Wood Mackenzie

Evaluation of Proposed Tax Changes on the US Oil & Gas Industry

Evaluation of Proposed Tax changes

August 2010

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Executive Summary

API has retained Wood Mackenzie to estimate the impact of proposed tax changes that will affect the oil and gas industry. The tax changes Wood Mackenzie has considered are:

- Intangible drilling cost (IDC) expensing
- Domestic production activities deduction

Wood Mackenzie utilized its Upstream Database of 230 play and field files with future development potential to test the impact of proposed tax changes in the Alaska, Lower 48, and the US GoM regions of the US. Economics for a typical well in each play and full field development was calculated in Wood Mackenzie's Global Economic Model (GEM) to determine what impact the current proposal could have on US production and investment.

Among the current proposed tax changes, Intangible Drilling Costs (IDC) and the Domestic Production Activities deduction (Section 199) were identified as having the greatest impact on the industry. The play/field metrics and the estimates for lost production and investment were determined by analysing returns with the current tax treatment and after the loss of these two deductions.

With the proposed changes to IDC and the Section 199 deduction, 88 of the 230 plays/fields considered for this analysis fall below a 15% IRR threshold. Almost 90% of the plays falling below a 15% IRR are gas targets, while oil is shielded by price assumptions greater than $80/bbl. In the current gas price environment, many of the gas plays are sub-economic before accounting for the tax increase and these plays become more severely disadvantaged under the additional tax burden.

Under the proposed tax changes, Wood Mackenzie estimates a total of 300,000-600,000 boe/d of production additions in 2011 are at risk. Total at risk volumes include 57,000 b/d and 2.9 bcfd in 2011, with as much as 250,000 b/d and 9 bcfd at risk by 2017, representing more than 10% of US productive capacity. These volumes account for approximately $10-17 billion in direct upstream investment per annum.

Breakevens for the average gas and oil development shift from $5.40/mcf and $47.00/bbl to $6.00/mcf and $52.00/bbl, respectively.

In the scenario where gas prices remain low and the industry loses both the IDC and Section 199 deduction, Wood Mackenzie expects that almost all additional productive potential in the US would be eliminated. More than 27 tcf and 700 mmbbls of production are at risk under the worst case scenario. Wood Mackenzie does not expect the full effect of the tax changes would be as dramatic as indicated in this scenario, but volume impacts would be significant enough to alter pricing fundamentals in the US gas market.

1. Background and Study Objectives

Wood Mackenzie has been appointed by the American Petroleum Institute (API) to provide an evaluation of legislative proposals in 2010 put forward by the US Congress that would affect the tax burden on the US oil and gas industry.

Background

API is concerned with, and would like to assess, proposed changes to the tax code under consideration by the US Congress and the Obama Administration that will likely impact the oil and gas industry's investments and activity plans in the United States. In particular, the API would like Wood Mackenzie to provide an independent view and evaluation of specific tax changes as they relate to different fields and plays onshore and offshore across the US upstream industry. The tax changes we will consider are:

- Intangible drilling cost (IDC) expensing
- Domestic production activity deduction

We understand that the API will use this analysis to inform policy makers as to the impacts of these proposed tax changes. Furthermore, we understand that analysis developed in this study by Wood Mackenzie will be presented in a way to preserve its objectivity.

Study Objectives

Evaluate the impact of the current tax proposals on upstream oil and gas production and investment. The focus of this project will be on the proposed changes in tax treatment for the following items:

  - Intangible drilling cost (IDC) expensing
  - Domestic production activities deduction

2. Methodology

Process

- Firstly, Wood Mackenzie carried out an internal review our tax models for Alaska, Gulf of Mexico Shelf and Deepwater, and all relevant onshore US Lower 48 states. We added the Section 199 deduction to our models as well as 15% depletion for study in a single well.
- In step 2, we modelled the repeal of IDC deduction and the Section 199 tax deduction for all plays identified with future development in the Lower 48. This allowed us to evaluate the overall impact to the industry, should all the changes be implemented at once.
- Wood Mackenzie utilized its existing Upstream Database of oil and gas fields across the US to generate economics via our Global Economic Model. We generated two economic cases: the first using the current tax terms, the second with the proposed changes. Economics were generated using Wood Mackenzie base price assumptions, which are detailed on page 13 of this report.
- Prior to running these two scenarios we built models for expected future development in the US:
    - All new and proposed fields in the Gulf of Mexico and Alaska, including production profiles and associated capital and operating costs
    - Type wells for all onshore plays, including production profiles and associated capital and operating costs
- For each field and type well we generated the following economics under the two tax scenarios for analysis:
    - Internal Rate of Return (IRR)
    - Present Value at 10% and 15% (PV10 and PV15)
    - Break-even prices at 10% & 15% discount rates
    - Future annual cash flow (including production/costs/taxes)
- The economic data was used to identify fields and plays that become sub-economic (for the purpose of this analysis, below a 15% nominal IRR) under the higher tax scenario.
- Once the fields and onshore drilling targets (plays) were identified, we estimated the production and investment impact of the cancellation of these projects by geographical region.
    - For the fields we summed the production and costs as modelled in our Upstream Database
    - For the plays, we took the difference between the economic case for each basin (ie where companies continue to drill and develop as per their current plans) versus the sub-economic case (ie where limited or no future investment occurred and summed production from these plays)
- Within this methodology, we are assuming that all companies will cease investing if a project becomes sub-economic at our base price case. In plays where a known core is identified, we limited the impact to 50-70% of development.

Fields and Play identification

Wood Mackenzie identified 230 different plays and fields for evaluation in this study.

3. IDC and Section 199 Domestic Production Activity Tax Deductions

The Intangible Drilling Costs (IDC) deduction and the Domestic Production Activities deduction have been identified as having the broadest impacts on the economics of the US oil and gas industry.

IDC

The IDC deduction has been part of the tax code for almost 100 years and provides capital and cash flow for the industry to drill and develop domestic oil and gas. The current deduction allows for a majority of expenses that do not have a salvage value to be expensed in the year incurred. The tax proposal would repeal this treatment in favour of amortizing the costs over a longer period. In our modelling, we have generally assumed a units of production depreciation method.

Section 199 tax deduction

In 2004, Congress passed legislation that gave US tax payers a 3% deduction on their income from domestic production, manufacturing, and extractive activities. The statute allowed this deduction to increase to 9% in 2010, but was capped at 6% for just the oil and gas industry. Under the current proposal being considered by the US congress, we have assumed that this deduction is entirely eliminated and its benefits are lost for the oil and gas industry.

4. Proposal impact

4.1 Scope of consideration

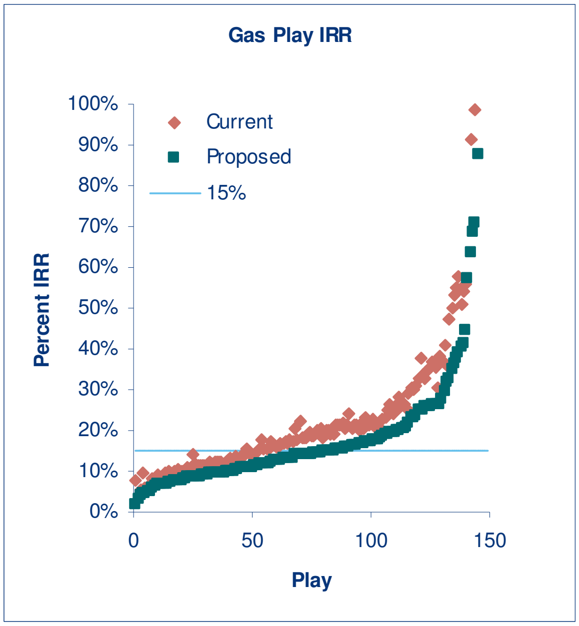
Wood Mackenzie analyzed 230 fields and plays with future development potential for purposes of estimating an overall production and investment impact from proposed tax changes in the US for the IDC and 199 deductions. The analysis was undertaken for each play on a PV, IRR, and breakeven basis. We included results for plays and fields in Alaska, US Gulf of Mexico, and the Lower 48.

4.2 Economic results

For onshore and Gulf of Mexico – Shelf development, we consider production and costs for the average well drilled, while considering full field economics of probable developments in Alaska and the US Gulf of Mexico – Deepwater.

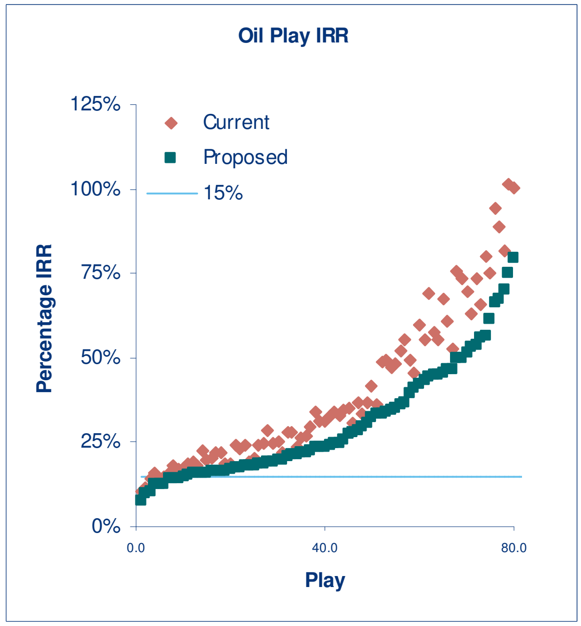
The following charts illustrate the shift in IRRs across all of the plays covered by Wood Mackenzie. Of the 230 fields/plays, Wood Mackenzie found that 55 are sub-economic at a 15% discount rate at Wood Mackenzie's base case gas and oil prices. With consideration for the proposed tax changes, this number grows to 88 fields/plays. Almost 90% of the sub-economic plays are gas developments. The heavier weighting to gas plays is due to the overall size of the natural gas industry as well as a lower fundamental price outlook. Breakeven prices also shift significantly as the average play experiences a breakeven price increase of 10%.

Gas Play IRR (Current and Proposed)



Source: Wood Mackenzie – Upstream Service, GEM

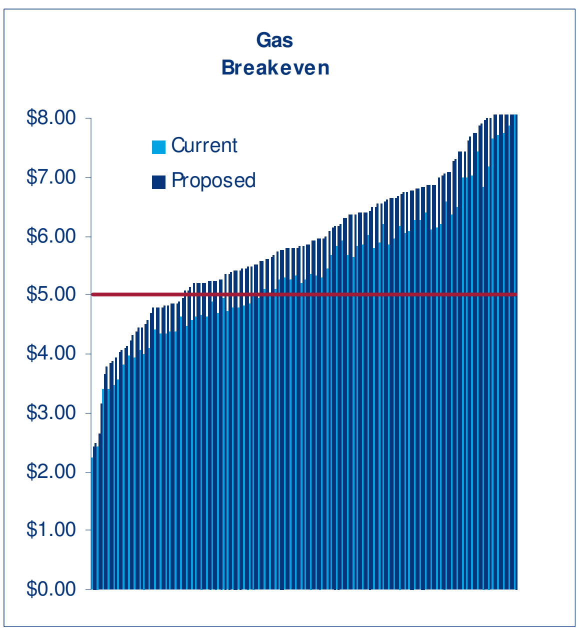
Oil Play IRR (Current and Proposed)



Source: Wood Mackenzie – Upstream Service, GEM

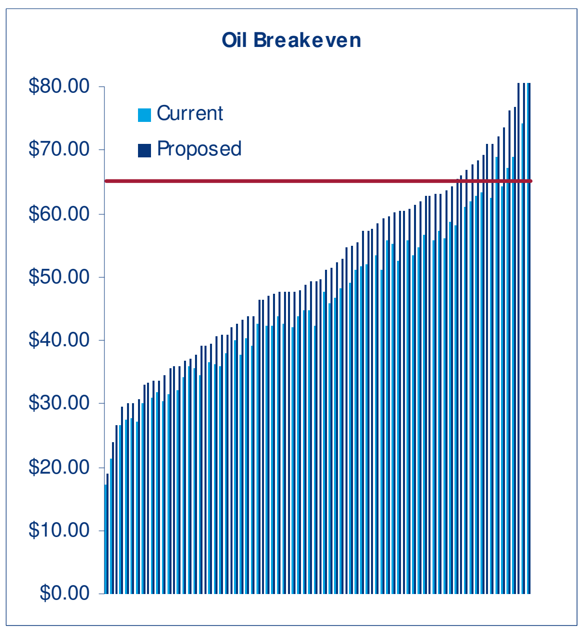
The following charts depict breakevens for the gas and oil plays analyzed. In general, the proposed repeal of the IDC and the Domestic Production Activities deductions increases breakeven prices by approximately 10%. For natural gas, the average breakeven price shifts from $5.40/mcf to $6.00/mcf when losing the deductions. The average oil breakeven shifts from $47.00/bbl to $52.00/bbl. Almost 80% of gas developments need $5.00/mcf or greater to breakeven, while less than 20% of the oil developments need more than $65/bbl to breakeven.

Gas breakevens



Source: Wood Mackenzie – Upstream Service, GEM

Oil breakevens



Source: Wood Mackenzie – Upstream Service, GEM

Alaska

In Alaska, only the one field is considered sub-economic. The field provides a negative PV, and a breakeven price of $81/bbl under the proposed tax changes. The negative values are largely the result of stranded gas that does not reach market until 2025.

Gulf of Mexico – Deepwater

Three of the 18 projects in the GOM Deepwater are at risk with the proposed tax changes. Long lead times between initial investment and first production make these projects more sensitive to the tax changes and subsequent higher breakevens.

Gulf of Mexico – Shelf

There is limited development in the Gulf of Mexico – Shelf and economics of probable developments did not fall below our economic threshold. Although known development is not affected, lower expected returns could alter exploration plans in the region.

Gulf Coast

Results from the onshore Gulf Coast region highlights that 21 of the 59 plays with future development potential become sub-economic under the proposed tax changes. The sub-economic plays are entirely gas weighted and include portions of major plays such as the Barnett, Bossier, Cotton Valley, and Haynesville unconventional gas plays. Non-core areas of shale plays and mature tight gas plays fall below our economic threshold. The ArkLaTex Basin of northeast Texas and north Louisiana will suffer disproportionately to other areas of the region. Also, companies without positions in core areas of the major unconventional gas plays will see the largest proportion of their portfolio suffer from marginal economics.

Mid-Continent

In the Mid-Continent, 17 of the 32 plays are sub-economic under the proposed tax changes. This includes portions of the Woodford shale and liquids-rich vertical drilling in plays such as the Granite Wash. New drilling in mature plays is largely rendered sub-economic under the tax changes. Horizontal drilling in growth plays such as the Cleveland, Fayetteville, Granite Wash, and Woodford continue to provide sufficient economics under the proposed changes.

Northeast

Play level economics in the Northeast show a majority of plays falling below the economic threshold. The major growth plays such as the Marcellus and Huron shales provide lower returns, but provide economic returns above the 15% threshold. The smaller plays that fall below a 15% IRR are gas weighted and heavily dominated by small private operators. Drilling by larger operators in these plays is motivated by requirements to hold leases that are prospective for the higher value shale plays in the region. With this, smaller operators will be disproportionately affected by the increased tax burden.

Permian

In the Permian, oil weighted prospects hold economics relatively strong compared to other regions as only 9 of the 30 plays analyzed are considered sub-economic under the proposed changes. These are predominately limited to gas plays in the region. The growth in emerging plays such as the Barnett Woodford and Deep Haley will be limited under the increased tax burden.

Rocky Mountains

Major producing plays in the Rocky Mountains fall below the economic threshold as 20 of the 33 plays fall below a 15% IRR. This set of sub-economic plays includes tight gas and CBM plays in the Piceance, Powder River, and Uinta basins, as well as the Bakken Oil Play in the non-core Montana portion of the formation. The most viable areas such as the core Bakken, the Jonah field, and the Pinedale field provide sufficient economics under the proposed changes. Development is expected to continue in areas of many of the marginal plays, but the periphery of the developments is at risk due to higher taxes.

West Coast

There is limited development in the West Coast region with a strong weighting to oil targets and no plays fall below our economic threshold under the proposed changes.

4.3 At risk production and investment

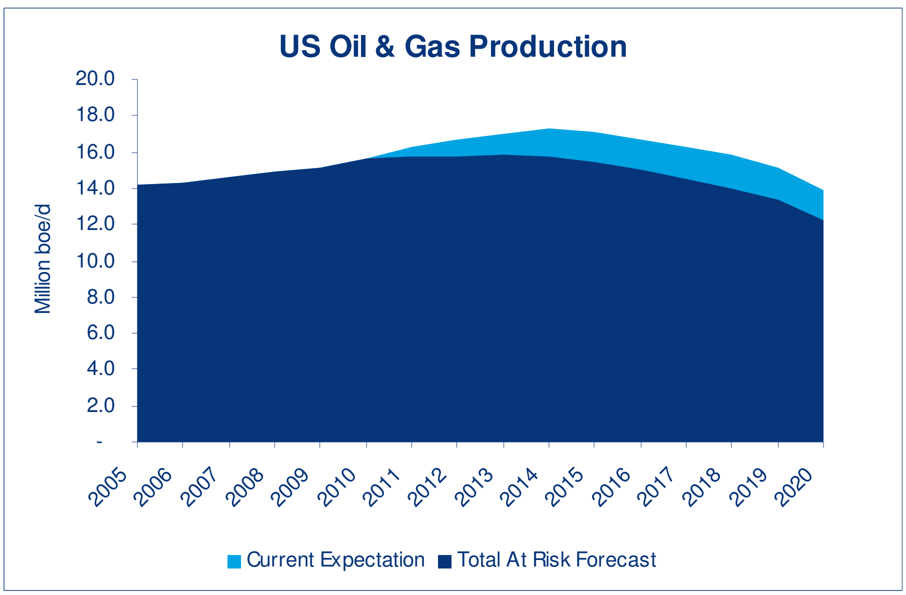
In 2011, Wood Mackenzie estimates that the proposed budget changes put almost 600,000 boe/d (60,000 b/d and 3 bcfd) of domestic production at risk. These volumes equate to almost $15 billion in capital spend in 2011 alone. In the first year of the tax changes, the potential loss of production volumes represents 1% of expected oil production and 5% of domestic gas production.

Production

Oil and gas production in the US is set to grow through 2015 as operators add 1.5 mmboe/d of production. Almost all of the US production growth is driven by gas development, which has the potential to grow production by almost 10 bcfd from 58 bcfd in 2010. The proposed repeal of IDC and Section 199 deductions puts almost 3 bcfd and 60,000 b/d at risk in 2011. Projects that are currently marginal are expected to be affected first and are included in our "Low Case At Risk" in the following investment at risk charts. These projects represent production additions of 313,000 boe/d, 34,000 b/d and 1.7 bcfd, in 2011. When adding projects that fall below a 15% IRR to estimate our "Total At Risk" under the proposed tax changes, the production loss grows to 573,000 boe/d, 57,000 b/d and 2.9 bcfd, for the first year implemented. In 2011, the high case volumes represent approximately 1% of oil and 5% of domestic gas production.

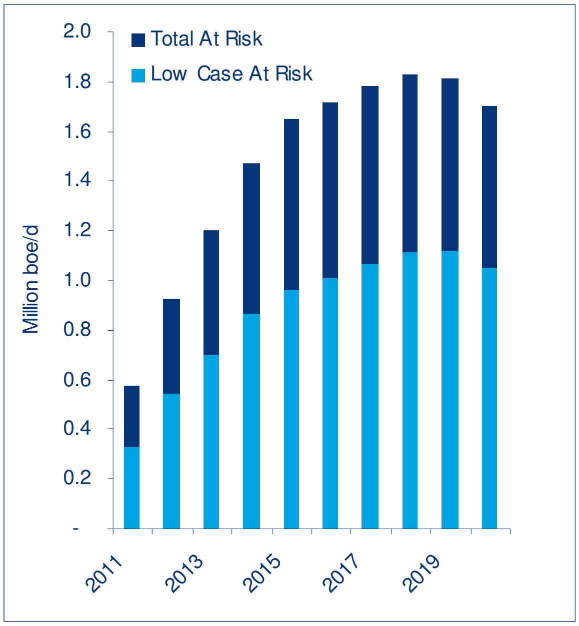
Much of the US gas industry has suffered from marginal economics in the low gas price environment experienced since late 2008. While production growth is largely gas, a lower fundamental view of gas prices subjects a greater number of gas developments to lower returns. If prices were to remain at current levels below $5.00/mcf, the amount of at risk production grows to over 10% of US productive capacity at 9 bcfd and more than 250,000 b/d by 2017. Over the next ten years, the proposed tax increases would affect 27 tcf of gas and 700 mmbbls of oil production. This translates into a volume of gas that exceeds the amount of gas produced or consumed in the US in a given year.

US oil equivalent production forecast (probable)



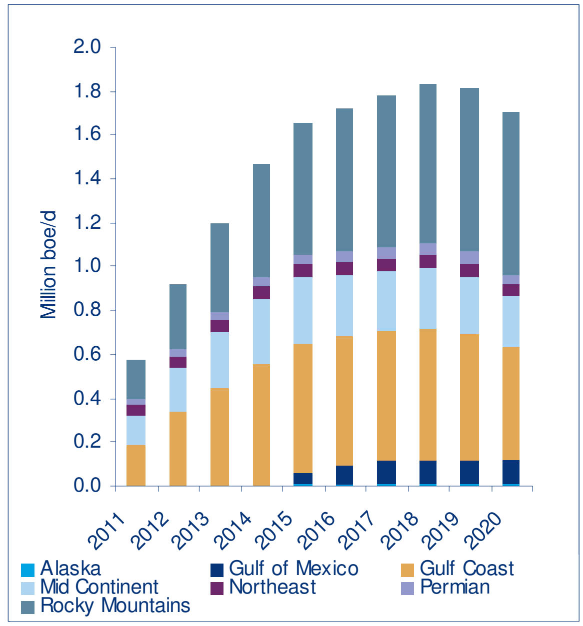
Source: Wood Mackenzie – Upstream Service
1 Bcfd = 0.18 million barrels of oil equivalent per day

Production at risk



Source: Wood Mackenzie – Upstream Service

Total at risk production by region



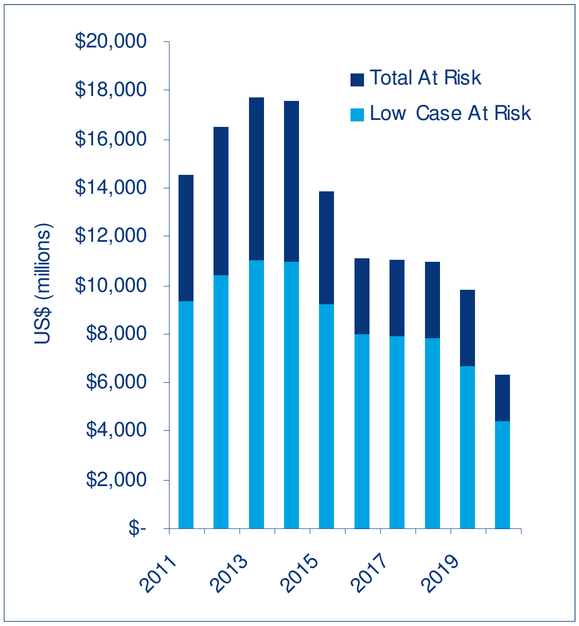
Source: Wood Mackenzie – Upstream Service

Investment

Under the proposed legislation, Wood Mackenzie estimates that almost $15 billion of investment is at risk in 2011 and almost $130 billion is at risk over the next ten years. For the first year of implementation, projects that are currently marginal represent over $9 billion (Low Case At Risk) in investment, with an additional $5 billion at risk under the proposed tax changes.

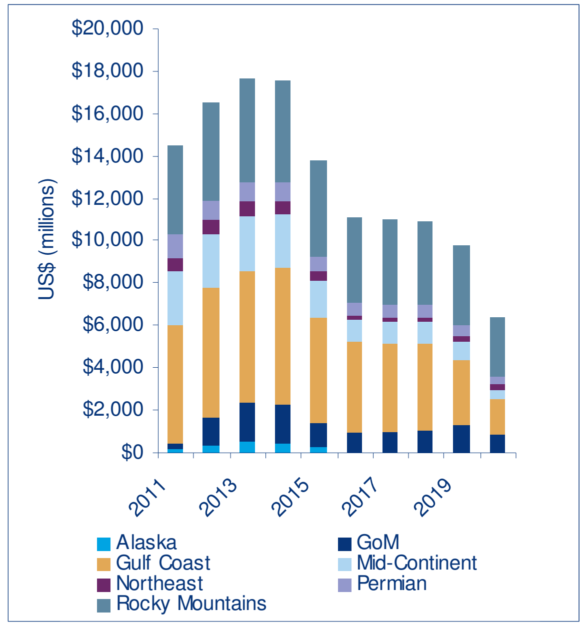
The producing regions of the Gulf Coast (onshore), Mid-Continent, and Rocky Mountains see the largest decrease in investment spend under the proposed tax changes. The lost investment includes drilling in major tight gas and shale plays across all three regions. Many resource plays become challenged outside of the core areas of development where economics are best.

Investment total at risk



Source: Wood Mackenzie – Upstream Service, GEM

Investment total at risk by region



Source: Wood Mackenzie – Upstream Service, GEM

5. Summary

5.1 Summary of findings

Before the proposed tax changes, 55 of the 230 plays and fields that Wood Mackenzie covers in the US are considered marginal and the current tax proposal lowers returns further and increases the number of plays with less than a 15% IRR to 88. Proposed legislation impacts will limit gas development more severely than oil development. Total US production lost could be as much as 3 bcfd of natural gas and 60,000 b/d of oil in 2011. Total investment expected to be spent on the lost volumes equates to almost $15 billion in total upstream investment spending in 2011. This investment and production impact becomes even greater over the coming years if prices do not improve to levels that provide sufficient returns in marginal plays in the US. Total production losses could reach almost 9 bcfd and 250,000 b/d by 2017.

The proposed tax changes put a large resource base at risk in a low gas price environment. Total resources not produced could reach as high as 27 Tcf of gas and 700 mmbbls of oil over the next ten years. Almost half of the gas plays we consider to have future development potential are at risk under the proposed tax changes. The gas plays that become sub-economic are not only great in number, but represent more than 10% of the gas that will be produced over the next ten years.

Direct upstream investment losses will be between $10-17 billion each year in a scenario where prices do not rise to incite drilling. This represents a loss of approximately 10-20% of expected total upstream spending in the US each year.

5.2 Conclusions

In a case where the IDC and the Domestic Production Activities deductions are lost, the proposed changes have been shown to have a material impact on gas assets. This could have a number of implications such as an increase in gas prices, import substitution, fuel substitution, or companies shifting their portfolios to overseas opportunities. These implications are beyond the scope of the study, but Wood Mackenzie expects the US would need higher gas prices to incite drilling or almost all growth potential in the US would be eliminated.

The expansive resource of non-core areas becomes marginal under the proposed tax changes. The average breakeven gas price needed to realize a 15% IRR will shift from $5.40/mcf to $6.00/mcf. The shift in breakevens and the subsequent lower returns in the current environment puts up to 3 bcfd of production additions at risk in 2011 and a total of 27 tcf of gas resource at risk over through 2020. Even the plays that do not fall below the economic threshold yield much lower returns and development could be impacted over the long-term. A typical Marcellus well in Pennsylvania has a typical IRR that drops from 27% to 21% and the prolific Pinedale field of Wyoming has typical returns drop from 29% to 22%. The impact to the oil market is much lower as less than 60,000 b/d are at risk under the proposed changes in 2011.

The producing regions of the Gulf Coast onshore, Mid-Continent, and Rocky Mountains are disproportionately affected by the proposed tax changes. Over $12 billon of the total $15 billion of investment at risk in 2011 is directly related to these three onshore regions. Conventional drilling and many of the emerging unconventional resource plays across the US become sub-economic under our high case.

Wood Mackenzie does not expect the full effect of the tax changes would be realized as 55 of the 88 sub-economic plays already provide a return of less than 15% without the additional tax burden. This reflects current low gas price expectations and suggest volumes impacted could be less than considered in our analysis.

6. Appendix

Variances from our forecast

The high case scenario would require that prices stay at or below $5/mcf after the proposed tax increases come into effect and our "Total At Risk" expectations are a high case. If prices increase or producers are able to hedge at sufficient prices, development will not be impacted as severely as we have estimated. Additionally, the plays that do not fall below the economic threshold yield much lower returns and development could be impacted over the long-term.

Company strategies also vary and companies might require a higher or lower IRR than 15% for investment decisions. Companies can also be motivated to continue drilling without sufficient economics for reasons not considered such as: drilling to hold leases, a portfolio view of drilling, better long-term well recovery and production rate expectations, as well as higher future price assumptions.

Additional consideration

We have assumed that most if not all drilling ceases in a play/field when the IRR falls below a 15% IRR, but companies are currently drilling in plays with sub-15% IRR at our current expectations. Our "Low Case At Risk" assumes that plays that are considered marginal in the current environment see development halted, while all other plays continue development. The "Total At Risk" case assumes development is limited or ceases for the currently sub-economic plays as well as development in the plays that fall below our economic threshold due to the tax changes.

Alaska and the GoM do not see a production impact until 2015 due to the long lead times for investment decisions in these two areas.

The impact for oil investment and production could be greater if the long-term outlook for oil prices falls below $60/bbl.

While oil is highly favoured in the current price environment, the liquids contribution from many of the liquids-rich gas plays is not high enough to offset the additional tax burden. Vertical drilling is challenged by lower returns in plays such as the Cotton Valley in East Texas and Granite Wash of Texas and Oklahoma, as well as other plays across the Lower 48 that contribute to NGL and condensate supply.

The amount of investment loss drops considerably through the 2015-2020 timeframe. This is a function of Wood Mackenzie modelling probable developments. We do not account for technical or 3P reserves, which will require further investment in the later years of our forecast.

"Core" areas are defined as portions of a gas or oil development target that provide superior economics to that of an average well.

Wood Mackenzie's Henry Hub gas price assumptions, in nominal terms, are $5.20/mcf in 2011, $5.45/mcf in 2012, $6.14/mcf in 2013, and $6.54/mcf in 2014, with a long-term inflation rate of 2.0% per annum.

Wood Mackenzie's WTI oil price assumption is, in nominal terms, $87.40/bbl in 2011, $84.00/bbl in 2012, $81.18/bbl in 2013, and $82.81/bbl in 2014 inflating in nominal terms at 2.0% per annum long-term.