken on fields subject to PRT. To illustrate the taxation issues in this section an exposition is given of a possible CO_2 EOR project in the Claymore field. This could be part of a futuristic CO_2 EOR cluster in the Central North Sea/Outer Moray Firth region of the UKCS. The case study is part of a larger study on this subject. The cluster involves cost sharing for some of the transportation costs to the fields. The costs attributable to the project on the Claymore field obtain benefits as a consequence. The returns to the project take this into account. The oil price employed is $120 per barrel reflecting possible price increase in the longer term when the project might become a reality. To illustrate the possibilities 2 cases of the CO_2 transfer price, namely £0 and £9 per tonne are employed. The results of the extensive modelling are shown in terms of NPV/I ratios at 10% discount rate.

In Charts 121 and 122 the pre-tax and post-tax returns are shown where the current BFA scheme is applied to CO_2 EOR. A wide range of values of the allowance is shown within the present constraints of investment costs per tonne of EOR.
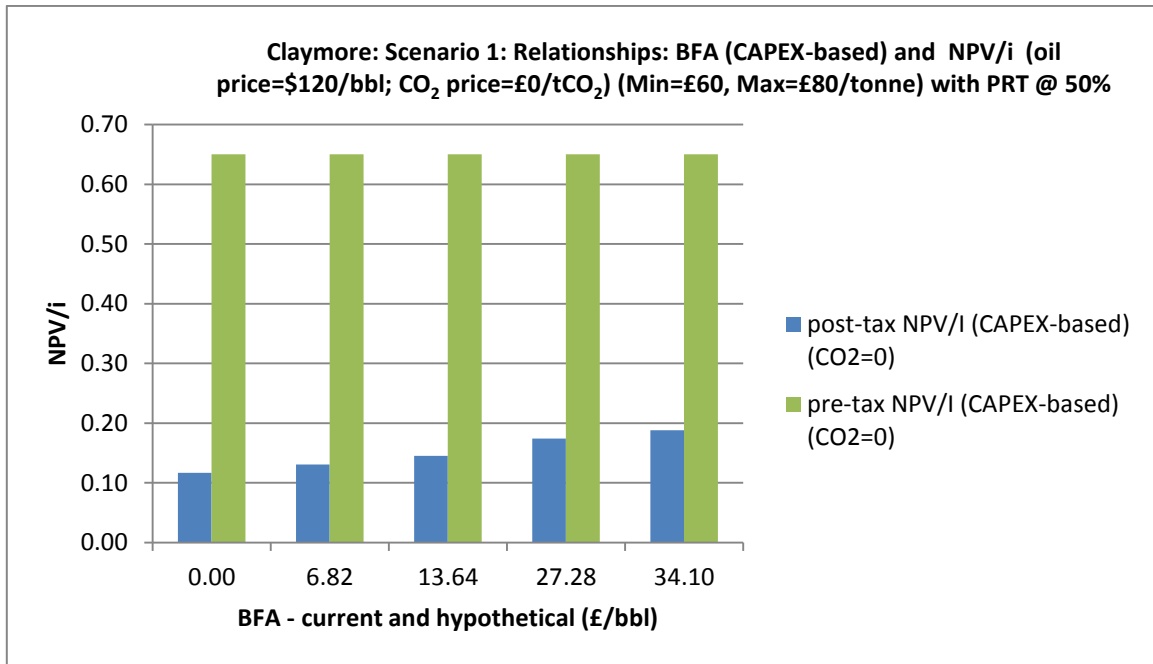
Chart 121

Claymore: Scenario 1: Relationships: BFA (CAPEX-based) and NPV/i (oil price=$120/bbl; CO_2 price=£0/tCO_2) (Min=£60, Max=£80/tonne) with PRT @ 50%

- post-tax NPV/I (CAPEX-based) (CO2=0)
- pre-tax NPV/I (CAPEX-based) (CO2=0)

NPV/i

BFA - current and hypothetical (£/bbl)

Chart 122

Claymore: Scenario 2: Relationships: BFA (CAPEX-based) and NPV/i (oil price=$120/bbl; CO_2 price=£9/tCO_2) (Min=£60, Max=£80/tonne) with PRT @ 50%

- post-tax NPV/I (CAPEX-based) (CO2=£9/tonne)
- pre-tax NPV/I (CAPEX-based) (CO2=£9/tonne))
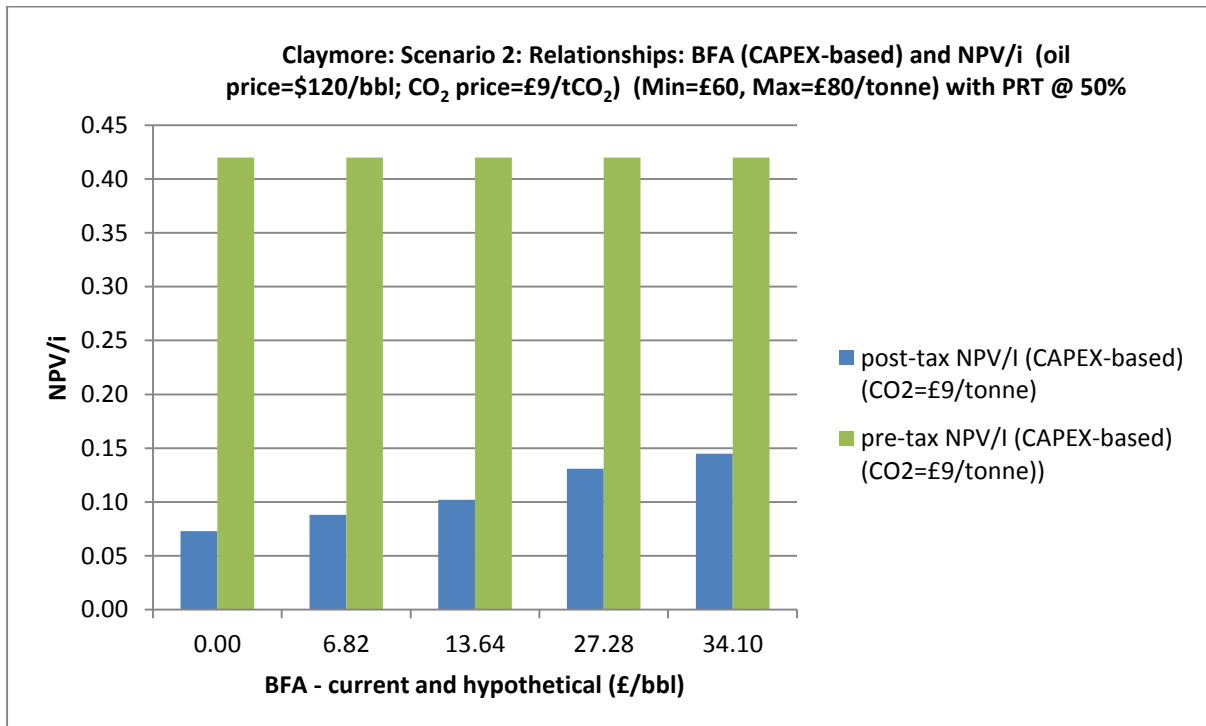
NPV/i

BFA - current and hypothetical (£/bbl)

The pre-tax NPV/I is seen to comfortably exceed 0.3 even with CO_2 being purchased at £9 per tonne. But the post-tax returns even with a very large value of the allowance are well below 0.3. Reducing the PRT rate to 25% improves the post-tax NPV/I ratio, but it is still well below the presumed threshold level even with very high values of the allowance (See Charts 123 and 124). It was also found that a PRT rate of 17.5% did not make a significant difference.
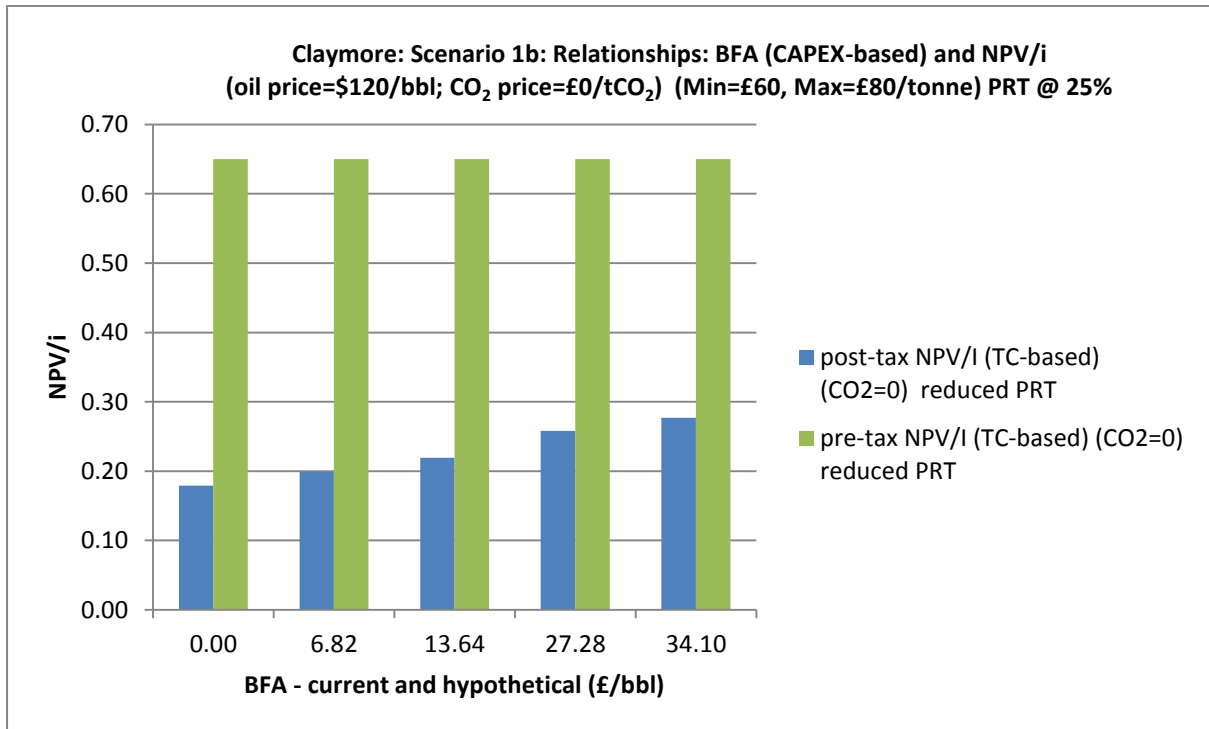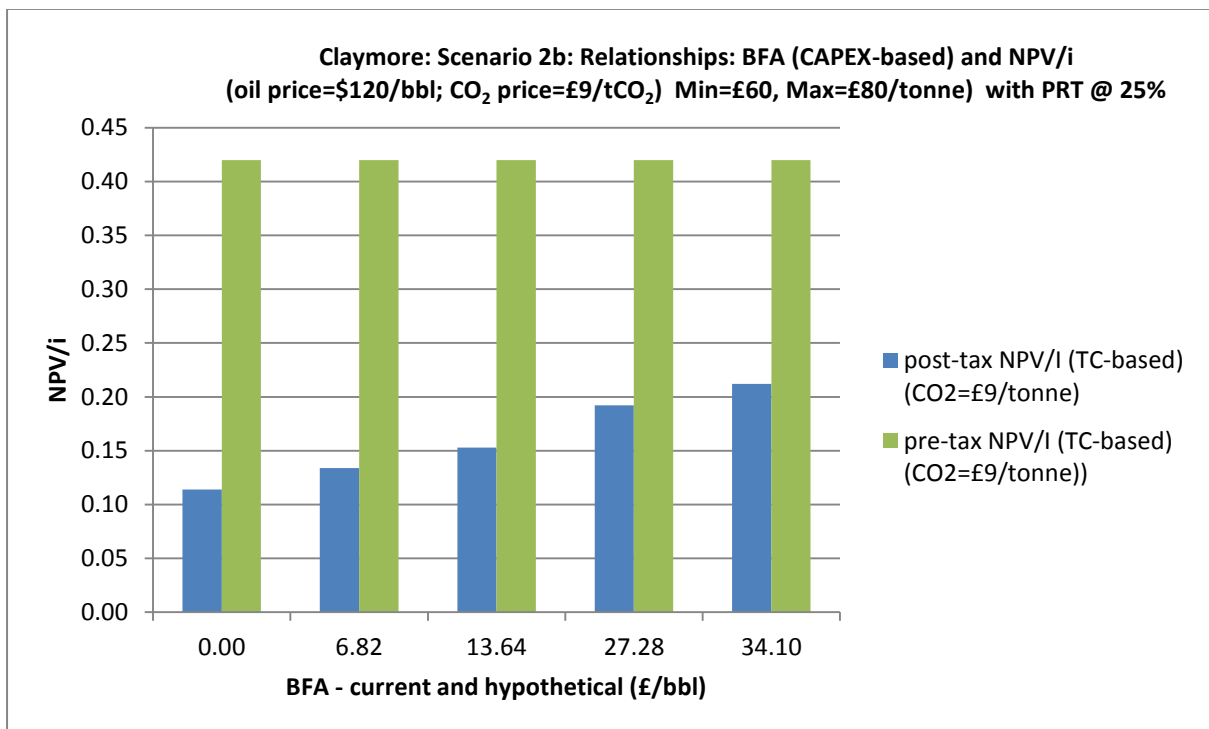
Chart 123

Claymore: Scenario 1b: Relationships: BFA (CAPEX-based) and NPV/i
(oil price=$120/bbl; CO_2 price=£0/tCO_2) (Min=£60, Max=£80/tonne) PRT @ 25%

- post-tax NPV/I (TC-based) (CO2=0) reduced PRT
- pre-tax NPV/I (TC-based) (CO2=0) reduced PRT

NPV/i

BFA - current and hypothetical (£/bbl)

Chart 124

Claymore: Scenario 2b: Relationships: BFA (CAPEX-based) and NPV/i
(oil price=$120/bbl; CO_2 price=£9/tCO_2) Min=£60, Max=£80/tonne) with PRT @ 25%

- post-tax NPV/I (TC-based) (CO2=£9/tonne)
- pre-tax NPV/I (TC-based) (CO2=£9/tonne))

NPV/i

BFA - current and hypothetical (£/bbl)

In Charts 125 and 126 the results are shown of introducing the investment uplift at various levels instead of the BFA. Even at very high levels of uplift the threshold ratio of 0.3 is not reached.
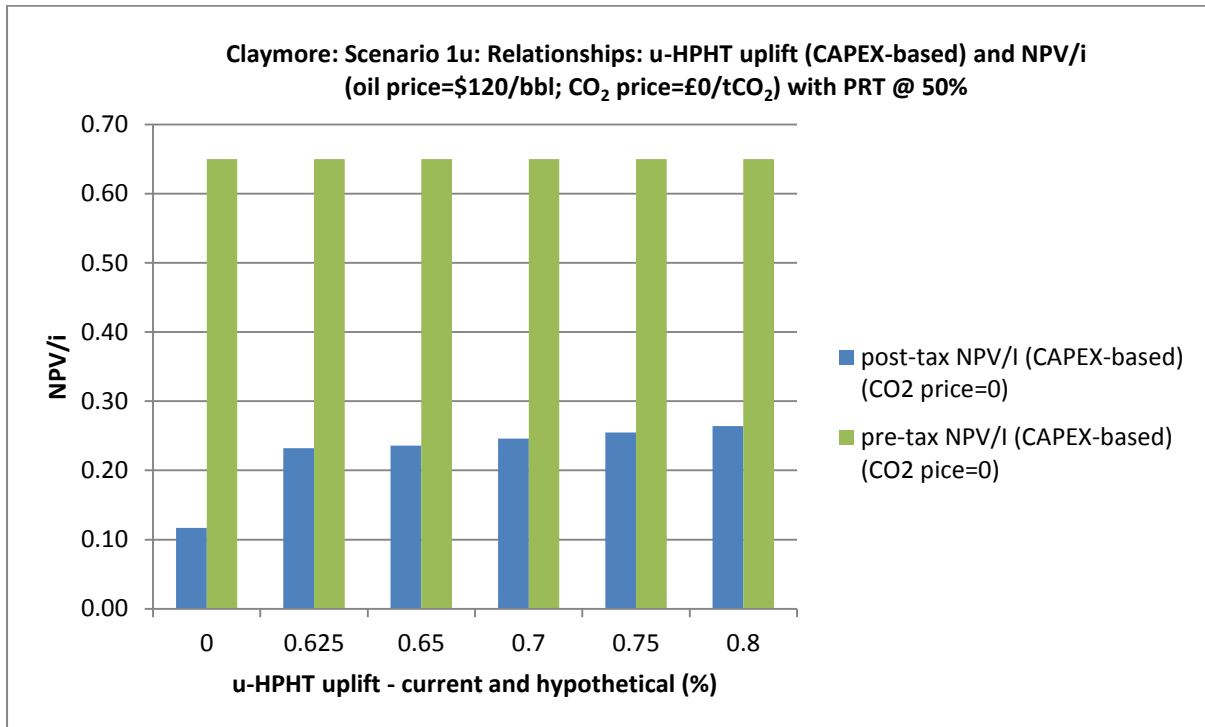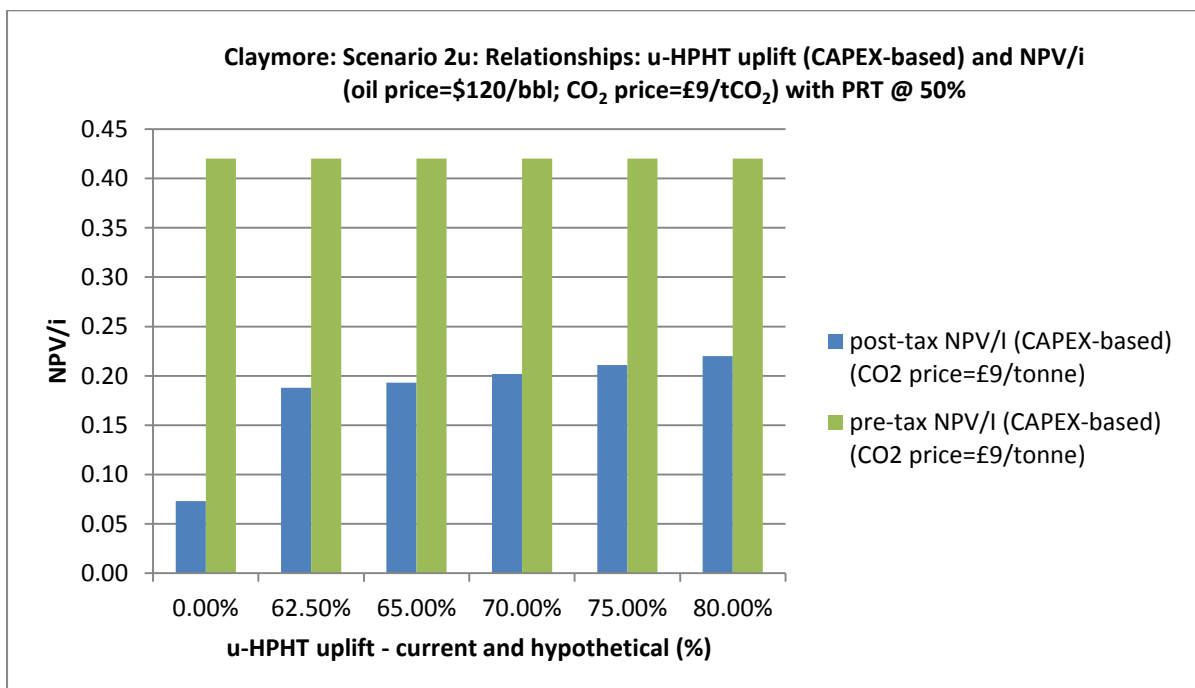
Chart 125

Chart 126

If PRT were reduced to 25% the threshold ratio is reached at high levels of uplift when the transfer price of CO_2 is £0 but not if it is £9/tonne (See Charts 127 and 128).

Chart 127

Claymore: Scenario 1bu: Relationships: u-HPHT uplift (CAPEX-based) and NPV/i (oil price=$120/bbl; CO_2 price=£0/tCO_2) PRT @ 25%

Chart 128

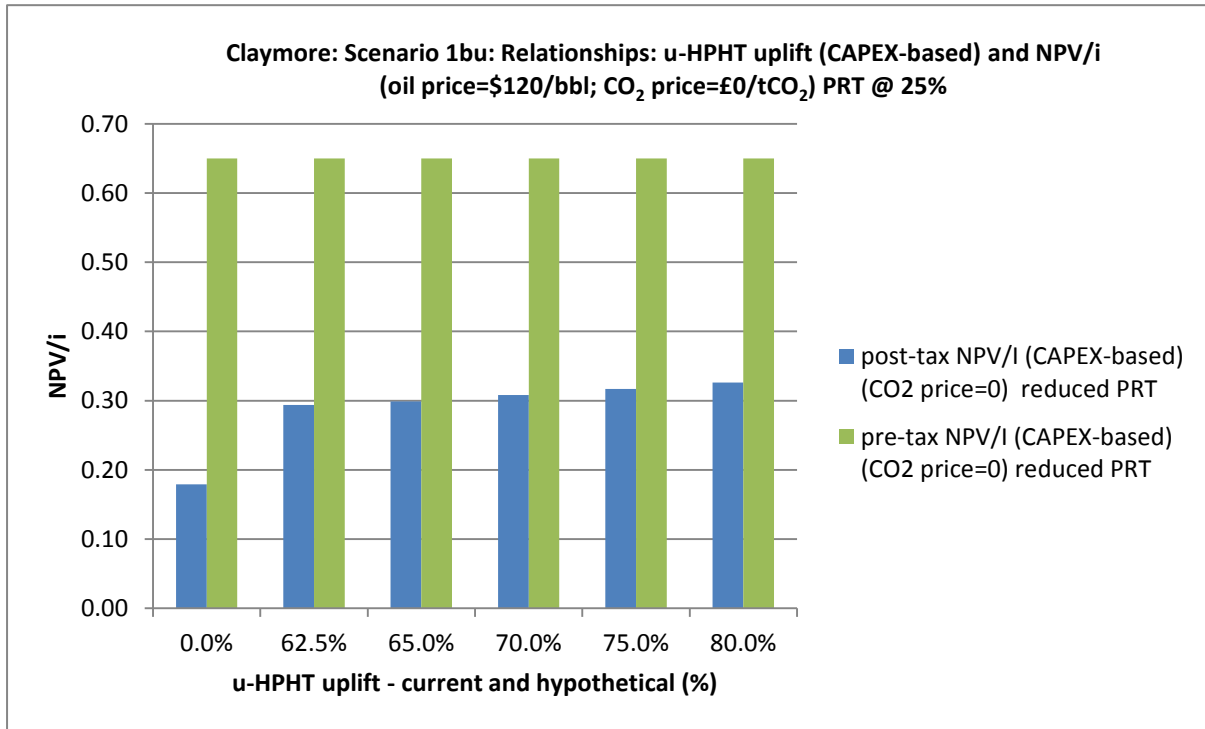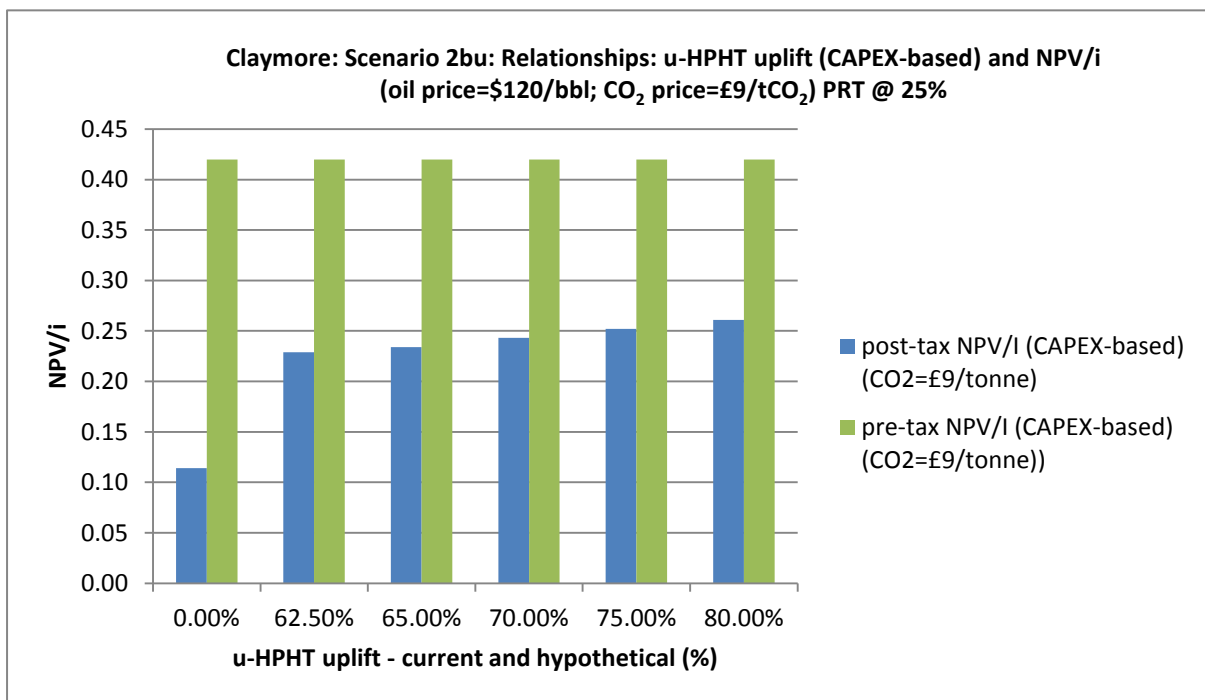Claymore: Scenario 2bu: Relationships: u-HPHT uplift (CAPEX-based) and NPV/i (oil price=$120/bbl; CO_2 price=£9/tCO_2) PRT @ 25%

The effects of incorporating operating costs in the base for the allowance against SC were then investigated. In Chart 129 and 130 the effects are shown of the BFA allowance at different rates but based on total costs, plus a reduction in the PRT ratio to 25%. Even at high values of the allowance the threshold ratio of > 0.3 is not reached even when the CO_2 price is £0.

Chart 129

Claymore: Scenario 1b: Relationships: BFA (TC-based) and NPV/i (oil price=$120/bbl; CO_2 price=£0/tCO_2) (Min=£60, Max=£80/tonne) with PRT @ 25%

- post-tax NPV/I (TC-based) (CO2=0) reduced PRT
- pre-tax NPV/I (TC-based) (CO2=0) reduced PRT

Chart 130

Claymore: Scenario 2b: Relationships: BFA (TC-based) and NPV/i (oil price=$120/bbl; CO_2 price=£9/tCO_2) (Min=£60, Max=£80/tonne) with PRT @ 25%

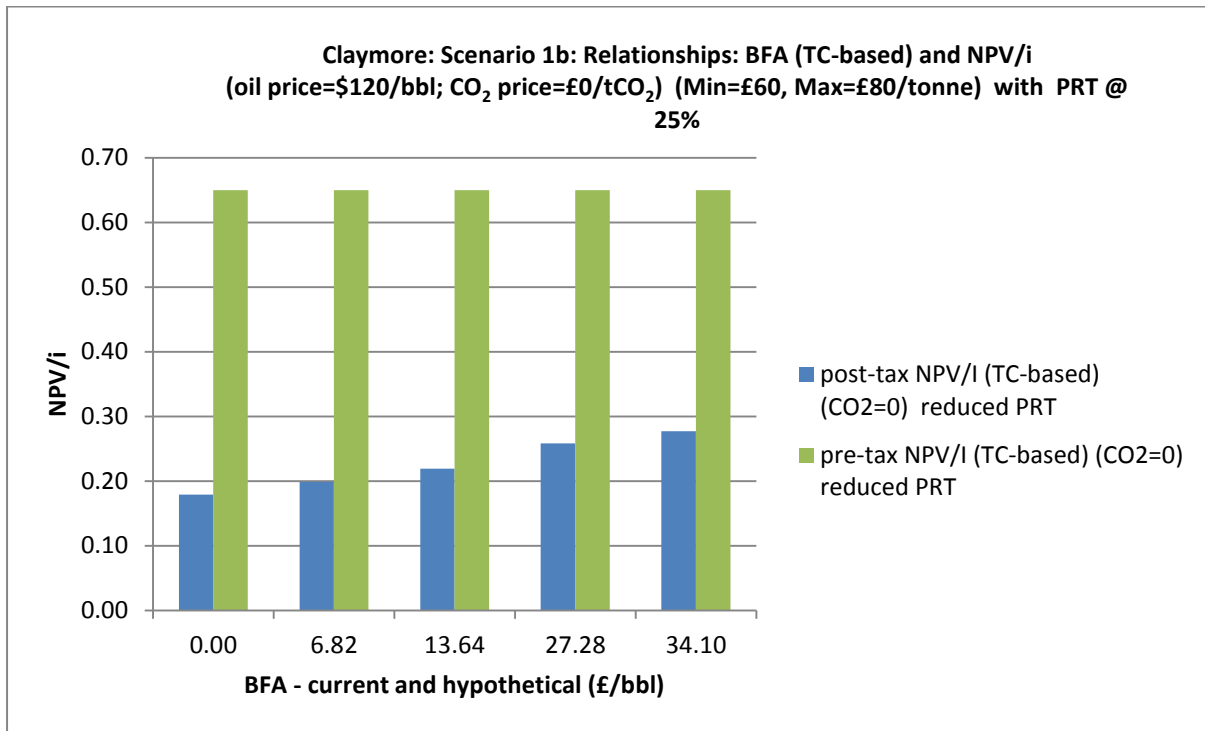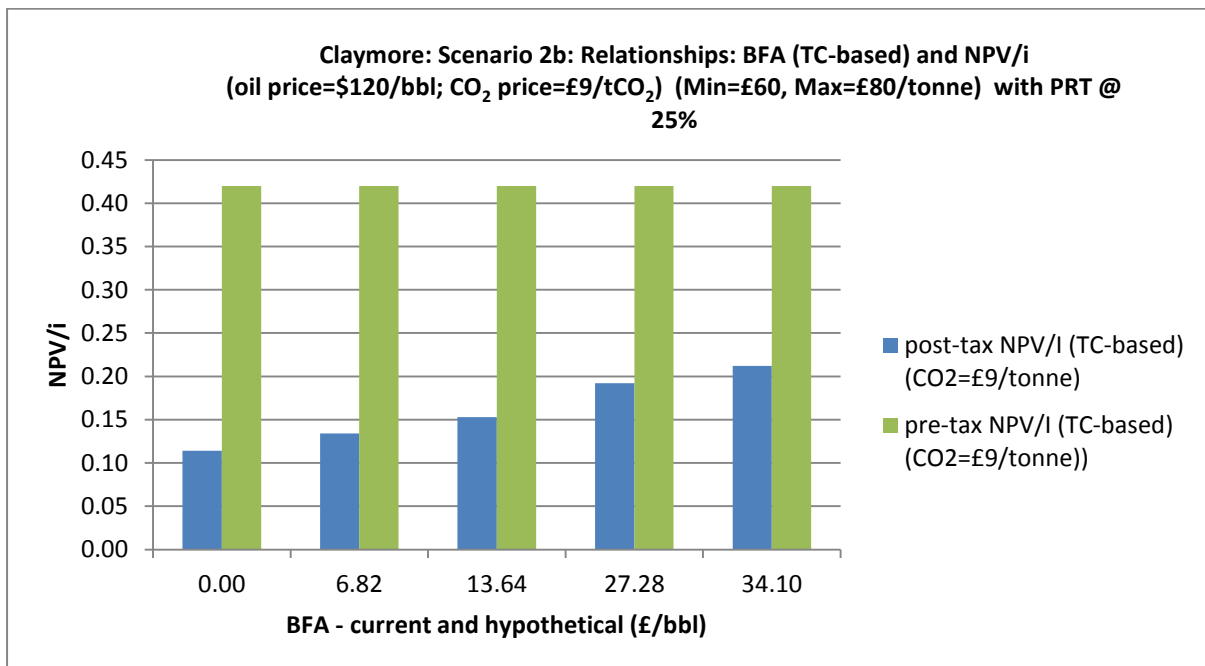- post-tax NPV/I (TC-based) (CO2=£9/tonne)
- pre-tax NPV/I (TC-based) (CO2=£9/tonne))

In Charts 131 and 132 the effects are shown of the uplift allowance at various levels being applied to both investment and operating costs with PRT remaining at 50%. It is seen that when the CO_2 price is £0

89

the threshold ratio of 0.3 is attained in several cases and is attained at very high levels of allowance when the CO_2 prices is £9/tonne.

Chart 131

Claymore: Scenario 1u: Relationships: u-HPHT uplift (TC-based) and NPV/i
(oil price=$120/bbl; CO_2 price=£0/tCO_2) with PRT @ 50%

- post-tax NPV/I (TC-based) (CO2 price=0)
- pre-tax NPV/I (TC-based) (CO2 pice=0)

Chart 132

Claymore: Scenario 2u: Relationships: u-HPHT uplift (TC-based) and NPV/i
(oil price=$120/bbl; CO_2 price=£9/tCO_2) with PRT @ 50%

- post-tax NPV/I (TC-based) (CO2 price=£9/tonne)
- pre-tax NPV/I (TC-based) (CO2 price=£9/tonne)
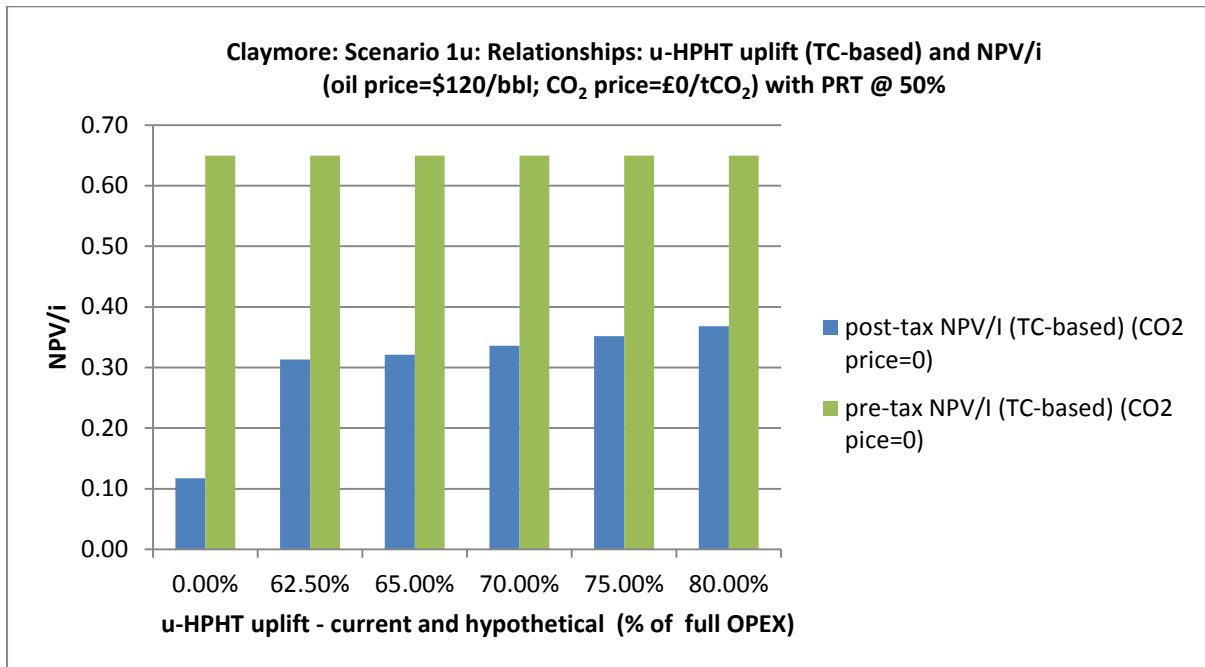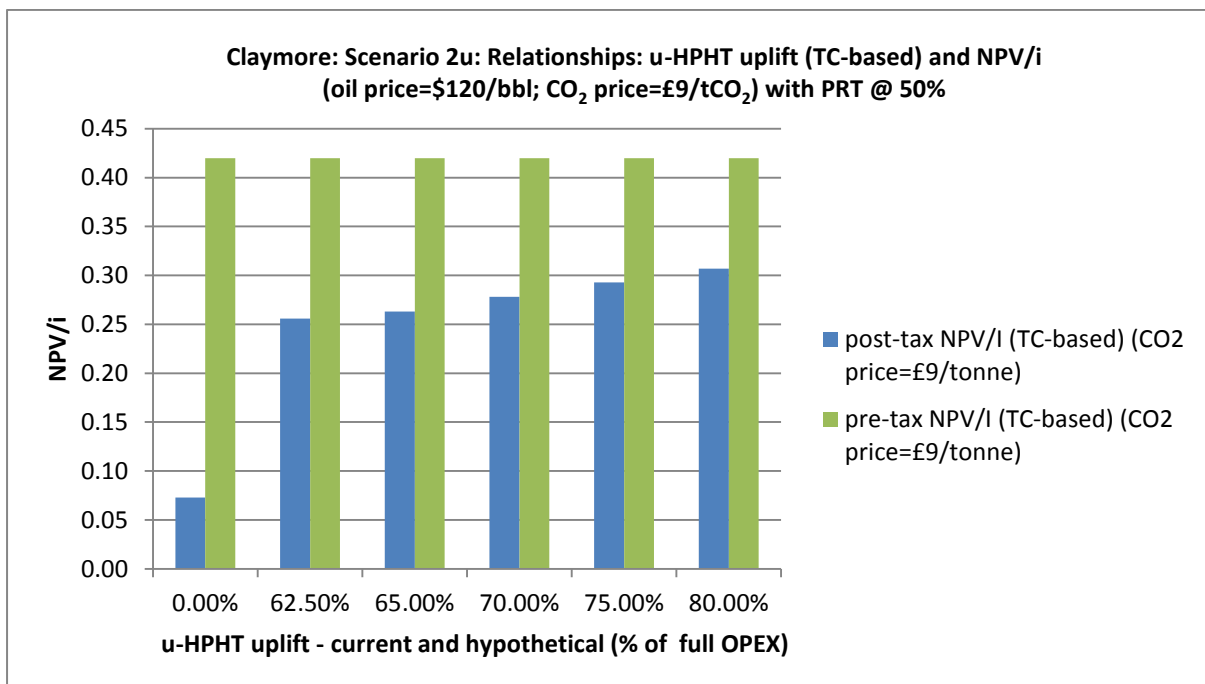
If the PRT rate were reduced to 25% the threshold return can be achieved at more modest levels of the uplift allowance. This is shown in Charts 133 and 134.
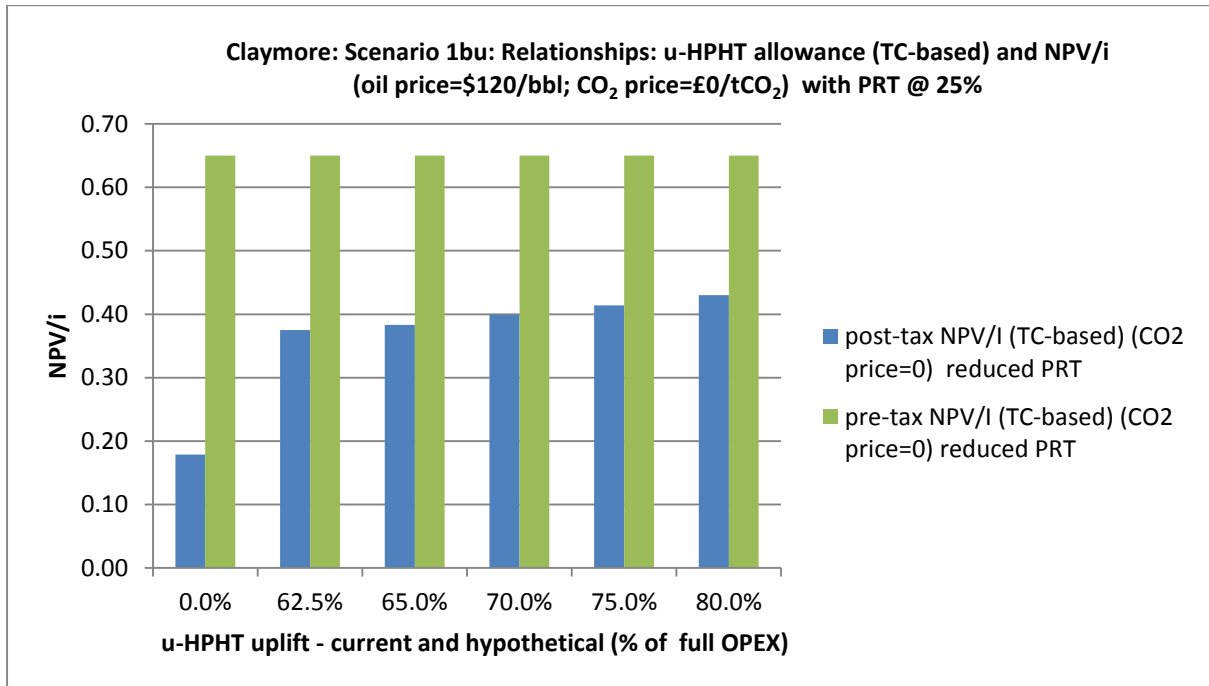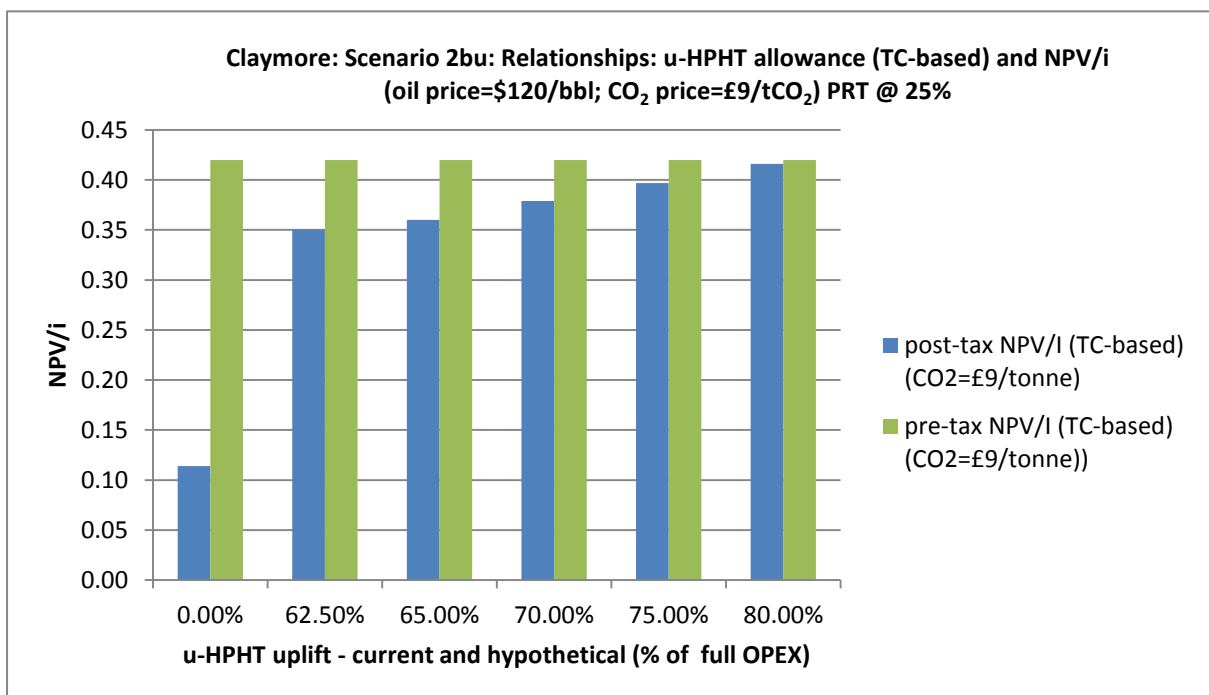
Chart 133

Chart 134

(v) Incremental Activity with PRT at 0% (Excluding Tertiary Recovery Projects)

The effects of reducing the PRT rate to 0% while maintaining decommissioning relief were examined. If the hurdle rate was NPV/I > 0.3 it was found that incremental hydrocarbon production could increase by nearly 140 mmboe. The additional investment amounted to £1.2 billion and the additional operating expenditures £2.1 billion. From the incremental projects there is a net increase in tax revenues of £944 million. There is, of course, a reduction in revenues from host fields currently paying PRT.

If the investment hurdle were NPV/I > 0.5 the reduction in PRT to 0% produces extra production of 109 mmboe. The extra investment is £960 million and the extra operating costs £1.9 billion. The tax revenues from incremental projects could increase by £1.6 billion.

6. Conclusions

The analysis in this paper supports the view that the petroleum tax system applied in the UKCS would benefit from changes to make it suitable for the maturing state of the province, and to rejuvenate it in ways consistent with the recommendations of the Wood Review. The results of the modelling indicate that allowances for the SC based on investment costs could substantially increase investment and production in new fields and also enhance tax revenues. The modelling also found that, where capital rationing is at a serious level, SC rate reductions could have a strong positive effect on investment and production.

The modelling also found that EOR (tertiary recovery) schemes in the UKCS are currently challenging from an economic perspective. Some

have very high operating costs reflecting the high purchase costs of polymer and gas as commodity material inputs. There is merit in basing the allowance against SC on investment costs plus at least the element of operating costs relating to the purchase of these commodity material inputs.

Some CO_2 EOR projects are suitable for development in fields subject to PRT. It was found that the returns to such projects were very challenged with a headline tax rate of 81%. Even when investment allowances are included the difference between pre-tax and post-tax returns remains substantial. A significant reduction in the PRT rate makes a worthwhile difference to the investment returns.

To incentivise exploration and reduce the gap between the expected returns of investors not currently in a tax-paying position compared to those paying tax the RFES should be available over a more extended time period. It is arguable that there should be no limit. This would still leave the existing tax-paying investor with the advantage of being certain to obtain relief for unsuccessful exploration. To produce neutrality in tax treatment between the two categories of explorer the tax credit scheme currently in use in Norway deserves serious consideration. It would be necessary to estimate the elasticity of response of the exploration effort and returns to the resulting discoveries to ascertain the national benefits. If it were applied for new approved exploration wells only the front-end cost to the Exchequer would not be very high. As well as incentivising more exploration it could also reduce the problem of partner drag.

In considering tax changes for the upstream industry the effect on the whole supply chain cluster should also be taken into account. The total

value added is a very relevant consideration. The supply chain cluster adds to the GDP of the nation. The companies pay corporation tax and the employees pay income tax and National Insurance. These should be all considered in a final assessment. The results of the modelling in this paper which measure the incremental investment and operating expenditures are relevant for such an assessment.