**28 August 2018**

**Analysis of Transfer of Tax History (TTH) Proposal**

**Broad statement of impact:**

The UK Government has proposed that buyers of equity interests in UK oil and gas fields be permitted to acquire the tax histories of the sellers in order to be able to carryback and fully utilize tax deductions for the costs of decommissioning, known as Transfer of Tax History (TTH). The stated intent of this proposal is to foster a level playing field between those situations where there is an asset sale versus situations where current owners retain their interests through to decommissioning.

Before considering impacts of TTH the maximum decommissioning tax refund exposure to the UK Government in the future has been estimated by HMRC to be £24 billion[1]. But, extrapolating too far into the future can be somewhat misleading. Technology, costs, markets and tax rules have been shown in the past to change dramatically over a period of even ten years. Additionally, ten years also reflects a rough average period of time from a typical date of acquisition until the date of decommissioning. Consequently, this analysis has focused only on the next ten years, over which total decommissioning costs have been estimated to be £18 billion. (Based on the UK Oil and Gas Industry Association estimate of £1.8 billion of decommissioning costs per year times ten years.) [2]

If multiplied times a simple effective tax rate of 40%, derived as the 30% Ring Fence Corporation Tax ("RFCT") plus the current 10% Supplementary Charge ("SC"), this would result in a net tax refund of £7 billion over the next ten years. This estimate excludes PRT effects and the higher past 20% rates of SC against which losses might be carried back. If PRT and higher past SC rates were to be considered the tax refund exposure over the next ten years certainly would be even higher.

However, in estimating strictly the impact of TTH it must be considered that many of those field interests that were sold prior to proposed effective date of TTH would not be affected by TTH and will still not be able to obtain full tax refunds due to insufficient taxable income generated under their new ownership. Additionally, some field interests will not be sold at all and will be retained by their current owners through full decommissioning, and therefore the Government

[1] See HM Revenue and Customs "Statistics of Government revenues from UK Oil and Gas production" issued June 2018, p21: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/721314/Statistics_of_government_revenues_from_UK_oil_and_gas_production__June_2018__.pdf

[2]See UK Oil and Gas Authority's "Production and Expenditure" issued March 2018, p7: https://www.ogauthority.co.uk/media/4647/projections-of-uk-oil-and-gas-production-and-expenditure-march-2018.pdf

tax exposure would not be impacted by TTH. But in all cases where TTH applies, any new taxable income generated from the time of sale of interest until the time of decommissioning would reduce the value of TTH that would be need to be utilised. So, the estimated overall impact of TTH to the Exchequer will be affected primarily by the level of new sales of interest, the actual decommissioning costs, and the amount of future taxable income generated from those fields which is determined by the price of oil, production and operating costs.

**Stated Government Objectives and Estimated Impacts re Transfer of Tax Histories:**

The HMRC policy paper on Oil and gas taxation: transferable tax history and retention of decommissioning expenditure, states the following:

"Extending the productive lives of late-life oil and gas fields is an important aspect of this objective, as it leads to new investment, delaying decommissioning and supporting activity in the UKCS for longer."

"The measure should encourage new investment into late assets in the UK and UKCS which should lead to additional production of oil and gas, helping to increase the UK's energy security, and supporting jobs and supply chain opportunities."[3]

The same report estimates the following impacts of the TTH proposal:

## Exchequer impact (£m)

| 2017 to 2018 | 2018 to 2019 | 2019 to 2020 | 2020 to 2021 | 2021 to 2022 | 2022 to 2023 |
|---|---|---|---|---|---|
| +5 | +20 | +10 | +10 | +/- | +25 |

Presumably, the HMRC has incorporated the critical belief that the tax losses to the Exchequer due to permitting TTH will be more than offset by additional taxable income that could be generated from new oil and gas activity presumably incentivised by TTH.

**How Oil and Gas Asset Transactions typically take place**

In evaluating oil and gas asset sales opportunities in any part of the world, the seller usually estimates the remaining Net Present Value they would expect if the asset were to continue under their ownership and control. At the same time, the buyer prepares their own estimate

[3] See HMRC's policy paper "Oil and gas taxation: transferable tax history and retention of decommissioning expenditure" https://www.gov.uk/government/publications/oil-and-gas-taxation-transferable-tax-history-and-retention-of-decommissioning-expenditure/oil-and-gas-taxation-transferable-tax-history-and-retention-of-decommissioning-expenditure

of the remaining Net Present Value if the asset were under their ownership and control. These results typically vary due to differing views on oil prices, ability to reduce costs, and perceived potential for adding new production. But they also will vary due to different tax situations of the buyer and seller such as the buyer's lack of a history of taxable income creating an inability to fully recover the tax refund associated with deducting and carrying back the loss associated with the cost of future decommissioning.

As part of the seller's decision process the offer made by the buyer is compared to the seller's own estimate of remaining NPV. If the amount offered (after tax impacts*) is at least equal to or greater than the seller's estimate, the offer likely may be accepted. Additionally, the seller may also attempt to anticipate other potential benefits that the buyer may acquire with the asset. In the case of TTH the additional tax reduction value to the buyer certainly will be incorporated into the seller's analysis and part of that value may be "extracted" by the seller in the form of a higher sales price. So, any additional value associated with TTH in many cases will likely end up being "shared" between buyer and seller.

(*Other factors such as imposition of capital gains tax or limitation of future tax allowances for the purchase cost also have an impact on this difference in evaluation.)

**Decommissioning in the UK – Analysis of typical field costs, incentives and impacts**

In order to better and more simply illustrate how individual field cash flows, economics and taxes work in the UK North Sea a typical field data set was developed along with a sensitivity analysis of what the results would be under a range of circumstances. Some of the factors tested were crude prices, decommissioning costs, oil production and operating costs, both with and without TTH. In this way both the decisions that an investor would be faced with making and their impacts on taxes and incentives can be better illustrated. To achieve this, certain assumptions were made and tested under a variety of circumstances.

<u>Assumptions concerning the TTH proposal:</u>

1. TTH will apply only to future asset sales and not be applied to past asset transactions.
2. The amount of maximum TTH transferred to the buyer will be capped at twice the amount of decommissioning costs estimated at the time of granting the TTH.
3. Any losses from decommissioning must first utilize post-acquisition taxable income before utilizing any TTH. That is, the TTH will only have value to the extent that future taxable income from the acquired asset is less than the cost of decommissioning.
4. The Decommissioning Deeds (DCD's) will not create a different result or have an impact on the value of the TTH. The current DCD structure does not allow a payment to the taxpayer if it was attributable to a change in tax rates. DCD could have an impact in that in the future the TTH rules could not be rescinded or amended without triggering a payment under the DCD.

5. Assumes that the financial security arrangements in place through the UK Oil and Gas Authority will be sufficient to avoid defaults on decommissioning costs despite the potentially greater number of asset sales to less financially secure companies that might be occasioned by TTH.

<u>Tax assumptions applied in the analysis:</u>

1. Current tax rates of 30% Ring-Fenced Corporation Tax (RFCT) for and 10% Supplementary Charge (SC) will apply. This amounts to a combined rate of 40% tax. The rate of Supplemental Charge was set at 20% in 2015 and at 32% prior to that, although regulations limit decommissioning tax relief to the 20% rate. If TTH effectively permits buyers to utilize carryback of losses to offset profits prior to 2016 and obtain tax refunds at those earlier rates, then the combined tax refund impacts will be somewhat greater than the 40% in this analysis.
2. PRT impacts were not considered since current rules allow PRT losses to follow with the field, not the specific taxpayers. Whilst the TTH proposal does include PRT it is considered to be primarily a matter of administrative convenience rather than a net monetary impact.
3. Assumes no tax deductibility of the acquisition price paid, i.e. assumes that claw-back of prior capital allowances fully offsets.
4. Does not consider the impact on capital gains tax of potentially higher asset sales prices caused by TTH.
5. Assumes that acquirers have no other sources of taxable income with which they could offset decommissioning losses on acquired fields.
6. No consideration was taken of Tax treaty refunds of Advance Corporation Tax on dividends.

<u>Assumptions and sources of data concerning acquired fields:</u>

1. Average starting production rates for a typical acquired field was assumed to be 3.5 mbd ("thousand barrels per day"). This is based on the Oil and Gas Authority Petroleum Production Reporting System (PPRS) database, which indicated that as of the end of 2015 a full 76% of the 188 UK North Sea fields onstream produce less than 5 mbd and 90% produce less than 10 mbd.[4] Many of these fields produce well under 5 mbd.
2. Operating costs were assumed to be £17.00 per barrel, converted to a fixed sterling amount for the existing production. This is based on the UK Oil and Gas Authority Projections of UK Oil and Gas Production and Expenditure issued March 2018 which forecast AVERAGE operating costs to range from £11.70 to £12.40 per barrel which is likely to be low for an older declining field as an industry average would include the

[4] See UK Oil and Gas Authority's "Petroleum Production Reporting System" database: http://data-ogauthority.opendata.arcgis.com/pages/production.

higher production/lower cost per barrel fields.[5] The analysis assumes that as field production declines that costs become more fixed and less variable in nature.

3. Operating costs for any new production resulting from capital expenditures in acquired fields was assumed to be a **variable** rate of £17.00 per barrel.
4. In cases looking at the impact of projects to bring on new production in acquired fields a typical new project was assumed to generate 2 mbd of new production at initial rates and would require average new capital investment of £100 million.
5. The Oil and Gas Authority and the UK Oil and Gas Industry Association industry survey estimates annual decommissioning costs in the UK to be in the range of £1.7-2.0 billion per year over the next ten years.[6] The UKOGIA survey estimates that 214 fields will be decommissioned in this same ten-year period.[7] This equates to an average decommissioning cost per field of roughly £100 million (£20 billion divided by 200 fields). Wood Mackenzie in 2017 estimated US$19 billion to be spent in the next 5 years.[8] Depending on the number of fields and exchange rates these figures could represent a field average cost in the range of £110-130 million, somewhat higher than the UKOGIA survey. The base case assumption used in the economic analysis was that full decommissioning costs per field would average £125 million.[9]
6. For purposes of the economics model it was assumed that any field will continue operating until such time as the Gross Revenues less the Operating Costs become negative. At that point, it was assumed that production would no longer be considered economically viable and that decommissioning will take place the following year. This is a typical means of making abandonment decisions in the upstream sector. This means that the economic threshold is very dependent on the price of crude oil. Lower prices over a prolonged period generally result in fields being decommissioned sooner, irrespective of TTH.

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[5] See UK Oil and Gas Authority's "Production and Expenditure" issued March 2018 https://www.ogauthority.co.uk/media/4647/projections-of-uk-oil-and-gas-production-and-expenditure-march-2018.pdf

[6] See ibid and UK Oil and Gas Authority's "Decommissioning Insight 2017" p7: https://cld.bz/BoPAqso/6/

[7] Ibid

[8] See Wood Mackenzie's "Decommissioning: the UK's £66 billion headache" report summary: https://www.woodmac.com/reports/upstream-oil-and-gas-decommissioning-the-uks-us66-billion-headache-43689600

[9] Wood Mackenzie was inconsistent in how they translated dollars into sterling. For their long-term forecast they used $66 billion and 53 billion pounds, an effective rate of $1.2. For their five-year forecast, Wood Mackenzie seemed to use a rate of $1.7 to the pound, a rate which hasn't existed for many years. We assumed a more current rate of $1.35, which would equate the $19 billion to just over 14 billion sterling rather than the 11 billion sterling referenced by Wood Mackenzie. Dividing that 14 billion sterling by roughly 110 fields (half of the 214 over ten years estimate by O&G UK) would approximate the average of 125 million pounds.

7. It is not likely that in all cases the 100% equity interest will be sold in each field. In many cases only 1-2 of the JV partner interests would be sold, which would somewhat reduce the net impacts estimated herein. This analysis examined the 100% equity interest.
8. The economic analysis has not included non-associated gas fields for simplicity and due to the fact that these types of fields typically require more developed commercial and midstream expertise which make them slightly less likely to be targets of acquisition.

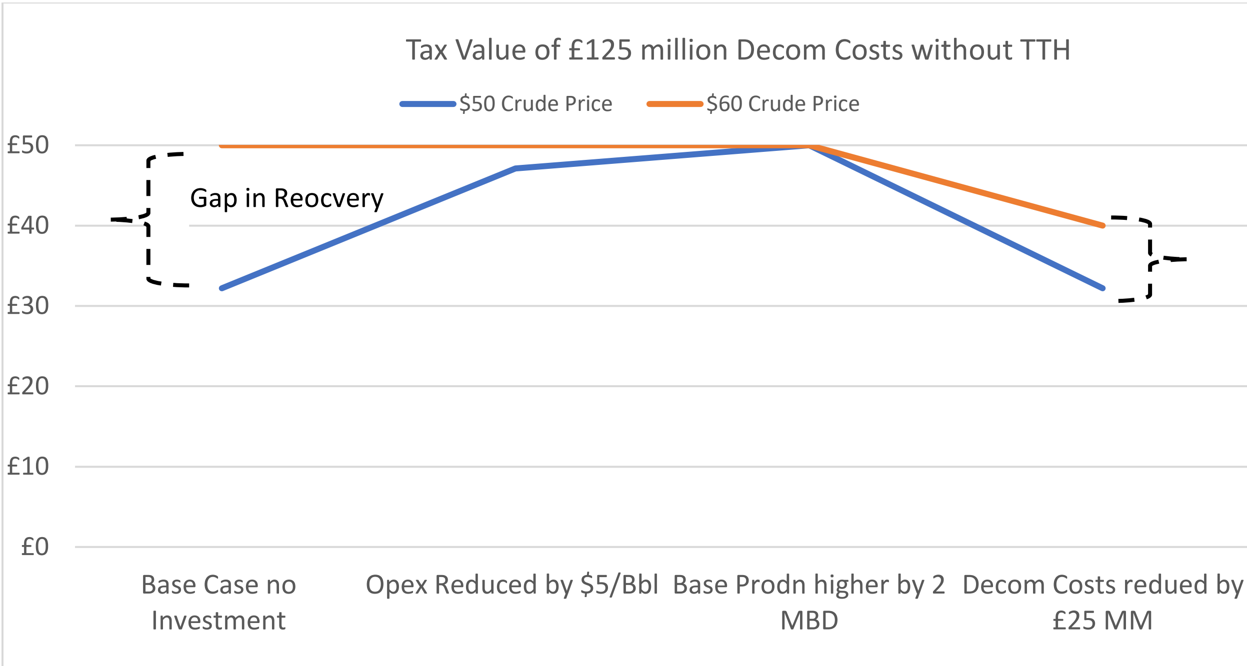
Analysis of the Representative Field economics with and without TTH

It can be difficult to extrapolate the impacts of a typical asset sale field scenario as the strategies of the acquirers can vary. The specific percentage equity interest being acquired can vary from relatively small to large, which will have an impact on the quantum of decommissioning costs and TTH involved. In some cases, the acquirer will become the operator in order to be in a position to drive lower costs and in others the acquirer will be more interested in developing additional reserves. In some circumstances at present an acquirer will seek to obtain equity interests in several fields with staggered dates of decommissioning as a means of balancing or smoothing the levels of taxable income available to recover decommissioning costs.

**Tax Recovery of Decommissioning Costs with and without TTH**

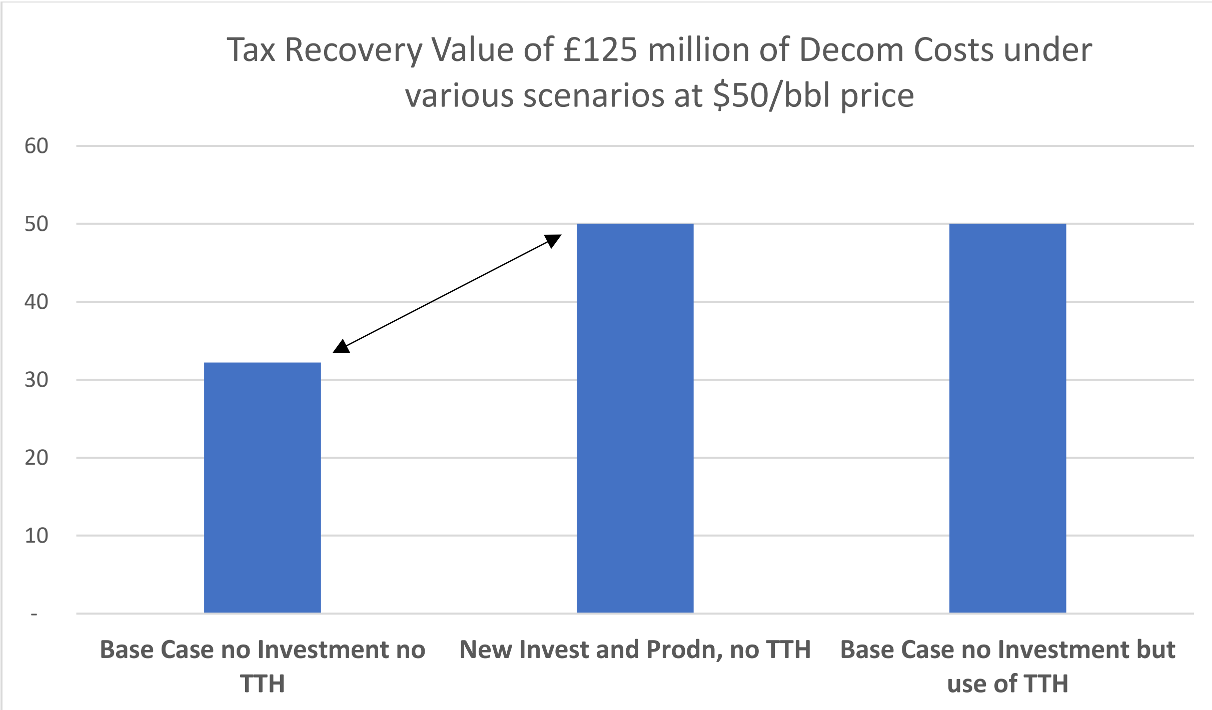
The field analysis results indicate that under certain circumstances there will indeed be a shortfall in full tax recovery of decommissioning costs without the benefit of TTH. The value of this short fall is greatly dependent on crude oil prices, costs and production levels as illustrated by the following two charts. In the base case, the value of full tax recovery would be equal to £50 million (the combined assumed 40% tax rate times the assumed £125 million of decommissioning costs).

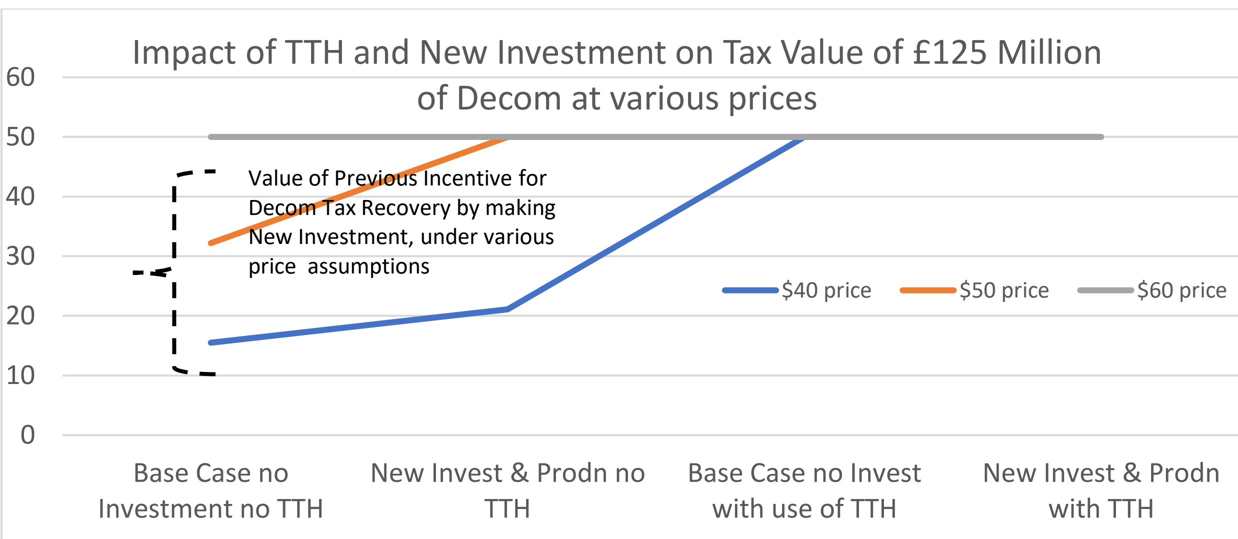
In a base case with no new investment and no TTH in an environment of relatively low crude prices ($50/barrel) and high operating costs ($23/barrel), there would be a roughly £32 million tax recovery in this example, which represents a £18 million gap in tax recovery of decommissioning costs due to insufficient new taxable income being generated by the buyer to fully carryback the losses. But this gap can be partially or fully closed by the buyer finding a means to reduce operating costs, in this case a £3 million (a $5/barrel, or 20%, reduction in operating expense), or to reduce the gap to zero by increasing production, in this case by 2 mbd. In any event, even without these types of actions, a higher crude oil price in the range of $60 per barrel would eliminate the gap entirely in most cases.



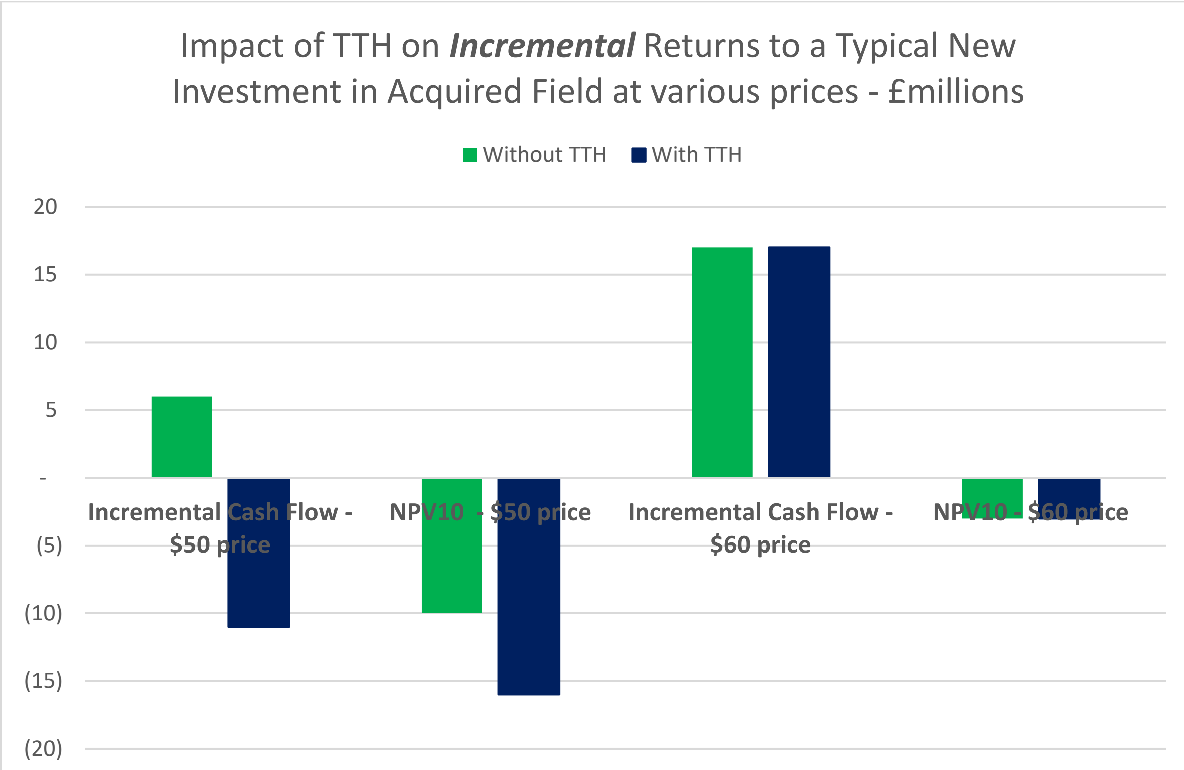

**New Investments with and without TTH**

But in virtually all circumstances *without TTH*, a buyer of a field equity interest currently has a built-in incentive to invest in developing additional production as the production associated with that investment would serve to add sufficient new taxable income to enable fuller deductibility and carryback of decommissioning losses. Without taking actions to reduce costs or make new investments a field equity buyer would have to rely on a higher crude oil price environment to generate sufficient new taxable income to fully utilize carryback of decommissioning costs without considering TTH.




In most circumstances (especially under lower crude price scenarios), the NPV of a new investment to increase production in an acquired field can actually have a lower ***incremental*** return on the new investment due to use of TTH. This is attributable to the fact that the new investment will no longer bring the added economic benefit of increasing taxable income to the point of being able to obtain full decommissioning loss carryback. In other words, one of the reasons for making new investments under the current system is the potential to attain fuller tax recovery for decommissioning costs. This “incentive” for new investment will no longer be in place under a TTH system.

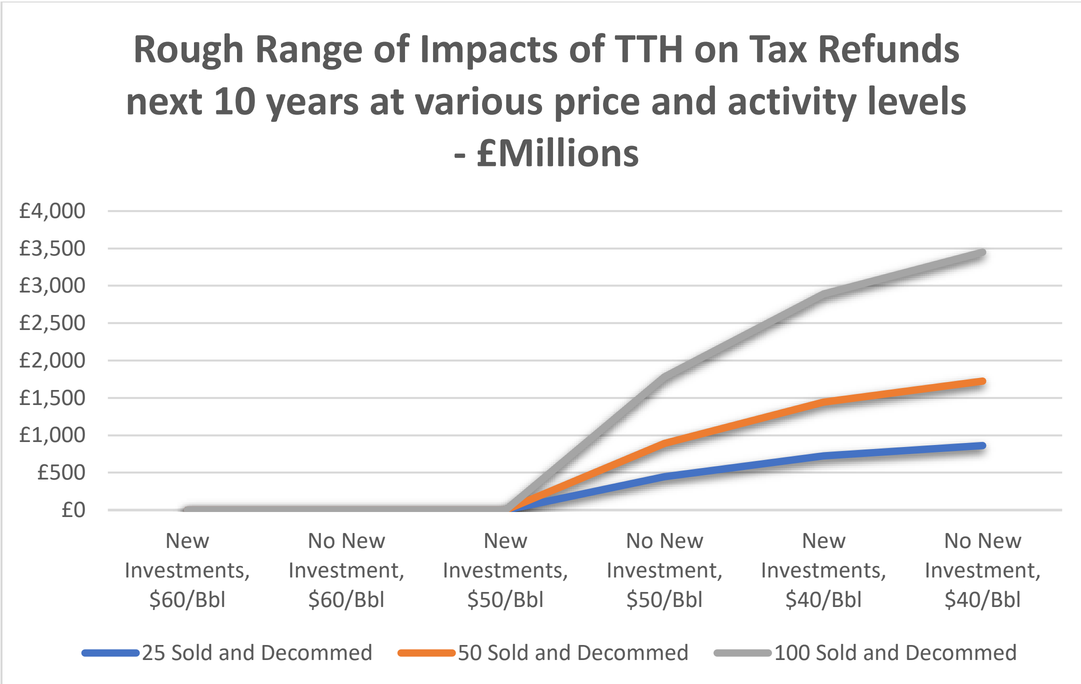



In the $50 oil price scenario example, both the incremental net cash flow and NPV of making an identical investment to expand production has a lower result under TTH system since it would serve to limit or eliminate the existing tax recovery incentive of new investments. At the $60 price level TTH has no impact since there is sufficient new taxable income generated to fully recover decommissioning costs even without TTH.

**Will the TTH proposal achieve the stated objectives?**

Government exposure to tax recovery associated with decommissioning costs is greatly impacted by crude oil prices. The higher are crude prices the greater is the amount of new taxable income generated that would then serve to reduce the amount of TTH required. Additionally, higher crude oil prices tend to extend field life which shifts decommissioning further into the future which would serve to also shift the Government exposure further into the future.

The impact and estimated value of TTH is heavily dependent on crude oil prices, levels of production and operating costs relative to costs of decommissioning plus the number of newly acquired fields post TTH that would be decommissioned.




In summary, the following impacts can be expected:

- In general, the lower are crude oil prices, the greater the impact that TTH will have on company cash flows and on Treasury taxes collected. In effect, during periods of lower prices TTH will exacerbate Treasury exposure and partially insulate buyers of assets.
- TTH will generally reduce existing incentives for making new investments in acquired oil fields, especially in lower price environments.
- TTH will generally reduce incentives for lowering operating costs in acquired oil fields, especially in lower price environments.
- Depending on how much of the additional value attributable to TTH will be extracted by the seller of the field interest, TTH may end up actually limiting or having no effect on the number of asset acquisitions.
- The positive impacts to the Exchequer that were envisioned presumably were based on greater investment and higher production levels expected to be incentivised via TTH. It is difficult to reconcile this expectation with the actual loss of economic incentives that the current system would have provided.
- Overall impact on the Exchequer of TTH could range from virtually zero to roughly £3+ billion reduction in tax receipts over the next ten years depending on oil prices and number of asset sales and decommissioning.* In any event, TTH will increase the £24 billion ultimate estimated cost over time to the Exchequer that was forecast by the HMRC in June 2018.

T.M. Mitro – August 28, 2018

*HM Revenue and Customs “Statistics of Government revenues from UK Oil and Gas production” issued June 2018,[10] indicates the following refunds of taxes relating to oil and gas activities issued to tax payers (presumably many are from taxable loss carrybacks due to decommissioning costs[11]) under existing tax rules as follows, in £millions:

| **Tax Period** | **Corporation Tax** | **PRT** | **Total** |
|---|---|---|---|
| 2015/2016 | 400 | 562 | 962 |
| 2016/2017 | 558 | 654 | 1,212 |
| 2017/2018 | 179 | 569 | 748 |
| Total | 1,137 | 1,785 | 2,922 |

[10] For tax refund figures, see table 11.11: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/721314/Statistics_of_government_revenues_from_UK_oil_and_gas_production__June_2018__.pdf

[11] Based on the statement the report makes, p21: ”The total industry costs between 2018-19 and 2062-63 for decommissioning all UKCS oil and gas infrastructure is £64 billion as measured in nominal prices and with discounting. The total projected Exchequer cost of tax relief from this expenditure is £24 billion. This is comprised of tax repayments as well as a reduction in Offshore Corporation Tax due as decommissioning costs reduces company profits.”

## Note on the Author

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