PRELIMINARY REPORT ON FISCAL DESIGNS FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

BY
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For

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Section 4.1

Overview & conclusions of modelling Alaska's fiscal design for natural gas

Part 4: Analysis of Alternative Upstream Fiscal Models for Alaska

4.1 Overview & conclusions of modelling Alaska's fiscal design for natural gas

Analysis of Alternative Upstream Fiscal Models for Alaska (Section 4)

This section focuses specifically on Alaska's upstream fiscal design, evaluating how it performs and how it might be modified to optimize Alaska's fiscal revenues from the development of natural gas fields that provide commercial returns to producers. An overview and conclusions of this work is provided in this Section 4.1 with more detail provided in Sections 4.2 to 4.6.

Ten hypothetical fields are defined in terms of detailed gas and oil production profiles and capital and field operating cost profiles (see Section 4.2 for details) and evaluated by applying base-case economic assumptions including: gas and oil price profiles covering a forty-year period, inflation rates and gas and oil transport, tariff and treatment (TT&T) costs to move gas and oil out of Alaska (see Section 4.3 for details). A detailed analysis of the base-case assumptions for each hypothetical field is conducted to establish the relative contributions of each fiscal element to Alaska's fiscal take and to review the commerciality of each field from a producer perspective (see Section 4.4 for details). A comprehensive sensitivity analysis of economic factors (e.g. gas price, gas TT&T, oil price, capex and opex) is presented, together with a sensitivity analysis of the rates applied to the specific fiscal elements of Alaska's fiscal design (see Section 4.5 for details). This sensitivity analysis establishes the relative impacts of variations in gas price, gas TT&T and costs on commerciality, and that the Alaska take is most sensitive to changes in BPT rates and progressivity tax rates. An evaluation and sensitivity analysis of ten different potential mechanisms for a gas progressivity tax (GPT), including the prevailing CPT mechanism as a base case, reveals that the performance of the current progressivity tax could be improved in terms of the revenues it could potentially generate for Alaska (see Section 4.6 for details).

The contents of Sections 4.2 to 4.6 of the study are summarized below.

Ten Hypothetical Fields for Analysis (summary of Section 4.2)

Ten hypothetical fields (five natural gas fields, varying from 0.5 tcf to 10 tcf of recoverable gas reserves with significant condensate yields, and five oil fields varying from 20 million barrels to 500 million barrels of recoverable oil reserves with significant associated gas yields) are developed to evaluate the economic performance and stakeholder-takes of Alaska's fiscal design from the perspectives of the state and producers. The fields are of diverse reserves sizes and sample various ratios of gas to oil (C5+) in order to test prevailing and alternative fiscal designs under a wide range of conditions. The five gas fields are assumed to have condensate yields and also to be progressively impacted over their producing lives by water production. Capital costs for each field are divided into an exploration and appraisal component and into several development components:

Upfront wells and facilities capex
- US$/mcf gas reserves
- US$/barrel NGL reserves
- US$ millions for gas processing/LPG extraction plant (varies according to capacity)

Incremental and late-life components
- US$/boe compression/pumping/work over/sidetrack costs
- US$ millions for decommissioning
- (no costs for carbon capture or re-injection are included)

Operating costs are assumed to have a fixed component (e.g. staff, overheads, planned maintenance and fixed consumables), a variable component (i.e. energy costs linked to capacity and variable consumables), a gas processing component (i.e. charges for gas and liquid throughput) and a transportation tariff component for shipping both gas and liquids out of state. The models assume separate downstream transportation gas and oil costs to take them to their respective markets. These costs are dealt with as tariff, treatment and transportation (TT&T) costs. In the models evaluated it is assumed that TT&T costs are downstream of the point of production and are therefore fully deductible (i.e. expensed in year incurred) for upstream fiscal purposes. These hypothetical fields were evaluated with the aid of an Excel workbook incorporating a wide range of sensitivity cases. The model for each field is structured such that costs, production profiles and economic assumptions (i.e. market prices, escalation and inflation rates) can be easily varied.

The ten field models are evaluated in this study to determine how current fiscal terms for natural gas impact their profitability and Alaska's state take of available economic rent. Sensitivity analysis (e.g. step increases and decreases in gas and oil prices, gas and oil TT&T, capital cost and operating costs) provide insight to the impact of the different fiscal elements constituting the Alaska fiscal design. This insight is used to compare the performance of large to small gas and oil fields from the perspectives of the state and a producer. Alternative fiscal designs with progressivity elements tailored separately for oil and gas provide better fiscal take performance.

Cost components for the models are held constant in real terms at year 0 prices (i.e. 0% per year real escalation) but inflated at 2% per year to provide money of the day (nominal) costs across the field life. In unit money of the day (MOD) terms averaged over the gas fields' lives: the total capital costs incurred vary from US$9.05/boe (small field #1) to US$4.35/boe (large field #5); the total operating costs incurred vary from US$5.97/boe (field #1) to US$2.46/boe (field #5); and, the total gas TT&T costs incurred vary from US$30.68/boe (field #1) to US$32.97/boe (field #5), that is to say roughly $5 per mcf or mmbtu.

A US$4.5 per mmbtu natural gas TT&T tariff and a US$4.6 per barrel oil (C5+) TT&T tariff (both in year 0 dollars) are assumed for the base case in this study. These tariffs are held constant in real terms at year 0 dollars (i.e. 0% per year real escalation) but inflated at 2% per year to provide money of the day (nominal) tariffs across the field life.

Model Economic Assumptions and Sensitivity Variables (summary of Section 4.3)

Economic assumptions for base case models to evaluate the economic and fiscal performance of each of the ten hypothetical fields are specified in section 4.2. The Excel workbook models are structured such that each economic assumption can be easily adjusted to facilitate analysis.

Natural gas prices are escalated from a base-case year 0 starting point of US$ 7.5 per mmbtu (AECO, Alberta hub price). Price escalators applied to the year 0 price are inflation of 2% per year to provide money of the day (MOD) prices across the lives of each field analyzed. An oil price base-case year 0 starting point of US$ 80 per barrel (Alaska North Slope West Coast) is escalated at 2% per year to provide MOD prices across the lives of each field analyzed. The nominal escalations are used to calculate MOD cash flows which are then adjusted for inflation by applying a 2%/year buying power deflator to provide cash flow values in real terms in year 0 dollars (Figure 4.1.1).

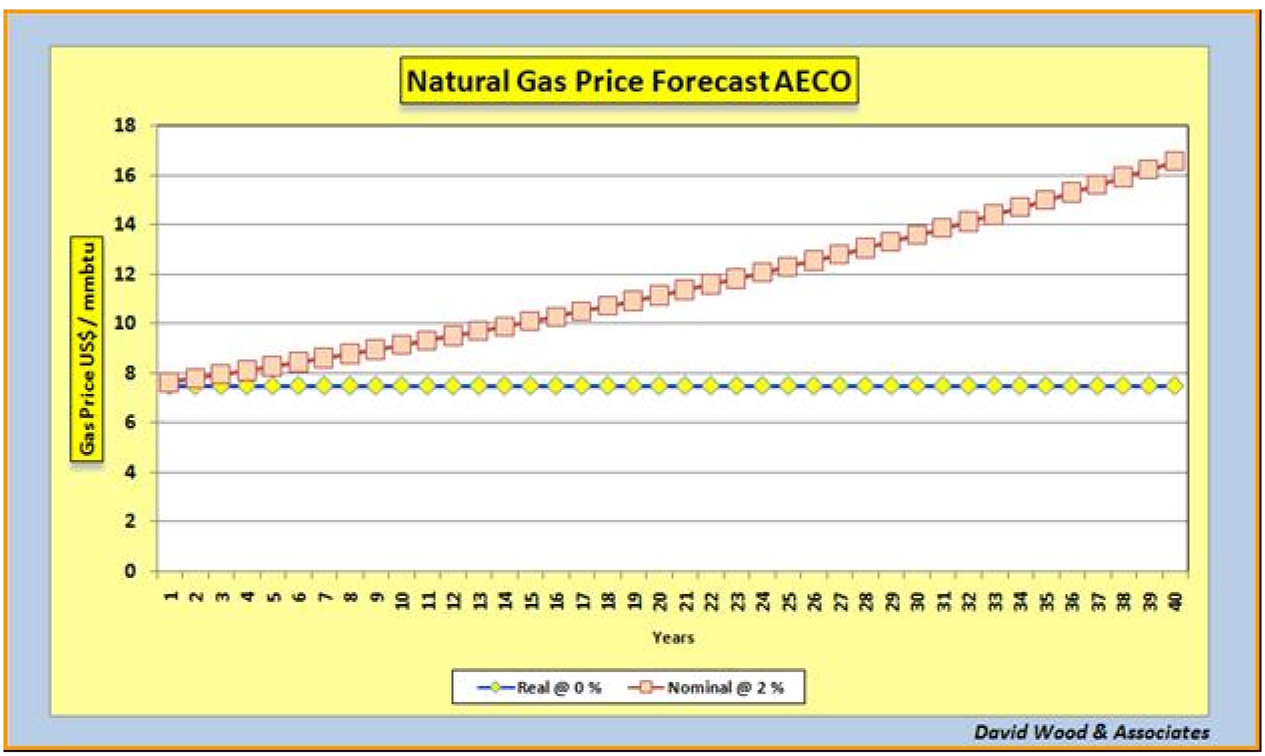

Figure 4.1.1. Base-case natural gas price forecast and assumptions for fiscal models. US$ 7.5 per mmbtu (AECO, Alberta hub price) is escalated at 0% per year real plus 2% per year for inflation.

Production rate, timing (start-up, decline, shut-in) and condensate yields can all be adjusted from the base-case assumptions. Water-cut, its timing and growth rate can also be adjusted for each field base case.

From project value perspectives five variables are identified as the main influences on field profitability excluding fiscal instruments:

- Product prices (gas and oil (C5+))
- Production volumes (gas and oil (C5+))
- Condensate yield
- Gas TT&T
- Costs (capital and operating)

Seven key variables from these categories are selected to build a comprehensive sensitivity analysis model. For example these cases vary year "0" gas price from US$3/mmbtu to US$22.5/mmbtu and gas TT&T from <US$1.8/mmbtu to <US$13.5/mmbtu.

Fiscal Performance of a Large Gas Field (Section 4.4)

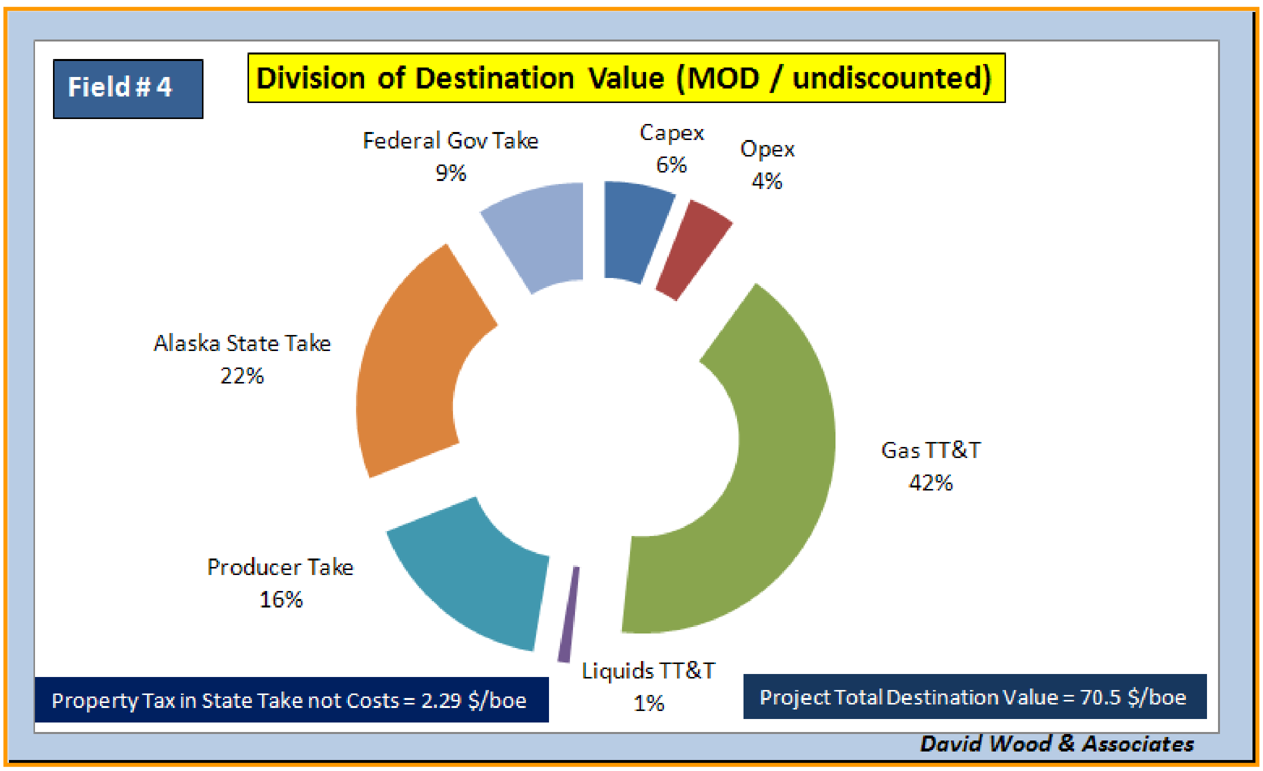

Figure 4.1.2. Division of destination value between parties and costs for gas field #4.

A large 5 tcf hypothetical gas field is used to review both economic and fiscal sensitivities. Similar analysis for all ten hypothetical fields is documented in Appendix 7.5. In the base-case assumptions Alaska takes some 22% of undiscounted MOD destination value over the life of field #4 (Figure 4.1.2), which combined with federal income tax amounts to a 31% total government take of destination value (compared to 16% producer take of destination value and 53% cost component of destination value). For the smaller gas fields (e.g. field #1 and field #2) the total government take of destination value falls below 30% (some 20% to Alaska) because costs take up a larger component of the revenue stream and make the small fields of marginal value to producers. For the large gas field #4 total costs (capex plus opex plus tariffs) amounts to some 53% of destination value, but this increases to some 63% for the smallest field. Producer share of destination value falls from 16% in field #4 to 10% in field #1.

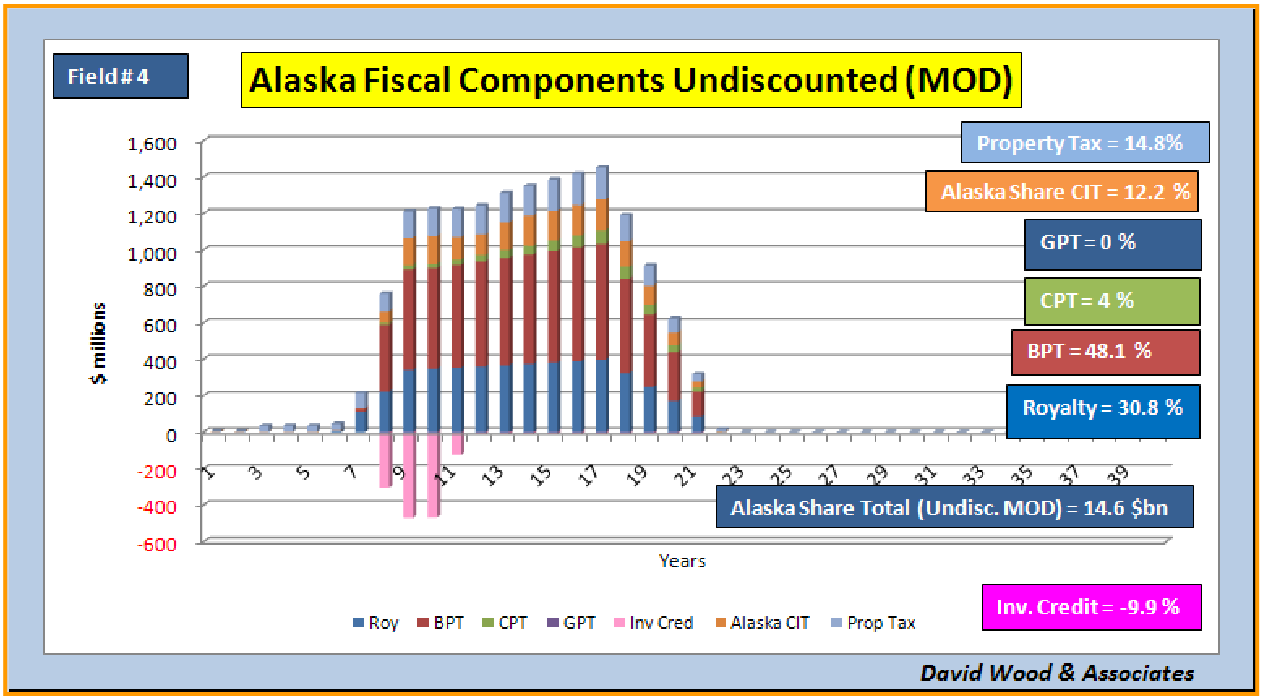

Figure 4.1.3. Alaska's undiscounted annual MOD cash flows for gas field #4 identifying contributions of individual fiscal instruments. BPT amounts to some 48% (or 38% net of investment credits) of Alaska's cash flow and royalty some 31%. The progressivity tax (CPT) amounts to some 4% of Alaska's cash flow. Note the percentages along the right of this figure are percentages that each makes up of Alaska's total take.

For large oil fields Alaska takes some 46% of undiscounted MOD destination value, with the total government taking some 57% of destination value, leaving the producer (excluding costs) some 19% of destination value. Clearly oil fields are substantially more profitable for all parties under the high base oil price assumptions used by the models. Alaska manages to take a larger share of revenues from the oil fields than the gas fields because the combined progressivity tax (CPT) component is structured to provide a higher state take when oil prices are high.

For the larger gas fields total government take of real cash flows discounted at 5% is close to 69%, whereas this figure rises to 74% for large oil fields under the base case assumptions. For the large gas fields, basic production tax (BPT) makes the largest contribution to government take (38% of total fiscal take), followed by royalty (31% of total fiscal take). For the large oil fields the combined progressivity component of production tax (CPT) makes the second largest contribution to government take (32% of total fiscal take), slightly less than basic production tax (BPT at 34.5% of total fiscal take) and royalty (24% of total fiscal take). It is concluded that CPT is very effective at taking a sizeable share of economic rent from oil fields producing under highly profitable market conditions, but quite ineffective at achieving the same outcome for natural gas fields.

For the smaller, more costly gas fields Alaska's take (discounted at 5%) increases to 77% and total government take is essentially 100% (producer NPV@10% real =$0) for those small fields (e.g. field #2). For the oil fields Alaska's take (discounted at 5%) is 60%, with total government take at some 76% on an NPV@10% real basis. Small negative returns occur for the producer with base-case assumptions at a 10% discount rate from the smaller fields (e.g. field #2: Alaska NPV@5% real = US$700 million, and producer NPV@10% real = minus US$0.051 million, IRR real of 8.9%). A loss for the producer versus a $700 million fiscal take for the state highlights the regressive nature of the existing Alaska fiscal design and suggests that fields below about 1 tcf of gas reserves will provide only marginal returns at best for a producer based upon base-case field costs, TT&T costs and destination market value assumptions applied in this study.

Sensitivity analysis: prices, yields, costs & fiscal terms (Section 4.5)

The sensitivity of the economic performance and fiscal contributions of each of the ten hypothetical gas and oil fields modelled in this studied is included in Appendix 6. It is presented as a series of graphs and tables applying a wide range of production, cost, price, liquid yield and fiscal assumptions modifying the base-case values.

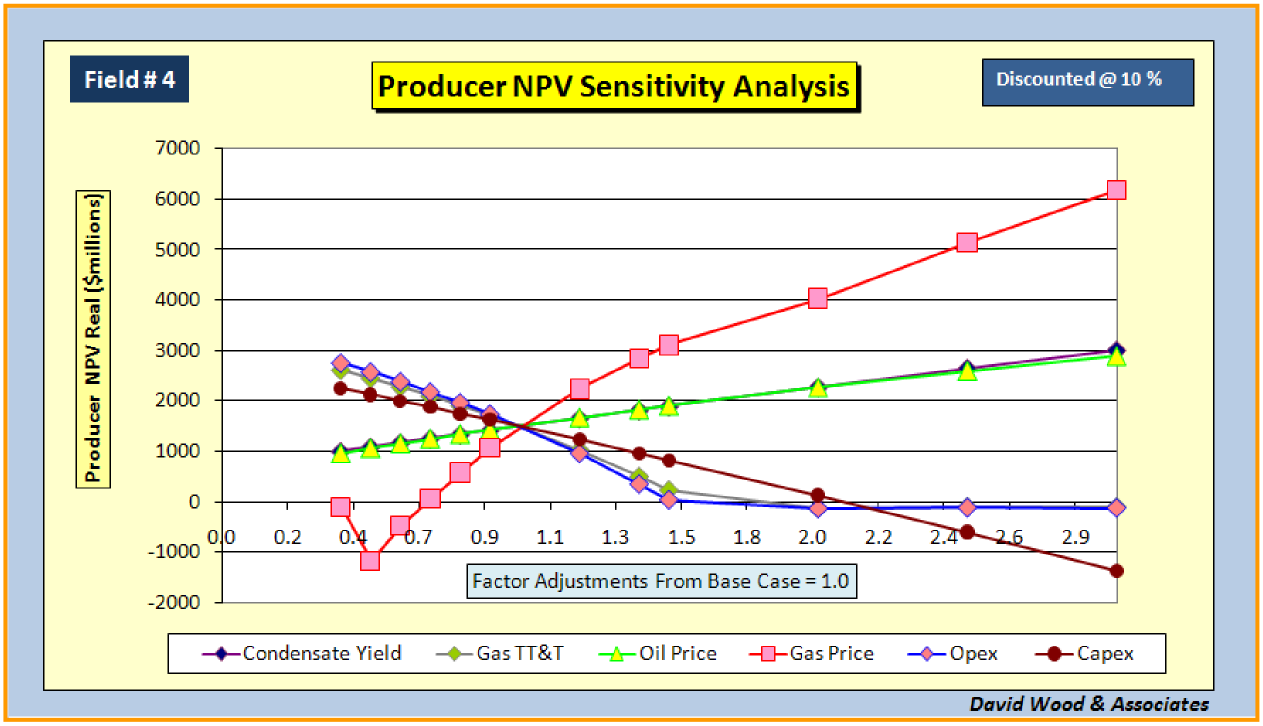

Figure 4.1.4. Spider diagram for sensitivity of producer NPV reveals that of the economic variables analysed natural gas prices have the greatest impact on this variable for gas field #4. Producer NPV is more sensitive to opex and gas TT&T costs than it is to capex. The reason for that is the impact of the investment credit which moderates increases and decreases in capex.

This information makes it possible to evaluate the impact of a wide range of economic and fiscal variables applied to the various oil and gas field sizes and types studied. The analyses for a large (5 tcf) gas field are considered in detail to highlight impacts of changing specific variables. Spider diagrams (e.g. Figure 4.1.4) and tornado charts are used to illustrate the sensitivity trends for several economic metrics. Alaska state take of real cash flows discounted at 5% (state NPV) and producer take of real cash flows discounted at 10% (producer NPV) reveal that natural gas prices have the greatest impact on cash flow. Producer NPV is more sensitive to operating costs and gas TT&T costs than it is to capital costs. The reason for that is the impact of the investment credit, which moderates increases and decreases in capital expenditure from the Producer's perspective. The structure of the CPT fiscal element means that at very high oil prices further increases in prices provide only moderate increases to Producer cash flow.

The impact of varying the rates and thresholds applied to fiscal instruments involved in Alaska's fiscal design for the large gas field reveal that on the downside reductions in BPT rate have the biggest negative impact on total government take. As gas price decrease cash flow also declines and eventually disappears and the project makes a loss. However, the royalty component (based upon point of production value) still accrues to the government take, resulting in the government share of cash flow in percentage terms increasing in low gas price environments. This increase in government take as projects become less profitable identifies regressive characteristics in Alaska's fiscal design due to royalty, property taxes and production tax floor mechanisms (see Section 3.1).

Upside sensitivities suggest that gas prices are the dominant factor for modest increases above the base case. However, if the first rate of the combined progressivity tax (CPT) is increased from its base case value of 0.4% to above 1%, that tax becomes the most significant in increasing government take. CPT is shown to be highly sensitive to the value of its first rate (i.e. 0.4% in the statute and base-case model) if that rate is increased to above about 0.75%. Reducing the first CPT threshold value for CPT below its statute value of US$30/boe also has a significant positive impact on total government take.

Alaska Gas Progressivity Tax (GPT) – Alternative Mechanisms (Section 4.6)

The prevailing CPT progressivity fiscal element and nine alternative gas progressivity tax (GPT) fiscal designs for a progressivity tax are considered and evaluated with another series of sensitivity cases. The sensitivity cases applied to each of the ten hypothetical fields are presented in Appendix 7. The sensitivity case information makes it possible to evaluate the impact of each of the ten mechanisms on the wide range of oil and gas field sizes and types. The nine alternative mechanisms for gas progressivity considered are driven by a gas PTV calculated separately from an oil PTV being used separately to calculate a GPT and OPT progressivity component to add on to BPT. The ten gas progressivity mechanisms considered are:

- Mechanism No. 1 CPT: 2008 Rules (based on combined PTV/boe calculation).
- Mechanism No. 2 GPT: Gas CPT Rules (separates gas and oil PTVs but uses the same PTV/boe scales as Mechanism 1 to calculate GPT and OPT).
- Mechanism No. 3 GPT: 33% Gas - CPT Rules (CPT only applied to 33% of gas PTV).
- Mechanism No. 4 GPT: Gas PTV (based on Gas PTV/mmbtu).
- Mechanism No. 5 GPT: R-Factor (cumulative PPV less royalty divided by cumulative project gas costs).
- Mechanism No. 6 GPT: IRR (IRR of cumulative PTV).
- Mechanism No. 7 GPT: Cum Res (cumulative gas reserves produced).
- Mechanism No. 8 GPT: Gas Prod (annual gas production quantity).
- Mechanism No. 9 GPT: Cum Gas PTV (cumulative gas PTV).
- Mechanism No. 10 GPT: Cum Gas PTV (as for Mechanism No.9 plus allowances tailored to counter regressive elements in the fiscal design).

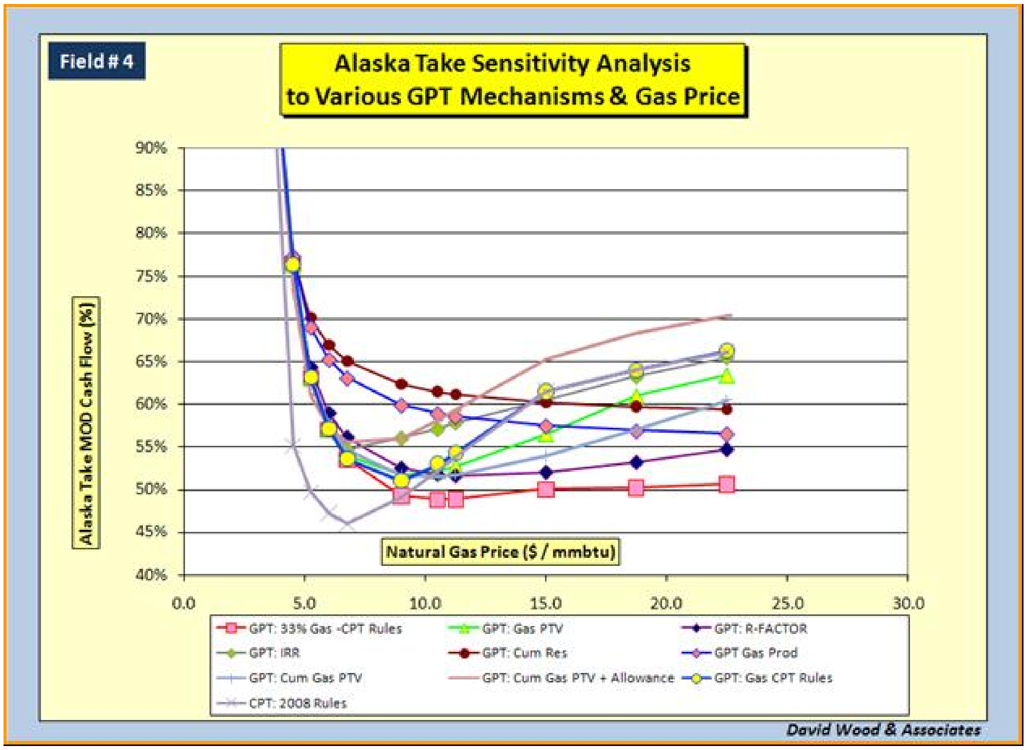

Figure 4.1.5 Impact on Alaska's take of MOD undiscounted cash flow of variable gas price on the ten GPT mechanisms for gas field #4.

As well as displaying progressive trends in upside sensitivity cases all the mechanism still display regressive effects of the fiscal design overall. This is due to the impact of the royalty, property tax and production tax floor in low gas price or high cost situations. However, some of the GPT mechanisms minimize its impact, particularly Mechanism 10, which includes tailored allowances for the producer in the least profitable phases of field development and production to specifically counter the regressive elements of the Alaska fiscal design.

Sensitivity analysis is presented in detail for the 5 tcf gas field #4. The most striking behaviour revealed by the sensitivity trends is for Mechanism No. 1 "CPT 2008 Rules" (Figure 4.1.5). Its fiscal take is substantially lower at low gas prices than all the other mechanisms which calculate GPT separately rather than from a combined PTV $ per boe value. At low gas prices the gas revenue stream not only fails to trigger the CPT threshold of US$30/boe PTV value but its low value Btus inflate the boe denominator and effectively dilute the CPT that oil (C5+) might have paid at high crude oil prices.

In order of sensitivity to capital costs are:

Mechanism No. 6 GPT: IRR (most sensitive)
Mechanism No. 5 GPT: R-Factor
Mechanism No. 10 GPT: Cum Gas PTV + Allowance

These mechanisms behave progressively. On the other hand mechanisms driven by cumulative PTV only, cumulative reserves and annual production behave regressively. These are:

Mechanism No. 7 GPT: Cum Res
Mechanism No. 8   GPT: Gas Prod
Mechanism No. 9   GPT: Cum Gas PTV

The other PTV $/unit mechanisms are essentially insensitive to capital costs.

Similar trends are shown in the sensitivity analysis of the smaller gas fields, but Mechanism No. 10 in such cases provides (except for CPT Mechanism No. 1) the minimum percentage take of profits for Alaska in those less profitable fields (i.e. it is more progressive in terms of responding to capital costs). In all cases the IRR mechanism provides Alaska with the greatest take in the lowest unit cost projects as these achieve the IRR thresholds very early in their cycle.

Operating cost sensitivity analysis also reveals regressive impacts of the Alaska fiscal design in high cost projects.

With the goal of a more progressive system in mind the study of alternative CPT and GPT mechanisms suggests that modifications to the Alaska fiscal design should focus on three issues associated with a gas progressivity fiscal instrument:

> 1) Calculate separate PTV streams for gas and oil (C5+) to enable progressivity components of production tax to be tailored specifically to gas streams (i.e. GPT) and to oil (C5+) streams (i.e. OPT using the mechanism introduced in 2007, which is effective and does not require amendments).
>
> 2) Select a driver and structure for GPT that provides Alaska with larger takes from the most profitable fields commencing at a lower PTV $/mmbtu than the prevailing CPT mechanism.
>
> 3) Construct a GPT mechanism that is less regressive in high cost or low price situations, particularly for smaller fields, by providing allowances to producers that moderate the impact of the regressive components of the Alaska fiscal design.

If it is decided to fix the problems with the existing CPT mechanism (i.e. as mentioned above, at low gas prices the gas revenue stream fails to trigger the CPT threshold of US$30/boe PTV value but its low-value Btus inflate the boe denominator and effectively dilute the CPT that oil (C5+) might have paid at high crude oil prices) by applying a simple change to the existing Alaska CPT progressivity mechanism, then adapting Mechanism No. 4 could offer such a solution. Separate OPT (using the thresholds and rates of CPT) for an oil (C5+) and GPT mechanisms for gas could be adapted. The GPT could apply one of several possible configurations of initial thresholds and rates for Mechanism No. 4, for example those shown in Figure 4.1.6, to significantly improve performance of a gas progressivity tax.

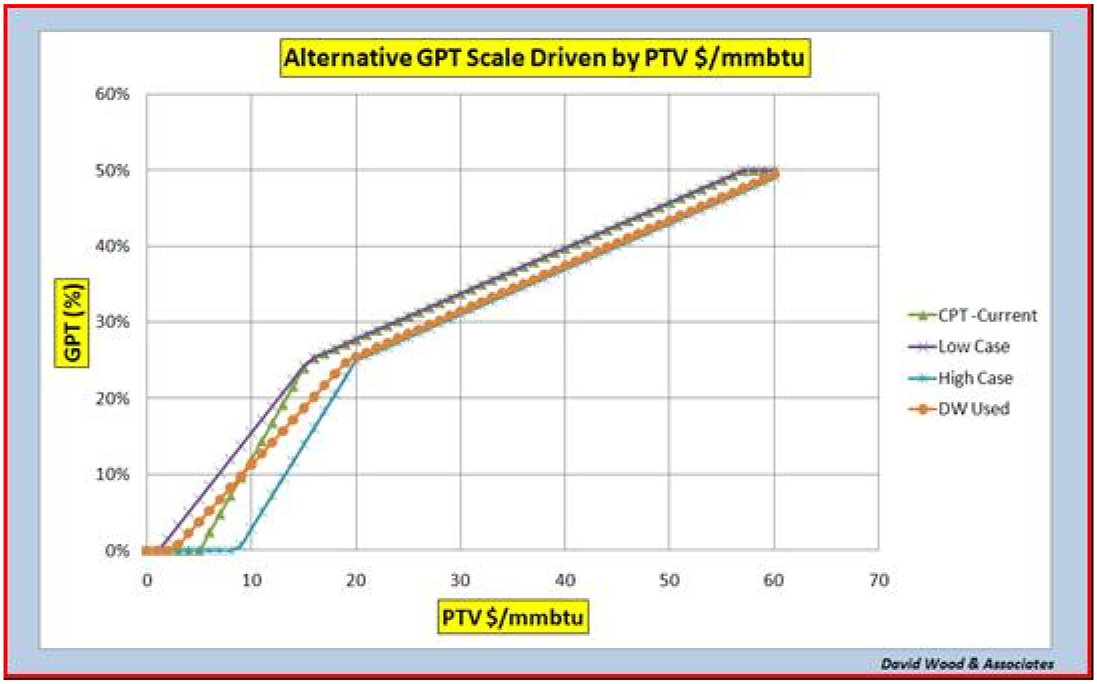

Figure 4.1.6 Alternative configurations for GPT Mechanism No. 4, with four distinct rates and thresholds applied. "CPT-current" refers to the prevailing CPT mechanism expressed in PTV $/mmbtu terms with the initial threshold at which GPT commences of gas PTV $5.0/mmbtu. "Low Case" refers to a mechanism with the low initial threshold at which GPT commences of gas PTV $1.135/mmbtu. "High Case" refers to a mechanism with the high initial threshold at which GPT commences of gas PTV $8.7/mmbtu. "DW Used" refers to the mechanism modelled by this study with the an initial threshold at which GPT commences of gas PTV $2.5/mmbtu, but with the GPT rate increasing more slowly than the other configurations.

Rather than adopt such a simple approach this author suggests that some fiscal allowances/incentives also be considered to mitigate the regressive elements in the current fiscal design which significantly limit commerciality for gas field developments with less than about 1 tcf of reserves. Making smaller gas fields commercial and extracting more value through progressivity from high-value gas production should, in the opinion of this author, be the objective of the design of a gas-focused progressivity (GPT) fiscal element, not just a quick fix that enables the CPT mechanism to handle gas.