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**Prospective Decommissioning Activity and
Infrastructure Availability in the UKCS**

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and
Linda Stephen

October, 2011

DEPARTMENT OF ECONOMICS

NORTH SEA ECONOMICS

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

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

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

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

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Prospective Decommissioning Activity
and Infrastructure Availability in the UKCS

Professor Alexander G. Kemp
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Prospective Decommissioning Activity and Infrastructure

Availability in the UKCS

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1. Introduction

One of the major current concerns in the UK Continental Shelf (UKCS) is the timing of and costs of decommissioning. Linked to this are concerns regarding the tax treatment of decommissioning expenditures and the level of relief that can be relied upon. Major changes were made to taxation in Budget 2011 one of which was the announcement that although the rate of SCT was to increase to 32% decommissioning tax relief was to be held at the 20% rate. This paper models potential decommissioning activity and gives information on the possible economic lives of the major pipelines and infrastructure. The time period considered is 2011 – 2042 inclusive.

2. Methodology and Data

Projections of activity levels including cessation of production dates and decommissioning expenditures have been made through the use of financial simulation modelling, including the use of the Monte Carlo technique, informed by a large, recently-updated, field database validated by the relevant operators. The field database incorporates key, best estimate information on production, and investment, operating and decommissioning expenditures. These refer to 350 sanctioned fields, 150 incremental projects relating to these fields, 41 probable fields, and 28

possible fields. These unsanctioned fields are currently being examined for development. An additional database contains 248 fields defined as being in the category of technical reserves. Summary data on reserves (oil/gas) and block locations are available for these. They are not currently being examined for development by licensees.

Monte Carlo modelling was employed to estimate the possible numbers of new discoveries in the period to 2037. The modelling incorporated assumptions based on recent trends relating to exploration effort, success rates, sizes, and types (oil, gas, condensate) of discovery. A moving average of the behaviour of these variables over the past 5 years was calculated separately for 6 areas of the UKCS (Southern North Sea, (SNS), Central North Sea (CNS), Moray Firth (MF), Northern North Sea (NNS), West of Scotland (WOS), and Irish Sea (IS)), and the results employed for use in the Monte Carlo analysis. Because of the very limited data for WOS and IS over the period judgemental assumptions on success rates and average sizes of discoveries were made for the modelling.

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

Table 1		
Future Oil and Gas Price Scenarios		
	Oil Price (real) \$/bbl	Gas Price (real) pence/therm
High	90	60
Medium	70	40

The postulated numbers of annual exploration wells drilled for the whole of the UKCS are as follows for 2011, 2030, and 2037:

Table 2				
Exploration Wells Drilled				
	2012	2030	2037	
High	35	28	25	
Medium	30	24	20	

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

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

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

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

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

Table 4	
Mean Discovery Size MMboe	
SNS	8
CNS	32
NNS	40
MF	15
WoS	75
IS	7

For purposes of the Monte Carlo modelling of new discoveries the SD was set at 50% of the mean value. In line with historic experience the size distribution of discoveries was taken to be lognormal.

Using the above information the Monte Carlo technique was employed to project discoveries in the 6 regions to 2036. For the whole period the total numbers of discoveries for the whole of the UKCS were are follows:

Table 5	
Total Number of Discoveries to 2037	
High effort/Low success rate	210
Medium Effort/Medium Success Rate	193

For each region the average development costs (per boe) of fields in the probable and possible categories were calculated. These reflect substantial cost inflation over the last few years. Investment costs per boe depend on several factors including not only the absolute costs in different operating conditions (such as water depth) but on the size of the fields. For all of the UKCS the average development cost was \$17.7 per boe with the highest greatly exceeding that. In the SNS development costs were found to average over \$13 per boe because of the small size of fields. In the CNS they averaged \$19.5 per boe and in the NNS they averaged \$18.9 per boe with the highest greatly exceeding that. Operating costs over the lifetime of the fields were also calculated. The averages were found to be \$13.8 per boe for all of the UKCS, \$9.7 per boe in the SNS, \$14.1 per boe in the CNS and \$17.1 per boe in the NNS. Total lifetime field costs (including decommissioning but excluding E and A costs) were found to average \$33.3 per boe for all of the UKCS, \$24.45

per boe in the SNS, \$35.7 per boe in the CNS, and \$37.8 per boe in the NNS.

Using these as the mean values the Monte Carlo technique was employed to calculate the development costs of new discoveries. A normal distribution with a SD = 20% of the mean value was employed. For new discoveries annual operating costs were modelled as a percentage of accumulated development costs. This percentage varied according to field size. It was taken to increase as the size of the field was reduced reflecting the presence of economies of scale. Thus the field lifetime costs in small fields could become very high on a per boe basis.

With respect to fields in the category of technical reserves it was recognised that many present major challenges, and so the mean development costs in each of the basins was set at \$5/boe higher than the mean for the new discoveries in that basin. Thus for the CNS the mean development costs are over \$24.5 per boe and in NNS over \$23.8 per boe. The distribution of these costs was assumed to be normal with a SD = 20% of the mean value. A binomial distribution was employed to find the order of new developments.

The annual numbers of new field developments were assumed to be constrained by the physical and financial capacity of the industry. The ceilings were assumed to be linked to the oil/gas price scenarios with maxima of 20 and 17 respectively for High and Medium price cases. These constraints do not apply to incremental projects which are additional to new field developments.

There is a wide range in the development and operating costs of the set of incremental projects currently being examined for development. For all of the UKCS the mean development costs are \$15.8 per boe but the highest is over \$79 per boe. In the SNS the average development costs are \$9.3 per boe, but in the NNS it is \$21.8 per boe. While operating costs are often relatively low and average \$6.84 per boe across all of the UKCS, they are very high in a number of cases, with examples in the \$50 - \$77 per boe range over their lifetime.

A noteworthy feature of the 150 incremental projects in the database is the expectation that the great majority will be executed over the next 3 or 4 years. It is virtually certain that in the medium and longer-term many further incremental projects will be designed and executed. They are just not yet at the serious planning stage. Such projects can be expected to be linked not only to currently sanctioned fields, but also to those presently classified as in the categories of probable, possible, technical reserves, and future discoveries.

Accordingly, estimates were made of the potential extra incremental projects from all these sources. Examination of the numbers of such projects and their key characteristics (reserves and costs) being examined by operators over the past 6 years indicated a decline rate in the volumes. On the basis of this, and, utilising the information of the key characteristics of the projects in the database, it was felt that, with a decline rate reflecting historic experience, further portfolios of incremental projects could reasonably be expected. As noted above such future projects would be spread over all categories of host fields. Their sizes and costs reflect recent trends.

With respect to investment decision making and project screening criteria oil companies (even medium-sized and smaller ones) currently assess their opportunities in the UKCS in comparison to those available in other parts of the world. Capital is allocated on this basis with the UKCS having to compete for funds against the opportunities in other provinces. A problem with the growing maturity of the UKCS is the relatively small average field size and the high unit costs. Recent mean discovery sizes are shown in Table 4, but, given the lognormal distribution, the most likely sizes are below these averages. It follows that the materiality of returns, expressed in terms of net present values (NPVs), is quite low in relation to those in prospect in other provinces (such as offshore Angola, or Brazil, for example). Oil companies frequently rank investment projects according to the NPV/I ratio. Accordingly, this screening method has been adopted in the present study. Specifically, the numerator is the post-tax NPV at 10% discount rate in real terms and the denominator is pre-tax field investment at 10% discount rate in real terms. This differs from the textbook version which states that I should be in post-tax terms because the expenditures are tax deductible through allowances. Oil companies maintain that they allocate capital funds on a pre-tax basis, and this is employed here as the purpose is to reflect realistically the decision-making process. The development project goes ahead when the NPV/I ratio as defined above is ≥ 0.3 in one scenario and ≥ 0.5 in a second scenario. The 10% real discount rate reflects the weighted average cost of capital to the investor. The modelling has been undertaken under the current tax system.

In the light of experience over the past few years some rephrasing of the timing of the commencement dates of new field developments and incremental projects from those projected by operators was undertaken

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

In the later part of this paper the UKCS infrastructure was mapped and the linkages between fields and infrastructure examined. For the sanctioned fields and current incremental projects the oil and gas transport routes are known. Regarding the probable and possible fields and the technical reserves fields some of the oil and gas transport routes are known but for others the most likely routes are assumed.

Decommissioning is modelled to occur at the beginning of the period in which a field has negative cashflows over 3 consecutive years.

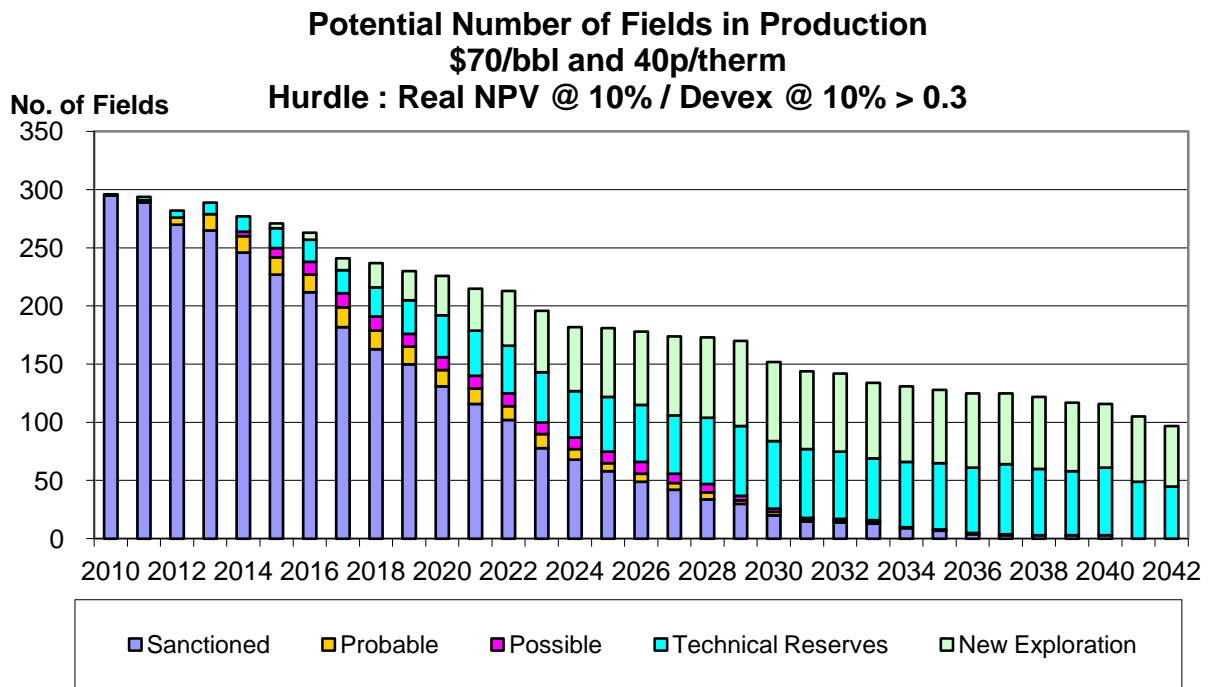
3. Results – Field COP and Decommissioning Activity

A. \$70, 40 pence price, Hurdle NPV/I > 0.3

(i) Numbers of Fields in Production

The changing numbers of fields in production under the above scenarios is shown in Chart 1.

Chart 1



The numbers reflect the balance of fields coming to the end of their economic lives (COP dates) and new fields whose development is triggered over the period to 2042. It is seen that the numbers of sanctioned fields fall steadily throughout the period. The numbers of probable and possible fields whose development are triggered are relatively small in comparison. In the longer term the development of significant numbers of fields in the categories of technical reserves and some new discoveries substantially moderate the decline rate, but there is a continuous overall decrease from 2013 onwards when the total is around 280 to 97 in 2042. Over the whole period the average annual number of new field developments was just over 11. These results depend on current major transport route cease to operate there may be a delay in production from some fields and should an alternative transport route prove more costly more fields may fail the hurdle rate.

(ii)Decommissioning Activity

In Chart 2 and 3 annual and cumulative decommissioning expenditures are shown for the different categories of fields and projects. Key features are the large increase in expenditures from 2014 for a few years followed by a fall and then a major further increase for a few years. The lumpiness in timing has implications for the demand for all the supply chain sources and facilities. Over the period to 2042 the total cumulative expenditure exceeds £31.9 billion at 2011 prices. These results depend on the current infrastructure remaining in place.

Chart 2

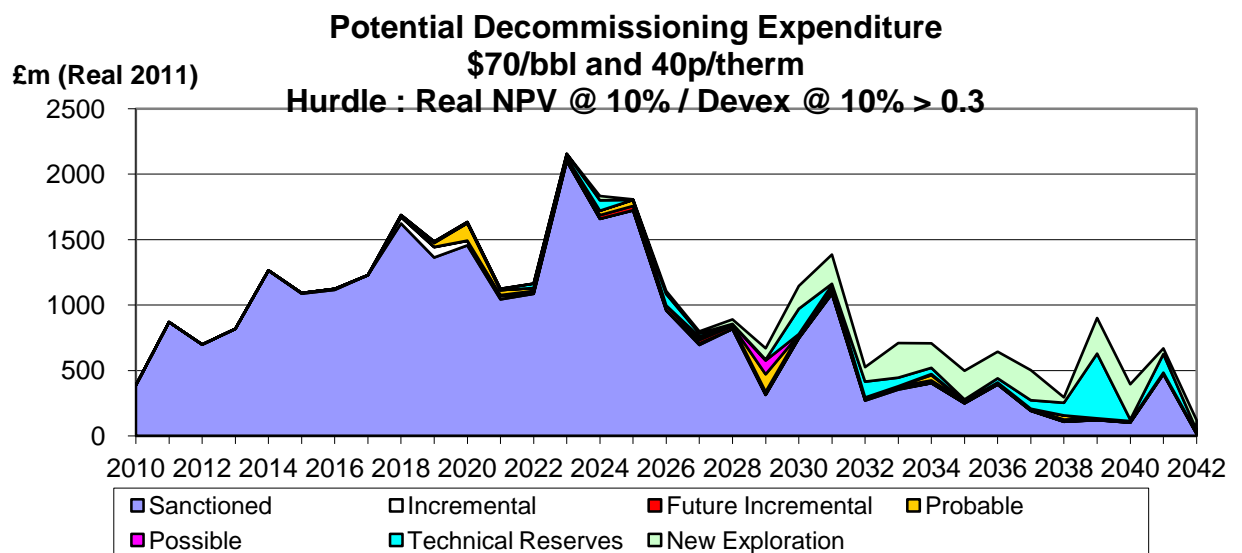
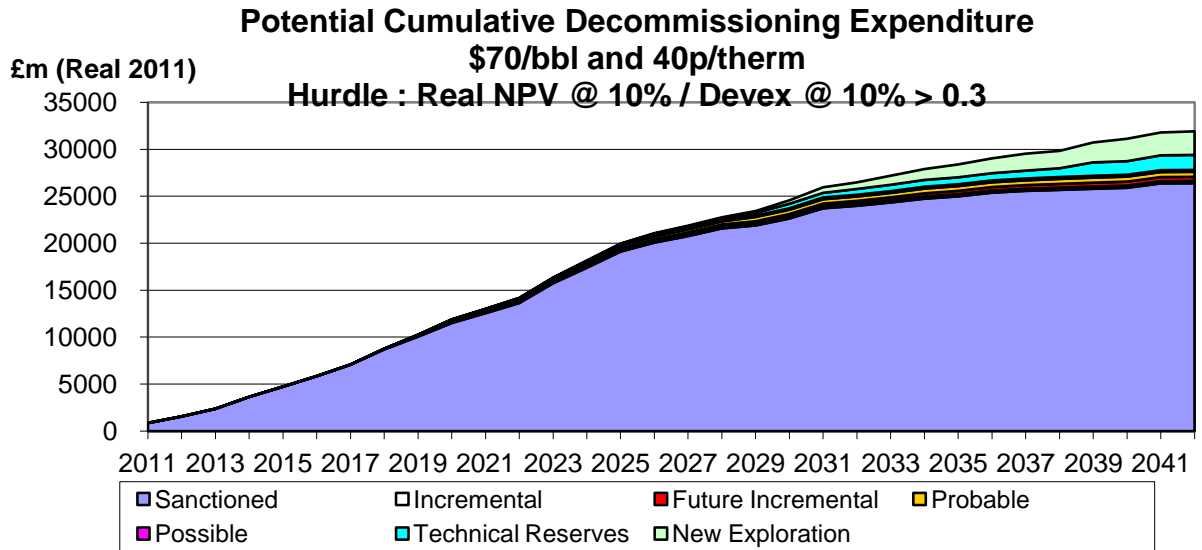


Chart 3



In Chart 4 and 5 the annual and cumulative expenditures are shown according to the 6 geographic areas of the UKCS. The importance of the NNS region is highlighted. This is because a high proportion of the very large field platforms is located in this region.

Chart 4

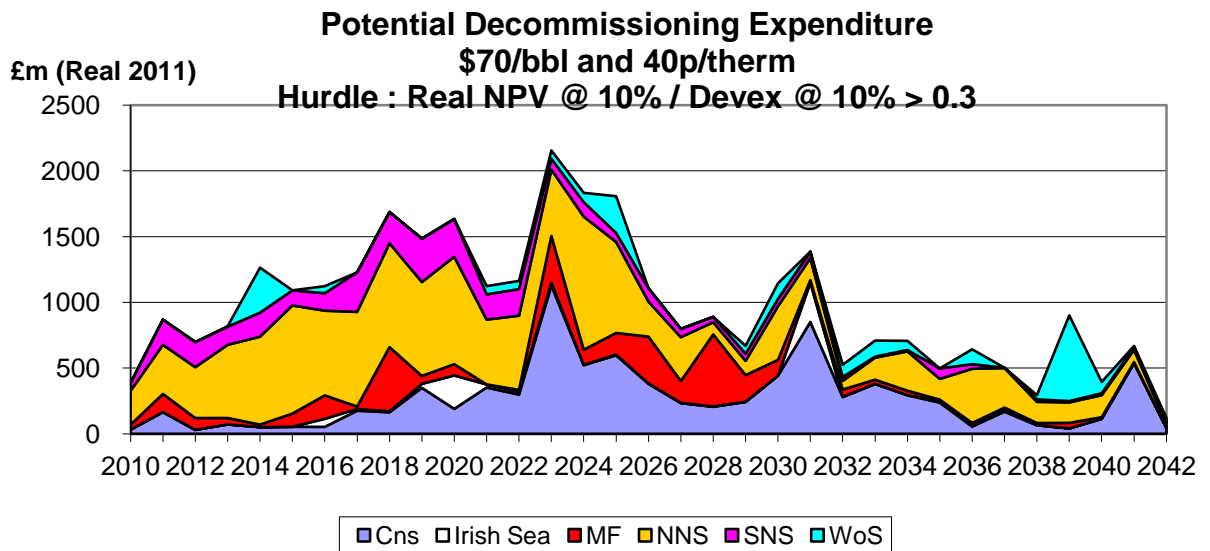
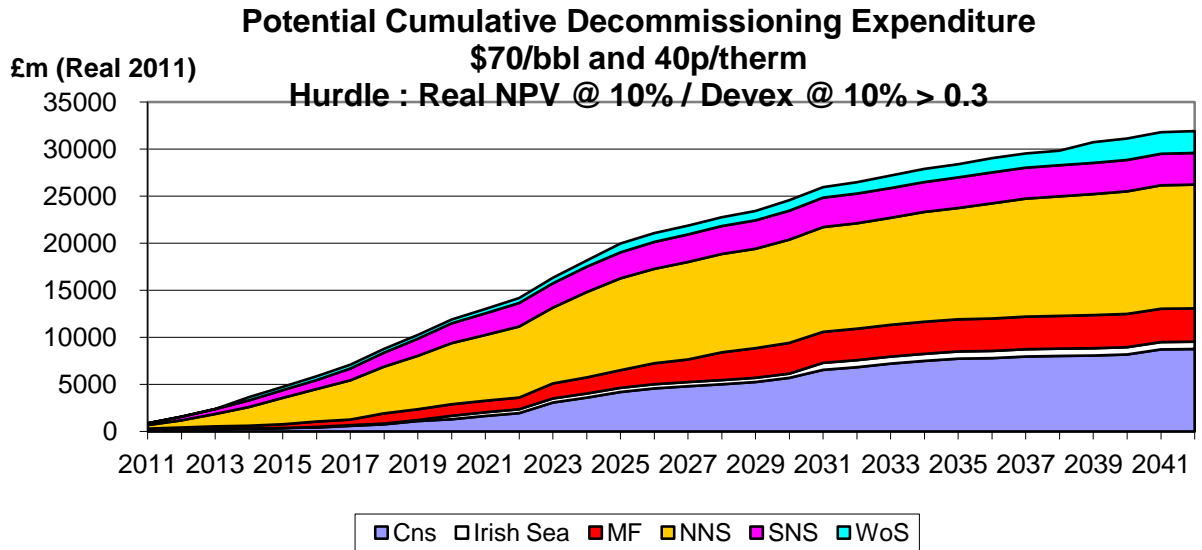


Chart 5



In Chart 6 and 7 the annual numbers of fields reaching their COP dates are shown. It is seen that over the period to 2030 the annual average exceeds 15 fields

Chart 6

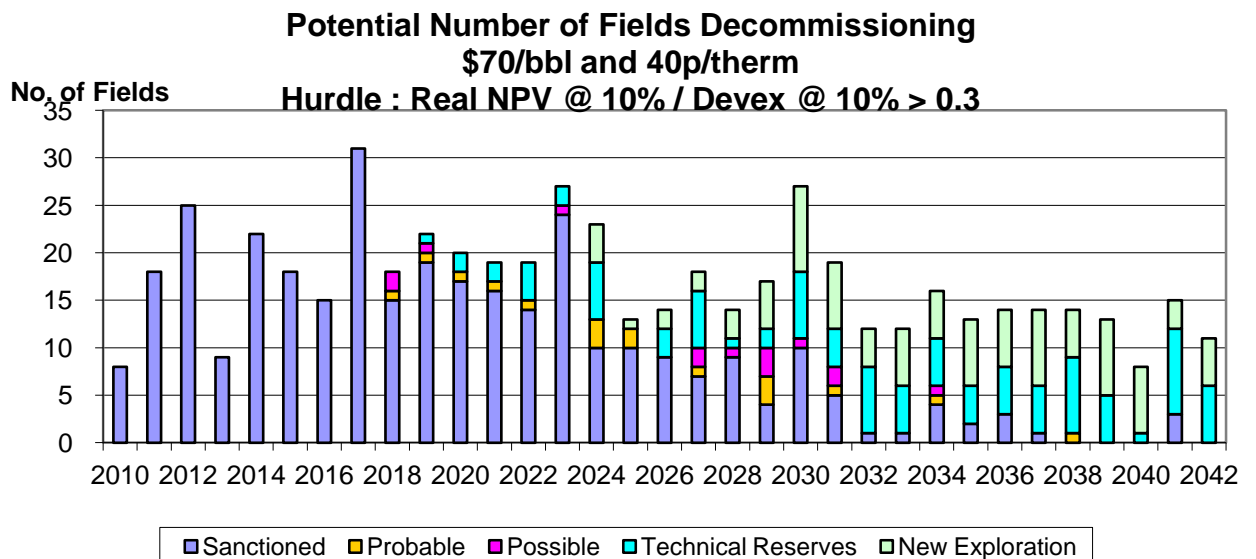
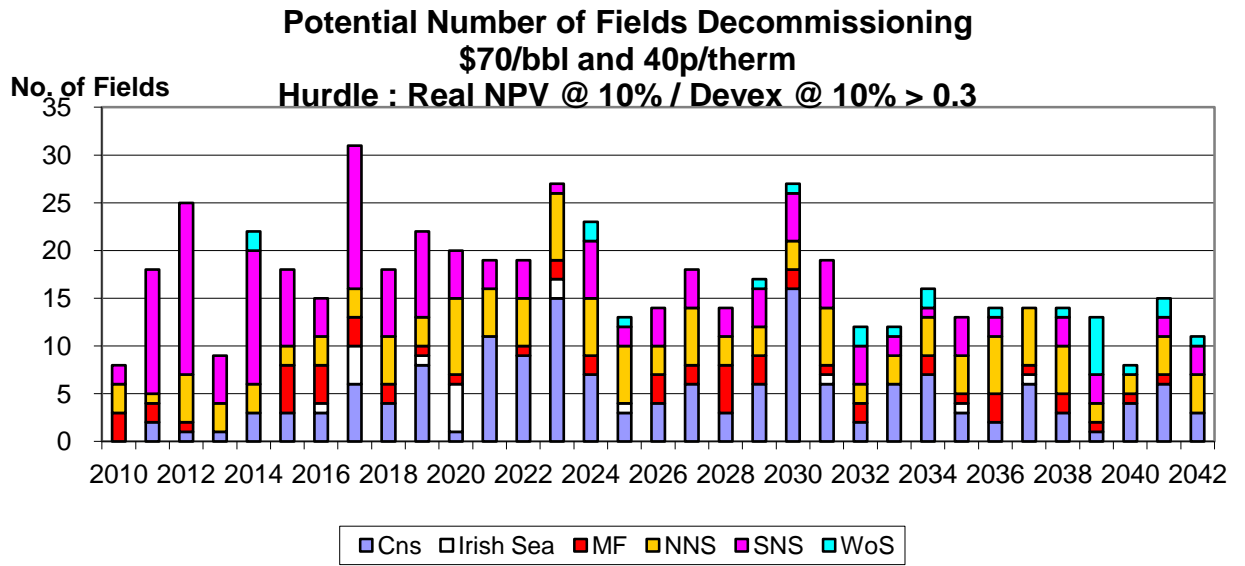


Chart 7



For convenience, in Chart 8 the number of fields decommissioning is shown with annual decommissioning expenditures. After 2030 the number of fields decommissioning is quite low but the annual decommissioning expenditures are relatively high.

Chart 8

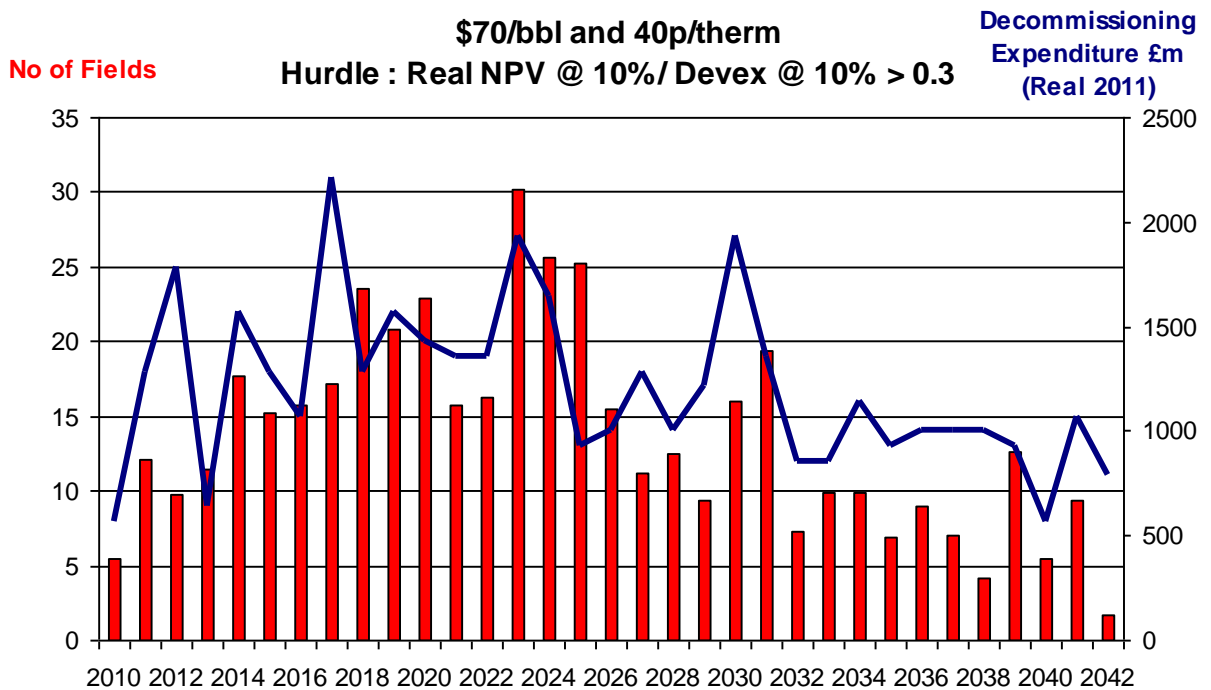
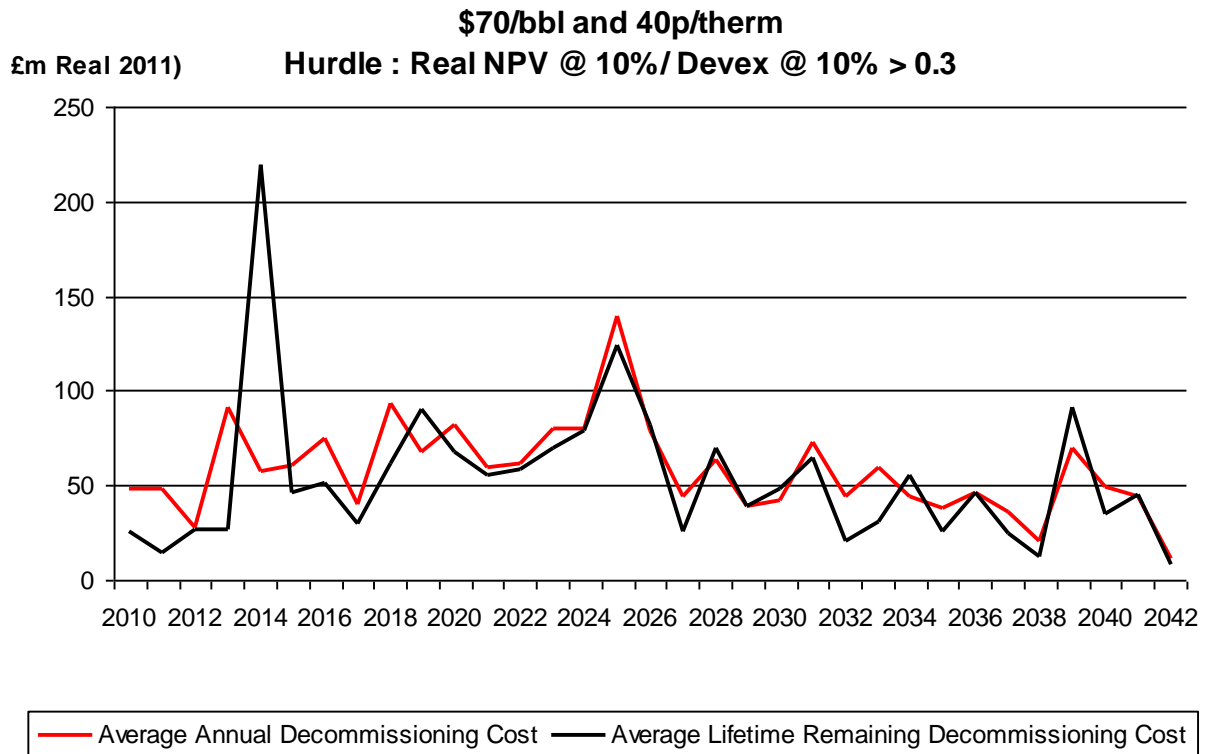


Chart 9 below shows the annual average decommissioning cost (annual expenditure divided by number of fields decommissioning) and the average remaining lifetime decommissioning cost. Large fields in particular may have decommissioning expenditure spread over many years before and after the decommissioning date. The average remaining lifetime decommissioning cost simply shows a fields remaining decommissioning expenditure as if it were all incurred in the year of decommissioning rather than spread over a number of years. This, in effect, shows when the expenditures is committed. From this it is seen that the average is very high in 2014 indicating a large field expenditure. The average remaining lifetime decommissioning cost is also high in 2017, 2018, 2019, 2022 to 2026, 2028, 2031, 2036 and 2039 showing that relatively large fields are committed to decommissioning in these years. The dates of large infrastructure decommissioning expenditures (expenditure > £350m) are 2014, 2017, 2018, 2019, 2020, 2022, 2024, 2025, 2026, 2028, 2031, 2034, 2036, 2039 and 2041.

Chart 9



Charts 10 and 11 show the potential decommissioning relief that would be given if there is no change to the tax treatment of decommissioning expenditure.

Chart 10

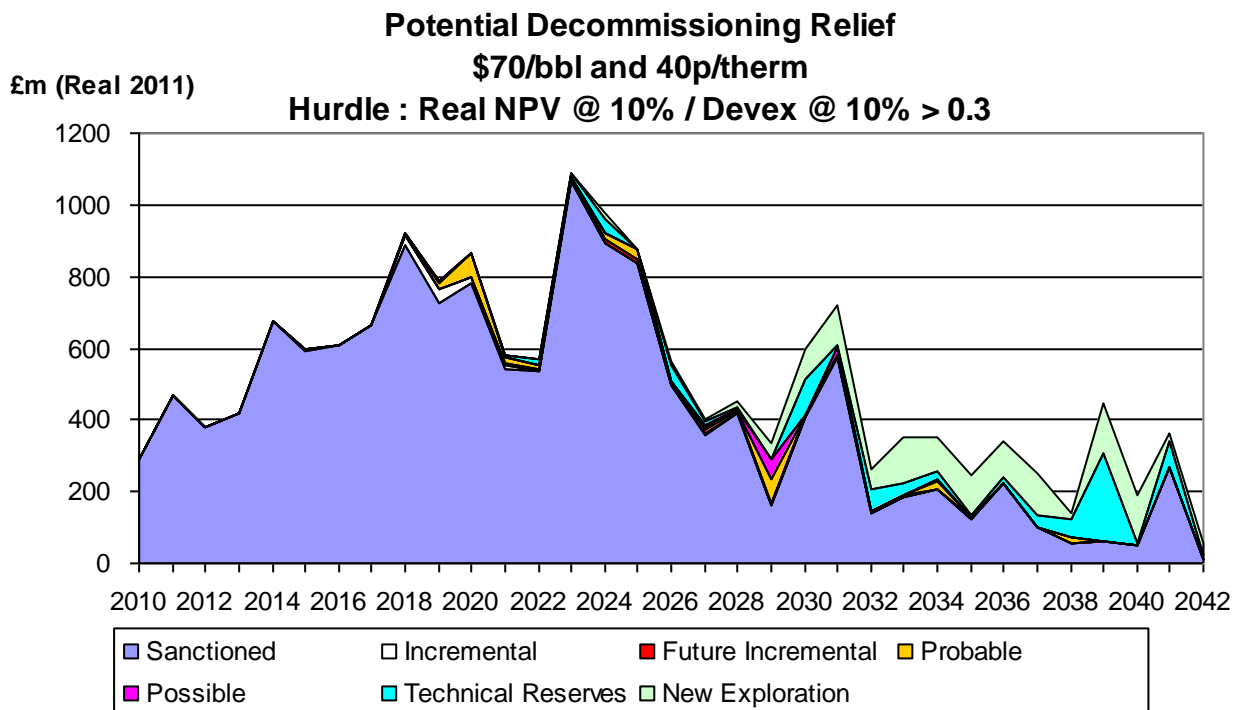
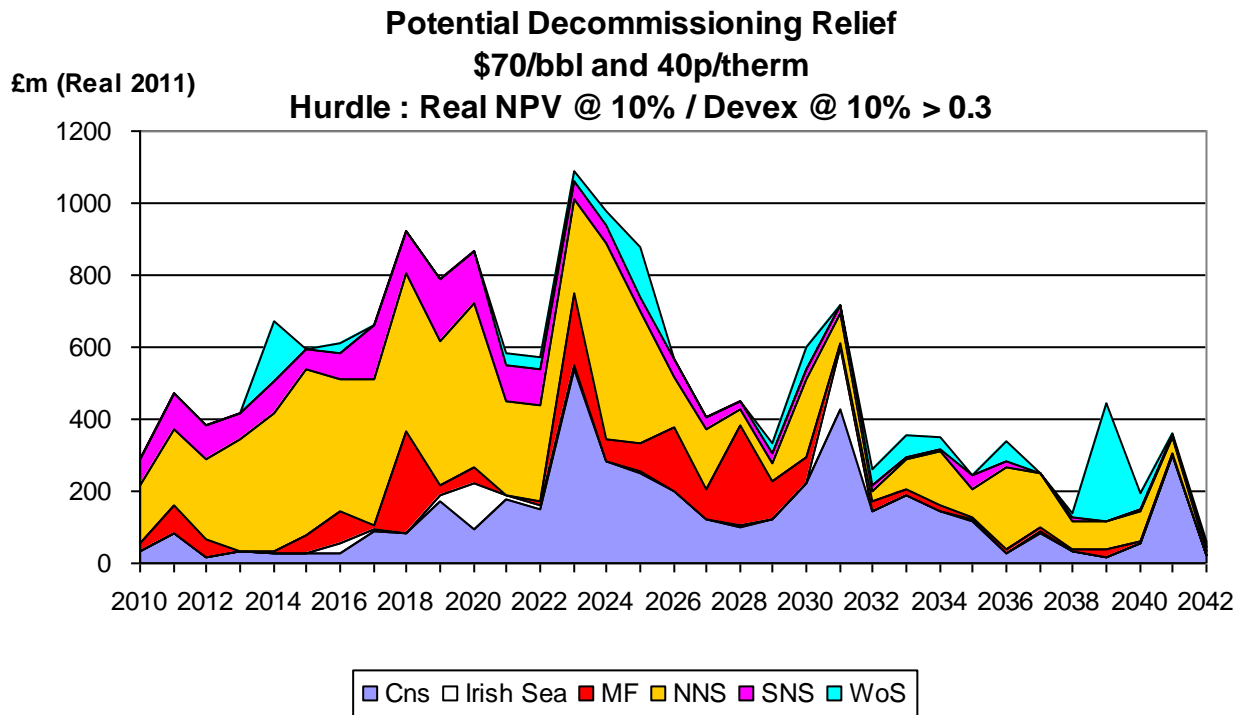


Chart 11



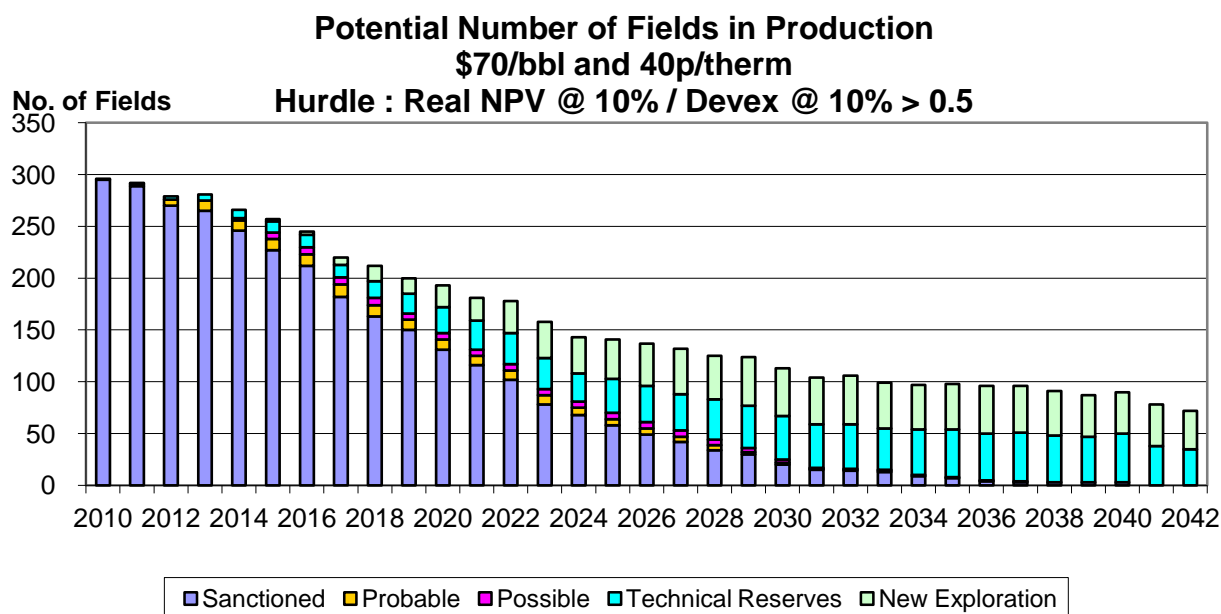
Total potential cumulative (2011 to 2042) decommissioning relief is £16.554 billion under the current tax system.

B. \$70, 40 pence, Hurdle NPV/I > 0.5

(i) Numbers of Fields in Production

In Chart 12 it is seen that the numbers of producing fields falls to 72 compared to around 300 (as defined) at the present time. There is a marked difference in activity levels under this scenario compared to the one where the hurdle was $NPV/I > 0.3$. In that scenario there are 96 producing fields in 2042. Over the whole period the average annual number of new field developments was just under 8.

Chart 12



(ii)Decommissioning Activity

In Chart 13 annual decommissioning expenditures are shown according to types of field and in Chart 14 the corresponding cumulative expenditures to 2042 are shown. The total is £29.5 billion at 2011 prices. The overwhelming importance of currently sanctioned fields in the total is highlighted.

Chart 13

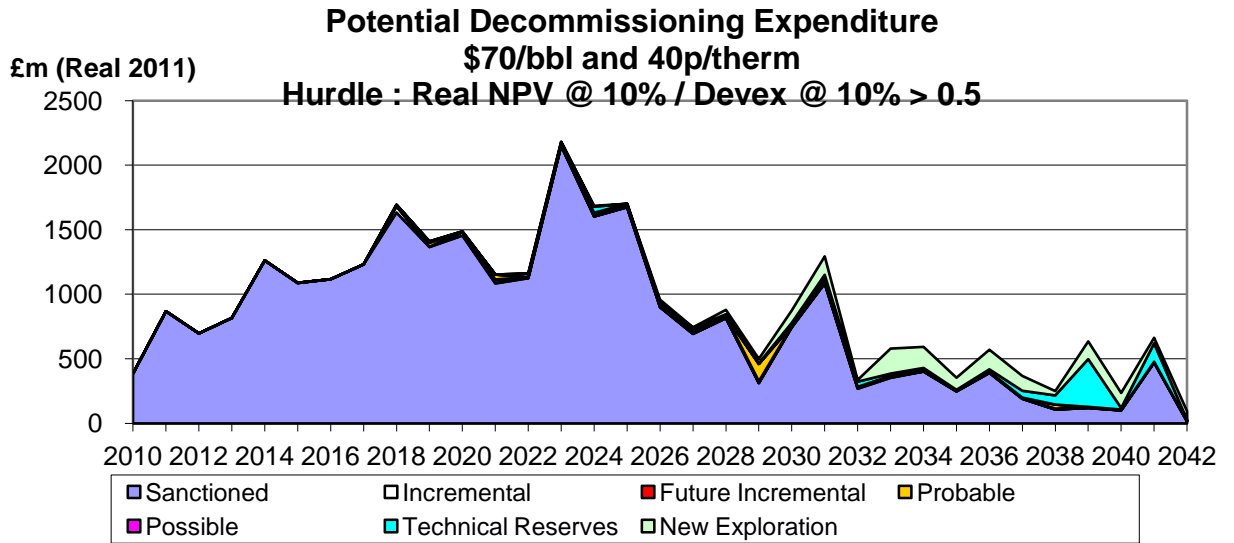
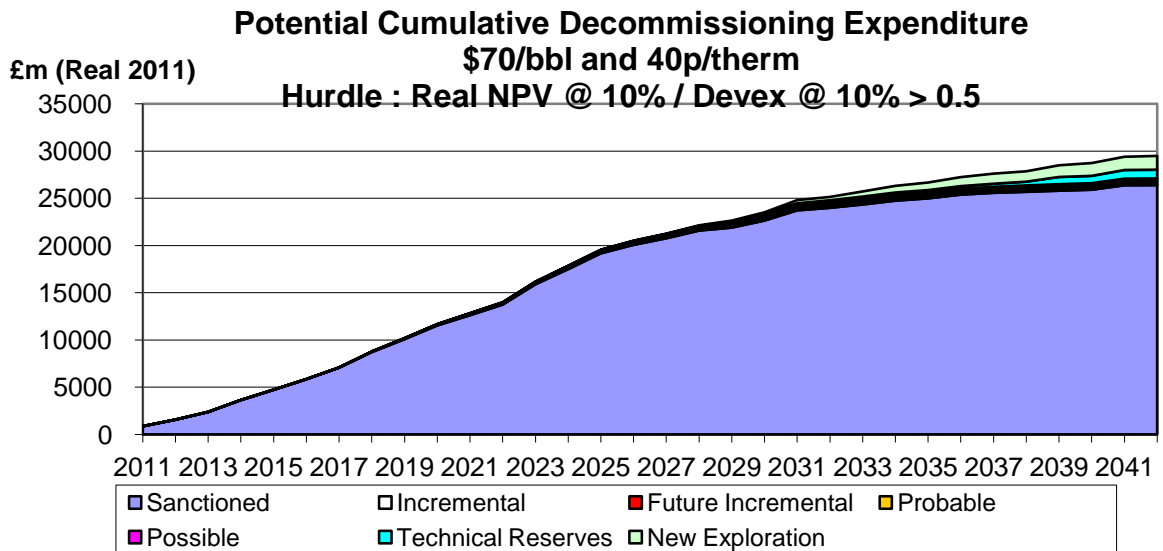


Chart 14



In Charts 15 and 16 the expenditures classified according to the 6 regions of the UKCS are shown. The importance of the NNS is highlighted.

Chart 15

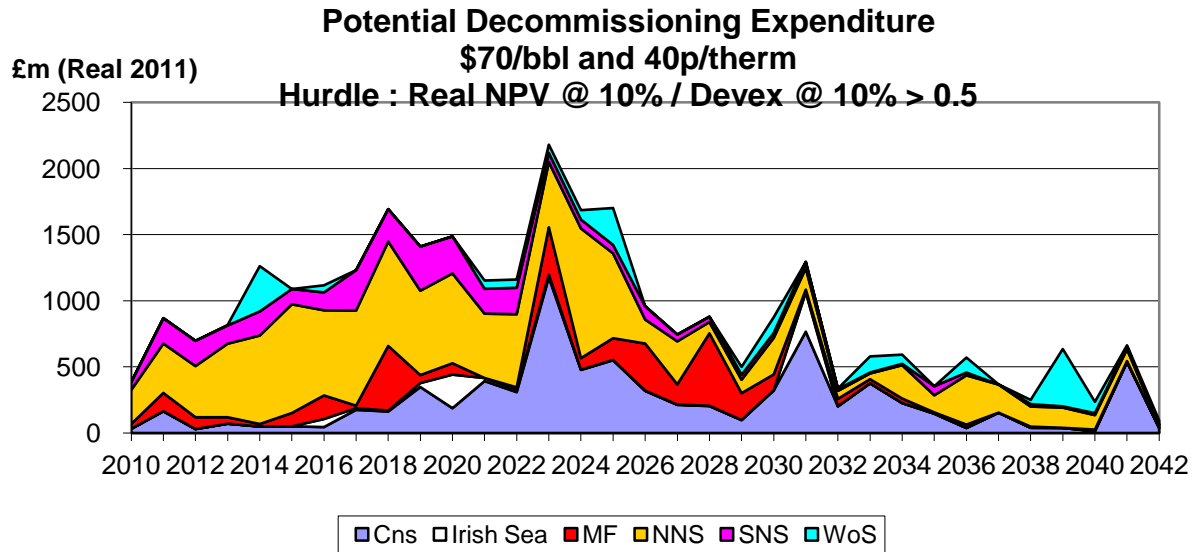
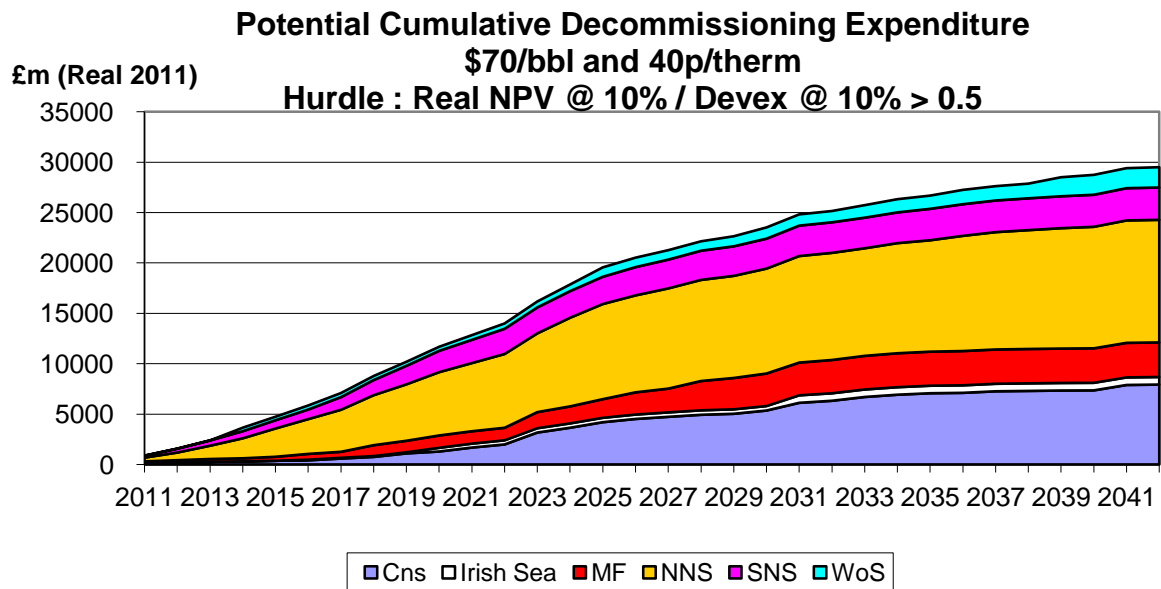


Chart 16



In Charts 17 and 18 the numbers of fields reaching their COP dates are shown. There are fewer fields in the total over the period to 2042 compared to the scenario when the economic hurdle was $NPV/I > 0.3$ because fewer fields are developed at the higher hurdle rate. The annual average over the period to 2030 remains in excess of 15.

Chart 17

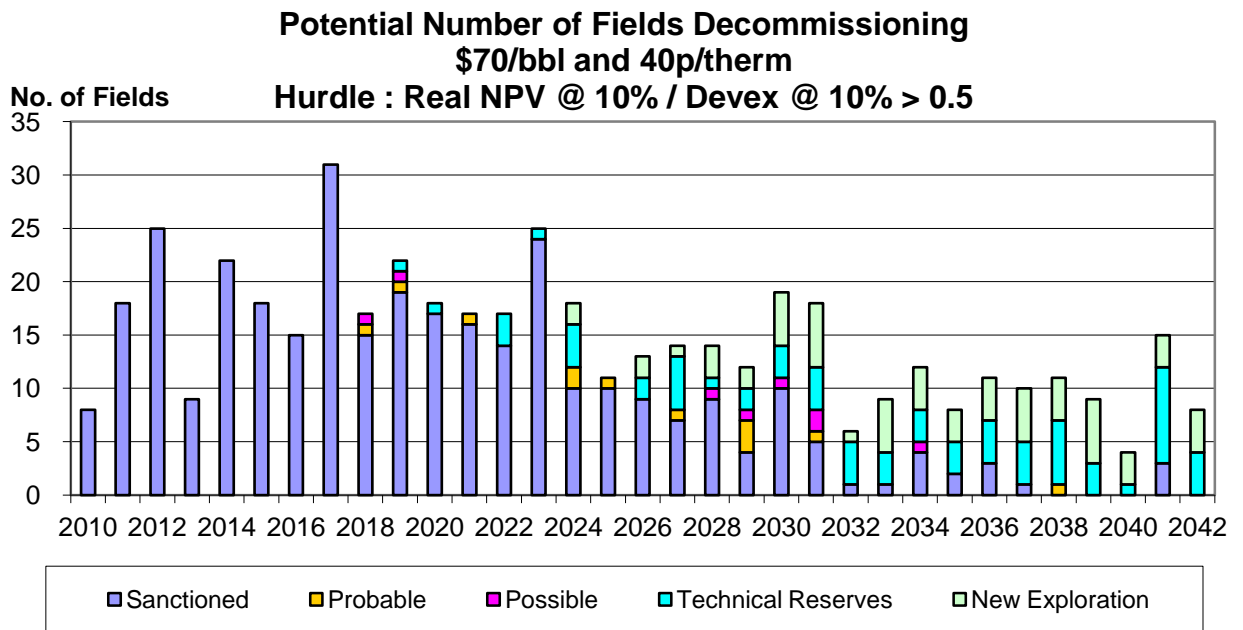


Chart 18

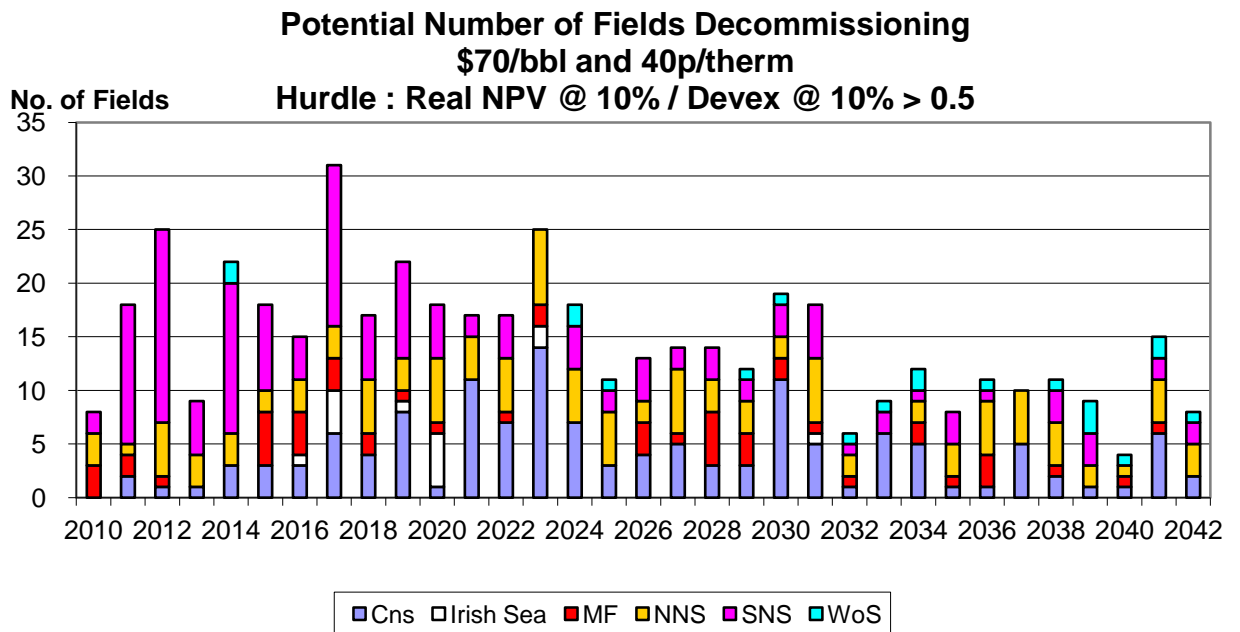
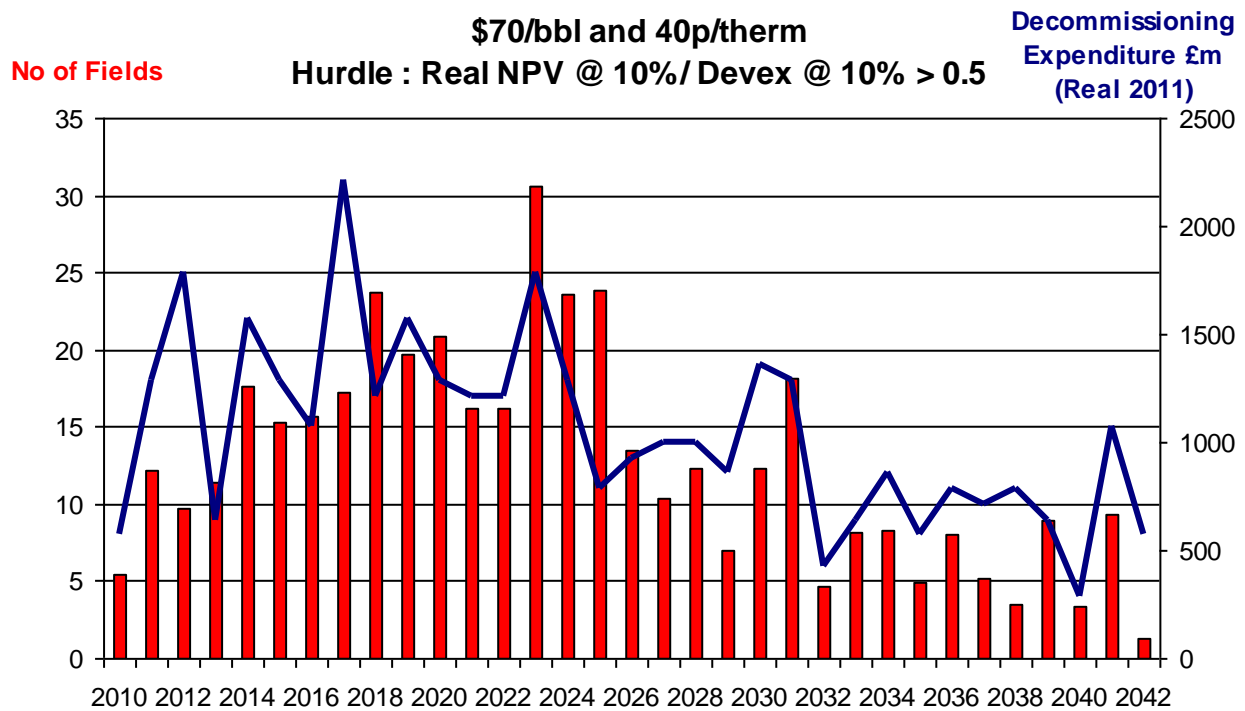


Chart 19 below shows the number of fields decommissioning with annual decommissioning expenditures whilst Chart 20 shows the annual average decommissioning cost and the average remaining lifetime

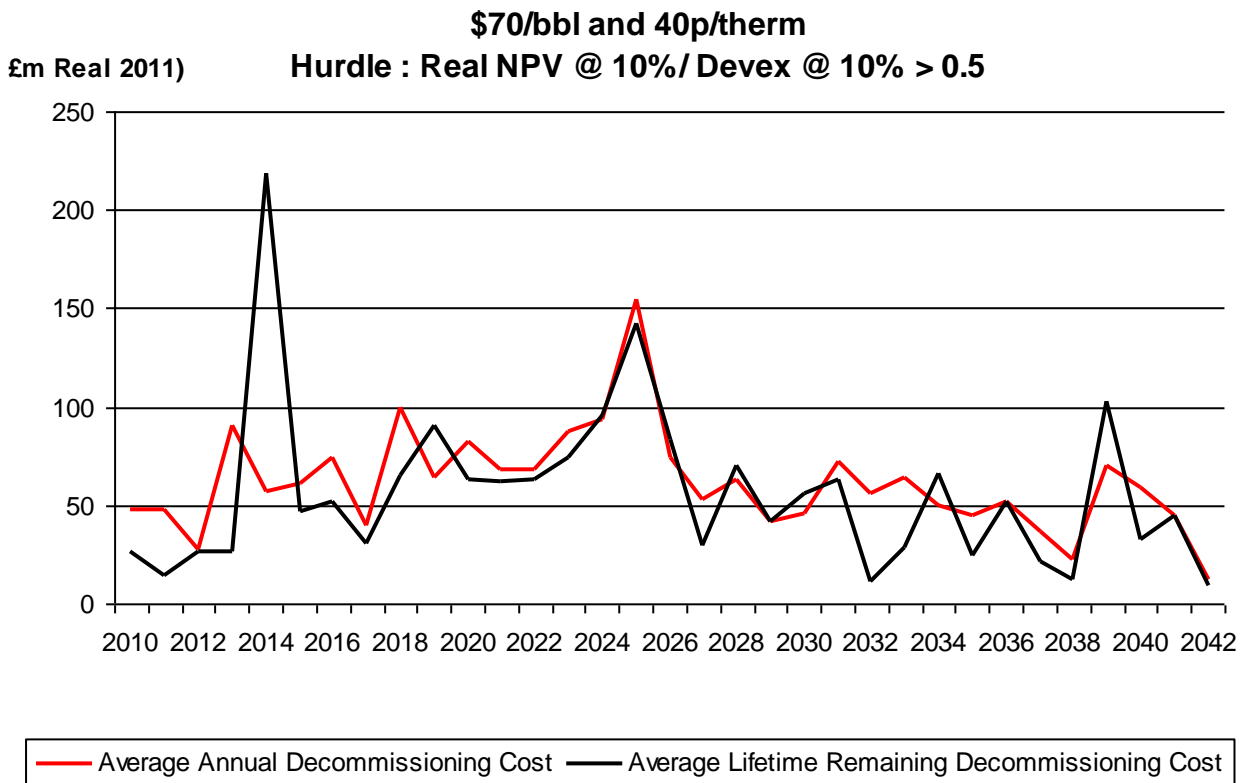
decommissioning cost. The timing of decommissioning is obviously the same as with the 0.3 hurdle but there is a change in expenditures and the number of fields because less fields pass the higher hurdle rate.

Chart 19



The annual average decommissioning cost is generally lower with the higher hurdle rate and the average remaining lifetime decommissioning cost differs from year to year being higher in some years and lower in others. The differences however are small.

Chart 20



Charts 21 and 22 show the potential decommissioning relief that would be given if there is no change to the tax treatment of decommissioning expenditures.

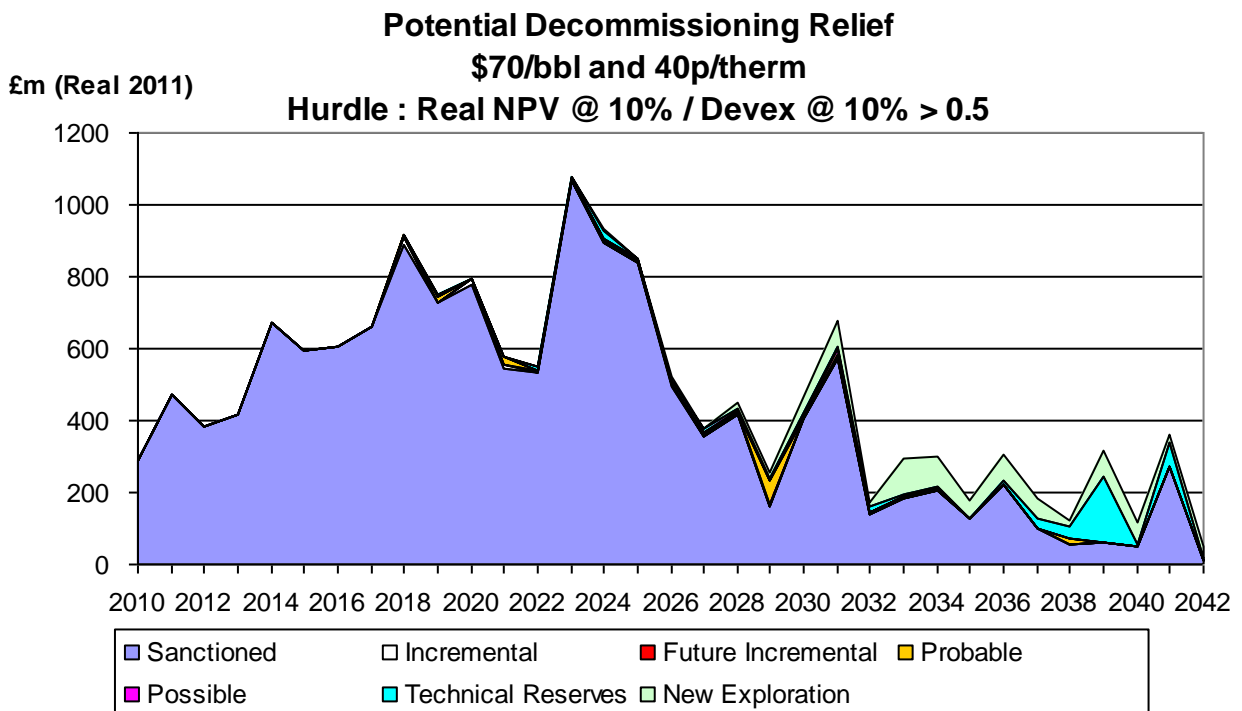
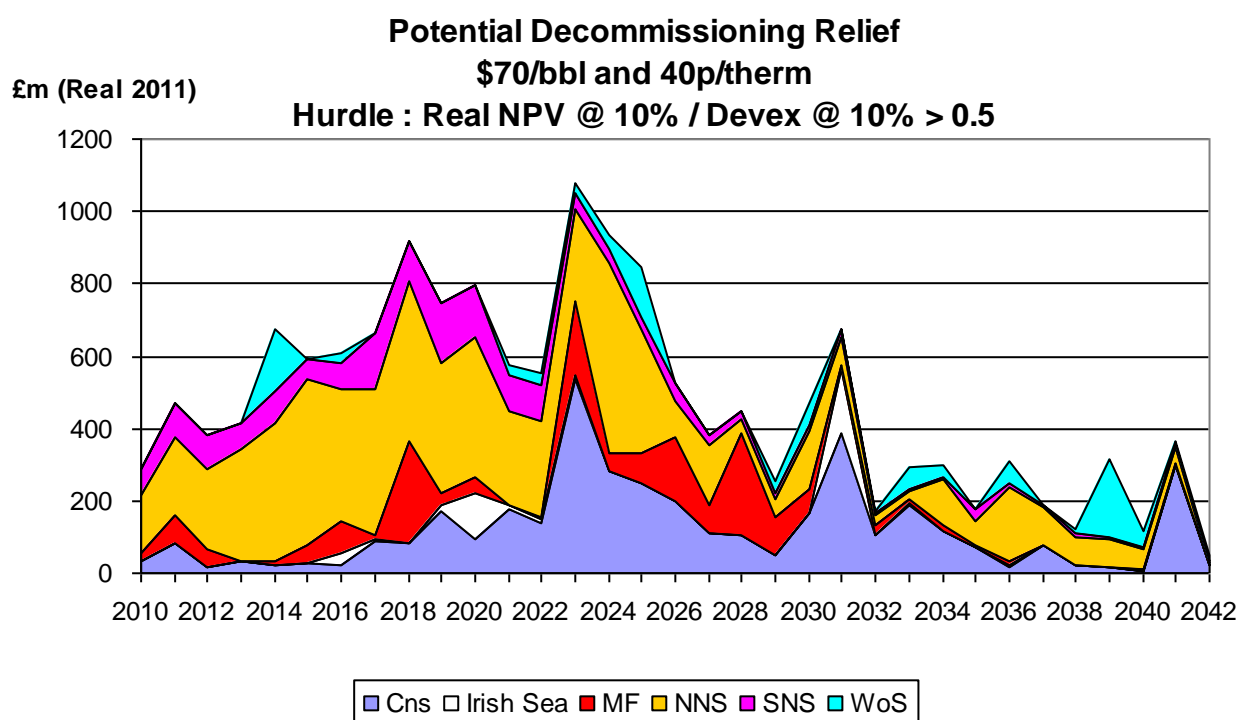


Chart 22



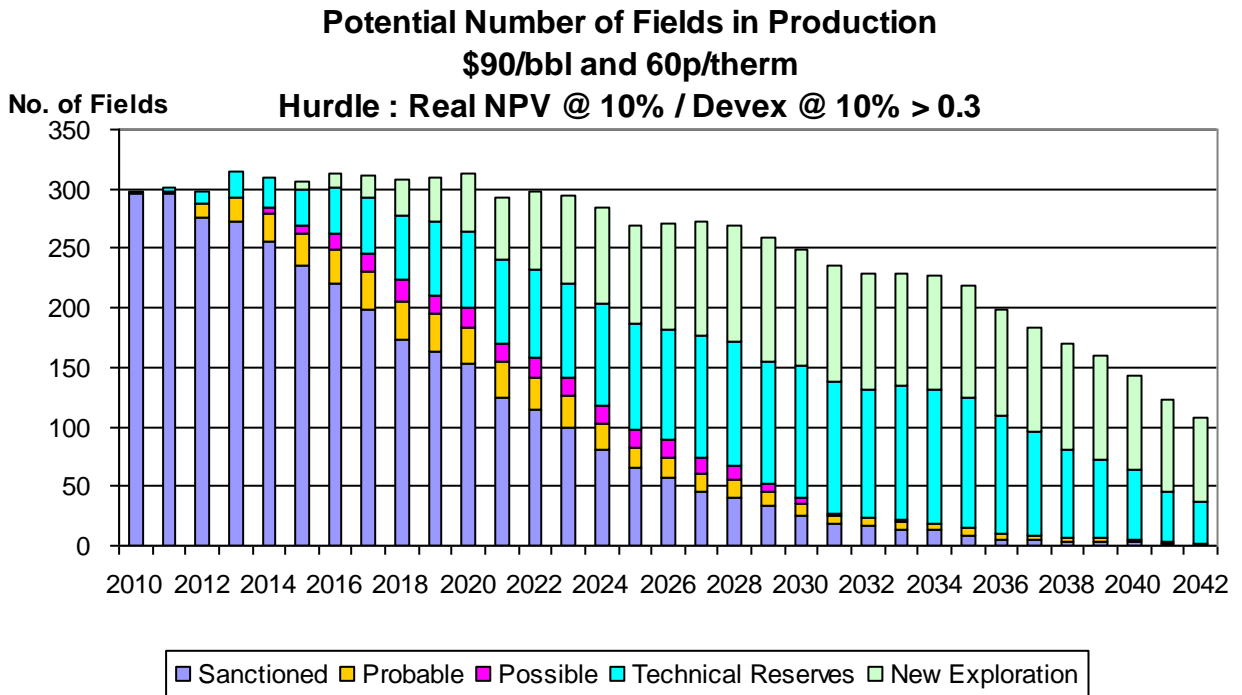
Total potential cumulative (2011 to 2042) decommissioning relief is £15.403 billion.

C. \$90, 60 pence, Hurdle NPV/I > 0.3

(i) Numbers of Fields in Production

In Chart 23 the numbers of fields in production over the period to 2042 are shown according to type. Compared to the medium price scenario the numbers are considerably higher reflecting the substantially larger number of new fields which pass the economic hurdle. It is seen that very substantial numbers of fields in the technical reserves category become viable as do many new discoveries. In 2042 there are still well over 100 producing fields. Over the period to 2030 the average annual number of new field developments was just under 18. These results depend on current major infrastructure remaining in place.

Chart 23



(ii) Decommissioning Activity

In Charts 24 and 25 decommissioning expenditures are shown according to type of field.

Chart 24

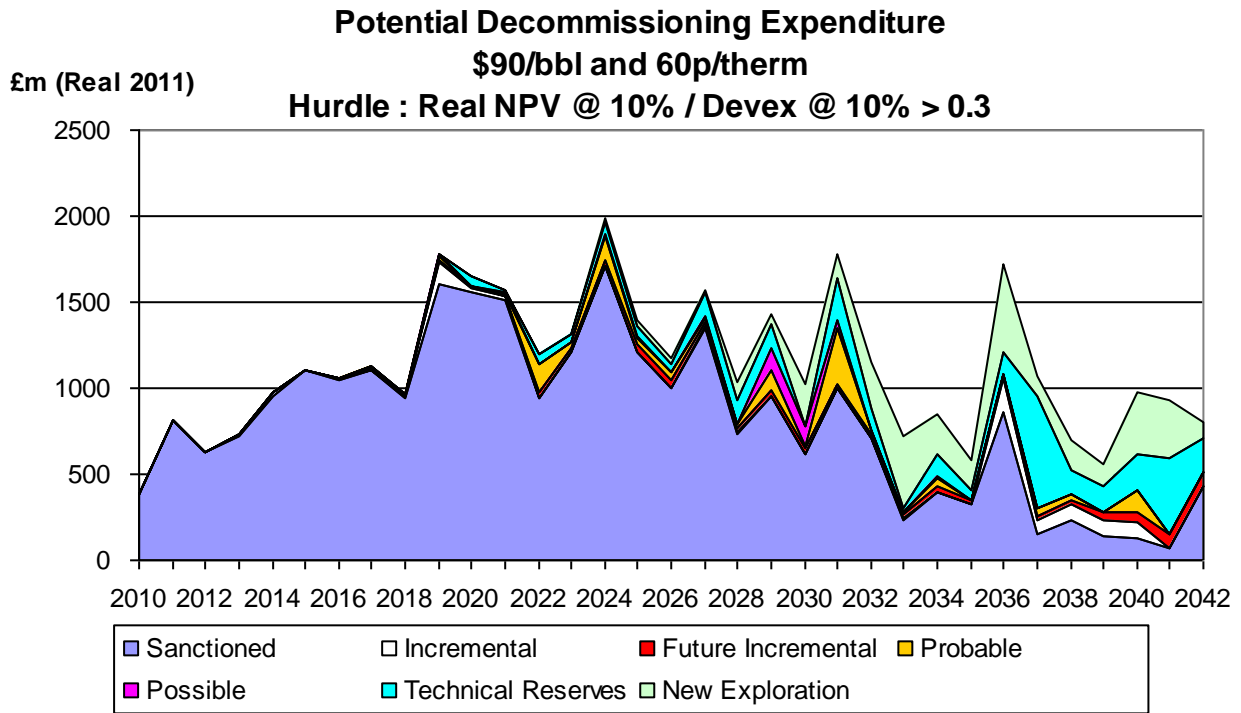
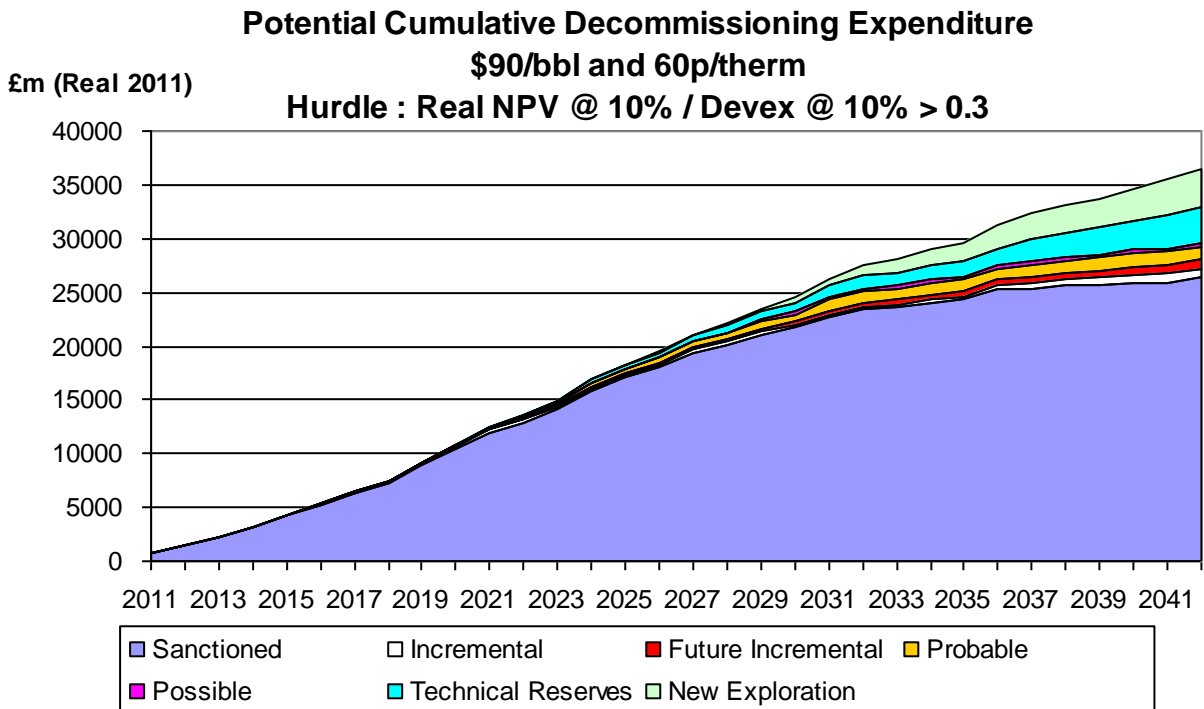
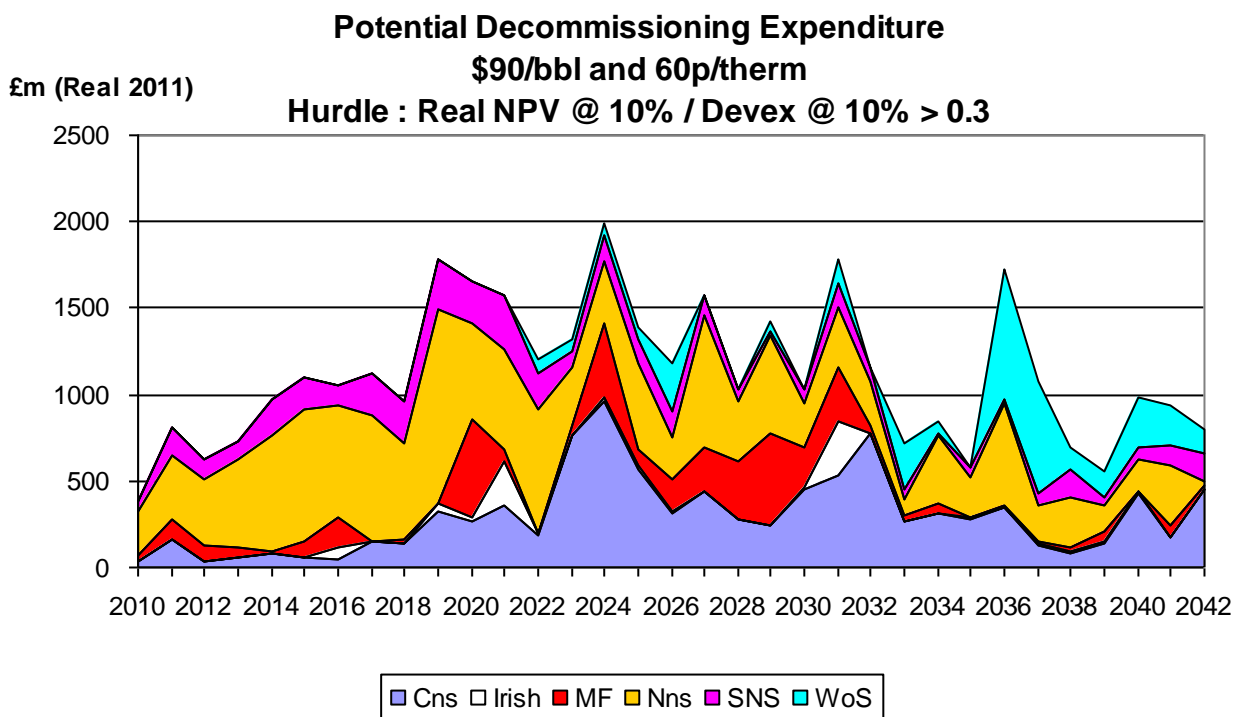


Chart 25



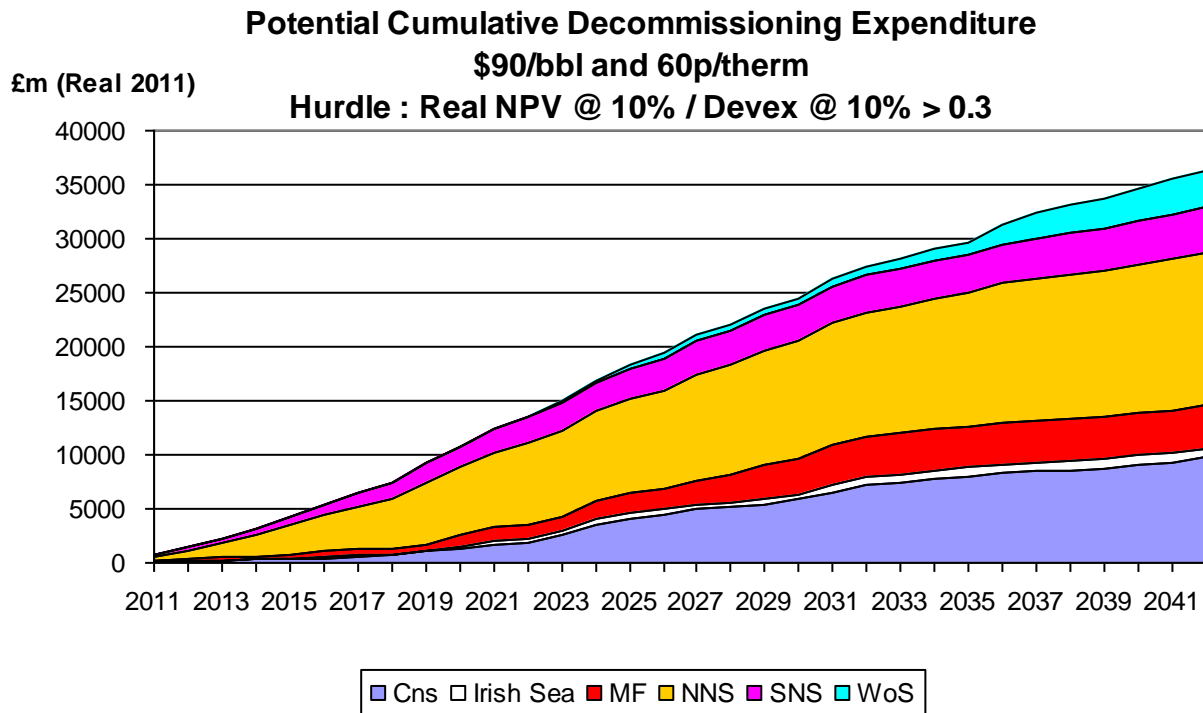
Over the period to 2042 cumulative expenditure amounts to £36.4 billion at 2011 prices. Under this price scenario there is some limited movement to later years of the very large levels of expenditure compared to the \$70, 40 pence scenario. In the later years the expenditures exceed those under the medium price scenario because more new field developments are triggered and reach their COP dates before the end of the study period.

Chart 26



In Charts 26 and 27 the decommissioning costs are shown according to geographic region. Over the whole period £14 billion (at 2011 prices) is incurred in the NNS and £9.8 billion in the CNS.

Chart 27



In Charts 28 and 29 the numbers of fields reaching their COP dates over the period are shown. Under this higher price scenario, with more fields being developed, the average annual number reaching their COP dates exceeds 15.

Chart 28

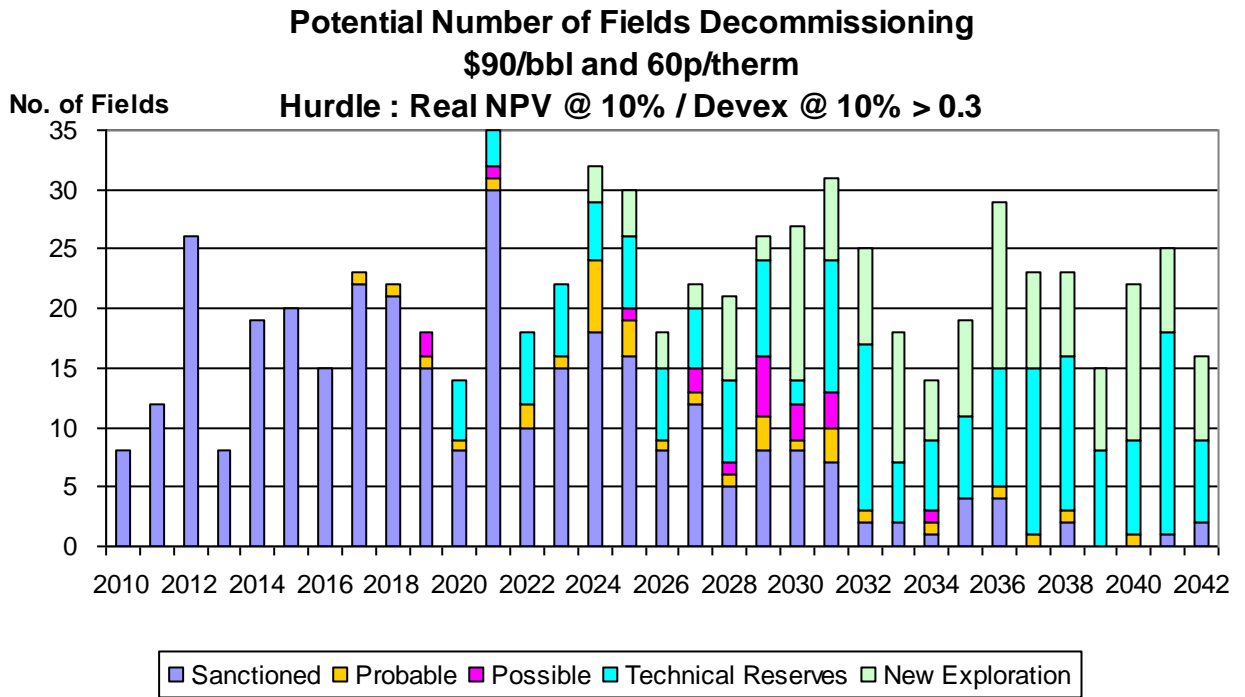


Chart 29

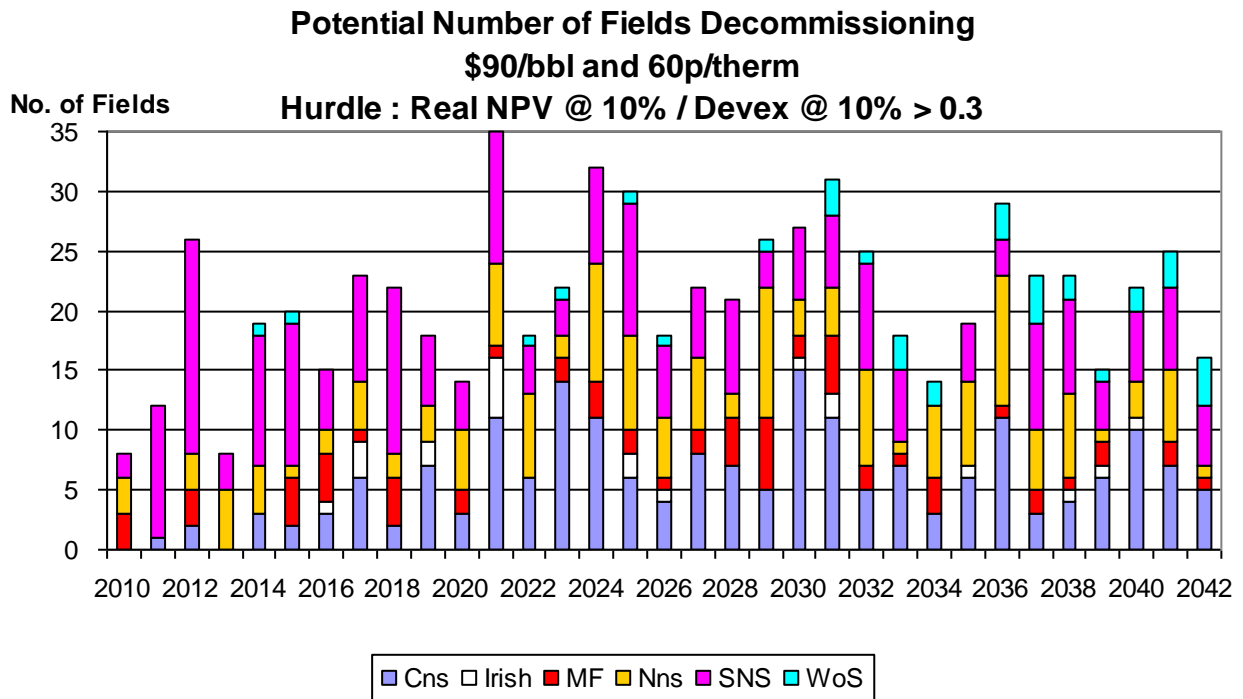


Chart 30 shows the number of fields decommissioning with annual decommissioning expenditures. Chart 31 shows the annual average decommissioning cost and the average remaining lifetime decommissioning cost.

Chart 30

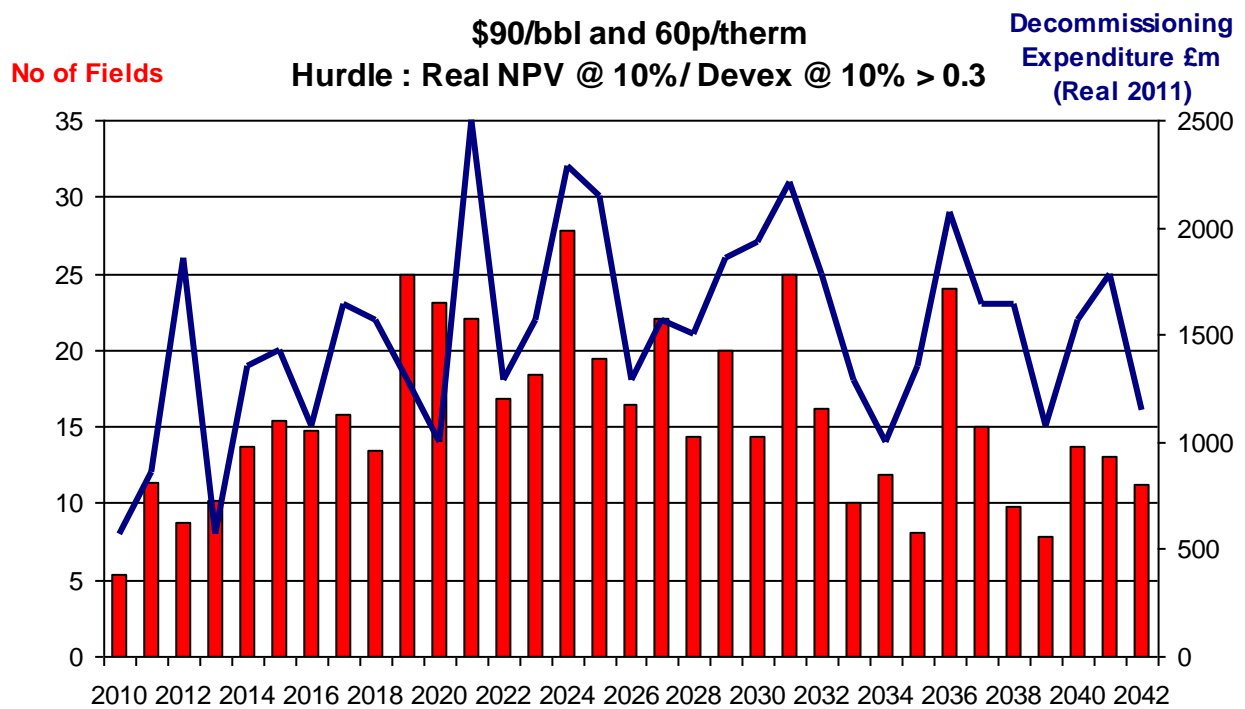
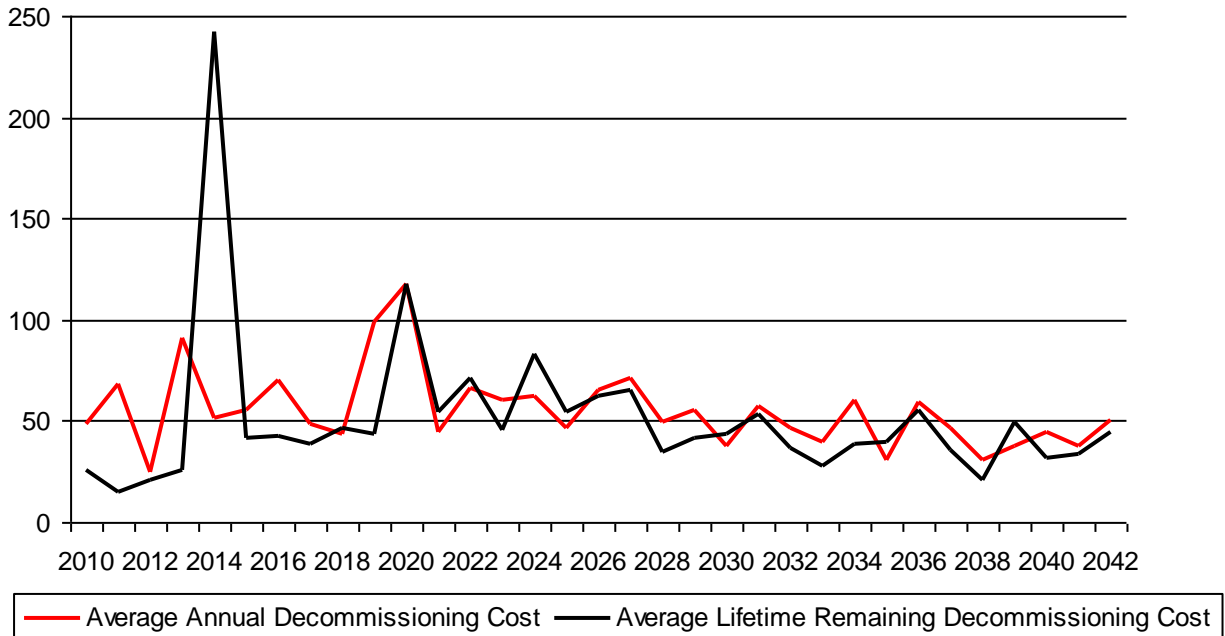


Chart 31

\$90/bbl and 60p/therm
Hurdle : Real NPV @ 10%/ Devex @ 10% > 0.3

£m (Real 2011)



Compared with the lower price case, the average remaining lifetime decommissioning cost is less peaked. The key peaks occur in 2014, 2020, 2022 and 2024. The dates of large infrastructure decommissioning expenditures (> £350m) however are 2014, 2015, 2018, 2020, 2021, 2022, 2024, 2025, 2026, 2027, 2029, 2032, 2035, 2036, 2037, 2039 and 2042.

Charts 32 and 33 show the potential decommissioning relief that would be given if there is no change to the tax treatment of decommissioning expenditures.

Chart 32

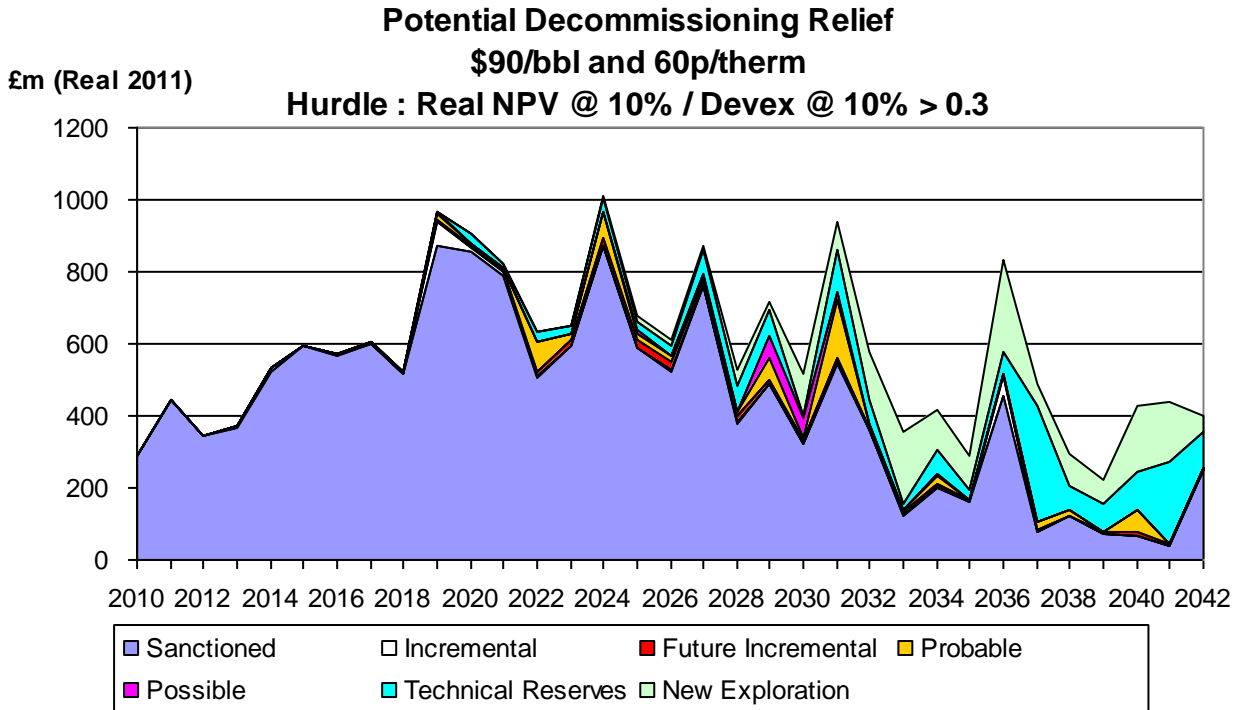
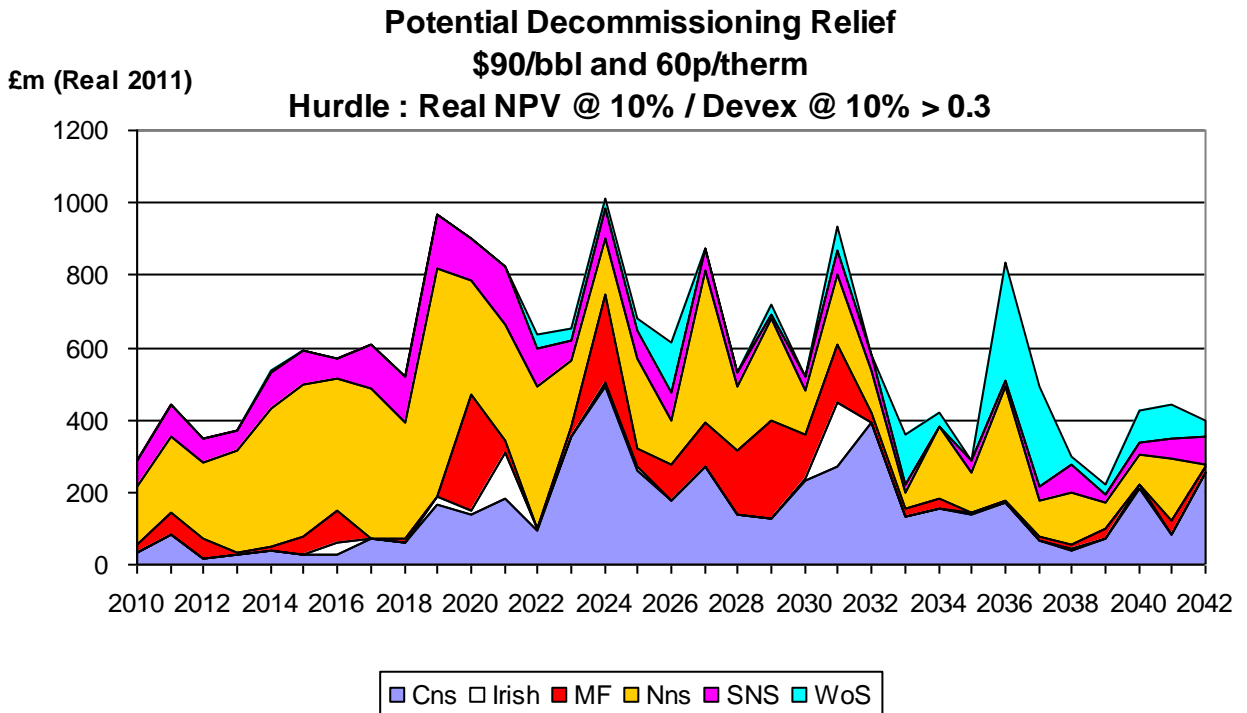


Chart 33



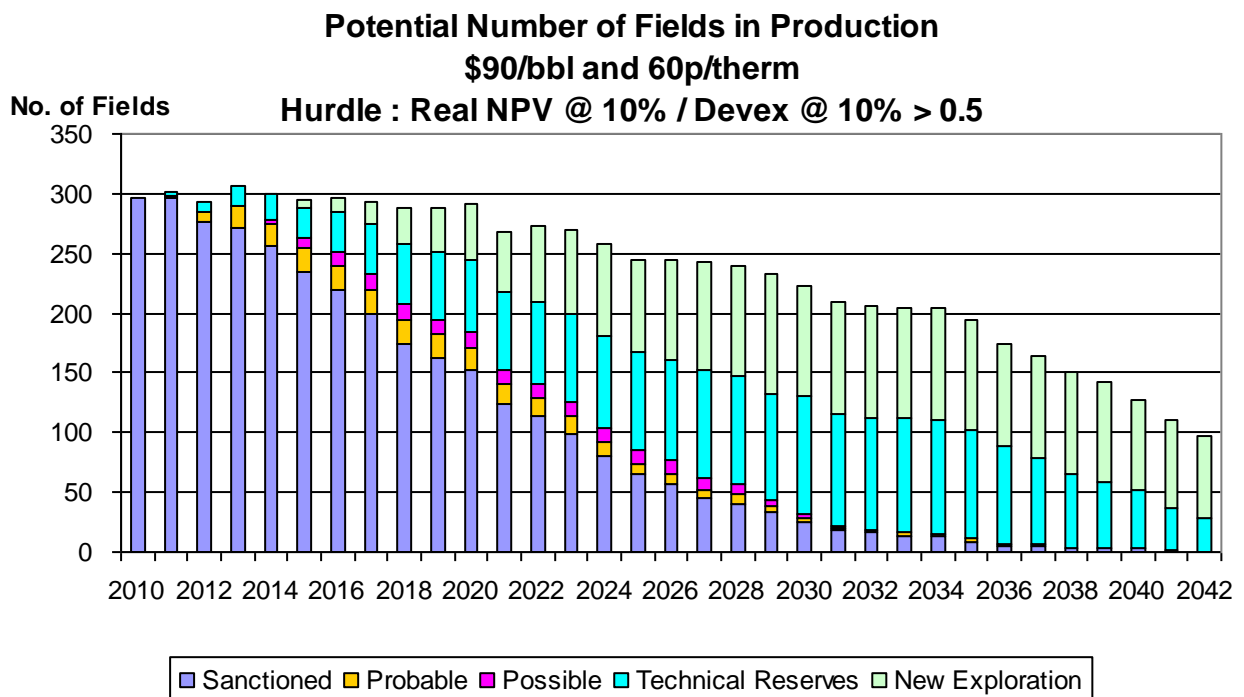
Total potential cumulative (2011 to 2042) decommissioning relief is £18.605 billion.

D. \$90, 60 pence price, Hurdle NPV/I > 0.5

(i) Numbers of Fields in Production

In Chart 34 the numbers of fields in production over the study period are shown. There is a steady decline in the numbers of sanctioned fields as they reach their COP dates. For some years these are fully replaced by the development of new fields. In the longer term large numbers of fields in the categories of technical reserves and new discoveries are developed with the result that in 2042 there are still nearly 100 producing fields. Over the period to 2030 the average annual number of new field developments was just under 16.

Chart 34



(ii)Decommissioning Activity

In Charts 35 and 36 decommissioning expenditures are respectively shown annually and cumulatively. Over the whole period the total cost is nearly £35 billion at 2011 prices. Of this total £26.4 billion relates to sanctioned fields. These results depend on current infrastructure remaining in place.

Chart 35

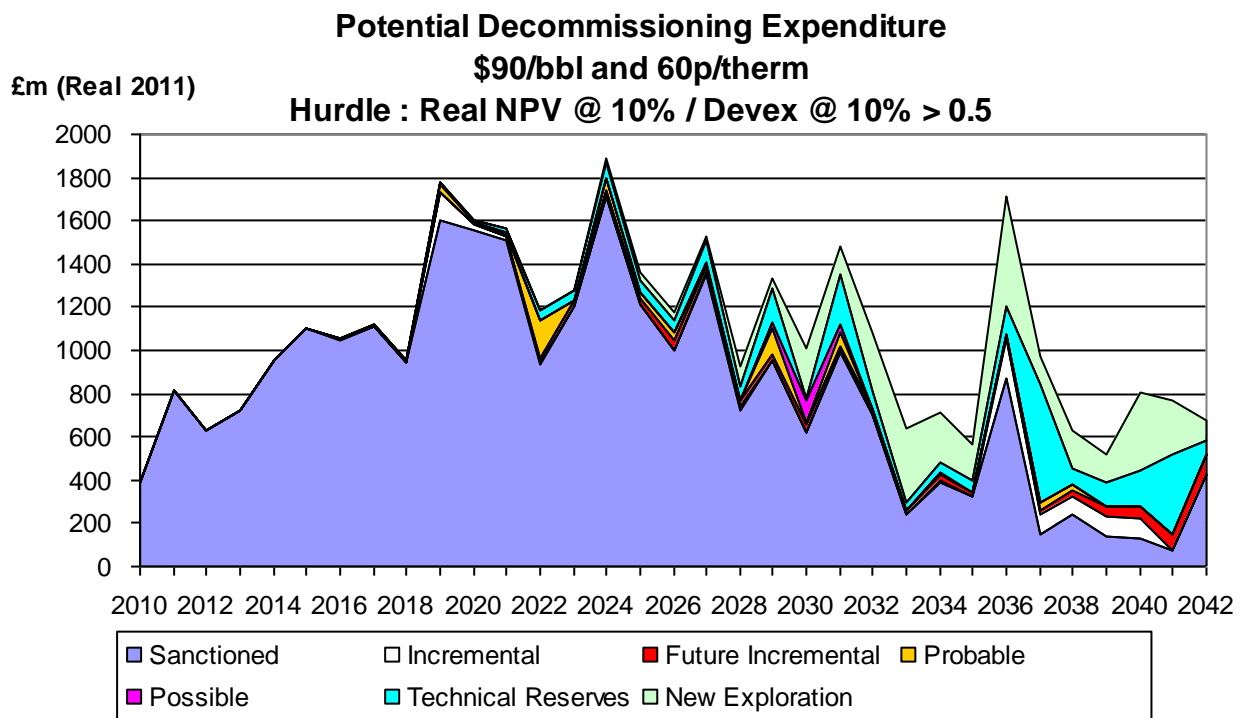
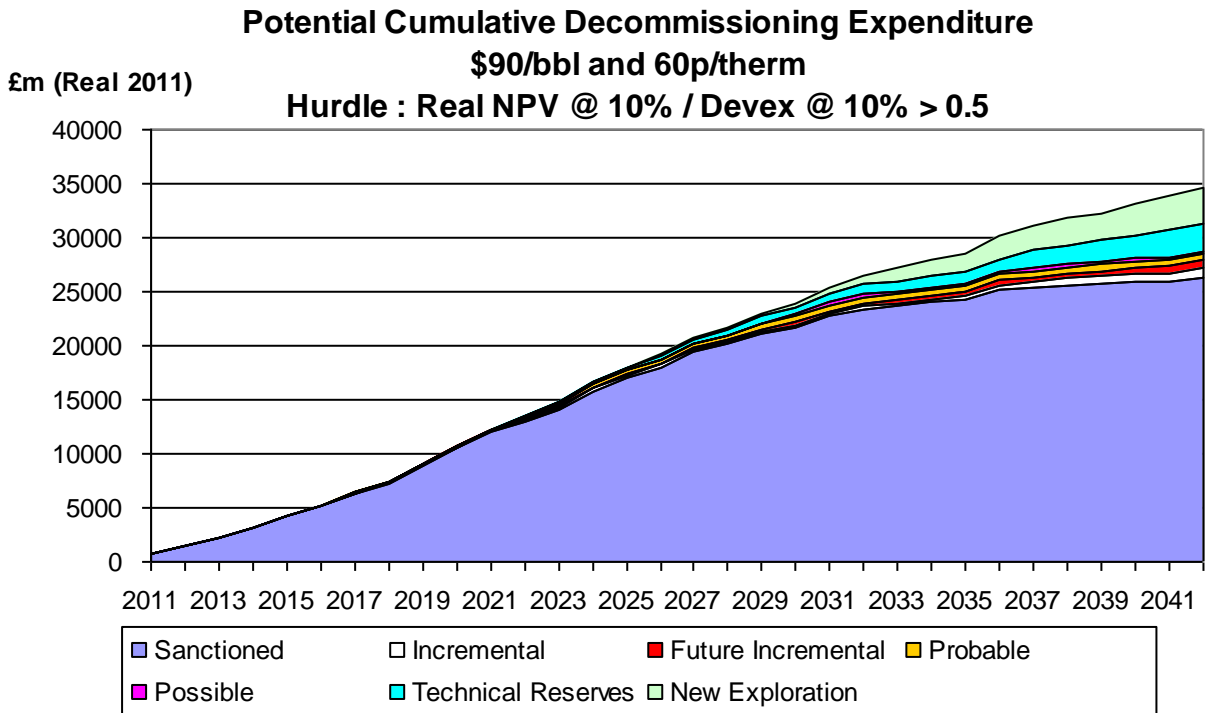


Chart 36



In Charts 37 and 38 the results are shown according to geographic areas of the UKCS. Over the period the NNS accounts for £13.6 billion and the CNS £9.4 billion.

Chart 37

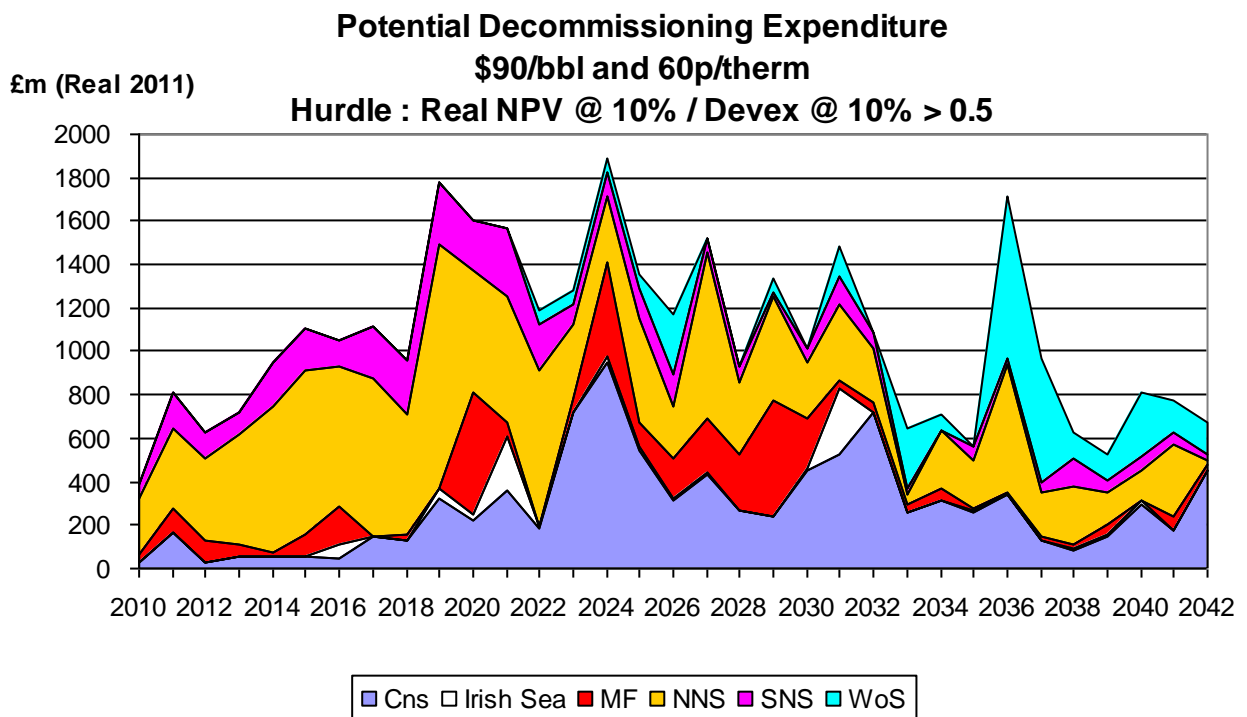
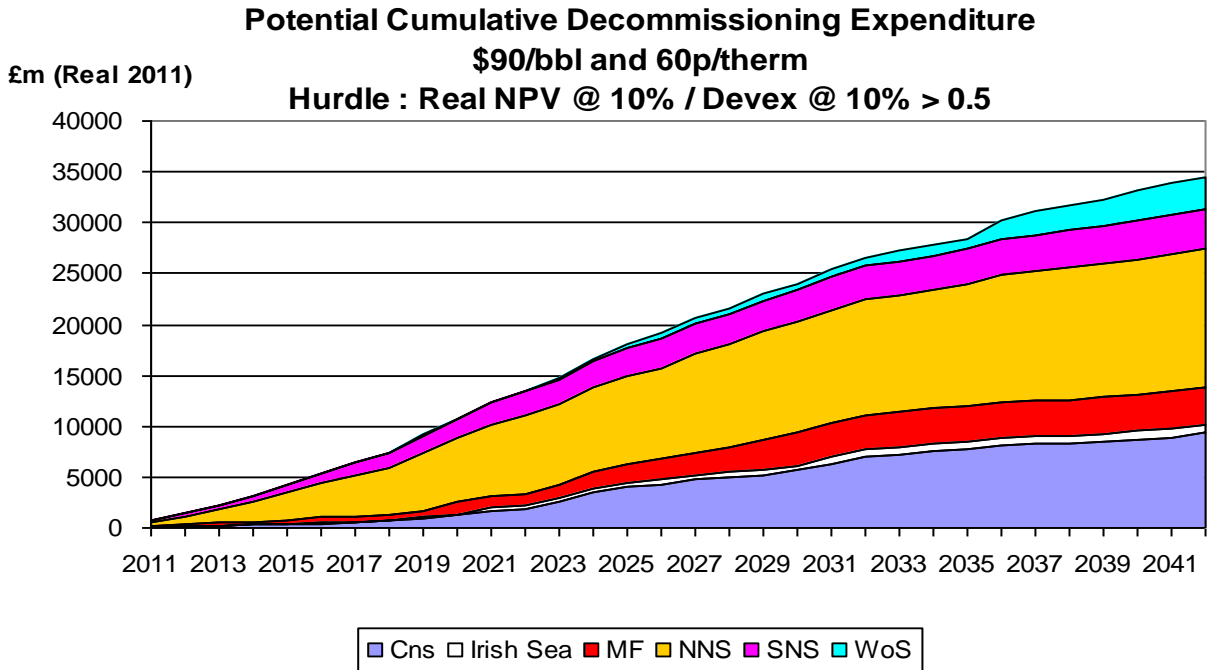


Chart 38



In Charts 39 and 40 the numbers of fields reaching their COP dates annually are shown. Over the period the annual total exceeds 15 in the great majority of the years.

Chart 39

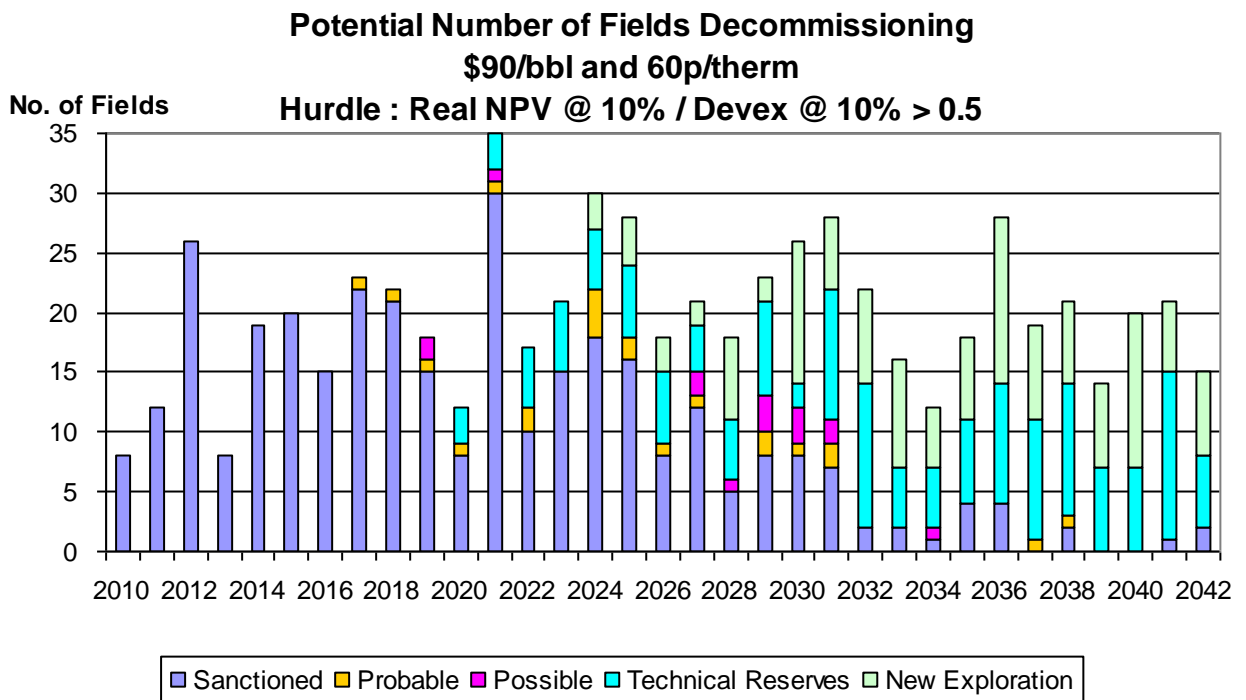
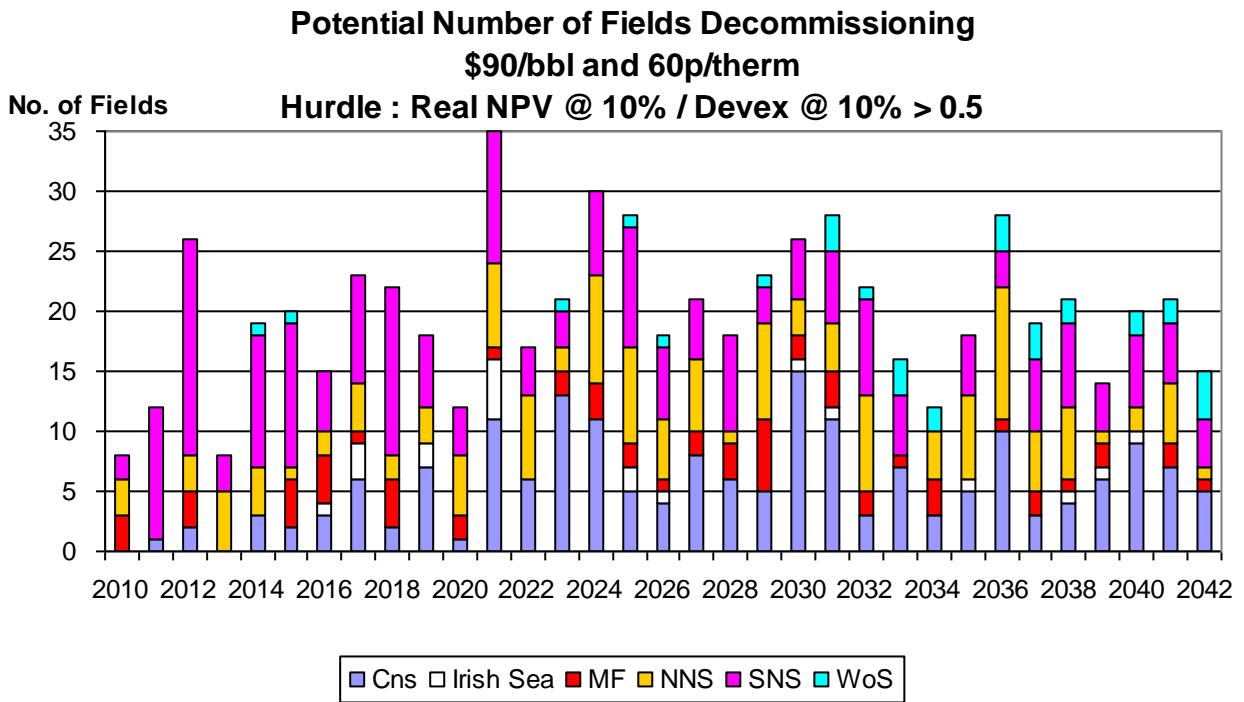


Chart 40



Charts 41 and 42 below show decommissioning expenditure with the number of fields decommissioning and annual decommissioning expenditures. The timing of decommissioning is obviously the same as with the 0.3 hurdle but there is a change in expenditures and the number of fields because less fields pass the higher hurdle rate. There is less of a difference in the average costs than there was with the low price case.

Chart 41

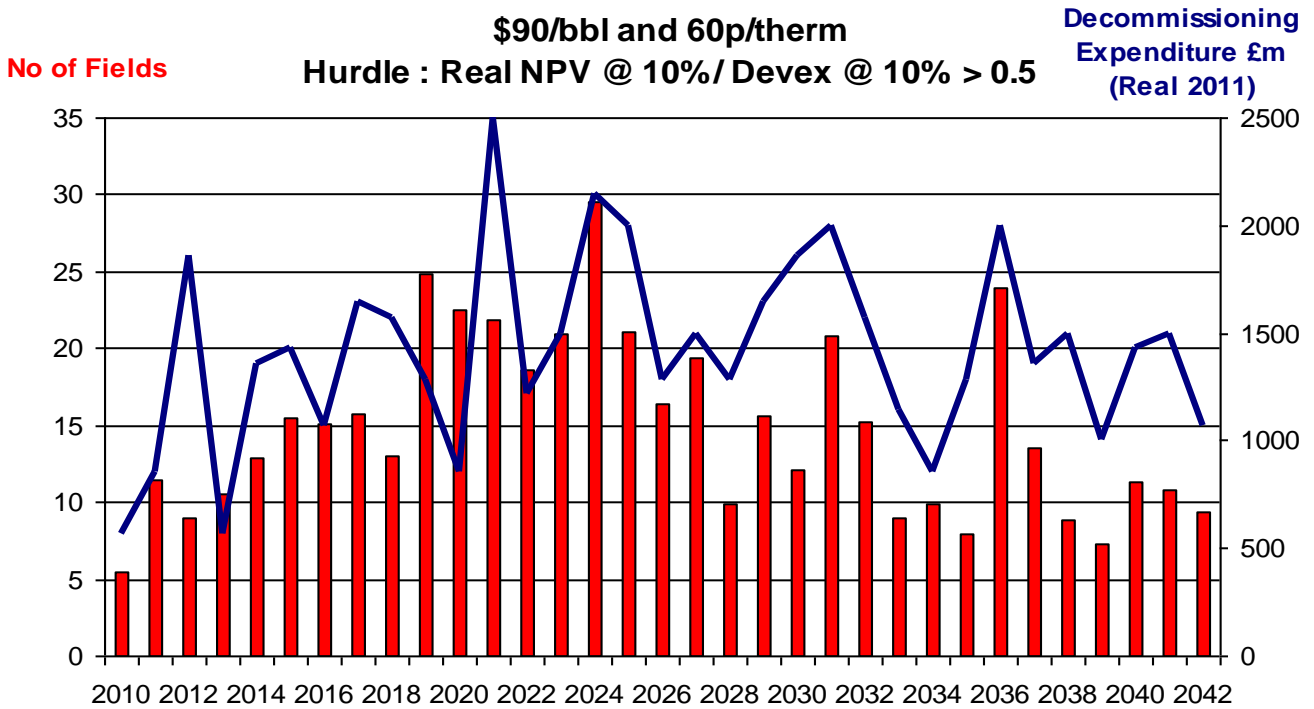
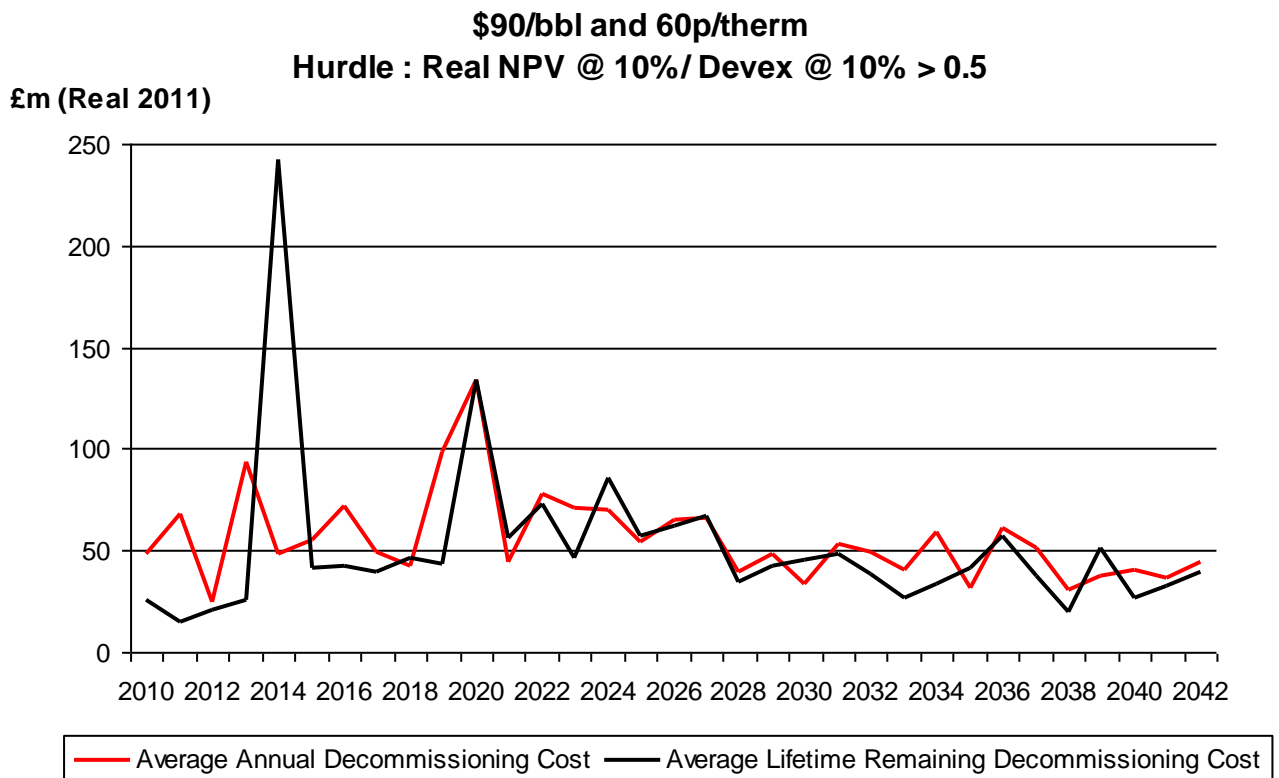
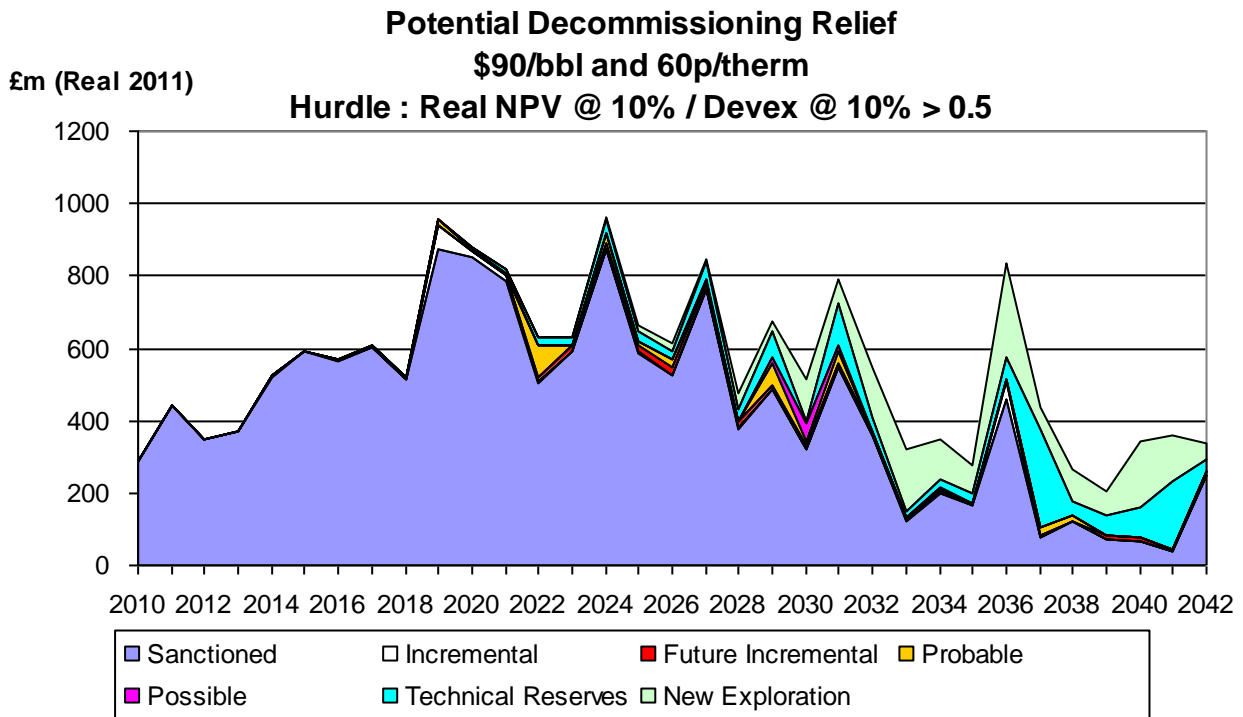


Chart 42



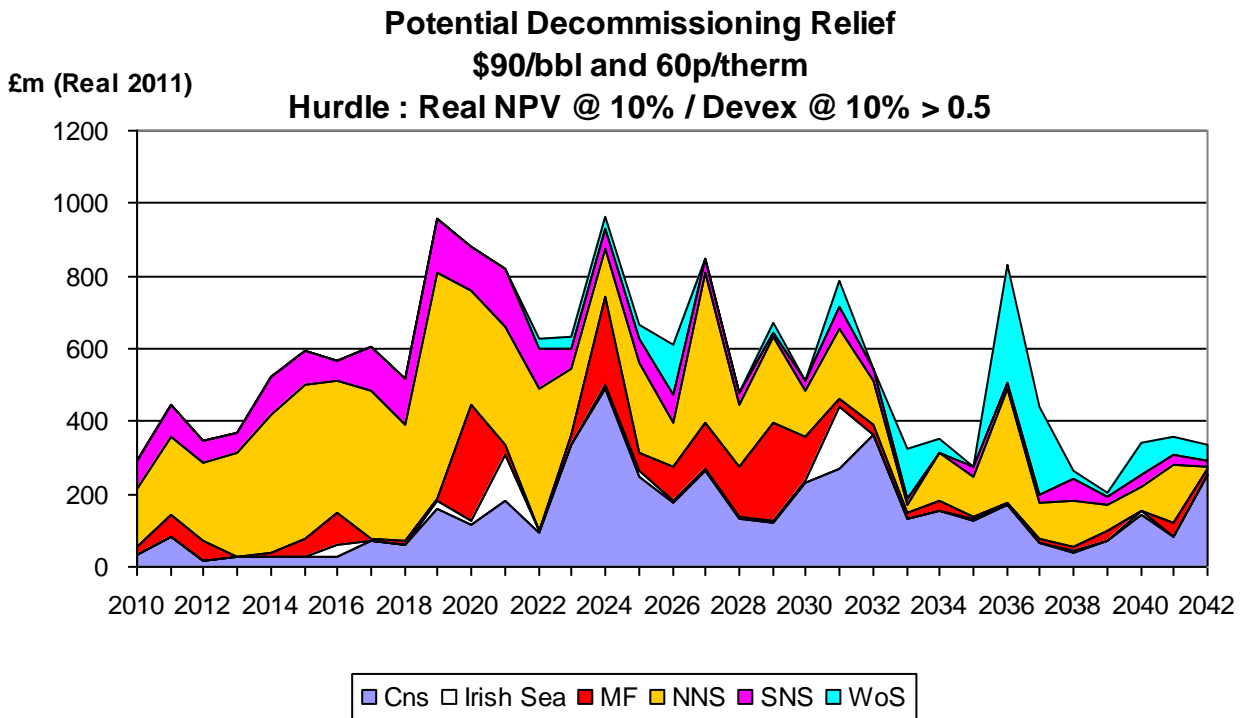
Charts 43 and 44 show the potential decommissioning relief that would be given if there is no change to the tax treatment of decommissioning expenditures.

Chart 43



Total potential cumulative (2011 to 2042) decommissioning relief is £17.706 billion.

Chart 44



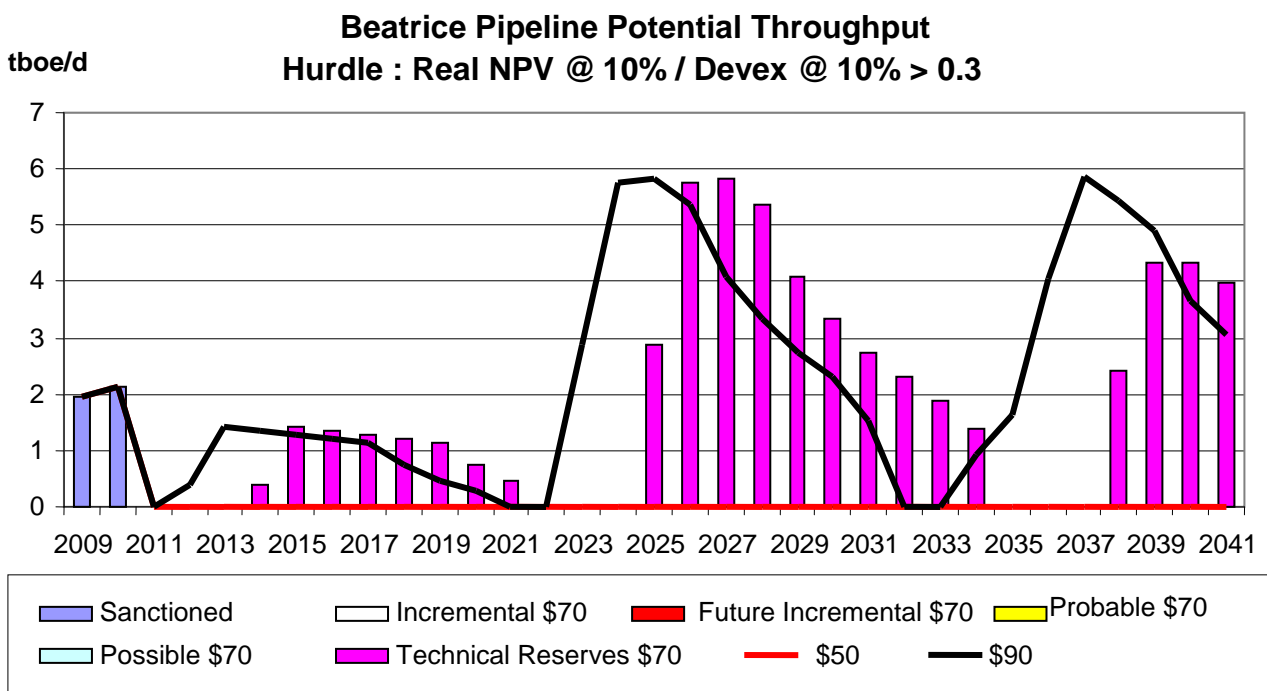
4. Results – Infrastructure Availability and Developments at Risk

For sanctioned fields, incremental projects and some probable and possible fields the processing hub and transport routes are known but for others there may be options. For most of the technical reserves fields the processing hub and transport route may be estimated, but for new exploration finds the transport route is unknown. They are thus excluded from this part of the study. A wider range of oil and gas prices is employed in this part of the study, namely \$50 and 30 pence, \$70 and 50 pence, and \$90 and 70 pence. The results for the main transport routes are discussed in turn. Pipelines not yet in operation such as those from Laggan and Tormore and the Breagh fields are not examined.

(a) Beatrice Alpha Pipeline to Nigg Terminal

The original sections of the Beatrice 78km 16” pipeline were laid in 1979. There are 111km onshore. The pipeline capacity was 50 tbo/d. In 2001, 59km of the pipeline were replaced. The pipeline capacity is 60 tbo/d. Decommissioning of the Beatrice field is expected to start in 2019. The pipeline’s life could be extended by 4 technical reserves fields. The timing of these developments is not known, but only one in the area is expected to be developed in the medium term.

Chart 45



The pipeline capacity is currently greatly underused. With an oil price of \$50/bbl no future throughput is expected but with a higher oil price of

\$70/bbl or \$90/bbl it is possible that the pipeline if available, could be used by fields currently in the technical reserves category.

SAGE Terminal

The SAGE terminal at St Fergus accepts gas from the SAGE pipeline which has a capacity of 1100 mmcf/d, the Britannia pipeline which has a capacity of 840 mmcf/d and the Atlantic and Cromarty pipeline which has a capacity of 232 mmcf/d.

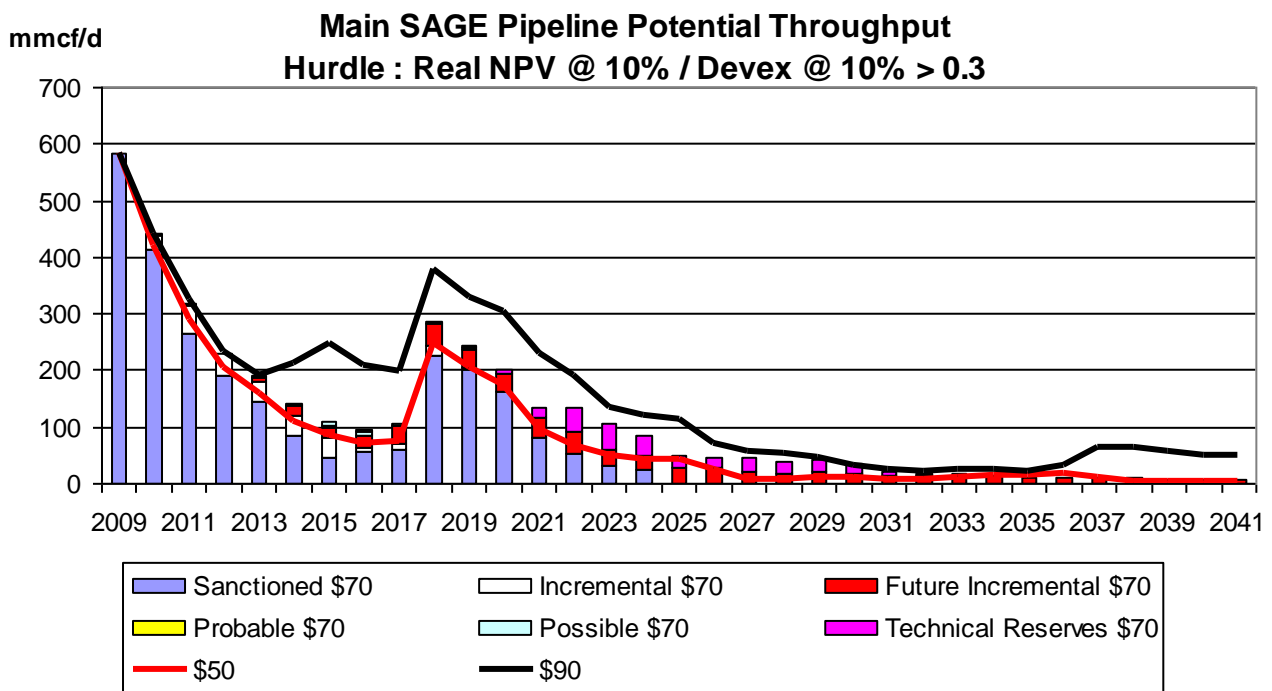
(b)SAGE Pipeline

The SAGE pipeline has 3 components. The main pipeline is a 323 km long 30" pipeline from the Beryl area to the SAGE terminal. The Beryl pipe runs from block 9/13 to block 16/1 and has a capacity of 550mmcf/d. At block 16/1 it links to the main pipeline. The Brae pipe runs from block 16/3A to 16/1 with a capacity of 550mmcf/d. SAGE pipeline throughput began in 1992 with gas from Beryl and in 1993 gas from Scott also used the pipeline. Brae area gas started in 1994.

There are currently 33 sanctioned fields using the SAGE pipeline, 3 probable/possible fields are likely to use it and 13 technical reserve fields are potential users of the pipeline. Ten technical reserves fields fail the hurdle at the low price, 7 fail at the medium price and 2 fail at the \$90 price.

At the low price SAGE will operate until 2022, at the medium price until 2024 and at the \$90 price until 2025. If the pipeline shuts in 2022, production from 5 sanctioned fields and 3 technical reserve fields may cease. If the pipeline shuts in 2024, production from 5 sanctioned fields and 6 technical reserve fields may also cease. If it shuts in 2025, production from 4 sanctioned fields and 6 technical reserves fields may also cease. Six of the sanctioned fields act as processing or transportation hubs for other SAGE pipeline users who may be adversely affected when a hub field ceases production.

Chart 46

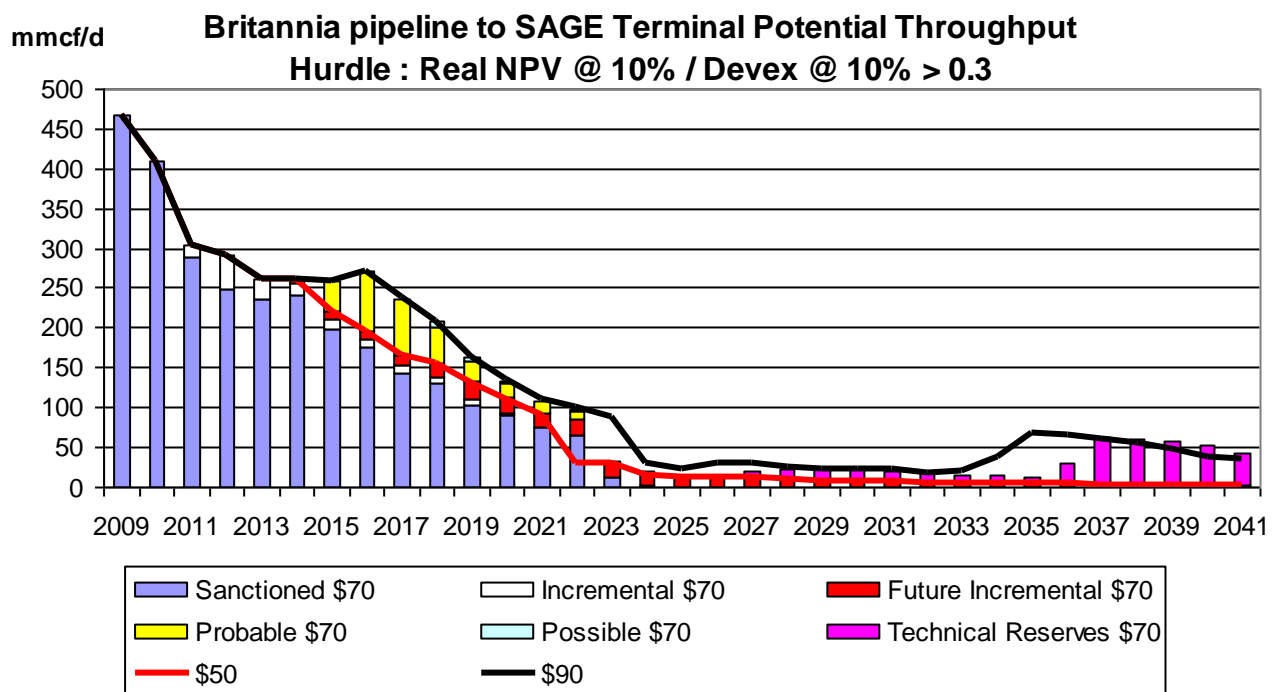


As seen in Chart 46 the main SAGE pipeline now has considerable underused capacity and potential usage is very low after 2025 at all gas prices.

(c) Britannia Gas (SAGE Terminal)

The Britannia 186 km 27” pipeline laid in 1997 connects the Britannia field with the SAGE terminal. The Britannia pipeline capacity is 840 mmcf/d. There are 4 sanctioned fields using the Britannia gas pipeline and 5 other potential users of the pipeline, but these 5 may fail the hurdle rate at the low price. Seven fields may be adversely affected if the Britannia pipeline shuts in 2021 or 2023.

Chart 47



The Britannia pipeline has substantial spare capacity.

(d) Frigg Pipeline

The Frigg system consists of the Frigg UK pipeline and the Vesterled pipeline. The UK pipeline starts at Alwyn North and joins the main Frigg

UK 32” pipeline via a 24” 110 km pipeline at the TC1 bypass close to the old Frigg Field. Piper/Tartan area gas joins the Frigg pipeline via a subsea link near the now decommissioned MCP-01 platform using an 18” pipeline. Bruce, Ross, Captain and Buzzard gas also tie into the pipeline.

The Frigg UK pipeline commenced operations in 1977. It is a 362km 32” pipeline with a nominal capacity of around 35 MMscm/d or 1236 mmcf/d. In 2004 Alwyn North was linked directly to the pipeline bypassing the Frigg field. In 2010 development consent was given for the Laggan and Tormore fields along with a gas processing facility at Sullom Voe. From Sullom Voe gas will be transported 230 km to the Frigg pipeline close to the decommissioned MCP-01 platform. The capacity of this line is 665 mmcf/d.

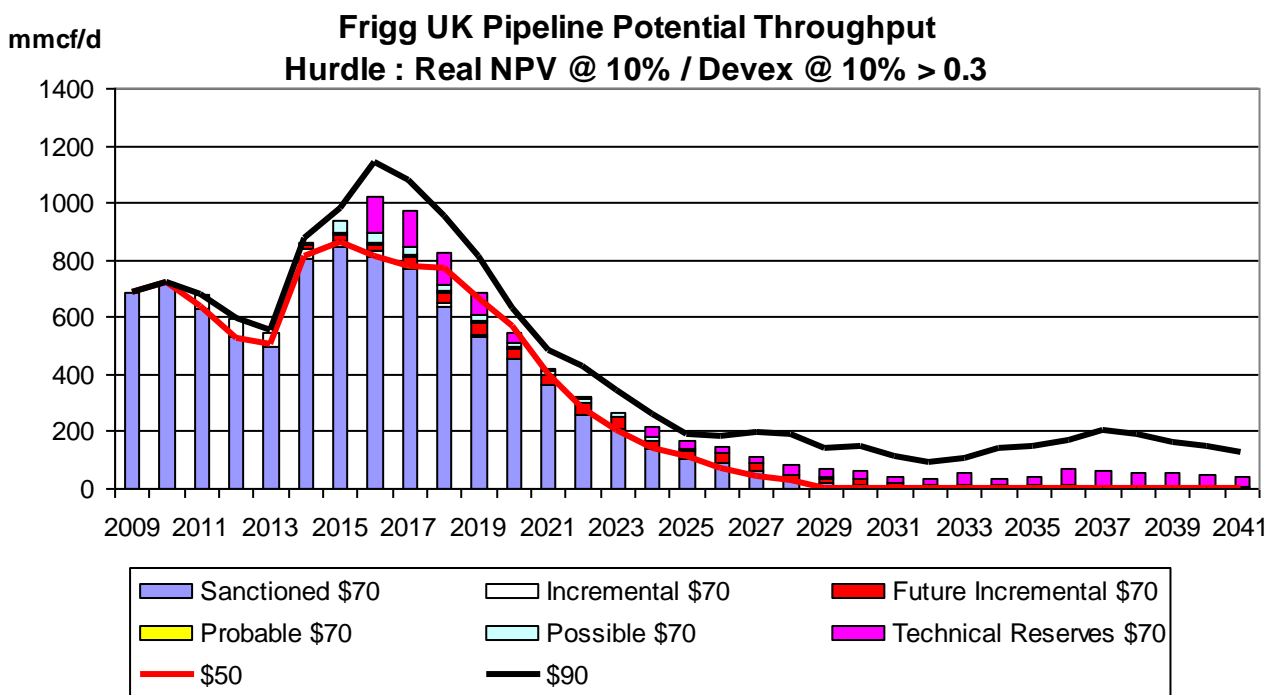
There are currently 21 sanctioned fields using the Frigg UK pipeline and 26 fields which are potential users. Twenty of the potential users fail the hurdle rate at the low price, 12 of the potential users fail at the medium price, and 2 fail at the high price. The Frigg pipeline may operate until 2044 or 2046.

The Alwyn North field is a gathering point for a number of fields which use, or are expected to use, the Frigg pipeline. Of these fields 6 are already sanctioned, and there are 3 potential users. Two of the sanctioned and 3 potential users may be adversely affected by the decommissioning of Alwyn North.

The Bruce field also acts as a gathering point tying into the Frigg UK line. There are 2 sanctioned fields (Keith and Rhum) in the Bruce hub and 1 potential field all of which could be adversely affected by the decommissioning of Bruce.

The Captain link to the Frigg pipeline is via Ross. Blake and 3 potential users may also link to Ross. One technical reserves field would be adversely affected by the decommissioning of Ross.

Chart 48



The Frigg UK pipeline system is quite near capacity until 2018.

(e) FLAGS Gas Pipeline (SEGAL FLAGS System)

The FLAGS pipeline from Brent to St Fergus is a 451km 36” pipeline which opened in 1982 although pipe laying was completed in 1978. The capacity is 1100mmcf/d. The Northern and the Western Legs are connected to the FLAGS pipeline at Brent. The Tampen link, Statfjord Late Phase, also links to the FLAGS pipeline. The pipeline may continue in operation until 2038 or 2043.

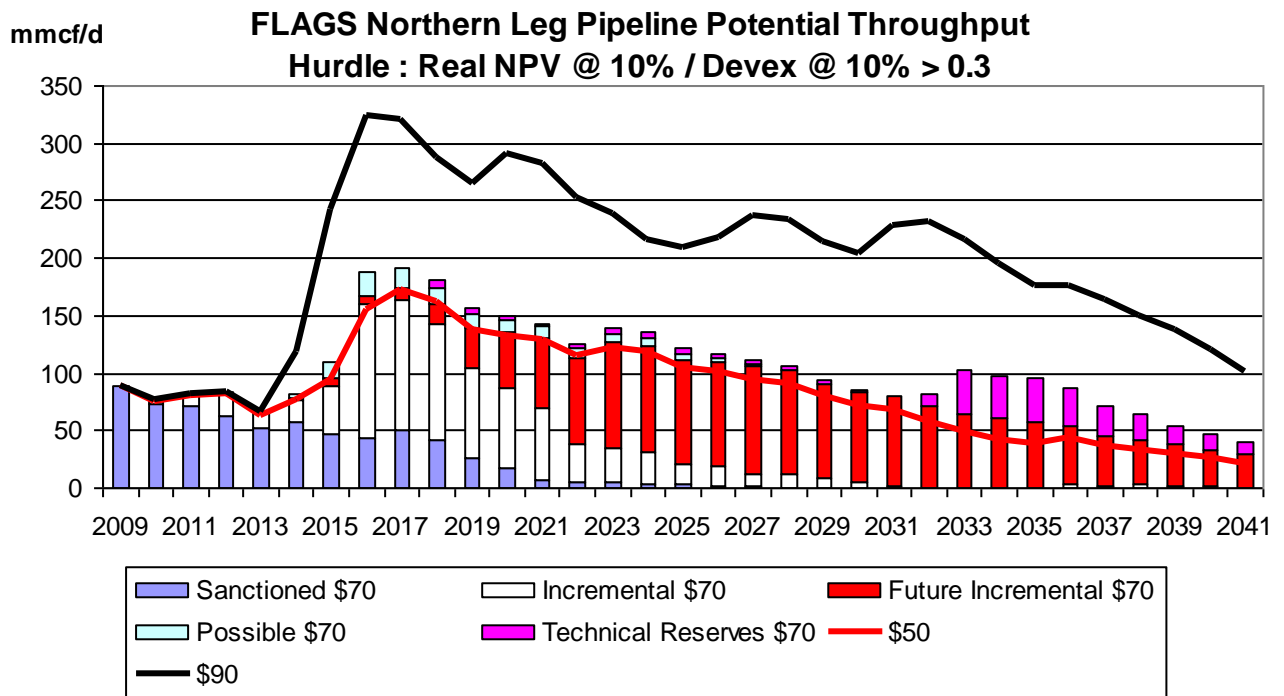
The FLAGS Northern Leg, a 79km, 20” pipeline, currently transports gas from 7 sanctioned fields, and there are 19 potential other users. The FLAGS Western Leg currently transports gas from 5 sanctioned fields and there are 5 potential other users. In total 21 may fail the hurdle at the low price, 13 may fail at the medium price, and 6 at the high price.

The Brent cluster includes Barnacle and Penguin whilst the Magnus field acts as a hub for a number of fields using the FLAGS system. The Magnus Enhanced Oil Recovery scheme uses West of Shetlands gas prior to exportation into the FLAGS system. Although Ninian does not now produce gas it acts as a hub field for FLAGS gas. Some fields access the FLAGS pipeline via Cormorant.

If the FLAGS pipeline decommissions in 2039, 1 sanctioned and 3 potential fields may be forced to decommission early, and if decommissioning is in 2044 2 potential users may have to decommission earlier than expected.

The results of the modelling are shown for the Northern Leg, Western leg, and total FLAGS system in Charts 49, 50 and 51 respectively.

Chart 49



The capacity of the Northern Leg is 391 mmcf/d which could be approached in 2016 at the high price.

Chart 50

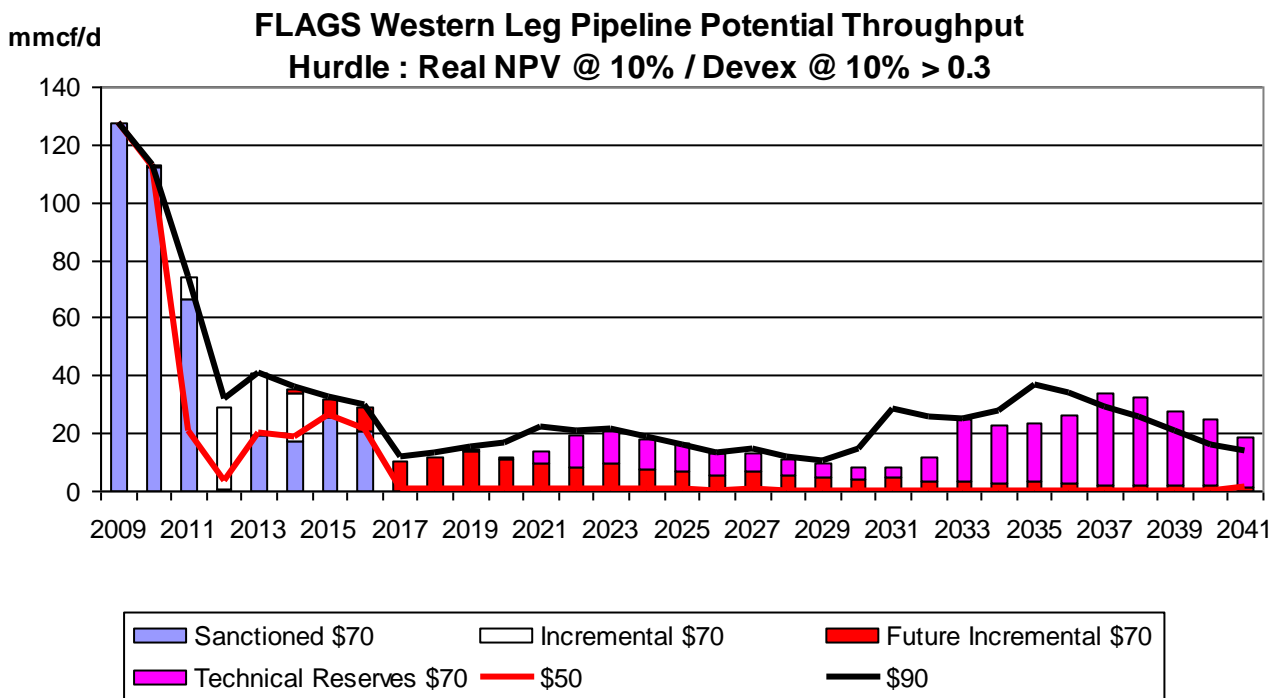
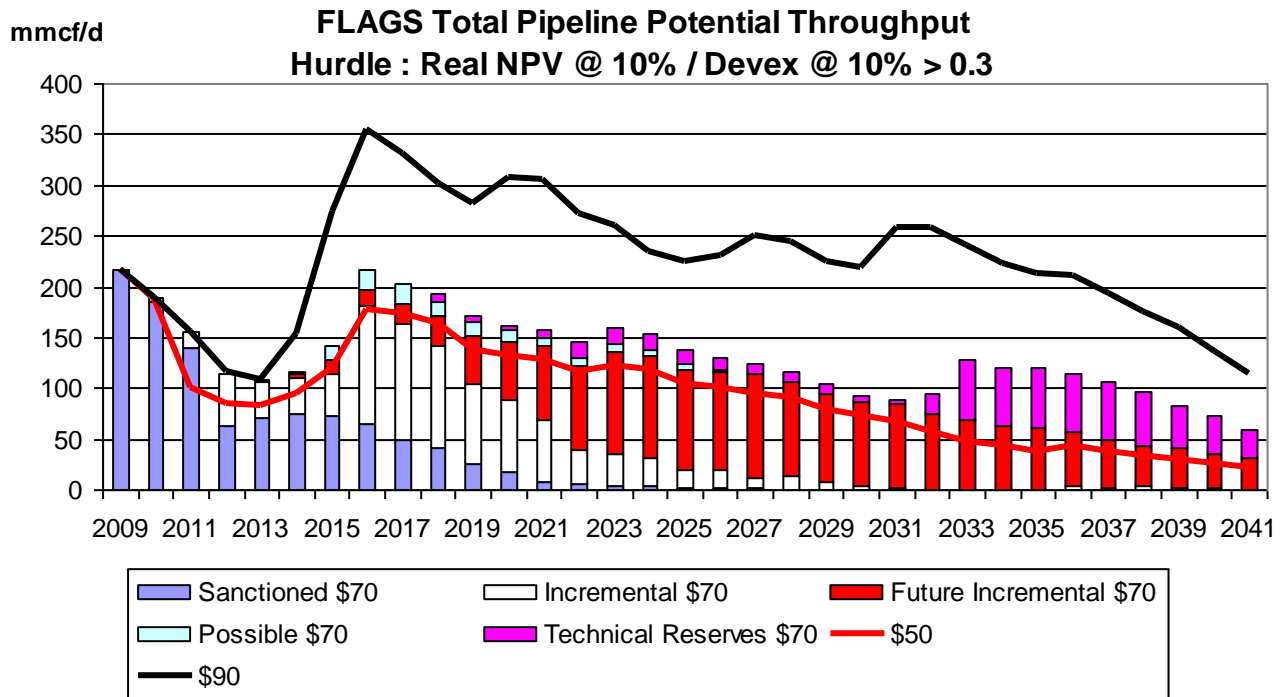


Chart 51



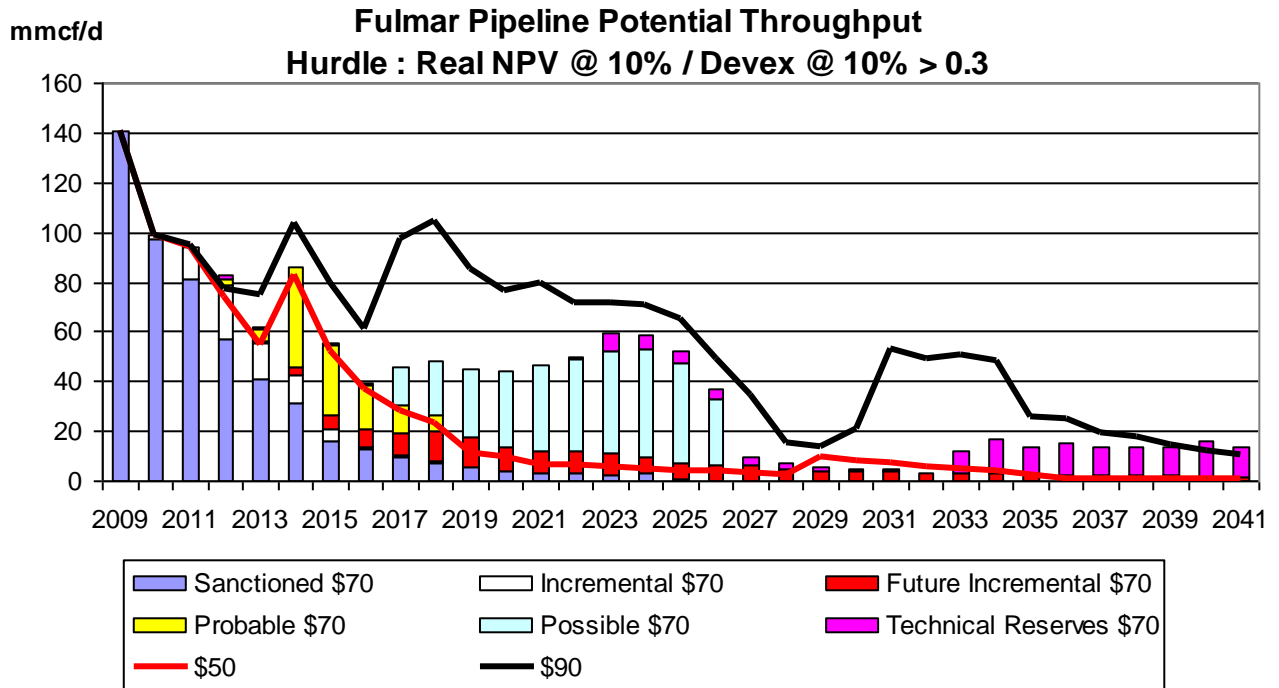
(f) Fulmar Gas Pipeline

The Fulmar 289km 20” gas pipeline to St Fergus began operations in 1986. The capacity is 365mmcf/d. There are currently 26 sanctioned fields using the Fulmar gas pipeline and there are 16 potential users. Fulmar may operate until 2025 or 2026. At the low price, 11 potential fields fail the hurdle rate, at the medium price 4 fail, and at the high price 1 fails. If Fulmar ceases in 2025 or 2026 1 sanctioned field and 9 potential fields may cease production earlier than expected.

The Bittern, Gannet, Mallard, Nelson and Anasuria fields act as gathering points for Fulmar gas. The cessation of production by Bittern may affect 3 other sanctioned fields. The cessation of production by the Gannet

fields may affect 3 potential pipeline users, and the cessation of production by the Mallard field may affect 3 other sanctioned pipeline users.

Chart 52



The Fulmar gas pipeline is currently underused and after 2025 the throughput is low.

(g) Goldeneye Oil and Gas Pipeline to St Fergus Terminal

The SEGAL onshore system provides transportation and processing facilities for the Goldeneye pipeline. Goldeneye may operate until 2013. The Goldeneye pipeline is 105 km in length.

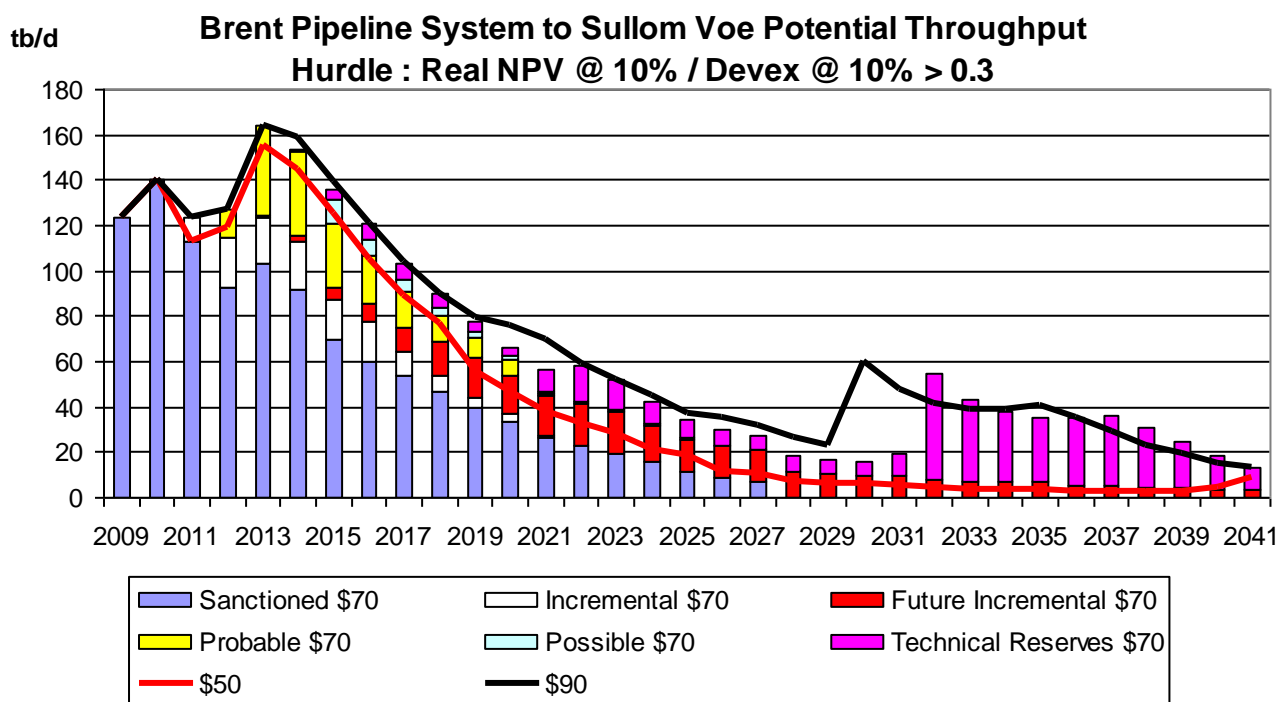
(h)BPS (Brent Oil Production System to Sullom Voe)

The Brent Oil and NGL 154km 36” pipeline to Sullom Voe began operations in 1978. The system has a capacity of 1 million b/d. From the economic modelling the Brent Production System (BPS) may operate until 2027 or 2034.

There are 27 sanctioned fields using the BPS system, and there are 16 potential users. Ten potential users fail the hurdle rate at the low price, and 1 fails at the medium price.

The Brent cluster consists of Barnacle, Brent, Devron, Don, Don South, Penguin and Thistle. Alwyn North, Cormorant, Dunbar, Dunlin, Hudson, Murchison, Thistle and Tern are, or may be, key fields for fields which access the Brent Oil Production System to Sullom Voe. Ellon, Forvie, Grant, Islay, Jura, Nuggets and 2 technical reserves fields form the Alwyn North cluster. The technical reserves fields could produce beyond 2034. Dunlin, Dunlin South West, Eider, Merlin, Murchison, Osprey, Otter, Pelican and 3 technical reserve fields form another cluster. One technical reserve field may produce beyond 2034. The Tern cluster consists of Hudson, Kestral, Tern and 5 technical reserves fields. Two of the technical reserve fields may produce beyond 2034.

Chart 53



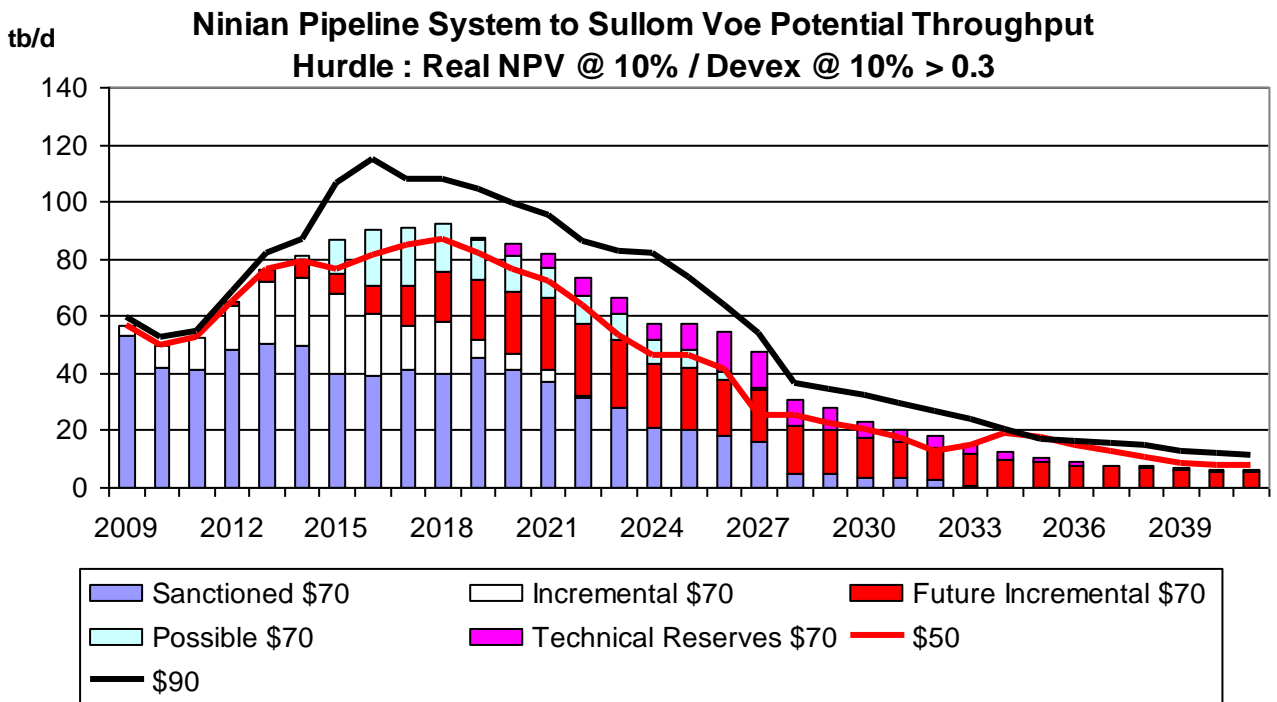
The Brent pipeline system has ample spare capacity.

(i) Ninian Oil Pipeline System to Sullom Voe

The Ninian Oil and NGL 175km 36” pipeline to Sullom Voe began operations in 1978 and is expected to continue in operation until 2026 or 2027. The system has a capacity of 910tb/d. Eight fields currently use the Ninian pipeline, and there are 8 potential users. At the low price 3 potential users fail the hurdle rate, and at the medium price 1 fails.

Two of the sanctioned fields and 3 technical reserves fields may be adversely affected if the Ninian system ceases in 2030. Heather and Magnus also link other fields with the Ninian Production System.

Chart 54

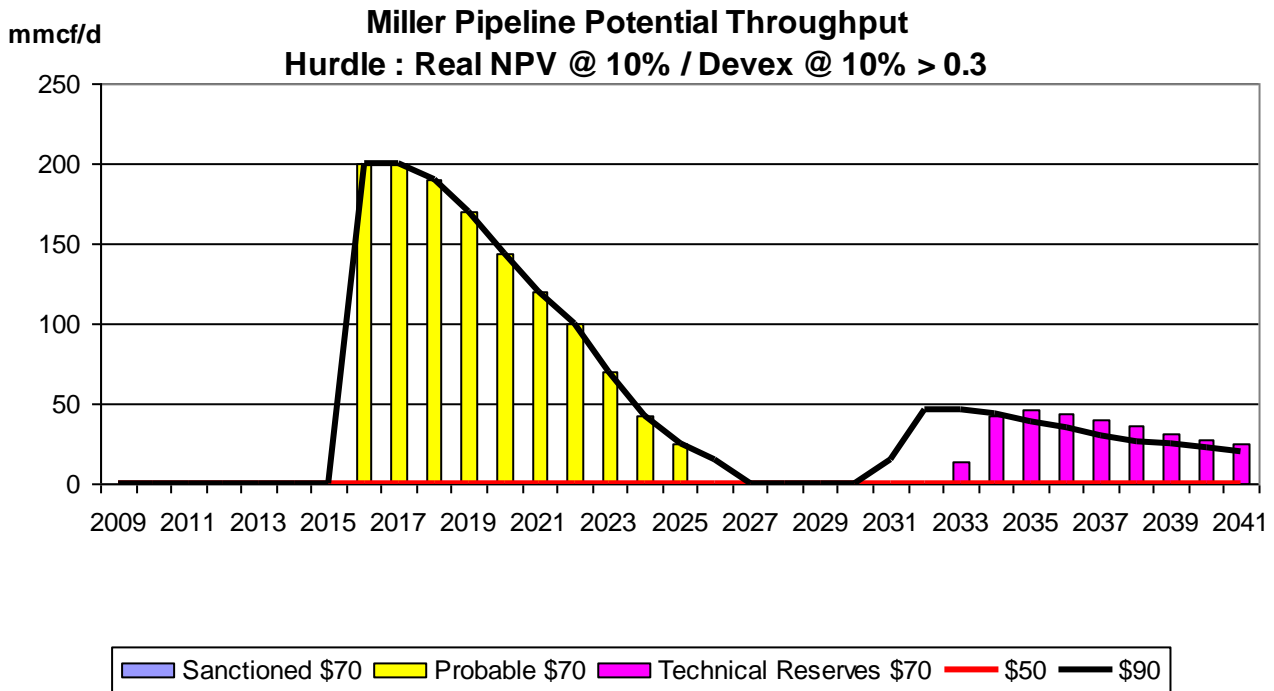


The Ninian pipeline is clearly underused.

(j) Miller

The Miller 242km 30” pipeline was commissioned in 1992. The capacity is 1200mmcf/d. Because of the sour nature of the gas it was built with very high grade steel and has a design lifespan of 30 years. Decommissioning began in 2004 and will continue for several years. There are 4 gas fields in the categories of probable and technical reserves which could be potential users of the Miller pipeline, if it were reopened. They fail the hurdle rate at the low price but pass at the higher prices.

Chart 55

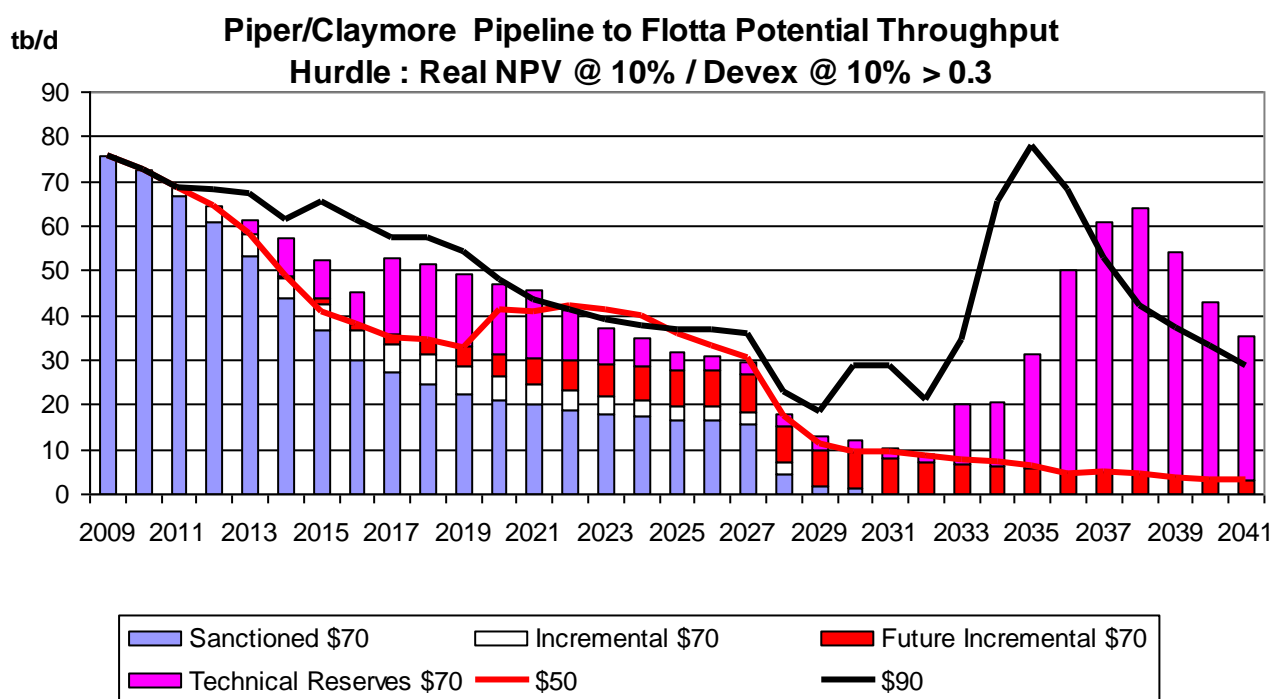


Even if these fields were to use the Miller line the capacity is not fully used.

(k)Piper /Claymore Oil Pipeline System

The Piper/Claymore 209km 30” pipeline began operations in 1976 but it was closed in 1988 after the Piper Alpha disaster. Throughput started again in 1989. The capacity is 560 tb/d and it may continue in operation to 2027 or 2028. There are 21 sanctioned fields using the pipeline. Claymore acts as a gathering point for Scapa and the Claymore fields. Tartan acts as a gathering point for Duart, Galley, Highlander and Petronella. Piper acts as the gathering point for 4 other fields. There are 14 potential users. Five potential users fail the hurdle rate at the low price, but pass at the higher prices. If the pipeline ceases in 2028, 6 sanctioned fields and 9 potential users may be affected.

Chart 56



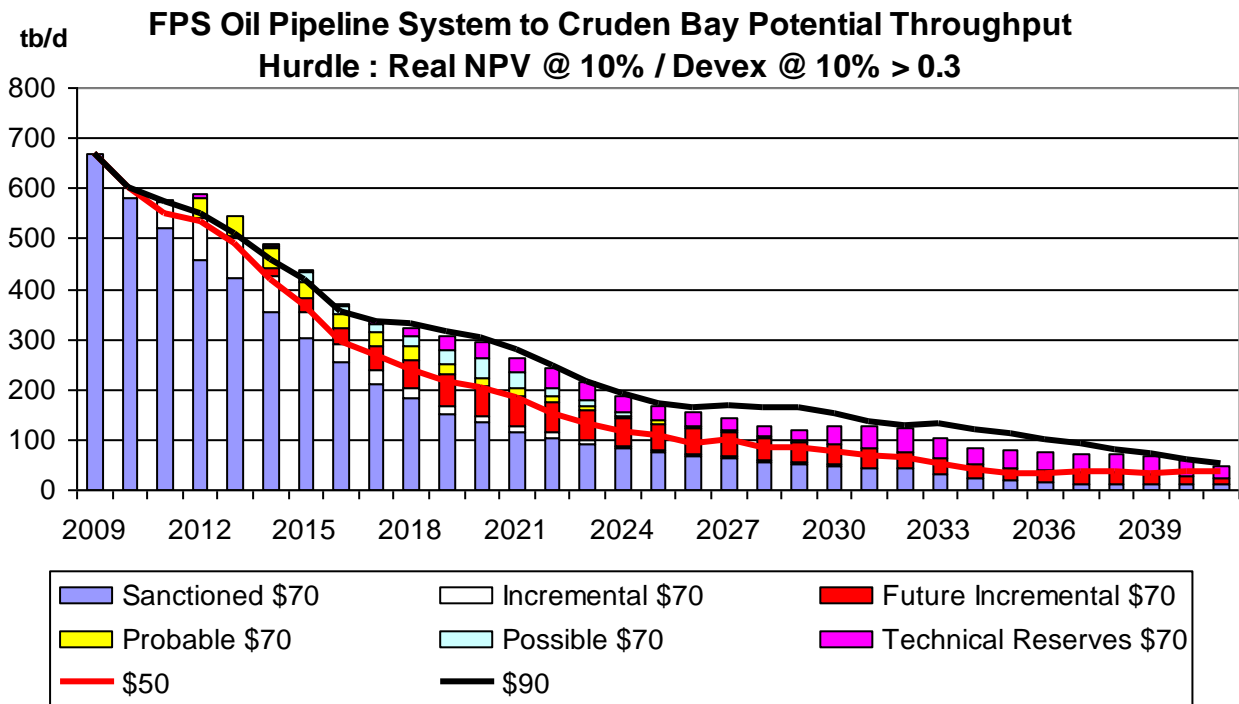
There is ample spare capacity in the pipeline.

(l) Forties Oil Pipeline System

The original Forties pipeline started operations in 1975 but a new Forties 169km 36” oil pipeline was laid in 1990. The capacity is 1.15mb/d. There are 72 sanctioned fields using the Forties pipeline, and there are 53 potential users.

At the low price 35 potential users fail the hurdle rate, 14 fail the hurdle at the medium price, and 3 fail at the high price. Twelve sanctioned and 28 potential users would be affected if the Forties pipeline ceased operation in 2030. Many of the sanctioned fields currently act as gathering points for oil being transported via the Forties Pipeline System.

Chart 57



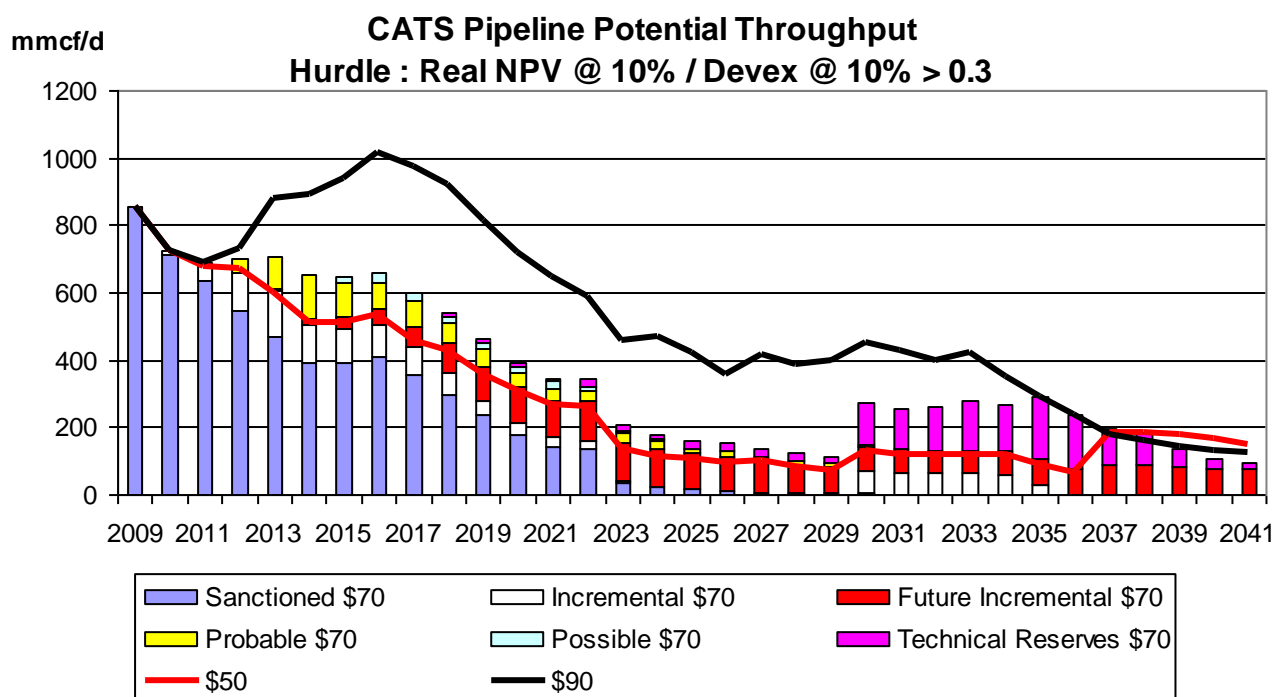
The Forties pipeline has considerable spare capacity.

(m) CATS (Central Area Transmission System)

The CATS 404 km 36” pipeline started operations in 1993. The capacity is more than 1.7 bcf/d. There are 34 sanctioned fields using the CATS pipeline and 31 potential users. At the low price 24 potential users fail the hurdle rate, 12 fail at the medium price, and 2 at the high price.

CATS could remain in operation until 2022 at the low gas price or 2034 at the higher prices. If CATS ceases to operate in 2034, 2 sanctioned fields and 12 potential users would be adversely affected. Several fields act as gathering points for gas to be transported in the CATS line.

Chart 58



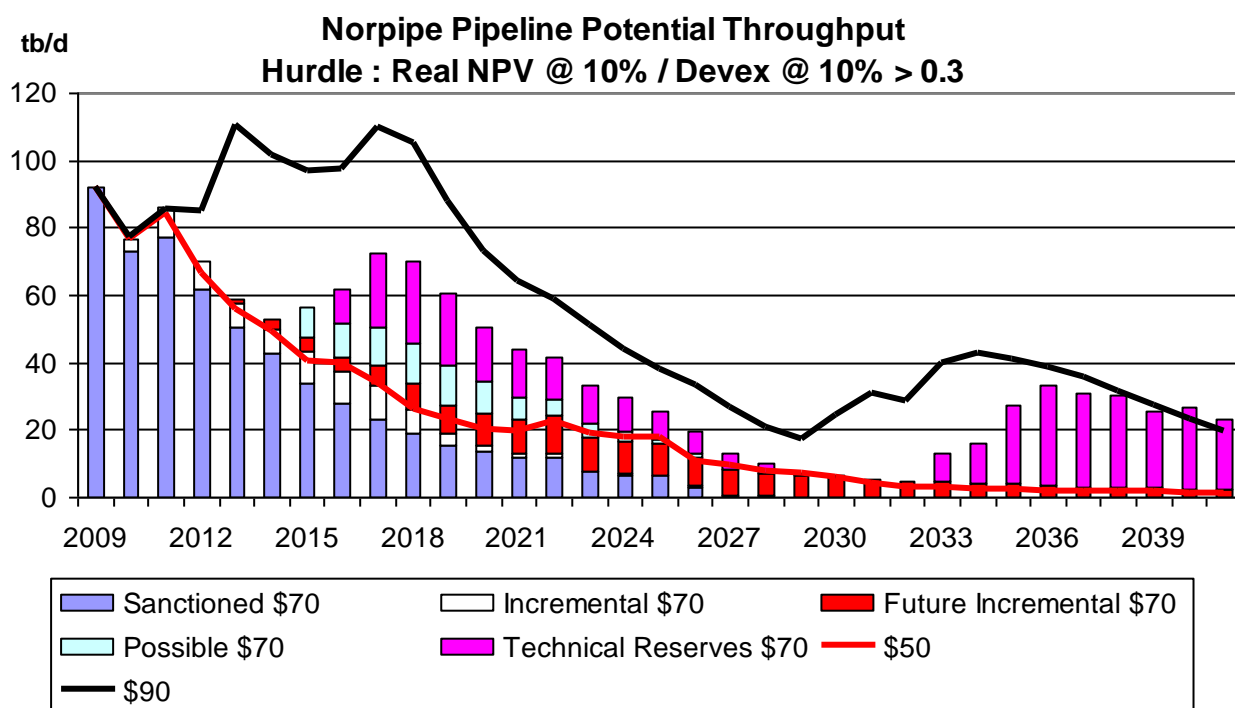
The pipeline has considerable spare capacity.

(n)Norpipeline Oil Pipeline to Teeside

The 34”, 335km Norpipe Oil pipeline from the Norwegian sector to Teeside was designed to be in use for more than 30 years and began life in 1975. The capacity which is limited by the capacity of the receiving terminal at Teeside, is 780 tb/d.

There are 17 sanctioned fields and 22 potential users linked to the Norpipe system. Nineteen possible users fail the hurdle rate at the low price, 6 fail at the medium price, and 1 fails at the high price. If Norpipe ceases in 2028, 1 sanctioned field and 14 potential users would be adversely affected.

Chart 59



The pipeline has ample spare capacity.

Bacton Gas Terminal

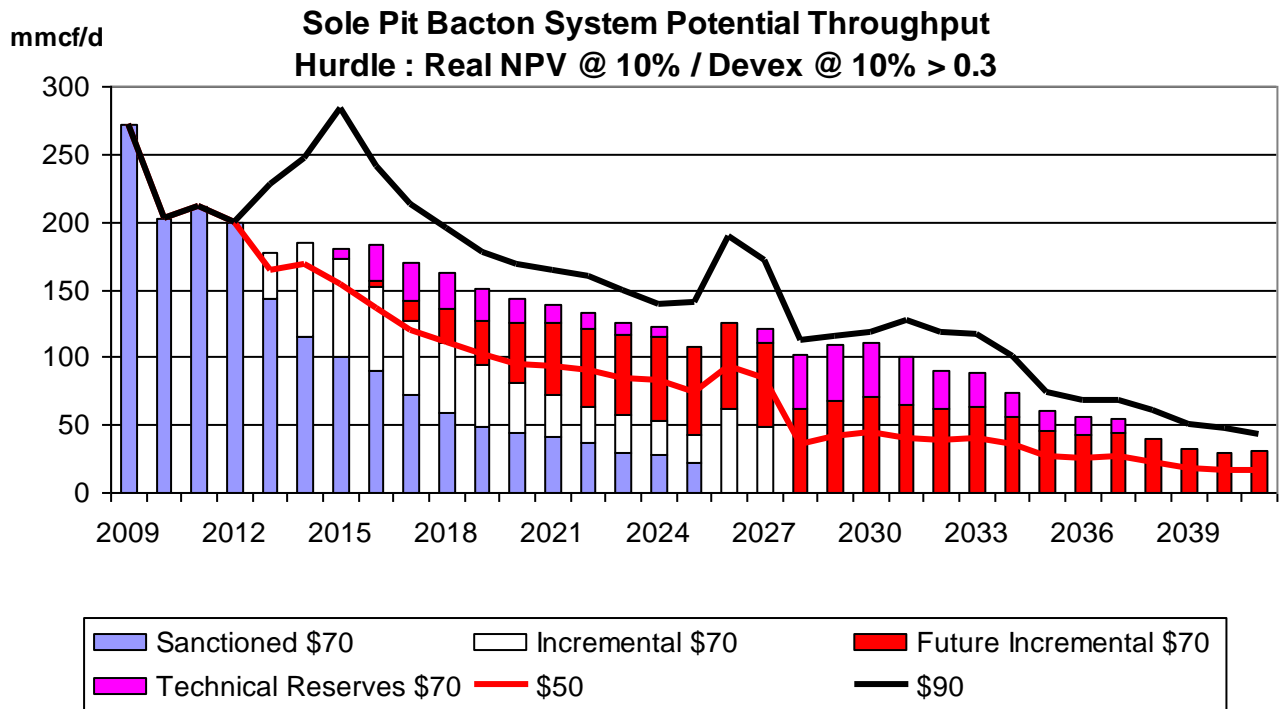
The Bacton gas terminal has 3 separate systems operated by Shell, Perenco and Tullow.

(o) Sole Pit System

The Sole Pit 72 km 24” pipeline has transported gas from the Clipper area to Bacton since 1988. The capacity is 725 mmcf/d. The Sole Pit System is used by 6 sanctioned fields, and there are 4 potential users. At the low price, 4 potential users fail the hurdle rate and 2 fail at the medium price. If the pipeline ceases to operate in 2027 or so then 2

potential users would be adversely affected. Clipper and Carrack act as access points to the Sole Pit system.

Chart 60



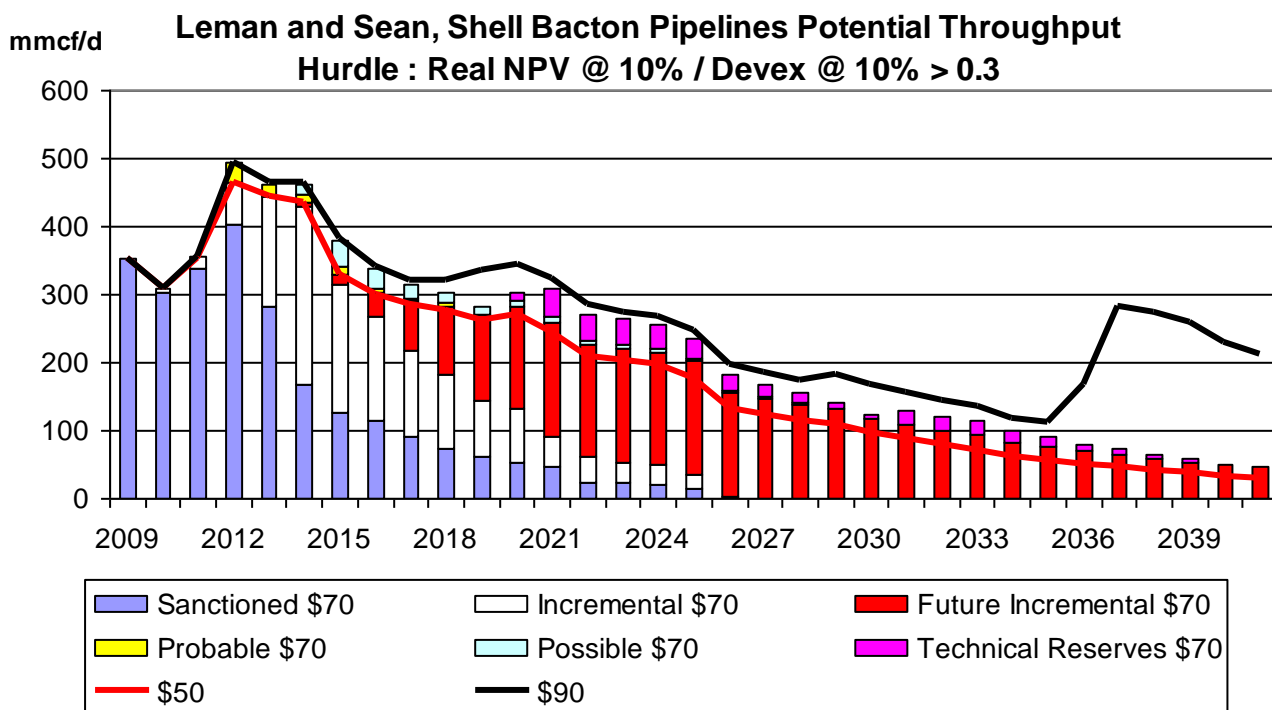
(p)Leman System

The Leman system began operations in 1968 and consists of 3 56km 30” pipelines with a capacity of 900mmcf/d. The Leman System is used by 9 sanctioned fields and there are 5 potential users. The system is expected to be in use to 2025. At the low price, 5 potential users fail the hurdle rate, 2 fail at the medium price and 1 at the high price. If the pipeline ceases to operate in 2025 then 2 sanctioned fields and 3 potential users would be adversely affected.

(q) Sean System

The Sean system consists of a 107 km 30” pipeline which has transported gas to Bacton since 1986. The Sean System is used by 3 sanctioned fields and there is 1 potential user. At the low price the potential user fails the hurdle rate. If the pipeline ceases to operate in 2020 the potential user would be adversely affected.

Chart 61

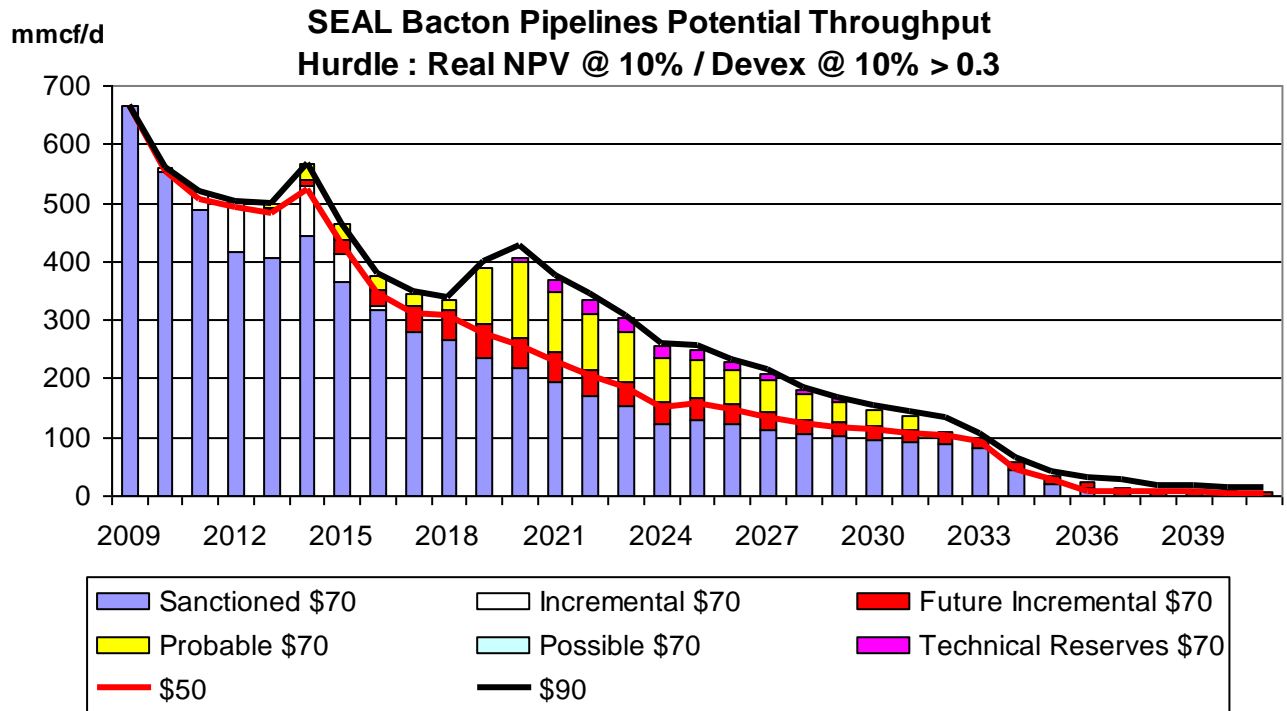


(r) SEAL Pipeline

The SEAL 463km km 34” pipeline to Bacton commenced operations in 2000 and has a capacity of 1200mmcf/d. The capacity of the SEAL terminal facilities is 1100 mmcf/d. There are 8 sanctioned fields using the SEAL pipeline and 3 potential users. The pipeline could operate until

2037. At the low price 3 potential users fail the hurdle rate and 1 fails at the medium and high price.

Chart 62



There is ample spare capacity in the pipeline.

Tullow Gas System

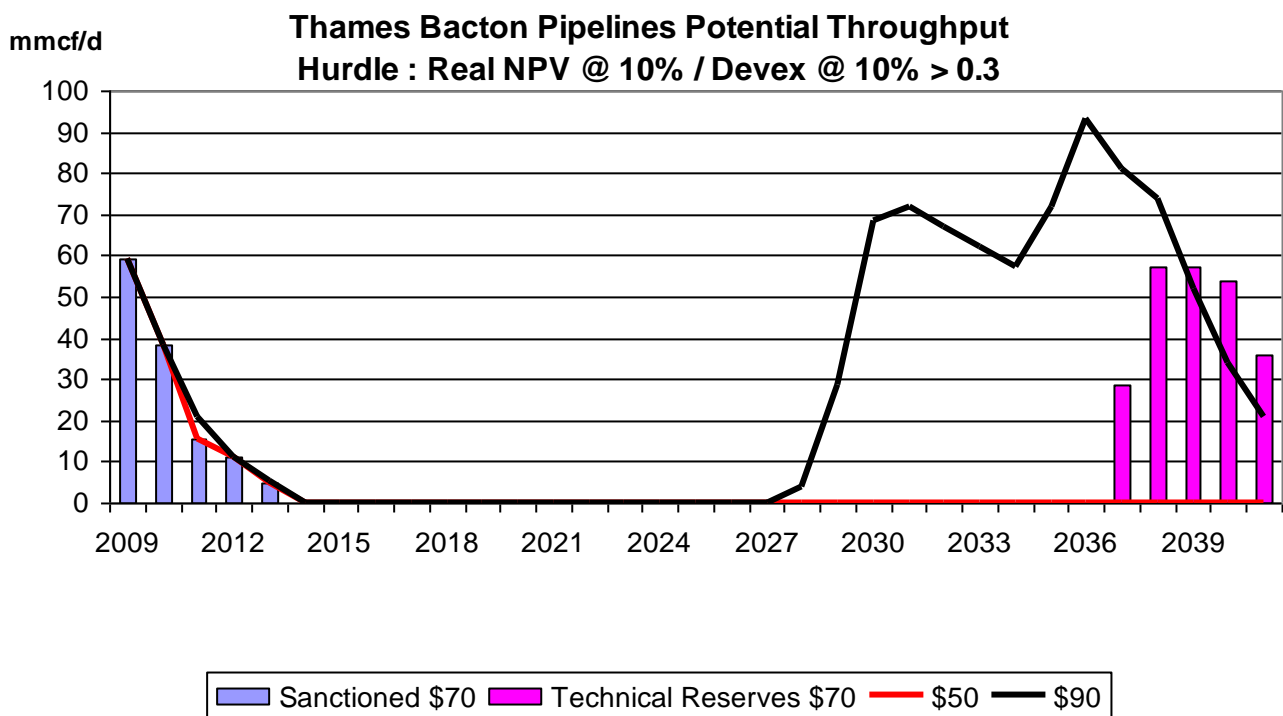
The Tullow gas system at Bacton is comprised of gas from the Thames, Hewett and Lancelot Pipelines.

(s) Thames System

The Thames 90km 24” pipeline system came onstream in 1998. The pipeline has a capacity of 600 mmcf/d. There are 9 sanctioned fields using the Thames pipeline and 3 potential users.

The Thames area production is very low and 3 potential users fail the hurdle rate at the low price whilst 2 fail at the medium price.

Chart 63

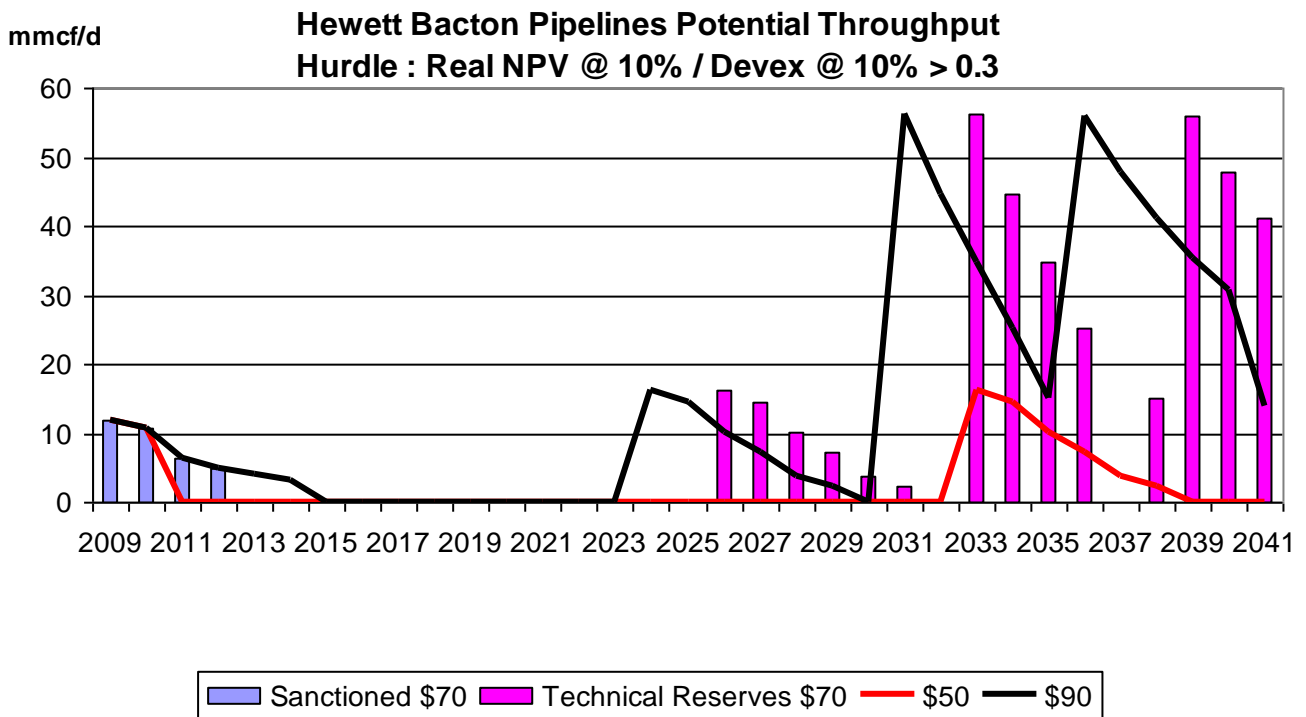


To keep this pipeline in operation, the technical reserves fields would need to be brought onstream very much earlier.

(t) Hewett System

The first Hewett 28km 30” pipeline system began in 1969 and the second 32km 30” pipeline started in 1973. The pipelines have a design capacity of 900mmcf/d. One of the pipelines carries sour gas. The sanctioned Hewett area fields use the pipeline and 3 potential users could use it. The Hewett area production is very low with some reservoirs no longer producing. The potential users would have to come on stream much earlier than indicated in Chart 64 to maintain use of the system.

Chart 64

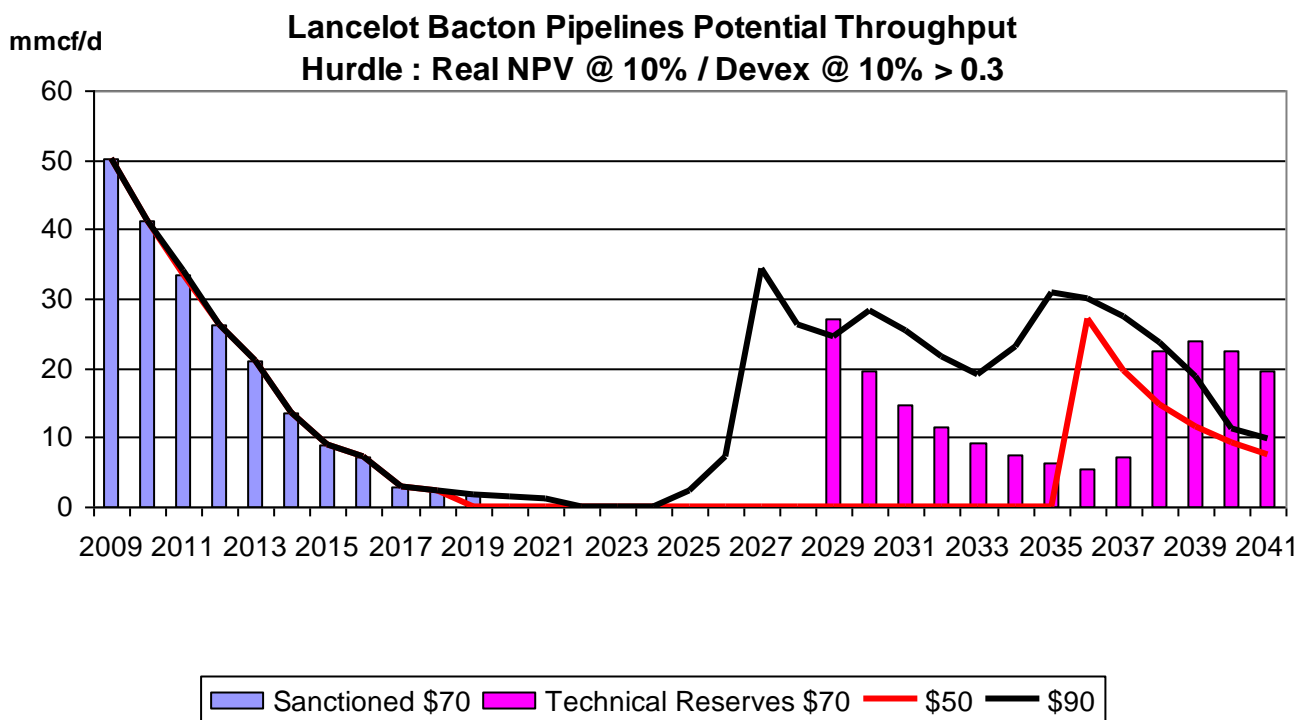


(u)Lancelot Area Pipeline System (LAPS)

The Lancelot 61km 20” pipeline system began operations in 1992. The pipelines have a design capacity of 480 mmcf/d, but effective capacity is reduced at the current lower offshore operating pressure. There are 7 sanctioned fields and 4 potential users of the Lancelot system.

The sanctioned fields production may cease in the period 2017 – 2021. Two of the potential users fail the hurdle rate at the low and medium price.

Chart 65



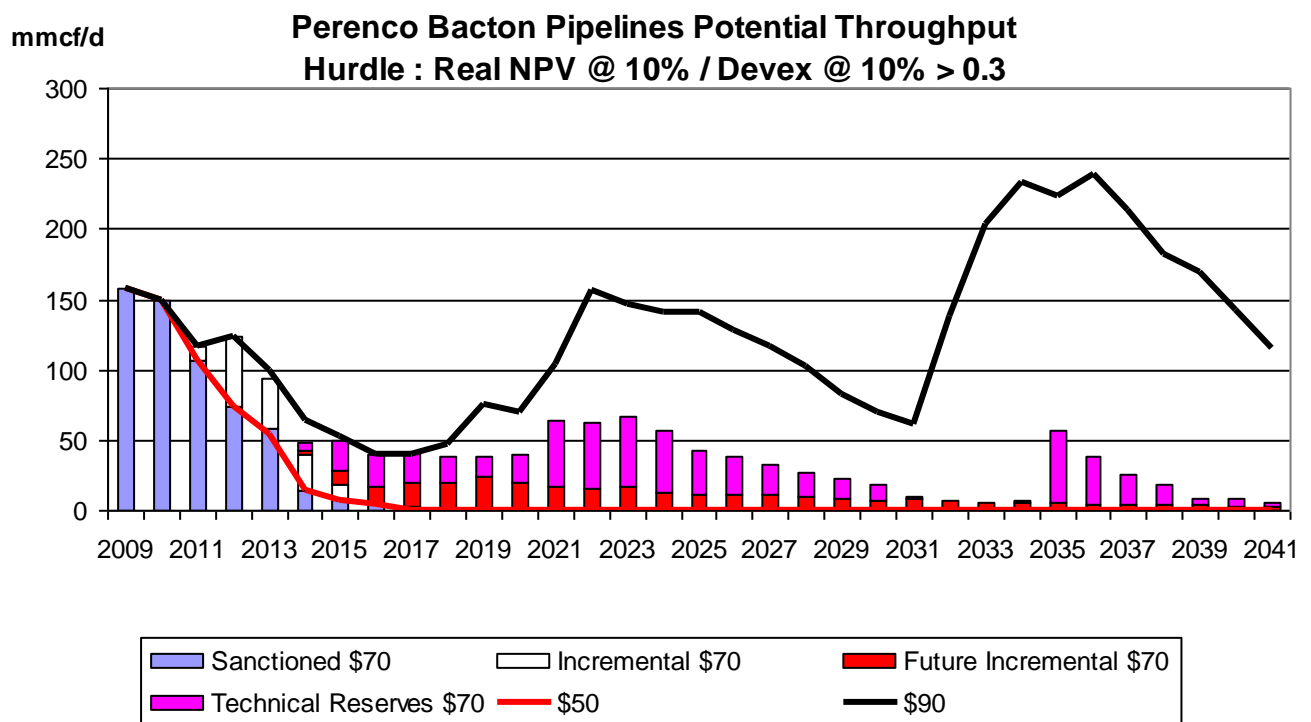
The development of the technical reserves would need to be accelerated greatly to prevent closure of the system by 2020.

Perenco System

(v) Perenco Bacton

The Leman A 62km 30” pipeline began operations in 1969 and the ETS 167km 24” pipeline in 1985/1995. The Perenco system used to be operated by BP –Amoco. There are 14 sanctioned fields and 13 potential users of the Perenco system. The sanctioned fields may produce until 2015 – 2018. At the low price 13 potential users fail the hurdle rate, 8 fail at the medium price, and 1 fails at the high price.

Chart 66



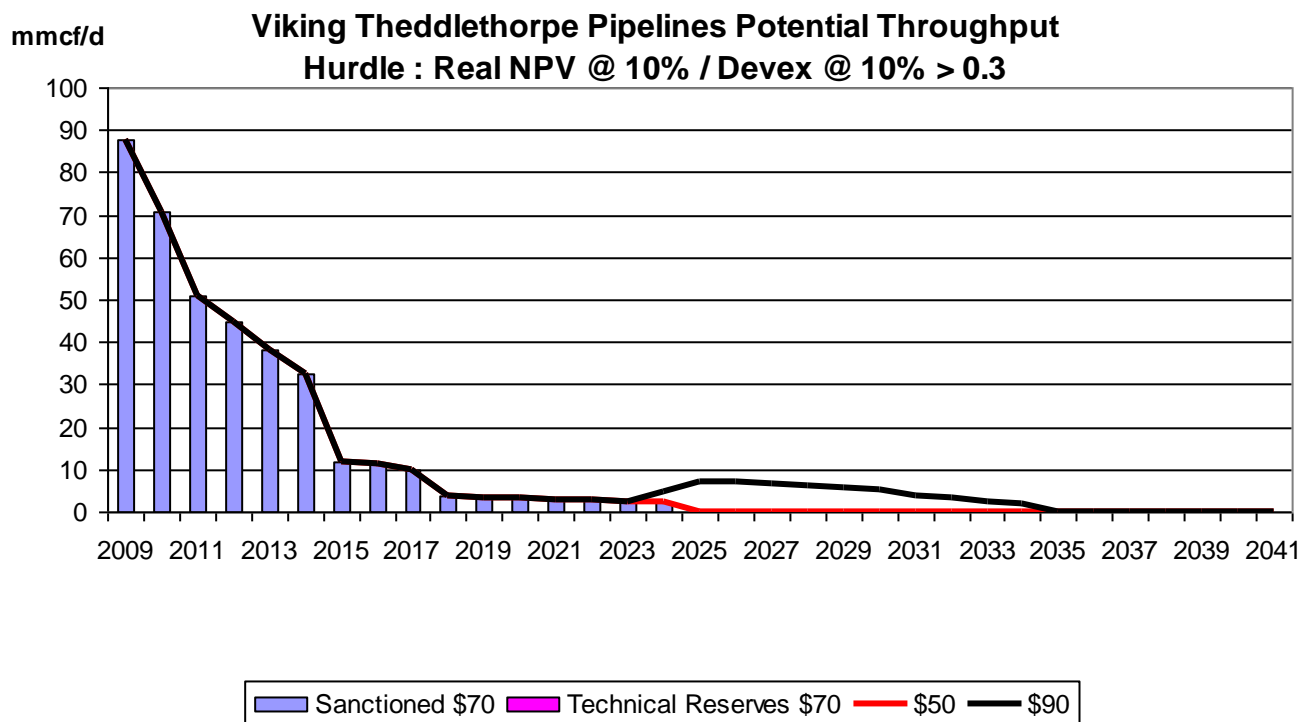
Theddlethorpe Terminal

The Viking, Caister/Murdoch, Pickerill and LOGGS pipelines transport gas to Theddlethorpe.

(w) Viking Pipeline (VTS)

The Viking 140km 28” pipeline system began operations in 1972. The capacity is 400mmcf/d. There are 4 sanctioned fields and 1 potential user of the Viking system. The system may continue to operate until 2024. The potential user fails the hurdle rate at the low and medium prices, and is adversely affected if the Viking system ceases before 2024.

Chart 67

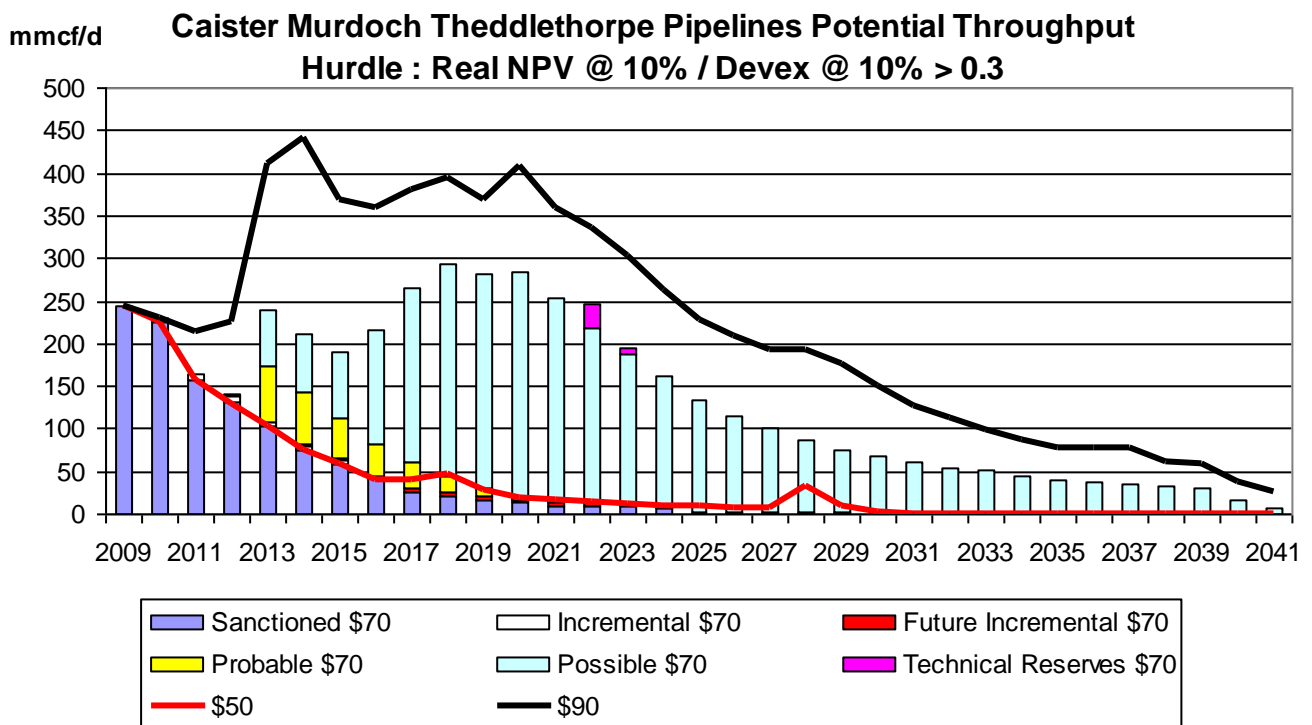


There is very little gas going through the system after 2014.

(x) Caister / Murdoch Pipeline

The Caister Murdoch 185km 26” pipeline began operations in 1993. The capacity is 450 mmcf/d. There are 12 sanctioned fields and 18 potential users of the CMS. At the low price 16 potential users fail the hurdle rate, 11 at the medium price and 2 at the high price.

Chart 68

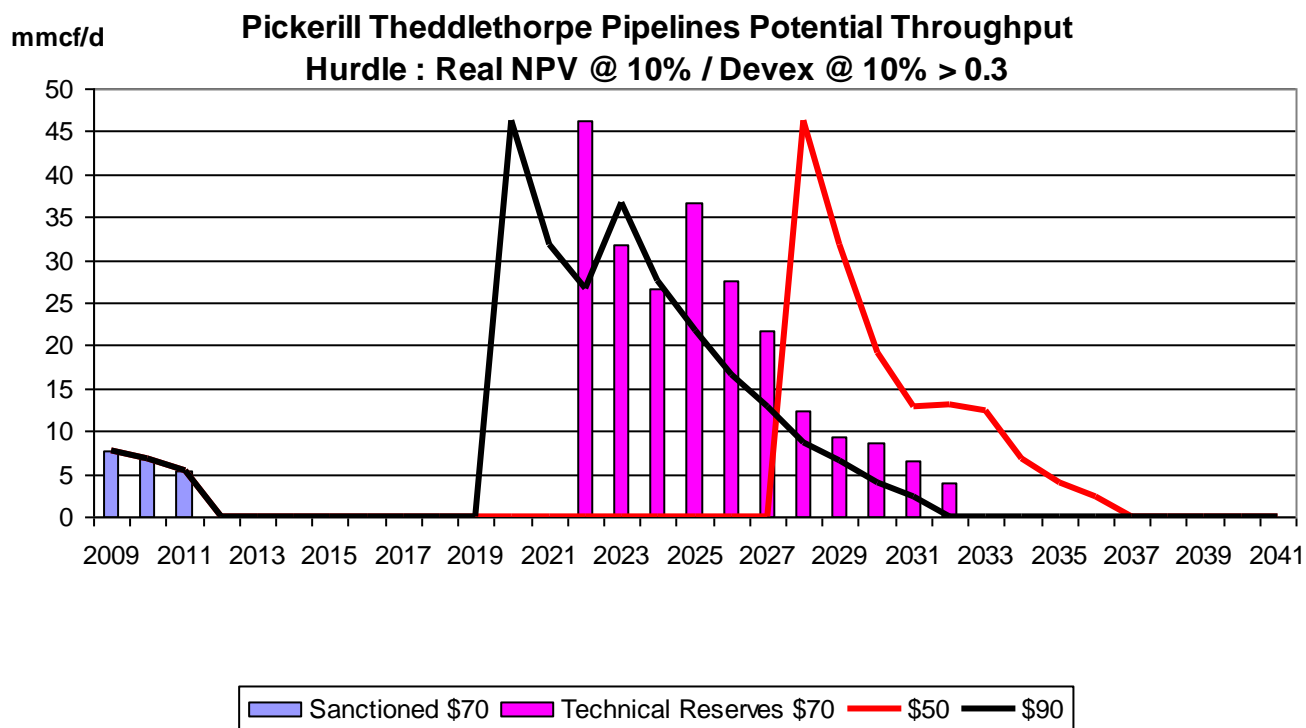


Near capacity useage becomes possible at the high price.

(y) Pickerill Pipeline

The Pickerill 63km 24” pipeline began operations in 1992. The capacity is 450 mmcf/d. In addition to the sanctioned Pickerill field there are 3 potential future users of the system.

Chart 69

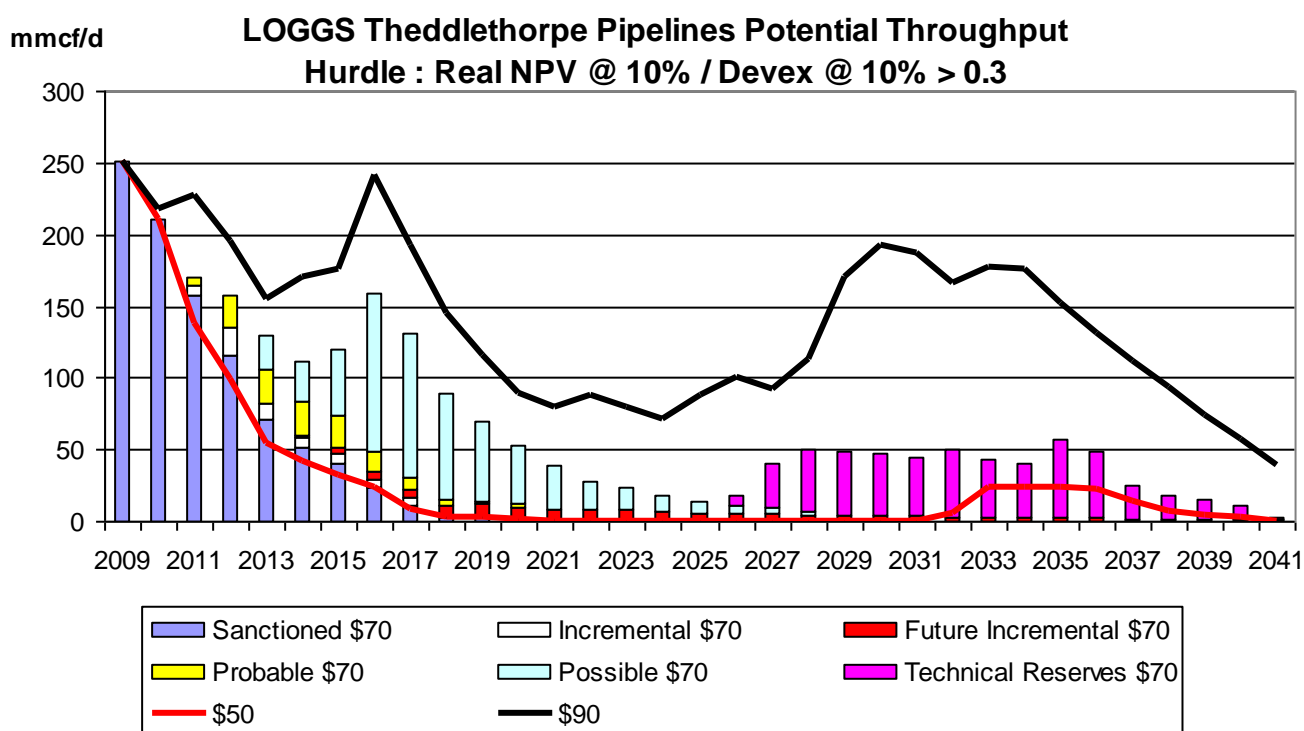


Pickerill has very little gas left and the pipeline will soon be non-viable.

(z) LOGGS System

The LOGGS 120 km 36” pipeline began operations in 1988. The capacity is 2000 mmcf/d. There are 18 sanctioned fields and 16 potential users of the LOGGS system. At the low price 15 fields fail the hurdle rate and 9 at the medium price. Alison, Annie, and Ann act as links to LOGGS as do Saturn and the Valiant fields. If the LOGGS System ceases around 2032, 7 of the technical reserves fields may be adversely affected.

Chart 70



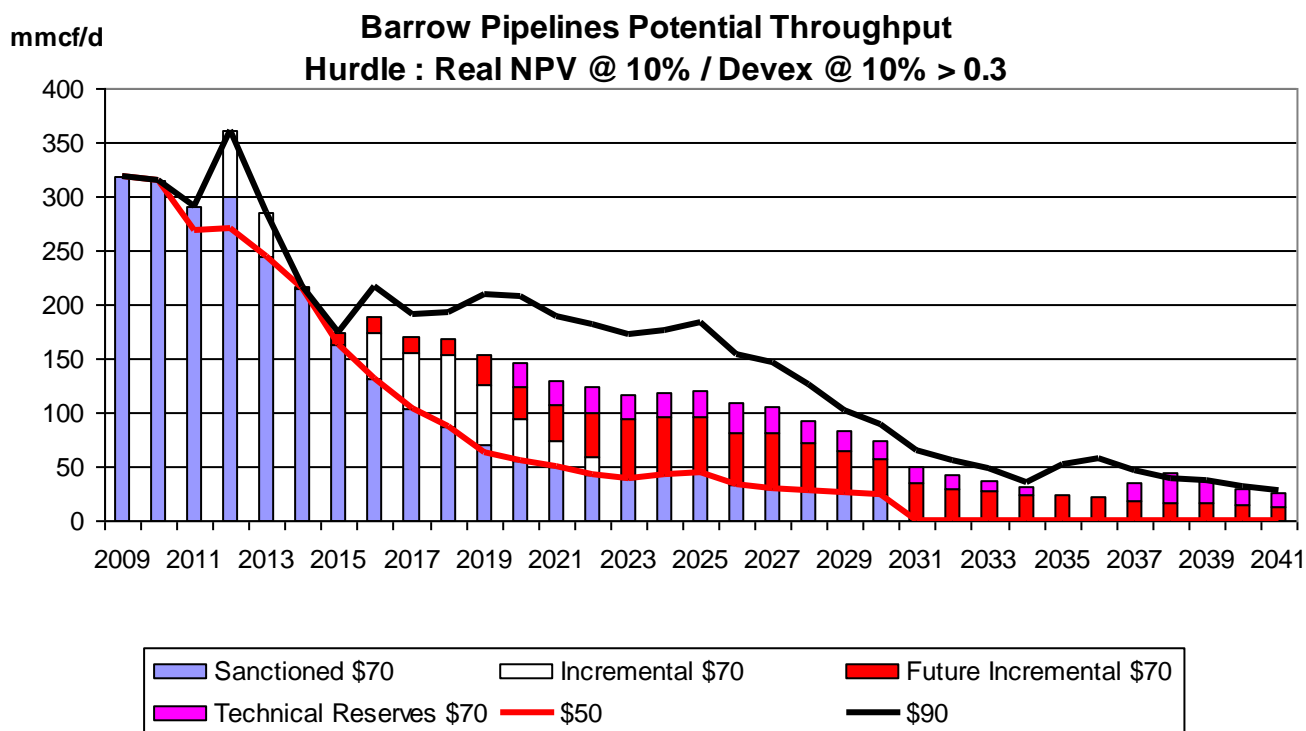
It is noteworthy that the LOGGS system was designed with excess capacity to accommodate swing gas and potential new users.

(aa) Barrow Terminal

The South Morecambe 38km 36” pipeline began operations in 1985 with a capacity of 2400 mmcf/d. The Morecambe North 31km 36” system began operations in 1994 with 530 mmcf/d capacity. The Rivers fields are linked to the North Morecambe terminal via a 45km 24” pipeline in the early 2000s. There are 6 sanctioned fields and 9 potential users of the system.

At the low price 9 potential users fail the hurdle rate, 6 fail at the medium price, and 2 at the high price. The system is likely to continue in operation until after 2030. If the Morecambe System ceases in 2030, 4 of the technical reserves fields are adversely affected.

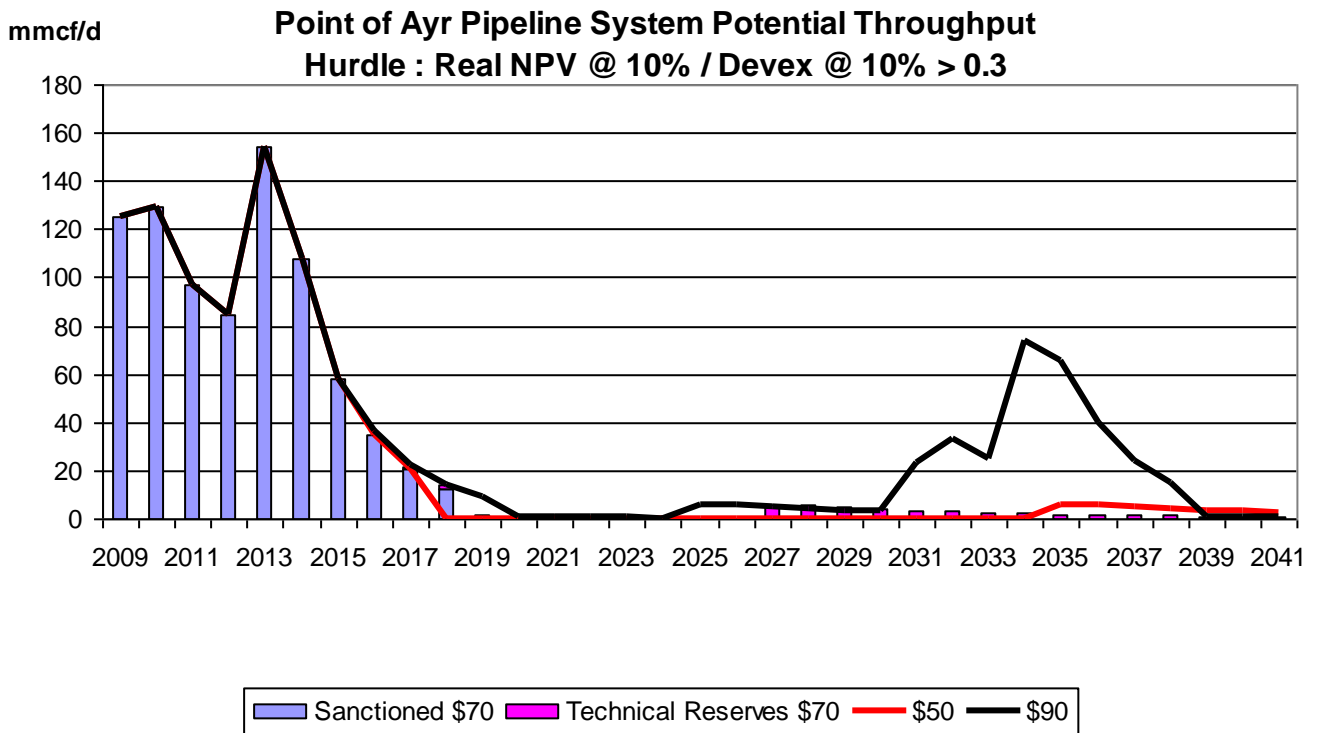
Chart 71



(bb) Point of Ayr, Liverpool Bay System

The Liverpool Bay 34km 20” pipeline began operations in 1995 with a capacity of 740 mmcf/d. The pipeline has a design lifespan of at least 20 years. The Liverpool Bay sanctioned fields and 4 potential fields use the Point of Ayr system. The Liverpool Bay fields may produce until 2017 or 2019. At the low price 3 possible users fail the hurdle rate, 2 fail at the medium price, and 1 fails at the high price. If the Liverpool Bay fields cease after 2019, 3 technical reserve fields may be adversely affected.

Chart 72

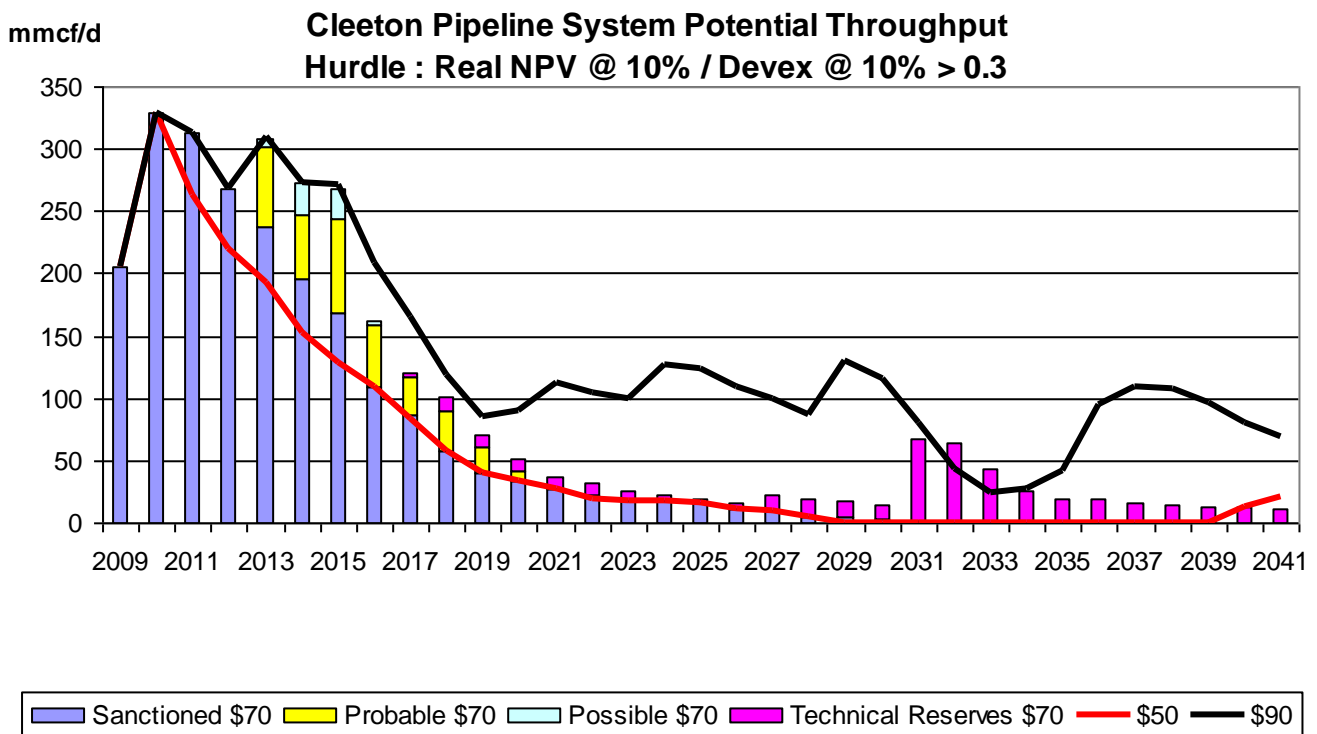


There is considerable excess capacity in the system.

(cc) Dimlington Terminal

The Dimlington 56km 36” pipeline began operations in 1988 with a capacity of 2000 mmcf/d. There are 12 sanctioned fields and 15 potential users of the system. At the low price 14 potential users fail the hurdle rate, 7 at the medium price, and 1 at the high price.

Chart 73



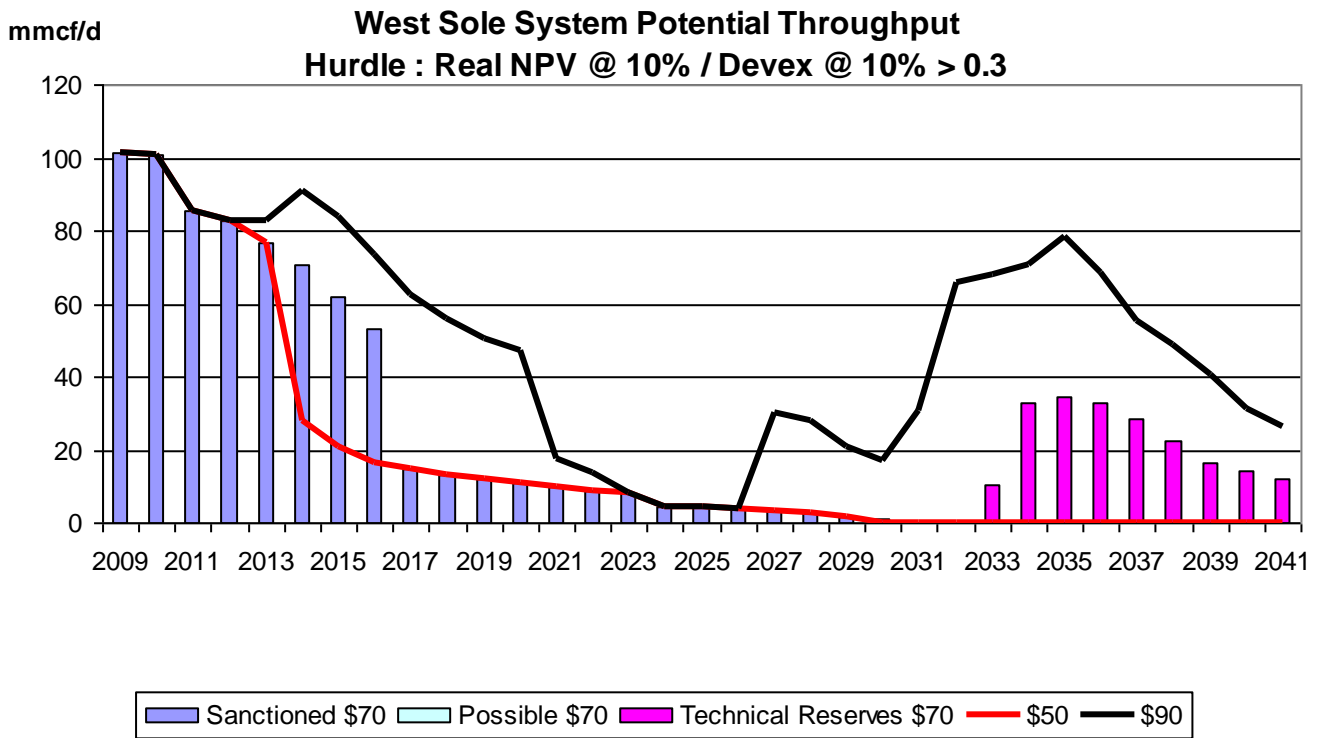
Easington

Easington takes gas from the West Sole pipeline and the Amethyst pipeline.

(dd) West Sole

The West Sole 70km 16” pipeline began operations in 1967. A new 24” pipeline was laid in 1980. The capacity is 300 million cf/d. There are 5 sanctioned fields and 4 potential users of the system. At the low price 4 potential users fail the hurdle rate and 3 at the medium price. The system is likely to continue in operation until 2020. If the West Sole System ceases after 2020, 1 of the sanctioned fields and 5 of the technical reserves fields are adversely affected.

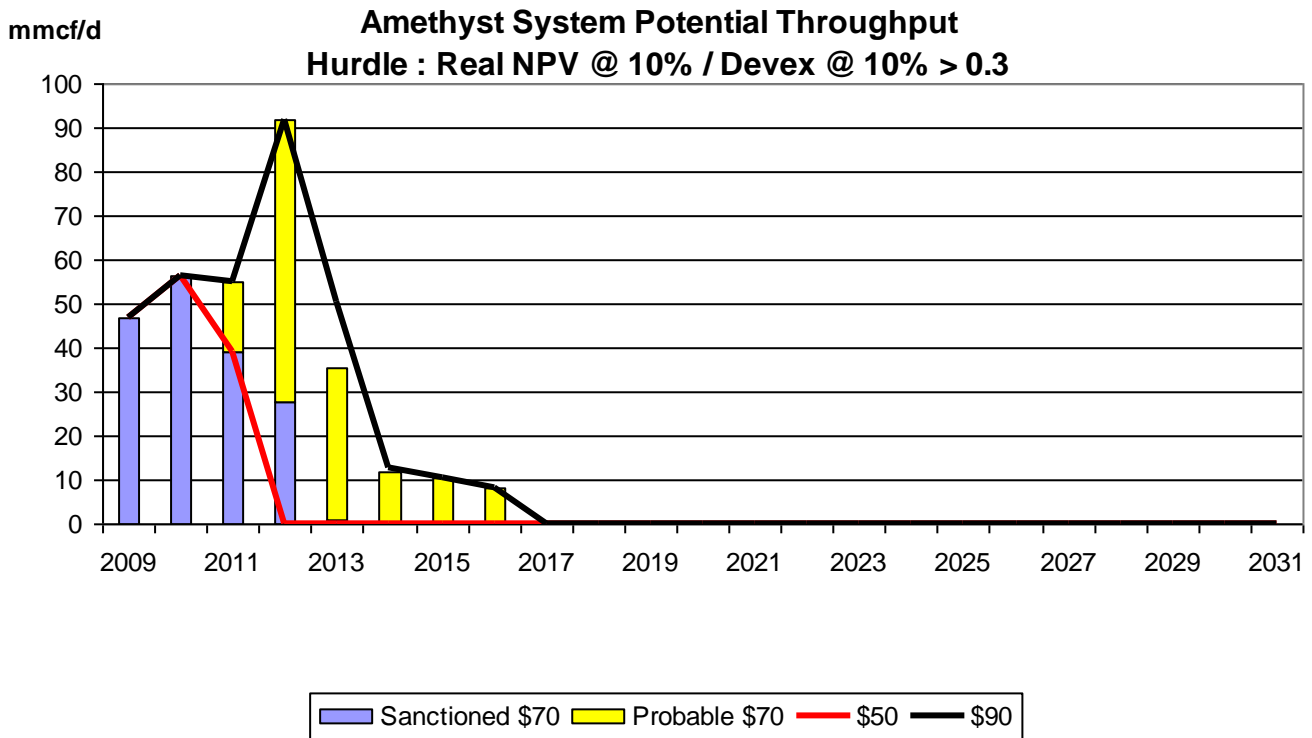
Chart 74



(ee) Amethyst

The Amethyst 48km 30” pipeline began operations in 1990. There are 4 sanctioned fields and 1 potential user of the system. At the low price the potential user fails the hurdle rate. The system is likely to continue in operation until 2013. If the Amethyst pipeline ceases in 2013, 1 sanctioned field and 1 technical reserve fields would be adversely affected.

Chart 75



5. Conclusions

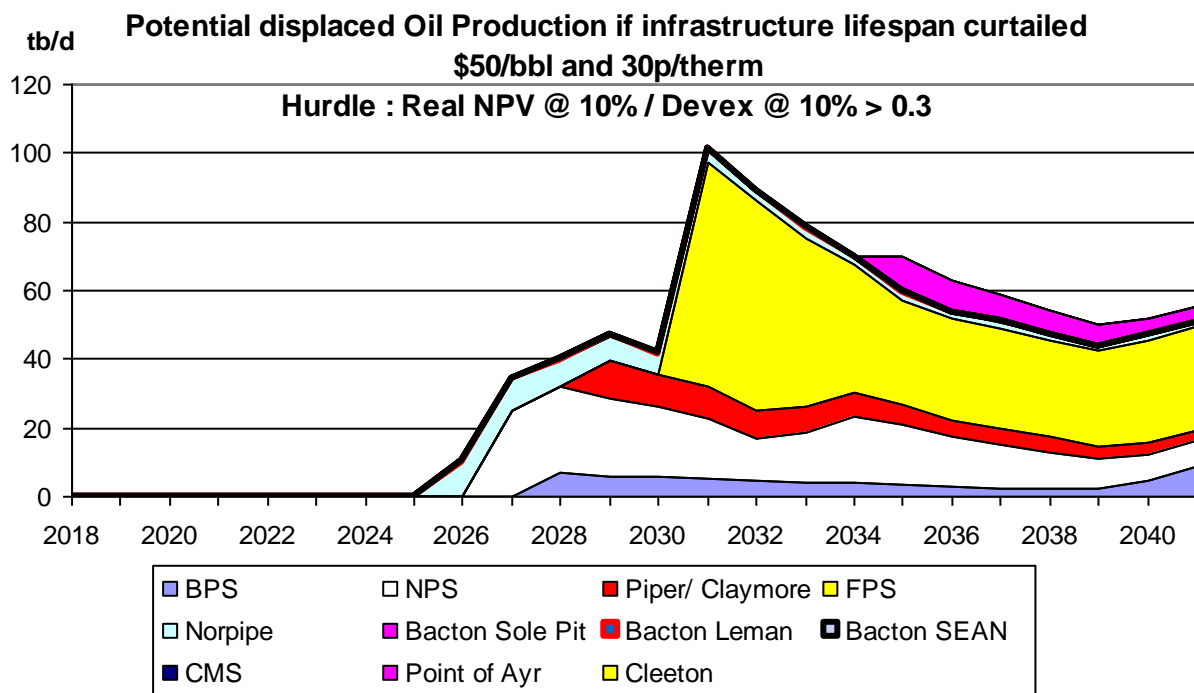
In this study prospective decommissioning activity in the UKCS to 2042 has been modelled under two oil/gas price scenarios and two investment hurdles. The price scenarios chosen (\$70, 40 pence per therm and \$90, 60 pence, all in real terms and thus increasing yearly with inflation), reflect the range likely to be employed by licensees in assessing long term investments. The investment hurdles employed ($NPV/I > 0.3$ and $NPV/I > 0.5$) reflect the presence of some capital rationing, the availability of investment opportunities elsewhere, and the consequent need to emphasise capital productivity in making long term investments. There are thus four detailed scenarios.

Under the \$70, 40 pence scenario with investment hurdle $NPV/I > 0.3$, 550 fields are decommissioned over the period 2011 – 2042. The

aggregate cost is £31.9 billion at 2011 prices. With an investment hurdle of NPV/I > 0.5, 476 fields are decommissioned at a total cost of £29.5 billion. Under the \$90, 60 pence scenario investment hurdle of NPV/I > 0.3, 690 fields are decommissioned at a cost of £36.4 billion. With investment hurdle of NPV/I > 0.5, 646 fields costing £35 billion are decommissioned.

The second part of the study examined the utilisation of the main pipeline systems and calculated when their economic lives might end. This enabled estimates to be made of the oil and gas production which could be at risk unless viable alternative transport routes could be found. The estimates of the production at risk are summarised below.

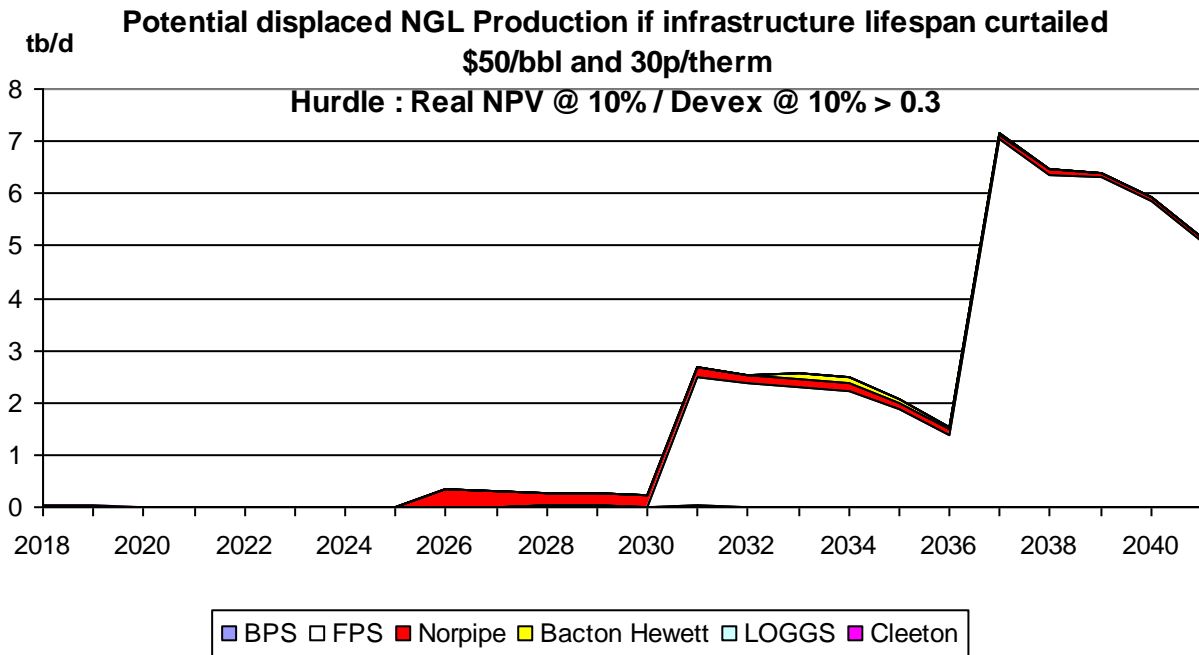
Chart 76



Under the low price case (\$50 and 30 pence) the total oil production at risk is shown in Chart 76.

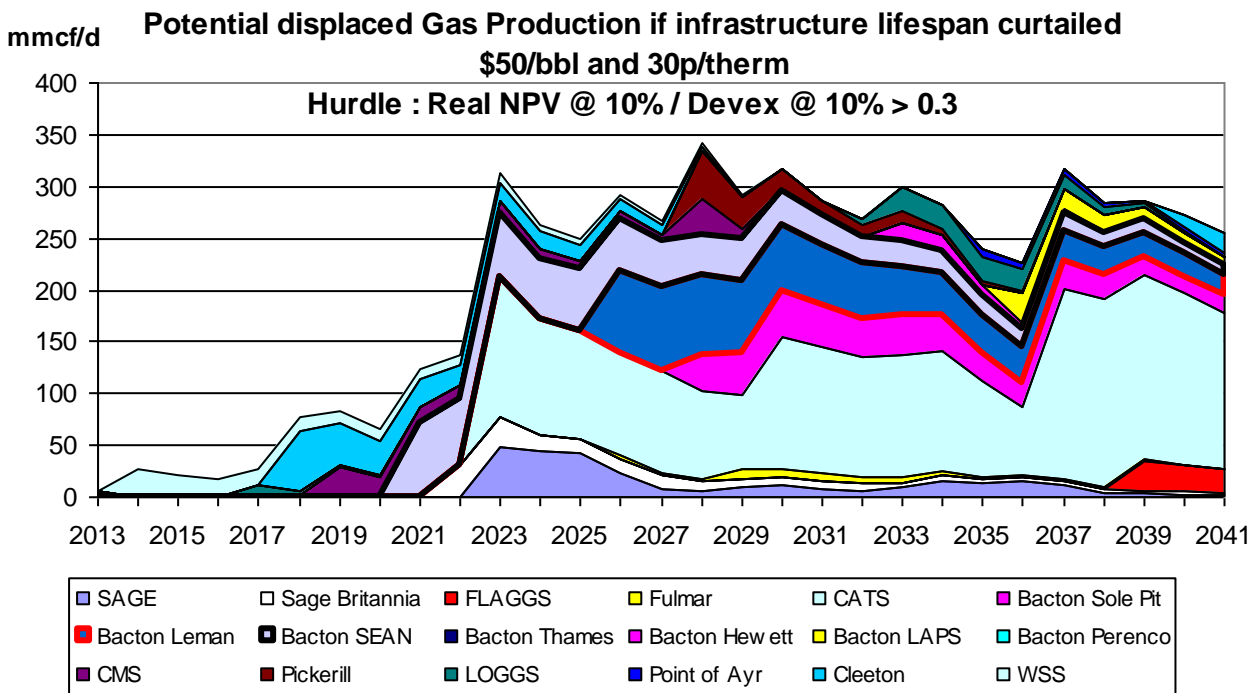
The cumulative amount is 335 mmbbls.

Chart 77



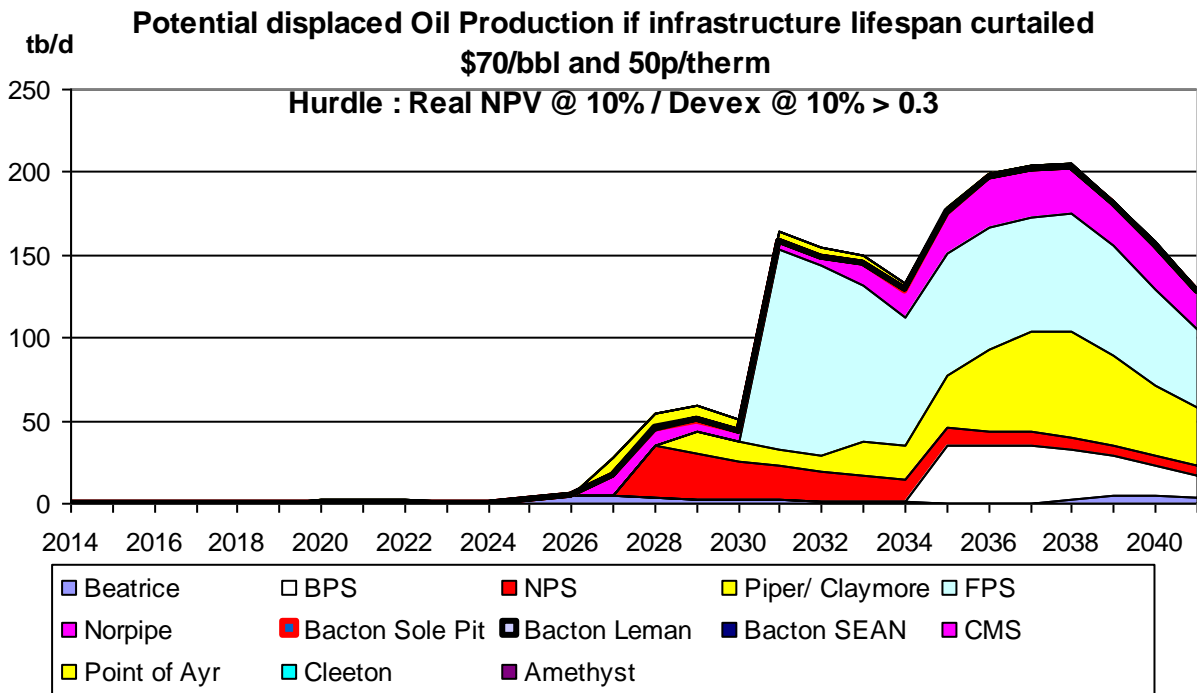
The cumulative amount of NGLs at risk is 17 mmbbls. (Chart 77)

Chart 78



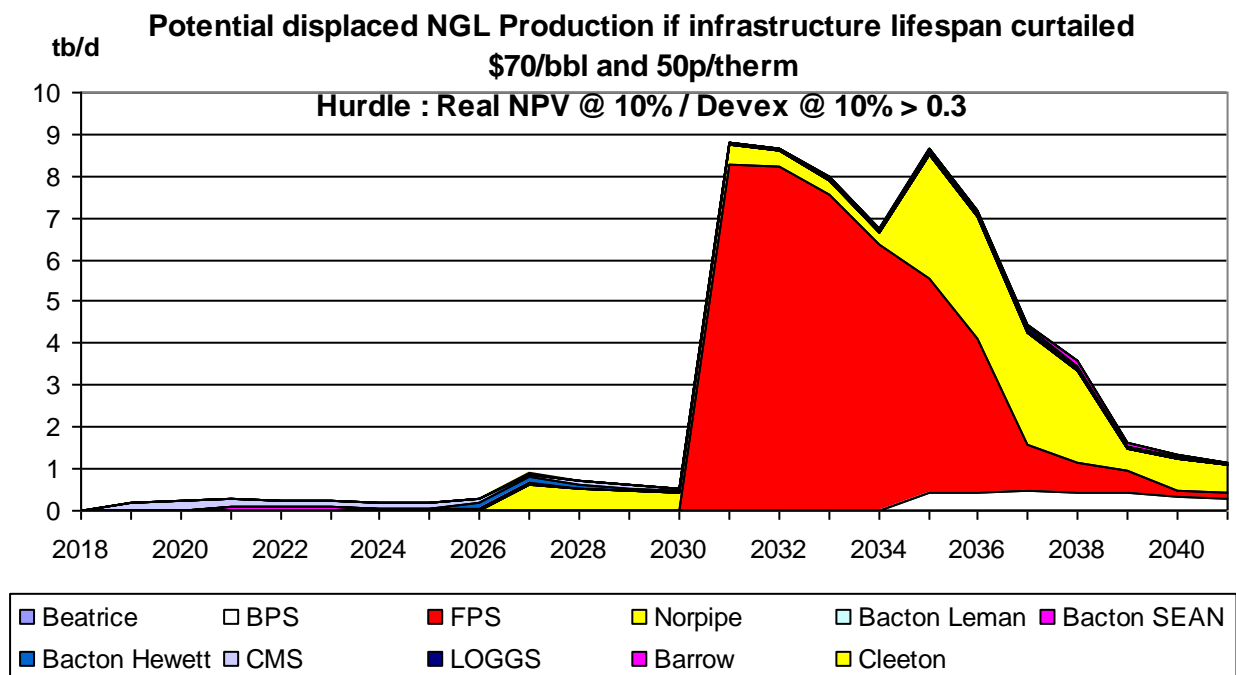
The cumulative amount of gas at risk is 2166 bcf. (Chart 78).

Chart 79



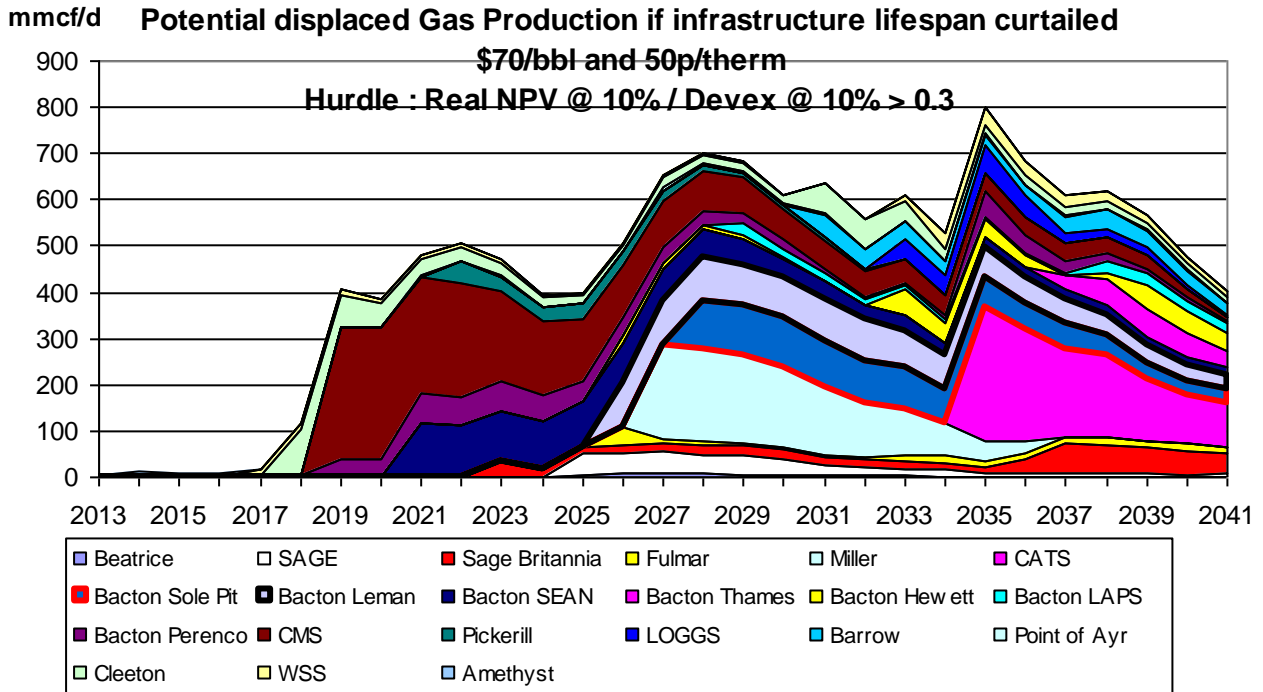
Under the \$70, 50 pence scenario the cumulative amount of oil at risk is 755 mmbbls. (Chart 79)

Chart 80



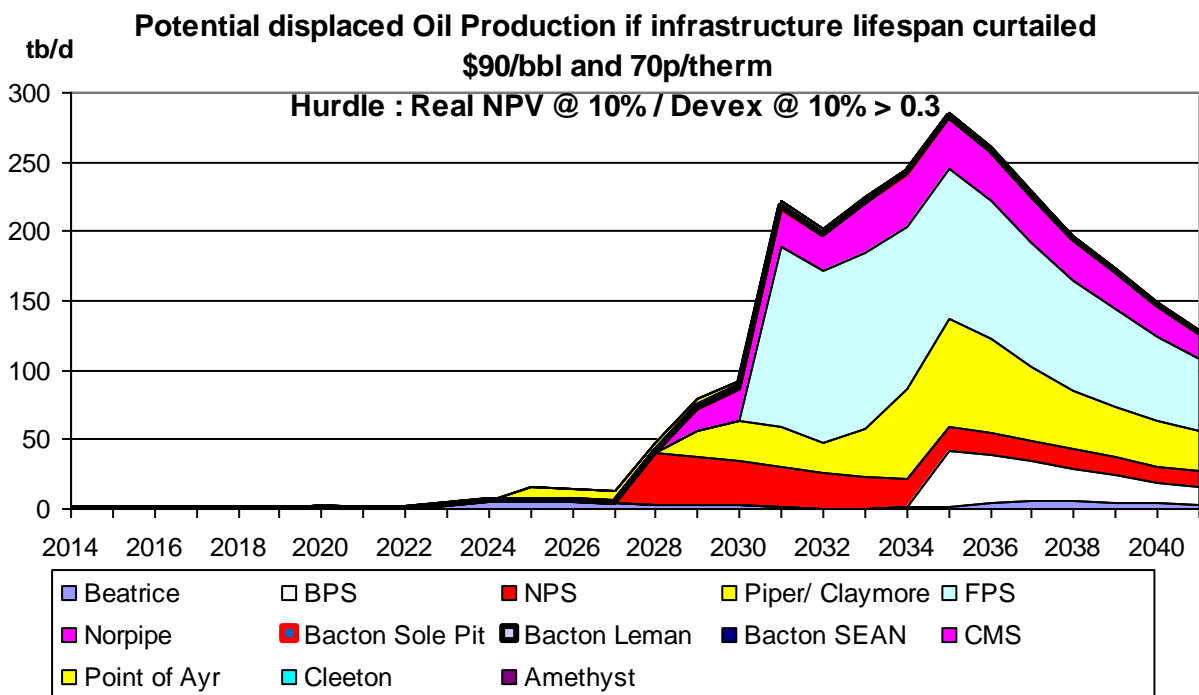
Under the \$70, 50 pence scenario the cumulative amount of NGLs at risk becomes 24 mmbbls. (Chart 80)

Chart 81



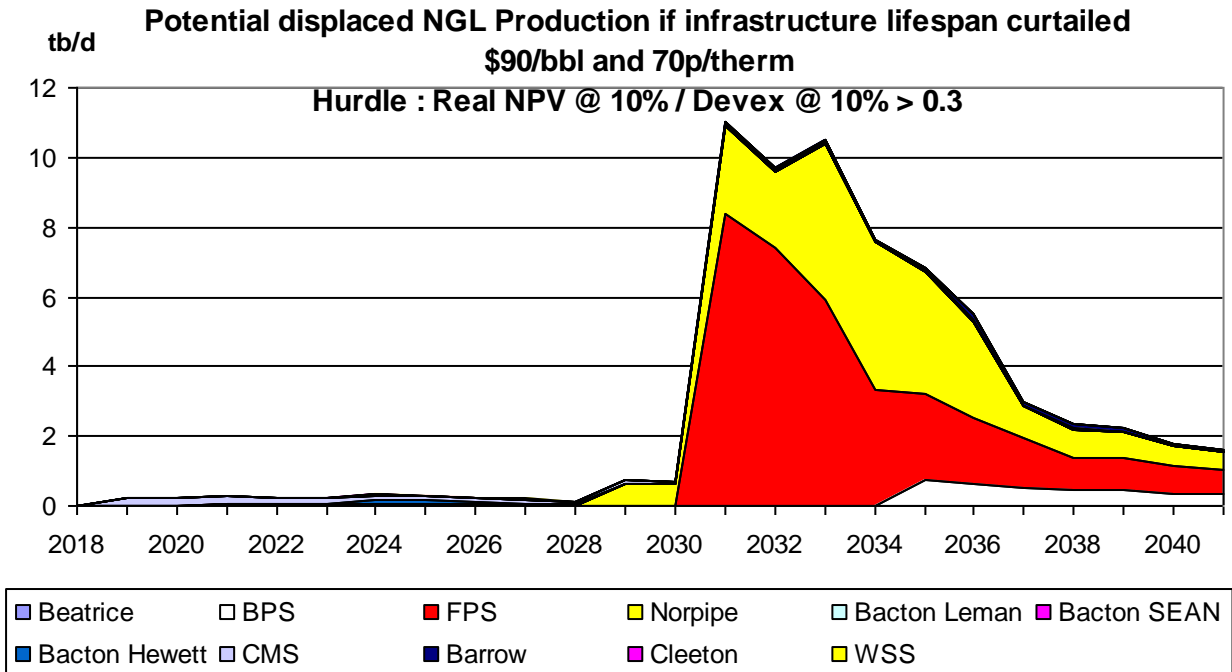
The cumulative amount of gas at risk is 4693 bcf. (Chart 81)

Chart 82



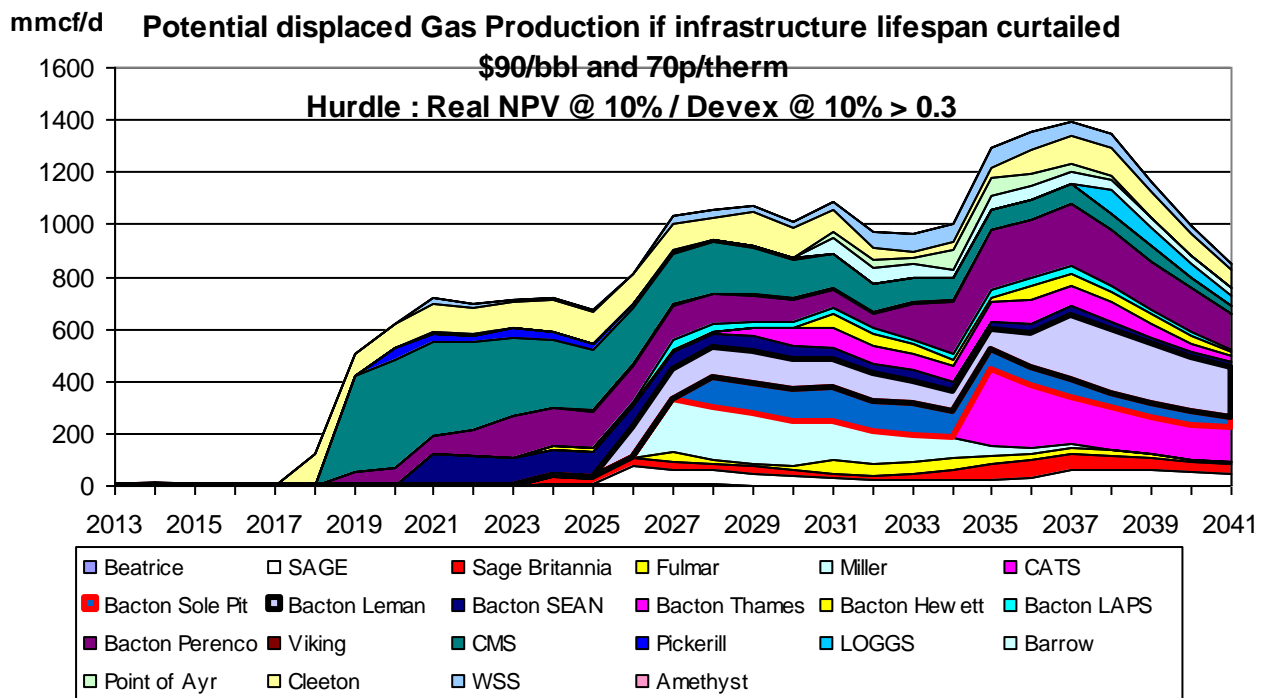
Under the \$90, 70 pence case the cumulative amount of oil at risk is 947 mmbbls. (Chart 82)

Chart 83



The cumulative amount of NGLs at risk is 24 mmbbls. (Chart 83)

Chart 84



The cumulative amount of gas at risk is 8106 bcf. (Chart 84)

For some potential users an alternative transport route or system may be readily available, but for others an alternative route may add considerably to costs and render the investments non-viable. A key implication of the findings of the study is the need to accelerate the development of fields in the category of technical reserves. This would reduce the total development costs of these fields and extend the economic life of the infrastructure.