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

BY
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For

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Section 1.0: Executive Summary

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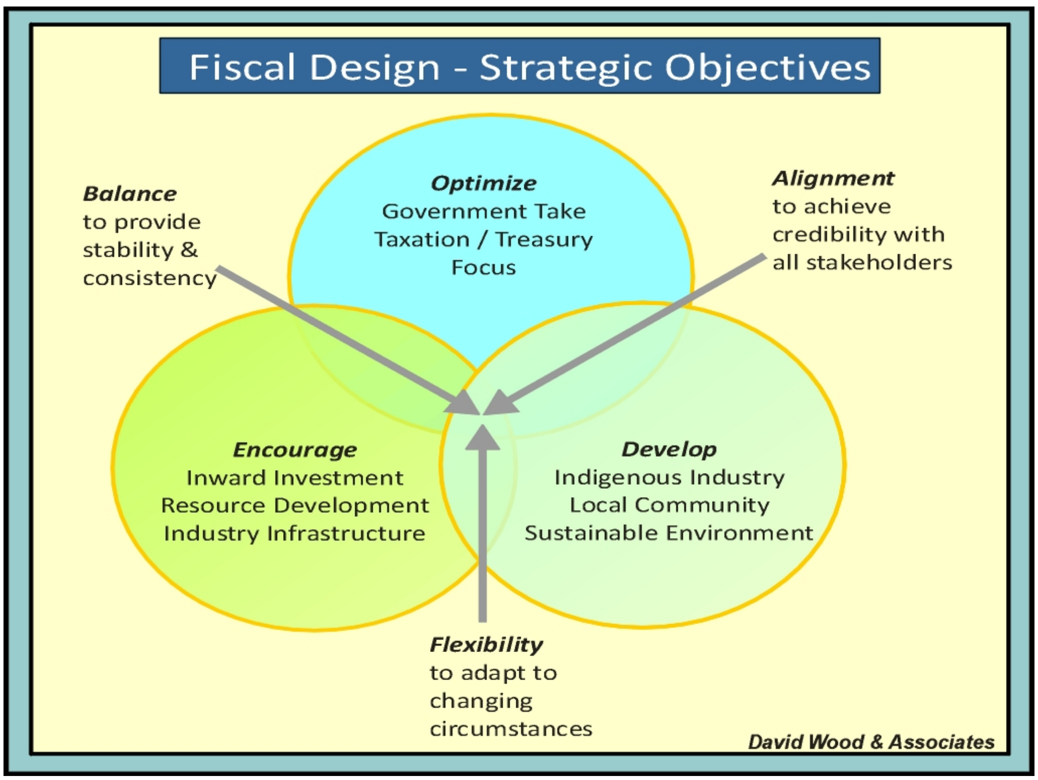
The three key strategic objectives and drivers considered to influence upstream oil and gas fiscal designs are:

- maximizing government take
- maximizing local jobs, services and suppliers
- maximizing investment and work program

In reality most countries are attempting to balance all three strategic objectives in their upstream fiscal designs and therefore select fiscal instruments that optimize all three.



This study explores all three strategic objectives from the general attributes of fiscal designs implemented worldwide by many of the major gas exporting nations and from a more quantitative analysis of Alaska's prevailing upstream fiscal regime. A clear consensus on the strategic objectives of fiscal design is considered essential in conducting successful fiscal reform.

Structure and Contents of the Report (Section 1.1).

This report is divided into eight sections.

Section 1 (this section) provides an executive summary and overview of the report and its analysis.

Section 2 discusses natural gas fiscal designs in generic terms concerning their objectives and the fiscal elements involved. A review of worldwide gas markets and the context in which major long-distance gas supply chain projects compete sets the scene for the more specific fiscal issues confronting natural gas. The options for extracting appropriate shares of economic rent from upstream projects are explored in the context of highly volatile market conditions and for a range of uncertainties concerning recoverable reserves and development and production costs. A review of how the expectations of producing companies and nations have changed with respect to fiscal stability concludes that governments of politically stable countries are no longer expected by equity investors to fix all the fiscal elements of their fiscal design for periods of decades. However, it remains important for governments and fiscal authorities to demonstrate a commitment to promoting an environment of long-term commercial viability. Demonstrating consistency, and garnering a reputation for fiscal stability and credibility, can provide nations with a competitive edge in competing for and securing multibillion-dollar investments for projects that will not pay back and provide investors with a positive return on their investments for a decade or more.

The issue of guaranteeing fiscal stability in Alaska (either upstream or downstream) has raised strong opinions for and against any set term, ranging from 10 to 35 years for those who support fixed terms. Although investors would clearly prefer absolute fiscal stability from governments (in order to reduce their long-term project risks), it is becoming more difficult internationally to obtain such commitments with volatile energy markets and governments around the world recognizing how much value could be sacrificed over decades by making such commitments. The more progressive and flexible the fiscal designs that are applied to gas supply chain revenue streams, and the stronger the commitment made by governments to promote a commercially attractive environment, the more likely investors are to commit investments without receiving cast-iron legislation or contractual guarantees of fiscal stability.

Fiscal designs that are not commercially oriented (i.e., do not recognise the need for producers to make commercial returns on the risk and investment capital they invest) find it more difficult to secure equity and debt investment (based on the higher risks and uncertainties for investors and lack of long-term alignment and trust between government and investor on what makes a successful project). Major investors and IOCs only engage in such arrangements on the expectation of access to very large and low-cost reserves. As recent outcomes to some large international projects show (e.g. Sakhalin-II in Russia and Kashagan in Kazakhstan), they are likely to fail to provide investors with high returns on their investments in the long term, but may be spectacularly “successful” for a time from a government’s perspective measured purely in terms of fiscal take, depending on market forces. Track record and credibility with investors is important. Governments that pursue fiscal designs that undermine long-term project commerciality and the returns expected by investors when they initially committed to make the investments will likely struggle to compete for future investments if, or when, funding and access to global investment capital and new technology becomes more competitive, as it inevitably does from time to time.

Does this mean that IOCs going forward are likely to put less emphasis on fiscal stability as a consequence of these developments, or will they try even harder to achieve fiscal stability? IOCs are likely individually to pursue a diverse range of strategies in this regard. When arrangements are via production-sharing contracts, fiscal stabilization and adaption clauses are likely to remain important negotiating items, sought where possible, but with lower expectations from investors that they will not be diluted at some stage over the life of an asset. There is now a realization by IOCs that contractual stability clauses can be circumvented and manipulated by resource-rich and cash-rich producing states, putting pressure on producers to accept harsher fiscal terms at certain times. However, there is also the belief amongst IOCs that they are in a stronger negotiating position with these clauses (plus provisions for international arbitration) than without them. This means that companies investing in large international upstream projects are likely to place greater emphasis on long-term relationships and strategic joint ventures with governments and their NOCs, working in several different countries (e.g. strategic alliance between Gazprom of Russia and ENI of Italy). Such alignments demonstrate that both parties are bringing expertise, risk taking and/or financing to projects that could not be easily achieved without both of them involved, and in return an equitable share of returns is divided between them.

Fiscal designs and combinations of fiscal instruments are summarized in Section 2 for 23 countries and regions with actual or potential gas exports. Twenty-five fiscal instruments and issues that should be given consideration when formulating an Alaska natural gas fiscal design, or focusing the fiscal design in a particular strategic direction, are identified and issues associated with implementing them are outlined. A ranking of those instruments in terms of their ability to facilitate investments and development of Alaska natural gas projects is proposed.

The need in certain circumstances to integrate upstream and downstream fiscal designs is also important for Alaska. Whether upstream producers are involved or not as equity investors in the gas line as it is currently envisaged, going forward there are likely to be requirements to build gas processing plants, gas treatment plants (e.g. NGL, LPG and LNG), and potentially gas storage facilities, CO_2 sequestration projects, connecting or spur gathering pipelines, local distribution infrastructure, etc. These will go beyond the defined scope of the initial construction of the gas line and the upstream field developments under the terms of the Alaska Gasline Inducement Act (AGIA). Gas producers may require such incremental infrastructure and be prepared to fund its construction, in order to enable commercial production from their upstream developments and to perhaps tie in the field developments of others. This could lead to overlap and integration requirements of upstream and downstream infrastructure and requests by investors for exemptions from third-party access rules clearly specified under federal regulations and supported by the AGIA.

Section 3 provides a detailed description of Alaska's prevailing fiscal design and the calculation mechanism of each of the component fiscal instruments, including a single-period worked example. The status of Alaska's natural gas reserves and likely distribution of yet-to-find resources between state and non-state lands highlights the importance of several regions. The fiscal elements contributing to the state's fiscal take from non-state lands are identified.

Section 4 provides an analysis of Alaska's existing fiscal design and the performance of the specific fiscal instruments involved. It uses ten hypothetical yet-to-be-developed fields (five gas fields and five oil fields), together evaluated with an Excel workbook model to explore the fiscal takes from both the perspective of the state and the producing company. The fields are of diverse sizes and types (i.e. NGL yields) to test the fiscal design under a wide range of conditions. A comprehensive and systematic series of sensitivity analysis cases are presented in summary and evaluated in Section 4. These sensitivity cases evaluate the performance of Alaska's fiscal design under varying economic conditions and establish the variables to which fiscal returns are most sensitive. A large 5 tcf hypothetical gas field is used to review both economic and fiscal sensitivities. These models highlight three problems applying the current progressivity tax to natural gas revenue streams:

1) By dealing with gas and oil as a combined boe revenue stream the production tax value per-unit boe can become significantly reduced by the gas stream when gas destination market values are low, even though oil destination market values are high.

2) Tying the production tax floor to value per-unit boe for the major fields as Alaska does can also lead to anomalies. If gas prices are relatively low and a producer is making a large investment, the production tax floor may extract a higher value per-unit boe PPV burden than anticipated.

3) The boe threshold at which progressivity tax becomes payable is set too high for natural gas and could shield non-associated gas fields from paying significant progressivity tax until very high PTV/boe values are achieved.

Establishing a progressivity mechanism for gas in the near future that starts to extract fiscal revenues from natural gas at a more realistic PTV value per mmbtu, while at the same time shielding gas fields in less profitable economic conditions or stages of development from progressivity payments, would avoid the need for the state to adjust the boe-based progressivity terms once major new gas production is established through a gasline.

Ten alternative fiscal designs for a gas progressivity tax (GPT) are proposed and evaluated expanding the sensitivity cases for the hypothetical fields to do so. Suggestions are made to make a future Alaska GPT more progressive and more palatable to investors by combining it with fiscal incentives targeted at reducing the state take during the early years of a project.

Section 5 presents the conclusions of the study.

Section 6 is a bibliography that documents materials referred to and source materials used in producing the report.

Section 7 compiles supporting information and analysis. Appendices 1, 2 and 8 document the agreed scope of work, deliverables and David Wood's resume. Appendix 3 documents details of the fiscal designs of the 23 countries and regions capable of producing large-scale gas resource projects. These fiscal details are summarized for the 23 countries and regions in Section 2.5. Appendices 4 to 7 compile detailed evaluation results from the modelling conducted for Section 4, in the form of graphs and tables, for the ten hypothetical fields. Detailed sensitivity results displayed as spider diagrams and other charts identifying progressive and regressive fiscal elements of the Alaskan fiscal design are included in Appendices 4 to 7.

Section 8 provides copies of PowerPoint slides from a presentation summarizing the main conclusions of this report delivered to the Alaska legislature in December 2008.

Competitive Natural Gas Markets Influence Fiscal Design (Section 2.1)

There are three major natural gas markets worldwide (OECD Asia, Europe and North America), and natural gas imports are set to rise substantially over the next twenty years in all three markets with significant growth also in China and India. Global demand for gas is outstripping supply, particularly in liquefied natural gas (LNG). Although there are no global benchmark prices for natural gas, prices are at unprecedented high levels and arbitrage opportunities have led to short-term prices in one regional market influencing prices and supply to other regional markets. Tens of billions of dollars are being sunk into capital infrastructure projects focused on expanding and developing new gas supply chains to the three main regional gas import markets.

Most gas traded internationally is sold on long-term contracts on pricing mechanisms indexed primarily to crude oil but also in some cases involving petroleum fuel products or competing energy fuel prices (electricity, coal). This contrasts with the United States where natural gas is primarily sold on a short-term basis indexed to gas hub benchmark prices.

Such forecasts indicate that when Alaska gas finally reaches Lower 48 gas markets it will probably be competing in price and volume terms with both indigenous conventional and non-conventional gas (coal-bed methane and shale gas), much of that traded on a short-term basis indexed to pipeline gas, and imported gas in the form of LNG, much of it traded on longer term contracts. Trinidad currently dominates LNG imports to the U.S. because of its closer proximity and lower shipping costs than rival LNG suppliers. New LNG supply chains recently commissioned (Egypt, Norway, Equatorial Guinea) and others in development, notably from Qatar, Russia (Sakhalin via Mexico), Indonesia (via Mexico), Angola, Libya, Peru and expansions in Nigeria and Algeria will compete to supply the substantial new LNG import capacity coming on stream in the U.S. It is imported gas from such sources that Alaska gas will need to compete with in terms of destination market price and security of supply.

Many LNG supply chains to the U.S. involve long distances and significant shipping costs. They also involve supply countries imposing increasingly tougher fiscal terms on their liquefaction projects. These projects, like Alaska, will have high breakeven delivered gas prices and require long-term contracts with buyers to underpin their capital investments. It is the flexibility of LNG suppliers to potentially switch their supplies between markets to capture periodic demand premiums that provide them with some commercial advantage over a gas pipeline supply chain from Alaska to the Lower 48 states that is locked into U.S. gas market and gas price risks. Many of the more-recent LNG contracts have destination flexibility clauses included. These were originally negotiated by buyers wishing to redirect cargoes, but more recently sellers also have recognised there is significant value in having the ability to re-direct some cargoes to higher-priced markets at any given point in time.

Fiscal Designs and Instruments (Section 2.2)

There is a diverse range of fiscal designs implemented worldwide which employ many fiscal instruments that attempt to optimize divisions of economic rent to meet government objectives. Mineral-interest (concession) and production-sharing (PSA) agreements dominate the fiscal designs, with the former favoured by OECD and more-developed nations, and the latter favoured generally by developing nations. Some countries operate more than one system, and rates applied to specific fiscal instruments are varied to adjust to changing conditions. Fiscal designs in most countries are therefore dynamic and evolve over time to adjust to a wide range of circumstances. Although PSA mechanisms are inappropriate for Alaska, some of the fiscal elements applied in certain countries to PSAs do have some relevance to potential future gas-focused fiscal designs suitable for Alaska. This study therefore gives due consideration to countries with large gas export potential that operate PSA fiscal systems.

Evaluating the magnitude of fiscal payments to governments only in term of percentage “take” of revenues associated with a particular fiscal design usually fails to take into account:

- Non-fiscal terms, risks and issues that influence project value.
- Field size expectation and environment.
- Time-value issues impacting revenues and costs differently.
- Flexible scales and triggers for specific fiscal elements.
- Variable market conditions (oil and gas prices, demand).
- Country track records in respect of fiscal stability.

Distinguishing whether a particular fiscal design or instrument is progressive or regressive is important in evaluating its overall performance and attractiveness. A progressive fiscal system has two requirements: (1) as cash flow and net values increase, either due to lower costs or higher destination market revenues derived from higher product prices or volume sales, a government’s fiscal take in percentage and absolute terms also increases; (2) as project cash flows and net values decrease, however, either due to higher costs or lower revenues derived from lower product prices or volume sales, a government’s fiscal take in percentage and absolute terms should also decrease. Some governments interpret progressivity only in terms of requirement (1) and ignore requirement (2). This is a mistake in making systems that are attractive to investors with flexibility rendering them commercially viable over a wide range of challenging conditions.

Regressive systems have the opposite attributes. Upfront bonus payments, royalties, production and revenue-based taxes, and floor rates for taxes linked to revenues rather than profits, are all regressive elements widely involved in fiscal designs. Taxes based on project profitability (R-factors, cumulative revenues/cumulative costs, IRR, and prices) are more progressive. Alaska's recently introduced progressivity tax component is unique worldwide, and does perform as a progressive element targeting boe revenues within an otherwise generally regressive fiscal regime. Regressive elements in a fiscal design can be offset, at least in part, by offering tax credits or periodic tax holidays or rebates during the early, pre-payback periods of upstream projects. There are many other specific upstream commercial issues that require consideration in assessing performance of upstream fiscal designs. Such issues that can impact contract or project values and returns are identified and discussed in Section 2.2.

Fiscal Stability (Section 2.3)

It is perhaps naïve of the oil and gas industry to expect stability of fiscal terms and sanctity of contract with governments when there is so much volatility and uncertainty permeating almost all other facets of the industry. Nevertheless, even the most stoical of observers have been surprised by the pernicious and innovative nature of strategies employed since 2003 by several governments to challenge and erode either contractual or fiscal value of international oil and gas projects.

There are five main aspects to fiscal instability:

1. Fiscal tightening with increased royalty and/or tax rate and/or removal of tax incentives applied to new leases and licenses to be signed, but not applied to contracts or leases that had previously promised fiscal stability.
2. Changes as for Point 1, but applied going forward to existing leases, licenses or contracts, which though they may or may not have had some guarantees of fiscal stability issued with them by earlier governments may have led producers to believe at the time of signing that the fiscal terms would be more or less maintained over the life of the fields developed within them.
3. Changes as for Point 1, but applied retrospectively to existing leases and production, which may or may not have had some guarantees of fiscal stability issued with them by previous governments.
4. Partial expropriation with part of the equity ceded to an NOC under a forced sale at a price below fair market value or through leveraged renegotiations of existing rights under contract or lease.
5. Outright nationalization of the asset. There has been a correlation between the number of oil and gas asset expropriations and oil price spikes.

In Section 2.3 recent fiscal changes of each type are discussed with instability in several countries described in some detail (i.e. Kazakhstan, Russia, Nigeria, Bolivia, Angola, Trinidad & Tobago, Venezuela, UK, India, Canada and the U.S. Some of these cases suggest that fiscal stability clauses and guarantees in PSA contracts do not offer complete fiscal stability, whereas, five years ago, they were thought to do so.

The changing landscape and rules concerning fiscal stability and producers' expectations is due to a number of issues, not just oil and gas prices. Changing relationships between IOCs, NOCs, service companies and governments and more power and wealth in the hands of upstream producing nations are also factors. As recent events have shown, PSCs with fiscal stability clauses can be manipulated by persistent government pressure to increase the government's fiscal take. Clear statements reiterating fiscal design strategy, objectives and intent, such as those made by Norway (see Section 2.5), are perhaps worth more in the long term than limited or qualified guarantees of fiscal stability. The consequence for Alaska is that it can no longer realistically be expected to guarantee in law or by contract long-term fixed fiscal terms over the project life of a pipeline shipping gas out of state and the upstream projects associated with it.

Alaska offers gas customers and producers much lower political risk and more security of supply than many of its potential competitors. It can also offer investors more confidence in a commercially oriented fiscal regime without having to offer onerous long-term guarantees of fiscal stability fixing the rates of all elements of a fiscal design for decades. Few countries now offer or honour guarantees formally established in contract or law for long-term fiscal stability terms. As a consequence producers tend to place higher value on the political stability and fiscal attractions of a free market system for projects based in North America. This has been demonstrated by investments in Canadian oil sands and tight gas and shale gas projects throughout North America in recent years.

Producers are undoubtedly more willing to commit large long-term investments in regions where the government has a track record of fiscal consistency and stability (whether it is guaranteed or not). The 2006 and 2007 fiscal changes introduced by Alaska substantially increased its fiscal take and to an extent means that Alaska's fiscal credibility is somewhat tarnished from the perspective of many IOCs and is probably in need of some rehabilitation. The introduction of a commercially credible fiscal design for natural gas with tough but fair progressivity elements, offset by time-limited investment credits and fiscal allowances that reduce the impact of existing regressive elements in the fiscal design (i.e., royalty, property taxes, production tax floor and potential taxes on undeveloped reserves), and coupled with a reassuring fiscal strategy statement (to IOCs) of the state's intention to promote long-term commerciality for gas resource development, could, in this author's opinion, provide the necessary rehabilitation of Alaska's fiscal credibility. This could be done without the need to offer legislated, long-term fixed rates for all fiscal elements to those investing in a gas line. The offer of some long-term guarantees of fiscal stability would also undoubtedly help persuade some IOCs to invest (or invest more) in long-term/long-payback infrastructure projects, such as the proposed gas pipeline. However, this author does not believe that the absence of such guarantees will preclude substantial infrastructure investment commitments, but if Alaska elects to offer fiscal guarantees to upstream investors it should endeavour to extract substantial reciprocal commitments from the IOCs. For example, if fiscal stability is to be offered to those producers investing in the gas pipeline and/or committing gas to fill its first-phase delivery capacity, one option is for this to be done in such a way that the state takes a larger share of upside profits (i.e., should high project margins materialize an effective gas progressivity tax could be applied) and further that the state is provided with some protection from reduced margins in periods of low prices, significant capital cost and schedule over-runs or low market demand (i.e. producers accept the need for reinforced regressive elements to protect the state from downside fiscal risks).

Fiscal designs for long-term, high-cost upstream investment projects have to consider how best to sustain commerciality during periods of sustained low prices as well as ensuring appropriate distribution of economic rent in periods of very high prices. They have to do so by appropriate choice of flexible and progressive upstream fiscal instruments, integrated with fiscal returns from downstream infrastructure that are able to optimise fiscal values derived from transparent long-term gas sales agreements with terms conducive to establishing unambiguous price discovery for natural gas and the full range of NGL products extracted from that gas at various points along a very long and multi-national supply chain.

Long-term uncertainties about how natural gas will fit within primary energy supply strategies and energy mixes (e.g. politically influenced decisions to make concerning future fiscal incentives to build more nuclear and renewable power plants instead of natural gas-fired power plants) also impact upstream fiscal design. Global concerns over long-term sustainability of supply and greenhouse gas (GHG) emissions for all fossil fuels mean that additional costs either in the form of carbon taxes (a cost on production), emissions cap-and trade mechanisms or carbon sequestration infrastructure (capital investment) may be imposed on the gas and oil industry. If fiscal systems extract too much economic rent upstream, their projects are forced to charge high delivered prices that may be uncompetitive with alternative fuel options, particularly coal-fired and nuclear power plants and gas-fired power plants fed by local unconventional gas supplies derived from within the destination market.

Fiscal design in the upstream sector should not be considered in isolation of the downstream gas supply chain (which includes gas treatment, storage and multiple NGL offtake points), market issues and consideration of competing supply chain capabilities.

Division of Economic Rents (Section 2.4)

The important distinction between government revenue take and government profit take is clarified and expressed diagrammatically (see Figures 2.4.1 and 2.4.2). Distinctions between takes expressed in discounted and undiscounted terms usually show a government to have a higher take of discounted than undiscounted profits or revenues. This is because of the high upfront capital investment made by producers, but not required of governments. On an undiscounted basis government takes of profits vary between about 40% and 98% in worldwide upstream agreements. It is the combination of many fiscal and economic elements that determine actual government take, and in progressive and flexible fiscal designs singular examples of government take percentages are meaningless unless identified with a specific oil and gas prices and cost burdens.

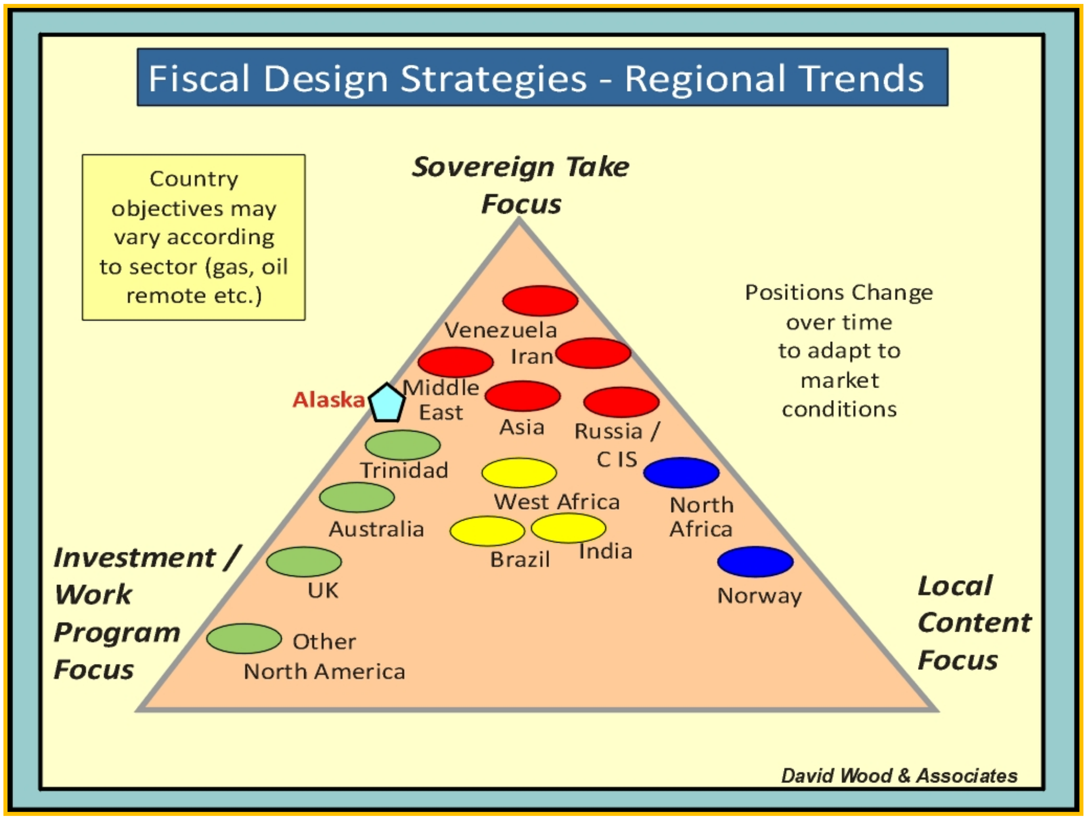
A 2007 GAO study compiled government take of revenue percentages for many countries based on several studies conducted over the past decade. These are tabulated for comparison in Section 2.4.

Petroleum projects are exposed to a wide spectrum of risks and opportunities. Certain fiscal elements involve more risks for governments than companies (e.g. taxes driven by profits and rates of return), but they also open up opportunities. Fiscal design in the upstream oil and gas industry is intimately associated with risk versus reward assessments and tradeoffs, and they are not always easy to implement.

Fiscal Designs of Gas Exporting Countries (Section 2.5)

Analysis presented in this section includes a review of the challenges the selected countries are facing in establishing gas export projects and focuses on their innovative exploitation of fiscal instruments. The key components of fiscal systems of each country are summarized in Section 2.5. There is a great deal of information presented in these country reviews that highlights not only the diversity of fiscal designs, but also how harsh many of them are in terms of shares allocated to IOCs.

Upstream fiscal designs should reflect the broader strategies and objectives that governments are striving to achieve. It is useful for Alaska to review its own strategic objectives for its oil and gas sector and consider them in terms of the fiscal designs of major gas exporting nations around the world in the context of their strategic objectives. The figure below illustrates the author’s assessment of how Alaska’s strategic objectives, as reflected in it current fiscal design, compare with those of selected countries and regions.



The 23 countries and regions analyzed in some detail for this study are listed below and then presented in alphabetical order. Those countries that could compete for $20 billion plus investments in gas developments over the next decade are marked with a star.

Alaska ☆	Algeria ☆
Angola ☆	Australia ☆
Azerbaijan	Bolivia ☆
Brazil ☆	Canada – Alberta ☆
Canada – Other Provinces ☆	Egypt ☆
Indonesia ☆	Libya ☆
Malaysia ☆	Nigeria ☆
Norway ☆	Papua New Guinea ☆
Peru ☆	Philippines
Qatar ☆	Russia – Sakhalin II ☆
Trinidad & Tobago ☆	Tunisia
United Kingdom	USA ☆

Fiscal Designs of 23 Selected Countries/Regions (Appendix 3)

The fiscal designs of the 23 countries and regions summarized in Section 2.5 are analyzed in more detail in this section. Both oil and gas fiscal designs are considered as the two interact, and in most cases the natural gas fiscal designs have evolved from existing fiscal designs focused on oil.

The countries have in most cases been selected because they represent the world's major gas exporting countries, have been major exporters (e.g. United Kingdom), and are about to become or have the potential to become important gas exporters (e.g. Angola, Bolivia, Papua New Guinea and Peru). Two countries, Brazil and Philippines, are included because they have some aspects to their fiscal regimes or issues that are relevant to upstream fiscal designs more generally, but are unlikely to become net exporters of gas in the foreseeable future. Some gas exporting countries, or those with potential to become gas exporters, have not been included in this analysis and are probably worthy of some consideration and monitoring from a gas perspective in the future (e.g. Argentina, Bangladesh, Burma, Iraq, Iran, Oman, Yemen, and Venezuela).

The information presented is from publicly available sources (publications or web pages). Every effort has been made to verify the information provided, but changes to fiscal systems occur quite regularly and often such changes are only partially disclosed by the bodies implementing the changes or reported upon publicly. Hence, the information as presented should not be relied upon as providing definitive up-to-date upstream natural gas terms for each country included. These country summaries rather provide an outline of the fiscal designs being operated, issues that have arisen in their implementation and how they have evolved. More importantly they should enable the designs selected to be compared and contrasted with each other and Alaska from various perspectives.

Fiscal Instruments Worthy of Consideration (Section 2.6)

As a prelude to considering specific fiscal instruments, the need for governments to make a clear statement concerning their fiscal design philosophy and the objectives being pursued by the state in implementing that philosophy are discussed. Making a clear strategic statement of fiscal objectives and underlining the state's intention to ensure commerciality can be more meaningful in today's upstream investment environment than contractual fiscal stability clauses. It is good practice though to avoid too many fiscal elements and/or administration of the fiscal design by multiple bodies with tax-raising powers. Even with no guarantees of fiscal stability provided, in the interest of industry confidence, it is wise for fiscal authorities to avoid revising fiscal design and tax rates too frequently.

Listed here and discussed in Section 2.6 are the pros and cons of the wide range of potentially beneficial fiscal principles, instruments and issues with relevance to Alaska:

i. Clear government statements concerning the philosophy and objectives of fiscal designs.
ii. Equity participation by state in pipeline or upstream facilities.
iii. Simplicity and consistency in a fiscal system.

iv. A single agency focused on natural gas and NGL.
v. Apply regional market prices (i.e., unit destination values) and price benchmarks to control or adjust fiscal instruments and establish fair prices.
vi. Target fiscal elements to specific NGLs and other natural gas-derived revenue streams.
vii. Refine progressive taxes linked to oil, gas and NGL values (gross or net mechanisms), or unit values with clear revenue netback methodology. [Modelled in Section 4]
viii. Tax transfers of interests between IOCs.
ix. Competitive bidding.
x. Fiscal terms linked to rates of return and R factors. [Modelled in Section 4]
xi. Fiscal terms linked to environmental issues.
xii. Define duration of future leases and timeframes to develop discovered resources.
xiii. Target investment instruments to promote strategically desirable behaviour from producers.
xiv. Cost control instruments.
xv Domestic market obligations (DMOs).
xvi. Fiscal benefits for direct equity participation by Alaska corporations.
xvii. Reward IOCs for partnering or investing in local companies.
xviii. Provide choice of fiscal designs for a limited period of time upon declaration of commerciality.
xix. Vary tax rates linked to size of an equity holding.
xx. Introduce tax incentives and fiscal mechanisms for IOCs committing to build strategic gas processing and gas storage infrastructure in Alaska.
xxi. Third-party access (TPA) and use-it-or-lose-it rules which need to be carefully crafted.
xxii. Offer tax holidays or time-limited reliefs to encourage investors to commit to costly infrastructure and/or field developments. [Modelled in Section 4]
xxiii. Training bonuses and technology transfer are subordinate elements in many upstream fiscal designs.
xxiv. Require long-term natural gas sales contracts or financing.
xxv. Consider integrated projects as these have facilitated multibillion-dollar investment commitments by major IOCs in several countries in recent years.

From the foregoing discussion of the twenty-five fiscal principles, instruments and issues identified and the results of the fiscal modelling conducted on items VII and X, the following points stand out, in the author's opinion, as worthy of detailed consideration by the State of Alaska. These points are ranked in terms of the decreasing positive impact they could potentially have in optimising revenues for the State of Alaska from fiscal designs focused on natural gas:

- Calculate progressivity taxes separately for oil, gas and NGL revenue streams.
- Link rates of progressivity taxes to progressive fiscal elements.
- Offer fiscal allowances as incentives to offset regressive elements for limited periods.
- Offer partial royalty holidays for low cash-flow generating field development phases.
- Target fiscal incentives toward strategic infrastructure projects.

- Specify limited durations for holding title to undeveloped discovered gas resources.
- Publish a strategic objective statement aimed at improving fiscal clarity & credibility.
- Link investment credits and tax allowances with cost-control incentives.
- Consider minority equity participation by the state in strategic infrastructure.
- Specify a transparent revenue netback policy for gas and NGL sales agreements.
- Establish a natural gas and gas liquids (NGL) state-run monitoring agency.
- Broaden competitive bidding terms to include fiscal elements.
- Provide IOCs with a choice of fiscal designs on declaration of commerciality.

Any changes in fiscal design should be introduced in association with emphasizing the many positive aspects of Alaska's upstream industry and opportunities for new investors, for example:

- Opportunity to find large natural gas (and oil) reserves.
- Political stability.
- Benefits of operating in supply chains that involve only U.S. dollar revenues and costs.
- Experienced and competitive service sector and workforce.
- A new gas fiscal design that is responsive to industry requirements (once unveiled).
- Welcoming business environment for non-U.S. companies.

Review of Alaska's Prevailing Fiscal Design (Section 3.1)

This section describes the fiscal instruments and mechanisms involved in Alaska's fiscal design. It highlights assumption made for the base-case modelling conducted in Section 4. It outlines which costs are deductible from the fiscal instruments and provides a flow diagram of the overall design together with a worked example for a single period. A brief account of the fiscal design changes introduced in 2006 and 2007 is provided in order to place into context the implementation of the progressivity fiscal element and its focus on production tax value/boe. Recent developments with respect to the Alaska gas pipeline projects are also outlined.

The current situation highlights the fact that there are many outstanding issues and uncertainties that need to be resolved prior to the sanctioning of a gas pipeline project and to provide a fiscal and commercial framework under which natural gas fields in Alaska can be developed and natural gas exploration can be encouraged. In addition to a revision of the overall fiscal design to make it more suited to natural gas developments some key uncertainties are identified:

- Should state equity participation be considered for midstream/downstream and upstream infrastructure projects?
- Should NGLs (including LPG) be subjected to the prevailing crude oil fiscal design or do they require alternative fiscal designs?
- How should upstream and midstream/downstream fiscal designs interact?

- Should infrastructure components such as gas processing plants be treated as upstream or midstream/downstream investments?
- What fiscal incentives, if any, are required to persuade producing companies to develop and explore for gas?
- How should natural gas fiscal design treat associated natural gas in oil fields?
- How will environmental issues associated with carbon emissions and potential carbon capture and sequestration (CCS) be handled fiscally?
- Should there be tax incentives to encourage investment in the additional costs involved in CCS?

The fiscal modelling and sensitivity analysis conducted by this study does not address these issues, but focuses on economic performance of the prevailing upstream fiscal design together with an evaluation of alternative mechanisms for making that fiscal design more progressive in response to both high and low net values and costs for natural gas field developments.

Status of Alaska's natural gas reserves and yet-to-find resources (Section 3.2)

The role of future lease sales under a non-expansion of capacity scenario for a 4.5 bcf/d proposed gas pipeline suggests that such a pipeline might need 57.5 tcf of gas over its lifetime. In such a scenario some 35 tcf of gas could be expected to come from Prudhoe Bay and Point Thomson on state land, while the rest would probably be split between land already leased by the state, land yet to be leased by the state, land already leased by the federal government (both inside and outside of state boundaries), and yet-to-be leased federal lands again both inside and outside state boundaries. In that case production from fields discovered on leases issued in new rounds of state leasing would probably cover substantially less than 30% of the yet-to-find reserves required for the pipeline capacity. However, an expansion-driven scenario where some 70 plus tcf is shipped over 50 years places much more emphasis on new lease rounds. This suggests that both gas in current leases and gas from land (state and other) yet to be leased will be important in long-term planning for sourcing gas to supply the gas pipeline.

Reports by the Alaska Department of Natural Resources (2008) and the U.S. Department of Energy's National Energy Technology Laboratory (NETL) (2007) suggest that near-term gas developments in Alaska are most likely to be associated with oil, especially in the northern Colville-Canning area (including Beaufort Sea state submerged lands within 3 miles), the National Petroleum Reserve-Alaska (NPR-A), and the Beaufort Sea OCS (with ANWR being mainly oil-prone with little gas potential).

Even with the DNR forecast of the potential for some 33.3 tcf of yet-to-find reserves proved up on state lands by 2050 (provided appropriate exploration investments are made), there is a strong case for extensive new leasing to boost exploration for gas in federal NPR-A and OCS areas.

The state receives 50% of all revenue from federal NPR-A lease sales, rentals, bonuses, and royalties. The state is entitled to collect production taxes on any oil and gas produced from

NPR-A, under the same general conditions and tax rates as are imposed on production from state lands.

The state receives 27% of the bonuses, rents and royalties from federal OCS leasing activity within three miles of state waters (i.e. the zone between 3 and 6 nautical miles from shore). The federal OCS - Beaufort Sea has a significant amount of prospective acreage within three miles of state waters. The federal OCS - Chukchi Sea has none. The state cannot levy a production tax on the sale proceeds from oil and gas produced from federal waters.

The state currently receives no money from taxes or bonuses, rents or royalties from waters seaward of three miles from state waters.

The potential impact on state fiscal policy and the state's economy from opening up NPR-A, OCS and ANWR to oil and gas exploration and production is likely to be significant. It is not only about direct fiscal revenues, but also about boosting employment and direct and indirect services and broader boosts to the private-sector economy. It is therefore important for the state to consider strategies for how it can optimize its fiscal revenues from both state and non-state lands. Coordinated competitive bidding strategies may help in this regard.

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 for Analysis (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 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$/boe compression/pumping/workover/sidetrack costs
- US$ 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. tariffs for gas and liquid throughput); and a transportation tariff component for shipping both gas and liquids out of state. The models assume separate downstream 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) provides 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.

Model Economic Assumptions and Sensitivity Variables (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). The escalator applied to the year 0 price is inflation at 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 (ANS West Coast) is escalated 2% per year to provide money of the day MOD prices across the lives of each field analyzed. The nominal escalations are used to calculate money of the day (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.

Production rate, timing (start-up, decline and 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
- Upstream production 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)

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, which combined with federal income tax amounts to a 31% total government take of destination value. For the smaller gas fields (e.g. Field #1 and #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.

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 cost, TT&T cost 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.

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 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 3.0).

Upside sensitivities suggest that gas prices are the dominant factor for modest increases above the base case. However, when the first tranche rate of the combined progressivity tax (CPT) rises above 1% for every $ increase in $/boe prices, that tax becomes the most significant in increasing government take. CPT is shown to be highly sensitive to the rate factors applied beyond rates of about 0.75%/US$/boe price increase. Reducing the threshold rate for the first tranche CPT below 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 status quo state 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
- Mechanism No. 4 GPT: Gas PTV (based on gas PTV/mmbtu)
- Mechanism No. 5 GPT: R-factor
- Mechanism No. 6 GPT: IRR
- Mechanism No. 7 GPT: Cumulative reserves
- Mechanism No. 8 GPT: Gas Production (annual)
- Mechanism No. 9 GPT: Cumulative gas PTV
- Mechanism No. 10 GPT: Cumulative gas PTV + allowance (tailored to counter regressive elements in the fiscal design)

As well as displaying progressive trends in upside sensitivity cases all the mechanisms 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. 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 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 any 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: Cumulative 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: Cumulative Res?
Mechanism No. 8 GPT: Gas production
Mechanism No. 9 GPT: Cumulative 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.

The study of alternative 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 CPT by applying a simple change to the existing Alaska 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 to significantly improve performance of a gas progressivity tax.

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 small fields commercial and extracting more value through progressivity from high value gas production should be the objective.