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

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For

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Section 2.6

Instruments and issues to consider in formulating fiscal designs focused on natural gas

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What features of international oil & gas fiscal systems should be considered when formulating Alaska's upstream natural gas fiscal design?

Irrespective of what can ultimately be considered as commercially or politically viable or acceptable as a fiscal design for Alaska, the upstream fiscal designs of the countries outlined in Section 2.5, and described in more detail in Appendix 3 of this report, suggest a number of features worthy of further analysis and consideration. They also pose some questions and raise some issues that should help Alaska to refine and, in a more international context, define and explain its fiscal strategy. These features and the issues and questions they raise are presented below. In the following analysis the general points made concerning each feature and issue includes comments on their relevance to Alaska's future fiscal design for natural gas.

Twenty-five issues for consideration when formulating a fiscal design focused on natural gas supply chains are identified and documented below in no particular order of importance.

I. Clear Government Statements Concerning the Philosophy and Objectives of Fiscal Designs

Clear government statements concerning the philosophy and objectives of fiscal designs help to build confidence amongst investors and state citizens that there is consistency and vision behind the fiscal design being introduced or implemented. Malaysia provides an example of such a statement. Alaska's statement with respect to natural gas should reflect its strategic vision and needs, and should prioritize objectives with respect to the following issues:

- Commit to providing a fair return to investors, commensurate with the level of risk taken.
- Encourage development of Alaska's industry infrastructure, employment and skills training.
- Integrate environmental, safety and societal perspectives, as well as good commercial practices to promote sustainable development decisions.
- Promote a long-term alliance and cooperative partnership with IOCs, encompassing shared visions and goals, or in the alternative, encouraging and promoting relationships with alternative stakeholders, if and where available.
- Encourage re-investment of equity profits in Alaska for the benefit of the wider community.
- Provide benefits for technological research and development of Alaska's non-conventional gas resources (e.g. hydrates).
- Optimize revenues to the state and its communities.
- Other concerns or policies that the state wishes to articulate.

It is important for the state to be clear on the strategic objectives and priorities it is trying to achieve with its fiscal design for natural gas. It should make sure that all stakeholders are aware of its strategic objectives and of any potential conflicts or differences of priority with potential investors. If there are policy preferences that are clearly being followed by the state but are not articulated, that will lead some to question the transparency of the fiscal strategy and potentially damage the state's fiscal credibility.

Making a clear strategic statement of fiscal objectives and the state of Alaska's intention and commitment to ensure long-term commerciality for oil and gas investments can be more meaningful and credible to investors than contractual fiscal stability clauses, which can limit flexibility in the future. In recent years fiscal stability has deteriorated in the upstream sector for IOCs around the world, and geopolitical risks have substantially increased. Alaska has strong cards to play in terms of its political stability, the U.S. government's commitment to free and fair trade, and the improbability of asset appropriation, except in cases where producers fail to perform to specified standards set out in law. Those strengths mean that Alaska does not need to offer long-term fixed tax rates or gas floor-price guarantees that impede it from adjusting tax rates in the future to respond to market conditions in order to attract investment.

Of course, offering such fixed guarantees or taking actions to create more fiscal stability, either actual or perceived, would increase its investment appeal to existing and new entrant producers. Alaska could probably achieve more investment by offering such guarantees. However, such guarantees involve more risk-taking and potential financial losses in the future for Alaska, which have to be balanced against the potential benefits of attempting to attract more investors. Alaska has to decide whether the constraints of such additional guarantees are worth those potential benefits. In this author's opinion the current competing international investment opportunities for IOCs suggest Alaska does not need to offer such guarantees, nor is the issue of fiscal guarantees the main make or break investment decision for IOCs in Alaska, which are the commercial issues of costs, tariffs and destination-market prices for natural gas. However, if Alaska does decide that it would enhance investor confidence by offering such guarantees, it should do so, in this author's opinion, only in return for guarantees from producers and infrastructure developers. Such guarantees could include: 1) an upper limit on the rate the pipeline owners will apply to FERC for the tariff to be applied per unit of gas transmitted through the gas line, 2) a cap on the upstream field development investment costs that would be considered eligible for capital investment credits, 3) application of a strict timeframe for use-it-or-lose-it rules for capacity in upstream infrastructure feeding a gas line, 4) and a time limit to develop discovered but undeveloped natural gas reserves which if not met would mean that those reserves would revert to state ownership.

Making a clear strategic statement of fiscal objectives and ***state's intention to ensure commerciality can be more meaningful than contractual fiscal stability clauses.*** Norway's approach is commendable in this regard. Its statements do not ensure fiscal stability but reassure investors about fiscal intentions. These statements can be summarized as follows:

The government emphasizes the low-risk nature of investments in [Norway], stating that IOCs can with a large degree of certainty regain a large part of their investments and other costs through fiscal allowances, such as limited ring-fencing, uplift and fast-depreciation rules applied to capital. The government also wishes to portray the tax system as a "sleeping partner," allowing IOCs to take a high participating interest, achieve technical control of projects and take part in large investment projects. The fiscal design philosophy is for the government-take system to be neutral on company decisions, whether those decisions relate to capital investments, operating costs and activities or field shut-down and decommissioning. The government's aim is that a decision that is economically viable before tax should remain so after tax and vice versa. The Norwegian government and the Norwegian Petroleum Directorate (NPD) do not state that taxation rates may not change in the future, but rather emphasize that IOCs' assets will not be appropriated and projects not rendered uneconomic by fiscal changes and that the state maintains a strategy of projects being profitable for both Norway and the IOCs.

Alaska may be better to adopt such an approach rather than be locked into decades of fixed tax rates and/or floor prices that may have unforeseen consequences or be exploited by IOCs if unforeseen tax loopholes materialize in the future. If Alaska cannot reach a consensus on a strategy for its long-term fiscal design objectives, a case could be argued that a contractual fiscal stability clause might be the next best option. There are, however, several implications to consider in a contractual commitment to fiscal stability and the need for certain exemptions involved in such a commitment. For example, how would potential future taxes/incentives on emissions/carbon capture be introduced and modified as climate change legislation and a potential carbon economy unfolds? Linking fiscal stability to project performance in terms of achieving delivery within specified budgets and time schedules might also be worth considering.

Outside the main scope of this report, it is interesting to look at what Alaska's consensus on fiscal design might look like from the perspective of the gas pipeline needed for a large scale commercialization. Clearly, it would have to reconcile the three conflicting opinions for the best use of Alaska gas: (1) in-state use and development, with an implied capture by consumers and developers of a below-market premium, but with the recognition that local demand is likely to fall far short of 4 bcf/day for the foreseeable future; (2) an LNG facility capable of capturing both the highs currently found in the spot market and the notion that Asian buyers are willing to pay a premium (over prices that can be realised in the Lower 48) for long-term stable sources of natural gas supply; and (3) a pipeline guaranteeing long-term, high-volume access to the Lower 48 gas market. If a gas line is constructed, the three conflicting views of optimum gas development strategy remain to be reconciled. Option (3) has to reconcile a producer-led and sponsored project with a third-party project and overcome the opposition from those favouring Options (1) and (2). Politically it may be possible to secure support of those stakeholders favouring Option (2) if that option is left open for a later phase of development. Likewise, it will be necessary to convince those who support Option (1) that the state revenues received from a gas line will lead to substantially greater long-term economic benefits for Alaska consumers than keeping those resources for in-state consumption and/or processing.

If fiscal stability is to be offered to those producers investing in the pipeline and 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) and is provided with some protection from reduced margins in periods of low prices, significant capital cost and schedule over-runs or low market demand. Some state protection from reduced gas sales margins, for whatever reason, is achieved in the prevailing fiscal design by the inclusion of a fixed-royalty component, production tax floor and property taxes (making the guaranteed fiscal regime more regressive). Second-phase producers (i.e. those producers prepared to develop new gas fields to provide gas supplies to the pipeline in the longer term to replace declining contributions from the first-phase gas fields) could then be offered a more progressive fiscal design (i.e., removing some or all of those regressive fiscal elements) but without guarantees of long-term fiscal stability.

In the context of the Alaska gas line there are two risks for producers that stand out from the typical upstream risks and natural gas market price risks: Either (or a combination of) (1) a gas line tariff and/or (2) government take that eats into the investors required return and makes the investment in the project no longer commercial. Clear strategic statements alone are not going to alleviate such risks. If the state and third-party pipeline companies build the pipeline, and take all the upfront construction cost risks associated with that commitment, a substantial amount of the risk (and capital investment) of delivering gas to the high-demand Lower 48 market is removed from the producers. Nevertheless, producers are still faced with other key risks, notably sales gas price risk (i.e. can they deliver gas into the Lower 48 market at prices that will compete with imported LNG and indigenous Lower 48 gas producers?), high gas line tariff, and the usual upstream risks.

The guarantee of a competitive pipeline tariff rate (i.e. limited to amortized capital costs and actual operating costs plus a realistic and published margin) may be sufficient to attract IOC investors without the additional contractual guarantees of upstream fiscal stability sought by some IOCs. FERC (and the NEB) are mandated to guarantee a competitive pipeline tariff rate, including a further limitation that capital costs must have been reasonably and prudently incurred and the resulting tariff must be fair and reasonable. There may remain some uncertainty over what constitutes a “competitive” rate for incremental pipeline expansion tariffs, but overall producers should be confident that the pipeline tariffs will be fair and transparent. If the state and third-party pipeline companies build the gas line, then it will be inevitable that to some extent the state will be taking on some of the tariff risk along with the capital costs of building the line and the construction cost-overrun risk. The state will not be able to nor wish to seek a tariff that renders the gas sales uneconomic to an IOC on a pre-tax basis and fails to sustain gas supply to the line. Without holding an ownership interest in a gas line, the state would want the gas line tariff, all other things being equal, to be as low as possible. A low tariff leaves more revenue for upstream taxation. However, taking on some tariff risk and guaranteeing long-term fiscal stability could turn out to be very expensive for the state. However, the state may deem such risks necessary in order to secure the investment needed for a gas line to be built and not incur the opportunity cost of no gas line being built.

II. Equity Participation by State in Pipeline or Upstream Facilities

Equity participation by the state in oil and gas facilities is a key feature of the fiscal design of many countries including many of those considered in this report. There are several questions to be answered when considering this issue:

- Should Alaska take equity positions in natural gas upstream and/or other projects aimed at getting gas to market?
- Up to what maximum percentage level?
- How and by whom should the level of state participation be decided?
- Should participation be focused on one or both of the upstream and transportation sectors? Should it be at different levels in different projects?
- Should it be conducted through a corporate vehicle fully or partially owned by the state?
- Should the state's interest be carried through exploration/risk capital investment?
- Should the state's share of development costs to earn its equity share be paid upfront in cash or deducted from its equity revenue share in the form of a back-in?
- Should state equity revenues accrue to an existing fund (e.g. Alaska's existing Permanent Fund)? Or should it accrue to a new fund. How should the money be managed and spent and by what entity?
- Should the rates applied to other fiscal elements impacting IOC revenues and profits vary according to the level of state equity participation (e.g. Tunisia)?
- There are problem issues with state equity participation for countries with strong free-market and capitalist traditions. These include:
    - The state's conflicting role as an environmental, labor, job, safety and financial regulator on a project/partnership where it also holds an equity stake.
    - Concern over lack of diversification in the state's broader investment strategy. Some would argue that it is better to invest in non-depleting industries to encourage long-term economic sustainability.
    - Investing in high-risk (equity) ventures with public funds needed to support the wider economy over the longer term. In low oil and gas price environments state-owned equity interests put more negative pressure on the state's budget than would be the case if the state did not hold such interests.
    - Prevailing Alaska public records and disclosure laws would likely raise

difficulties for the state in operating effectively with private-interest partners and put a strain on its relationship with publicly traded energy companies.

- Counter-arguments in favour of state involvement would highlight scenarios where state participation could be construed as diversification, e.g. participation in infrastructure projects along the supply chain to U.S. markets, such as pipelines/processing plants in Canada, gas storage facilities in Lower 48 and/or on Alaska federal lands. Such projects could actually open up new revenue streams for the state that cannot be accessed fully though tax and royalty revenues. Such ventures could also help to forge closer ties with some of the likely large customers for Alaska gas in the Lower 48 markets. The only oil and gas streams which Alaska cannot capture through taxes are projects where the value is created outside of Alaska's jurisdiction, and Alaska's right to tax does not extend. If the state invests in those projects, it is gaining access to a stream of revenue that is not tied to the Alaskan economy. Owning an interest in out of state gas facilities along the gas line could provide Alaska with more leverage into further construction and investment decisions.

One option worthy of consideration is to mandate minority equity participation by the state in strategic infrastructure. This could be linked with a commitment for such state-held interests to ultimately be sold once the infrastructure has achieved its desired objective. Such state involvement would be a politically controversial issue, but one that needs to be evaluated on strategic and commercial grounds rather than simply dismissed for reasons of political ideology.

Equity participation could offer an opportunity for Alaska to improve alignment with other investors in strategic infrastructure assets and to exert long-term influence on the development of and third-party access to those assets. Equity participation is widely used by governments around the world and enables them to take a valuable additional share of economic rent. For large, high-cost investments, other equity participants may welcome government participation if it is on a heads-up basis (i.e., government pays its full equity share of costs at the same time as the other equity partners, rather than being fully or partially carried through those costs and subsequently backing-in to an equity share once the other equity holders have taken all the construction/development risks and paid the costs upfront).

However, heads-up equity participation would be risky for the state. It not only requires large capital investment a long time in advance of receiving revenues but it also exposes the state to risks of cost overruns and delays. An alternative, which other investors find harder to accept, is a back-in option, i.e. the state exercises (or not) its option to back-in at a pre-agreed cost (e.g. budgeted amount at time of project sanction) for a pre-agreed equity percentage once the project enters production. In some countries the government is only required to pay for that share from the proceeds of production, removing the risk of having to raise substantial capital to pay the other equity holders the back-in costs. Such state back-ins are common around the world and IOCs agree to them. They significantly reduce the state's risk in participation, but once the field or facility is operational the state functions as a heads-up operating partner improving partner alignment and providing the state greater influence over the life of the project.

Such participation is usually administered by state-owned national oil companies (NOCs). Alaska would have to consider what entity would administer its participation interest and would probably have to establish a corporate entity specifically to achieve that. There are a number of potential conflicting interests and problems of state investment in a heavily regulated entity. Corporate objectives would differ between state and publicly traded companies concerning needs to manage wildlife, the environment, public safety and community issues. Such conflicting interests and exposure to a complex set of additional liabilities are two key downsides of state equity participation that could make it difficult for Alaska to pursue in current political and legislative circumstances.

However, the objective of partial and short-term state equity involvement does not have to be driven by political ideology. Some see state participation in any form as the manifestation of state capitalism wishing to establish centralized control of valuable industries (indeed in some countries this is the case). Some politicians would prefer to have this option ruled out simply on the basis that it is politically unacceptable. Nevertheless, minority state participation can be merely an instrument to support strategic investments that will have lasting value for the state and its communities. State involvement can be particularly valuable in projects which have found (because of the magnitude of the costs, risks and limited returns to their shareholders, etc.) private enterprise unwilling or reluctant for many years to sanction, even though the building of that key infrastructure could bring huge benefits, not just in terms of fiscal revenues to the state and the collective industry in the long term. Once that infrastructure is built and operating with established third-party access, then the state may elect (and some would say should elect) to sell its minority interest. The subsequent sale of the state's equity interest, at a time of its choosing, enables the state not only to monetize the value of that equity interest, but also to avoid some of the liability and potential conflict-of-interest issues that might arise during its long-term operation.

III. Simplicity and Consistency in a Fiscal System

Avoiding too many fiscal elements and/or administration by multiple bodies with taxing powers is a desirable aspiration, but one that many governments find difficult to establish in practice. Some countries have complex fiscal designs that include a raft of complex local and regional taxes administered by many taxing authorities with a multitude of direct community beneficiaries. Different taxing bodies have different priorities or apply strategies of self-interest rather than for the common good of the entire community. Lack of clarity of tax rules, or specific tax rules being applied differently by different bodies (e.g. Brazil), can cause uncertainty and unnecessary administrative costs and bureaucratic delays for investors and raise fears of fiscal instability. It can also lead to the central taxing authorities losing credibility with investors.

In Alaska, municipalities are prohibited from levying oil and gas production taxes. Municipalities can, however, impose sales taxes and excise taxes (e.g. hotels, rental cars, alcohol) and property taxes, but the property taxes must be on all property and cannot be targeted at only oil and gas property. Such community-based, tax-raising powers are currently unable to have a discernable impact on the state take from oil and gas upstream developments. However, uncertainty about future community taxes can act as a disincentive to investment. As the state gets more assertive in taking its fiscal take, this encourages the municipalities to do likewise. Although the impact of community-based taxes may be minor in terms of the overall tax burden, the uncertainty can result in a disproportionate impact on investment from IOCs.

It is prudent for governments to avoid revising fiscal design and tax rates too frequently and to avoid introducing too many fiscal elements in the fiscal design or complex interactions of fiscal elements that make the effective tax burden for investors difficult or ambiguous to compute. Doing so can lose credibility and raise fears of fiscal instability and deter investors. A well-structured and flexible fiscal design should remain robust in a wide range of market conditions. It should only need minor adjustments, or more significant ones, only if drastic changes occur to the market or industry. Changing the rate of a fiscal instrument every two or three years fosters an environment of uncertainty and suspicion between IOCs and government and works against long-term alignment and shared objectives. Substantial changes to fiscal design are best introduced after widespread public and industry discussions with all interested parties. When a government introduces workable fiscal changes in response to a well-recognised industry and/or community requirements with clearly stated objectives, it is likely to establish fiscal credibility. If successive governments introduce frequent politically-driven fiscal changes, paying little regard to long-term industry sustainability or community issues, it is more likely to lack fiscal credibility among investors and lead to a lower level of investment and project delays.

In terms of clarity it helps for governments to limit fiscal administration to one body at the state level with a comprehensive mandate to implement a fiscal design backed by legislation. If local and municipal bodies in addition to state authorities also have tax-raising powers over upstream and midstream oil and gas investors or their assets, and are able periodically to effect rate changes on a unilateral basis, the IOCs and other upstream and midstream investors are likely to lack confidence in long-term investment. Although the local bodies may have only minor tax-raising powers, uncertainty occurs when such bodies lobby for increased powers and could achieve that through changing state law in the future.

If and when it is deemed necessary to effect fiscal changes, it is best to ensure that it is done with prior input and comment from producers, investors and other stakeholders, with adequate time to deliberate on such advice before decisions are made. If fiscal changes are made on a retrospective basis it can reduce fiscal certainty from the perspective of would-be investors. The fiscal changes approved in Alaska in 2006 and 2007 involved only small periods (4 to 5 months for most provisions) of retroactivity in terms of the date from which new tax rates were applied. However, the other aspect to retroactivity is that some investment decisions can be made by producers on the basis of certain prevailing fiscal assumptions, and if fiscal changes adversely impact those projects the investors can be substantially disadvantaged. It therefore sometimes makes sense to grandfather fiscal terms applying to existing projects and apply a new fiscal design only to new projects.

Ideally it is better to establish a progressive fiscal design that does not need to be frequently adjusted when market conditions change (i.e., prices or costs rise or fall markedly). It appears to this author that the reason it was considered necessary for Alaska's fiscal changes of 2006 and 2007 to impact all existing producing projects was because of the lack of adequate progressivity in the former fiscal designs, a strong political drive for higher tax rates to feed the treasury, and a lack of investment by producers which had led to substantial declines in production and state revenue from royalties and taxes.

IV. A Single Agency Focused on Natural Gas and NGL Regulation

A natural gas and gas liquids agency run by the state could be established, or an existing agency expanded and mandated, to monitor and regulate natural gas and NGL markets, fair market value contracts and transparent pricing. Existing state agencies focused mainly on oil and economic development may well be able to cover the expanded and more complex (relative to oil) natural gas and NGL roles required. Some major gas exporting countries (e.g. Algeria) are using this approach to enable the government to take a more direct role in regulating gas sales along its LNG and pipeline supply chains.

This study has ***not*** conducted any analysis on:

(1) Whether the existing Alaska Oil and Gas Conservation Commission, Alaska Regulatory Commission, the departments of Natural Resources, Revenue or Law are adequately resourced and adequately performing their current roles with respect to oil and gas.

(2) If adding another agency would be the best solution or might cause administrative complication due to overlapping jurisdictions.

(3) Whether, within the U.S. context, having the same agency both "regulate and promote" an industry (given the experience with say aviation and nuclear power) might lead to conflicts of interest.

Nevertheless, the author is aware that the Alaska Industrial Development and Export Authority promotes in-state development by providing various means of financing to promote economic growth and diversification in Alaska. Also the Alaska departments of Revenue and Natural Resources do currently monitor oil pricing and contracts to ensure compliance with state laws and to optimize the state's fiscal revenues, and that the Regulatory Commission of Alaska has a role in regulating pricing for natural gas and other utilities serving the state. Are these existing bodies adequately resourced and briefed to tackle the new challenges that will be posed by large-scale natural gas and NGL sales outside the state?

Many countries and regions (some in the Lower 48) have encountered problems with producers and distributors manipulating, or being perceived to manipulate downward, natural gas and NGL prices through a chain of affiliates (or through complex processing/storage and distribution supply chains). Without clearly defined rules, regulatory responsibilities and regulatory powers of sanction in cases of misconduct, clear contractual benchmarks and transparent pricing is difficult to establish with sufficient levels of confidence. The handling of gas and NGLs is much more complex than crude oil and the responsible agencies need to be fully prepared for this task and be backed by clear rules and fiscal instruments that specify how prices for natural gas and NGLs are to be established and recorded. There are several questions to be answered when considering this issue:

- What should be included in such an agency's mandate?
- How will it interface with IOCs?
- How will it interface with existing state agencies?
- How will it deal with disclosure transparency, confidentiality and other rules?
- How will it integrate with federal anti-trust and other regulatory bodies?
- Will it have powers to impose penalties and incentives based on IOC performance?
- Will it have a mandate to seek and promote new gas monetizing initiatives to the wider industry? Or should it be constrained to a regulatory role?
- Will it be restricted to fiscal monitoring or include technical and operating best practice and efficiency?

Possible roles for an expanded Alaska natural gas and gas liquids (NGL) monitoring agency run by the state could be to:

- Monitor contract terms, contract performance, and market price trends and promote additional gas monetization efforts of Alaska's natural gas resources.

- Monitor and review pricing transparency in natural gas sales and swap contracts.

- Apply and regulate third-party access (TPA) rules and tariffs (coordinating with the Federal Energy Regulatory Commission and other federal agencies in this regard).

- Police use-it-or-lose-it rules to strategic infrastructure capacity and any exemptions from TPA rules (coordinating with FERC and other federal agencies in this regard).

V. Apply Regional Market Prices (i.e., Unit Destination Values) and Price Benchmarks to Control or Adjust Fiscal Instruments and Establish Fair Prices

Natural gas and NGL market prices can be used to adjust rates of specific fiscal instruments, or in the extreme impose price caps and windfall taxes when prices exceed certain specified levels and/or floors when prices fall below other specified levels. There are several questions to be answered when considering this issue:

- If these are to be used, which price levels should apply?
- Different price scales are required for natural gas, oil, C5+ and condensate and LPG.
- Above the threshold price levels, should profits be shared on a progressive basis or on a fixed basis between state and IOC?
- Price caps are disincentives for investment if shares are stacked too heavily against the IOC or price thresholds are too low.
- How are gas and NGL benchmark prices to be established? Delivered or netback prices?
- To what should Alaska natural gas prices (i.e. natural gas sold to Alaska consumers) be indexed? An Alaska gas benchmark? Henry Hub? Other North America gas benchmarks? Or competing fuels (electricity, coal, oil etc.)?

Gas sold around the world and throughout North America is generally indexed to a benchmark, ideally established by local and regional markets at gas trading hubs (or pipeline interchanges, e.g. Henry Hub in Louisiana, AECO in Alberta) where significant volumes of gas from various sources enter the market. If there is no market natural gas benchmark unit value (or a thinly traded one) in Alaska, that could pose a problem for establishing appropriate prices to be used for establishing a fiscal price for gas sold in-state to affiliates of producers. Although Alaska is, by law and under a series of court decisions that affect royalty, empowered to ignore such sales for fiscal purposes, that does not necessarily establish the appropriate sale price to apply to them. This is an issue the Regulatory Commission of Alaska (RCA) will have to address with producers and in-state distributors of natural gas, once in-state gas movements through a pipeline become a reality. However, the RCA would under current arrangements not have jurisdiction over gas moving through an Alaska gas pipeline if the gas would be moving into an interstate pipe system destined for Canada or Lower 48 markets. The RCA's jurisdiction covers only gas moving and consumed in state. Benchmark prices raise the following additional issues to be addressed:

- How is market-price discovery to be established if gas, C5+ and lighter NGL products are sold on term contracts involving various IOC affiliates?
- In volatile markets with poor price discovery it is difficult for investors to forecast returns and this can inhibit debt and equity funding for infrastructure and gas field developments.

- Alaska's fiscal take could be significantly affected by market price discovery and the selection of the benchmark market prices (unit destination values) to which sales contracts are to be indexed.

VI. Targeting Fiscal Elements to Specific NGLs and Other Natural Gas-Derived Revenue Streams

There are several potential revenue streams from natural gas in addition to the primary ones associated with methane-rich gas or LNG sales. Fiscal elements need to be clearly drafted to recognize the specific supply chain issues associated with each revenue stream. The potential revenue streams from upstream natural gas field include:

- Methane-rich sales gas.
- Liquefied natural gas (LNG).
- Stabilised crude oil.
- Condensate, condensed in conventional field separators.
- C5+ natural gas liquids (NGLs) condensed in cryogenic facilities.
- Liquefied petroleum gas (LPG) propane (C3) and butane (C4) liquefied in cryogenic facilities.
- Ethane separated for petrochemical feedstock.
- Native sulphur separated from hydrogen-sulfide-rich gas fields at gas processing plants.
- Noble gases (helium, argon etc.)
- Carbon dioxide (in some instances a costly waste product) may have a market as an injection fluid for some enhanced oil recovery projects on the North Slope.

These natural gas components trade into different markets attracting prices that vary relative to each other, depending upon global and local supply and demand issues. It is sometimes commercially and fiscally more beneficial for IOCs to sell NGL-rich gas into certain markets, while at other times it is commercially and fiscally more viable to sell NGL-lean gas. It is important that the fiscal arrangements do not penalize IOCs unfairly for certain commercially driven sales involving certain compositions.

It is also important that IOCs are prevented from avoiding fiscal elements on certain components by selling them in an NGL-rich gas stream and processing them outside Alaska on more fiscally attractive terms. Through careful structure of the fiscal burden on some components (e.g. LPG) it may be possible to secure IOC investment in a gas processing plant based in Alaska (creating local employment and added value to production volumes), rather than build or use facilities out of state.

VII. Refine Progressive Taxes Linked to Oil, Gas and NGL Values (*gross or net mechanisms*), or

Unit Values with Clear Revenue Netback Policies [issue modelled in Section 4]

For fiscal elements targeting natural gas it is better to use natural gas and NGL value units rather than barrels of oil equivalent (boe) units to adjust the tax rates and establish thresholds for such taxes to commence. The significance of this in Alaska's fiscal design is demonstrated by the modelling conducted in Section 4 of this study. It also necessary to avoid onerous price or value caps (i.e. above certain values or prices most or all of the returns accrue to the state), as these can act as significant disincentives to investors to make incremental investments.

Value-driven fiscal instruments need to work at both high and low price extremes (i.e. accrue more to the state at high value or price; decrease state take at low value and price) and therefore need to be constructed carefully, perhaps with incentives applied at the low value end of the spectrum. Section 4 models a range of value-driven mechanism that could potentially be applied to Alaska's progressivity mechanism targeted at natural gas.

Clear revenue netback policies are required to calculate value-driven fiscal measures and separate their upstream and downstream components. Alaska already has effective fiscal mechanisms that do this for oil (C5+), but it is more challenging to do this for natural gas and NGLs. It is usually more beneficial for governments to have as much revenue as possible netted back to the upstream and taxed according to a tailored upstream fiscal design. The alternative is for the upstream equity holders to sell their wet natural gas as feed gas at a relatively low but btu-based price at the entry point to gas treatment or other TT&T facilities. Much of the NGL value will then be passed to downstream equity holders for onward sale of natural gas and NGL products.

Hybrid arrangements are possible and different supply chains may be structured differently, some with integrated upstream and downstream components, others with separate upstream and downstream components. Therefore the upstream and downstream fiscal designs should be tailored to extract appropriate economic rent from each arrangement and satisfy third-party access regulations. IOC investors generally prefer integrated projects because they enable them to extract more value from NGL and C5+ products as well as natural gas sales.
Fiscal designs should specify clearly how revenue streams from different products (i.e. oil, condensate, C5+, LPG, ethane, sulphur, etc.) are to be consolidated or dealt with individually for fiscal purposes.

VIII. Tax Transfers of Interests between IOCs

Some governments successfully apply taxes or levies to assignments of equity interests between IOCs. Such countries impose transaction fees and levies on farm-in deals and asset sales and purchases. There are several questions to be answered when considering this issue:

- Are such impositions acceptable in a free-trade nation? More specifically if the transactions occurred out of state could the state constitutionally tax them? To a certain extent Alaska may already be taxing elements of the gains and loses associated with such transfers through the worldwide dimension to the Alaska CIT.

- If such fees are acceptable what would be their objective? To avoid undue speculation or raise revenue?
- Could such levies be linked directly to investment in local infrastructure?
- Should the state have some pre-emption rights? Some governments now argue that they have such rights even though contracts seem to state the contrary (e.g. Kazakhstan)

Such taxes, levies or a stamp duty on assignments of equity interests would enable the state to benefit from speculation involving its resources or infrastructure. Some countries apply such rules. Although such levies benefit the government on specific transactions, they may actually deter beneficial investment activity and reduce competition. To the degree that Alaska is trying to open up the North Slope to new players, such measures would be counter-productive. Not only is it not legally possible to establish one set of assignment rules for transfers to in-state corporations and another for out-of-state corporations, the current Alaska rules make very clear that there is no deductibility for costs associated with corporations reconfiguring themselves. This point is raised here because IOCs are accepting such provisions in some countries (e.g. Egypt), where they do not appear to be inhibiting inward investment into the gas industry.

IX. Competitive Bidding

Competitive bidding in lease sales has been successfully used to award exploration and production leases in many prospective U.S. regions (including Alaska) for many decades. It successfully raises hundreds of millions of dollars in low-risk, upfront revenue in the form of bid bonuses for the federal government and states. It should be a part of an aggressive fiscal design geared to promoting industry activity in regions that still have large areas of prospective land to be leased. The major limitation for Alaska in this regard is that most of the acreage on state lands expected to supply gas to the gas pipeline is already leased out and has been for many years, and most leasing rounds in the future with gas in mind will probably be held on federal lands and other lands not owned by the state (e.g. ANWR, OCS and NPR-A).

If future lease sales are to be involved in attempts to explore for and develop additional gas reserves to supply a gas line beyond about 2030, then it may be appropriate to consider broadening competitive bidding terms and conditions. Rather than awarding leases to the highest monetary bidder of a bid bonus, introduce other criteria for bidding. A wide range of terms are used as biddable items in oil and gas competitive bidding activities around the world, for example by making:

- Work program (number of wells, etc.) or a minimum guaranteed financial value of work

program to be completed in a specific time period (i.e. specified exploration phases) biddable on their own or accompanied by bid bonuses.
- Rates of a certain fiscal element a biddable item in addition to a bid bonus.
- Rates of a certain fiscal element(s) linked to the timeframe in which work is completed (i.e. lower rates applied to early work program completion dates).
- State equity interest or local company partner share a biddable item.
- Training fees or technology investments in Alaska a biddable item.

The state needs to consider strategies for optimizing its component of tax revenues from future federal leases and the high-profile competitive bidding rounds that are likely to accompany their award, but recognizing that the state has no control over federal lease terms. Competitive bidding may not be a direct option to amend new state fiscal terms (as there is little open state land to award), but indirectly the increased activity on federal lands should result in substantial tangible benefits for the state and more industry interest in the state. The production taxes on production from land in the state (not levied on production from federal offshore leases) may also make fiscal terms on already leased state lands tougher for investors than new federal offshore leases, causing some producers to switch investments away from state leases. Fiscal competition with federal lands is a potential future issue the state's fiscal design for gas needs to confront. Natural gas produced from state lands will in most cases be more valuable to the Alaska treasury than gas from federal leases. However, since the only difference is the royalty, production from federal land in the state could be more lucrative than production from state royalty-relieved land.

Are there other factors that could be linked to competitive bidding on federal lands? This is not for the state to decide as it has no authority to influence federal lease terms, but can appeal to Congress and make recommendations. Is this worth consideration by the state?

- A fiscal element (e.g. royalty) could be linked to the bidding system (e.g. Libya EPSA IV).
- Work programmes could be part of the bid (e.g. number of wells in a specified period of time or specified and guaranteed minimum monetary values on capital investment).
- Other bonuses (e.g. production bonuses, daily rates, cumulative volumes produced or production start-up) could be second-order biddable items (not determining the initial award).
- Timing to drill the first well from award of the lease (perhaps with royalty or other fiscal relief for early drilling).
- Too much focus on the magnitude of the bid bonus may raise short-term revenue for federal government but restrict competition for the most prospective areas to major companies able to afford high bonuses.
- NOCs and especially those backed by sovereign-wealth funds have proved themselves over the past few years as amongst the best funded and most aggressive companies for worldwide large-reserve potential exploration acreage

(e.g. CNOOC/China, Gazprom/Russia, Statoil, ENI, Petrobras) and are most able to win bid bonus competitions. Introducing other criteria into bidding process can achieve other government objectives and provide the federal government (and state?) with more discretion with respect to how acreage is best awarded to optimize competition and maximize exploration drilling.

Opinions vary as to whether there is a case to be made for more cooperation between the state and federal governments concerning the timing and terms of future lease sales of federal lands opened for exploration, both to optimize activity and government (federal and state) fiscal take over the long-term.

There are some peripheral benefits in having some fiscal terms negotiable or biddable in lease sales or direct negotiations with producers. Negotiations with a range of companies can help the fiscal authorities gauge what issues are important to all companies (large and small) operating in the region at any given time and how to potentially alter terms to improve performance or attract more investment. They also enable the government to gauge the industry's appetite for challenging projects and enable them to propose innovative solutions that include some fiscal design components.

X. Fiscal Terms Linked to Rates of Return and R factors [issue modelled in Section 4]

Many countries link rates of fiscal elements to project cash flow or return on investment (*net mechanisms*), regardless whether they are applying PSAs or mineral-interest systems.
Many countries use cash flows (revenues less costs), R-factors and IRRs as measures of profitability and return on investment to determine the rates of progressive taxes and also production splits, royalties and cost-oil allocations. Alaska's progressivity tax is linked to cash flow and production (PTV per unit of production) in a specific period (i.e. month). Linking progressivity to return-on-investment indicators could make it more sensitive to the overall commercial performance of each project (or lease, see ring-fencing issues below) to date, rather than project performance in a single period. There are several issues to consider with such an approach, including:

- Applying project R-factors or IRRs makes taxes progressive. A point illustrated by models presented in Section 4.6.
- Linking fiscal rates to cumulative profitability (and reserves) can help target large fields and increase take from more mature projects. This point is illustrated by models presented in Section 4.6.
- It is best to avoid linking fiscal rates mainly to production quantities as this leads to regressive consequences. This point is illustrated by models presented in Section 4.6.
- In applying such mechanisms it is necessary to establish clear guidelines for what costs are allowable in calculating R-factor and IRR.
- In applying such mechanisms it is necessary to establish rigorous cost auditing to guard against cost gold-plating by IOCs.

Linking fiscal elements to rates of return. There are several questions to be answered when considering this issue:

- How should the rate of return be calculated?
- Should it calculated on a nominal or real basis?
- Should it be before or after certain other fiscal elements are deducted?
- Should it be at the field or lease level?
- How can cost gold-plating by IOCs to avoid passing profitability thresholds be avoided?
- What are appropriate return percentages that should be used as thresholds?

The models presented in Section 4.6 include a rate-of-return mechanism as one potential option for driving an Alaska natural gas progressivity tax and compares it with other mechanisms.

Linking fiscal elements to R-factors [ratio of cumulative revenues to cumulative costs]. There are several questions to be answered when considering this issue:

- How should the R-factor be calculated? Cash-flow basis or accounting rules? Should destination value revenues, point of production revenues or production tax value revenues be used to calculate the R-factor numerator?
- Should R-factor calculated on a nominal or real basis?
- Should cost deduction be allowed for payment of other fiscal elements?
- How can cost gold-plating by IOCs to avoid passing profitability thresholds be avoided? How is it distinguished from reinvestment in more challenged reserves?
- What are appropriate R-factor values that should be used as thresholds?
- R-factor of 1 indicates nominal payback; R-factor of between 1.2 and 1.5 (depending upon timing and magnitude of investment and product prices) indicates payback on a discounted basis, taking into account time value of costs versus revenues. Should this be taken into account in setting thresholds? This can be used to provide incentives to IOCs to explore and develop high-cost/remote/deepwater regions.

The models presented in Section 4.6 include an R-factor mechanism as one potential option for driving an Alaska natural gas progressivity tax and compares it with other mechanisms.

Linking cost-recovery fiscal instruments to profitability. Some production-sharing contracts do this (e.g. Sakhalin II). This limits the amount of revenue made available for cost recovery once projects have exceeded certain thresholds of profitability. However, it can cause problems in cases of large cost overruns.

- Linking cost-recovery allocations to project IRR, R-factors or just allowing 100% of revenue to be allocated to cost recovery until all costs are recovered can lead

- to governments not receiving any taxation revenues for many years.
- The higher the costs the longer the delay in profits being shared or taxed.
- It is better to have such provisions accompanied by a fiscal element that guarantees the government some part of the revenue cost from the start of production (e.g. a royalty, even though that is a regressive element).
- It is also beneficial to introduce a cost-saving incentive to the cost-recovery allocation method (e.g. Malaysia).

This is unlikely to be an instrument that can be applied to the Alaska fiscal design or other mineral interests systems. However, it is worthy of note, because IOCs have negotiated and agreed to such arrangements in some PSAs.

Ring-fencing of cost allowances and measures of progressivity. On the revenue and profit-sharing side it is possible to apply ring-fences at the field level, lease level or country level. If R-factors or levels of daily production apply at the lease level and not the field level then once certain thresholds have been passed all future field developments will pay higher marginal rates of taxes or have lower profit shares accruing to IOCs. Such a situation can deter further investment in an already successfully developed lease. As exploration tends to find large fields first in a lease and then smaller satellite fields, having ring-fences at the lease rather than field level can fiscally penalize the later satellite fields and perhaps defer or postpone their development. Applying R-factors or profit split thresholds individually to each field offers investment incentives, but limits government potential taxation revenues. This feature has not been modelled in Section 4.6, but could be modelled in some detail if deemed necessary.

XI. Fiscal terms linked to environmental issues

Introducing fiscal elements linked to environmental issues. There are several questions to be answered when considering this issue:

- Should there be penalties and/or levies based upon volumetric emissions/natural gas consumed as part of field operations?
- How are emissions (all greenhouse gases: CO_2, CH_4, NO_x, etc.) to be measured/monitored?
- How are the fee levels to be set? And by which body?
- Should environmental charges/fees raised be invested in renewable energy projects, technology or research to improve emissions, performance, etc.?
- Should a levy be made in the form of a green or low-carbon fund to subsidize emission-reduction projects like carbon capture and sequestration?

Environmental damage and costs are an increasingly important issue for the upstream sector and IOCs are now used to having levies and penalties linked to certain environmental emissions limits. It is possible at some stage in the future that Congress will adopt some sort of carbon dioxide cap-and-trade system for CO_2 emitters, including fossil fuel producers, processors and shippers. Fiscal elements can target different issues, for example:

- Levies linked to carbon emissions (US$/ton).
- Green funds linked to volumes of production, perhaps with higher rates for oil and sulphur-rich gas than sweet gas.
- Penalties linked to volumes of gas flared, other toxic emissions or waste materials (e.g. drill cuttings).
- Research and development funds for investment in low-carbon, clean renewable energy technologies (flat-rate annual fees for all operators).

Such taxes or levies could be introduced at low rates initially and perhaps subsequently linked to broader national schemes as they emerge and carbon pricing achieves more transparency at a national and international level. They would represent a small component of the overall fiscal take.

It is unlikely that IOCs would be able to object to such taxes and levies from a public relations perspective, unless a double taxation mechanism at both federal and state levels were to be proposed. Those operators investing in environmentally beneficial schemes (e.g. carbon capture and sequestration) should expect to be granted reductions or exemptions from some of these environmental charges and probably provided with other fiscal incentives.

XII. Defining Duration of Future Leases and Timeframes to Develop Discovered Resources

In order to avoid the situation whereby an IOC discovers natural gas but then fails to develop that resource for several decades, clear rules on how long a resource may be held undeveloped by a lease should be defined. Natural gas projects generally take longer to develop and deliver gas to markets than crude oil reserves. As Alaska well knows, much of this additional time is associated with the construction of midstream transportation infrastructure (gas processing plants, pipelines and/or liquefaction plants and tankers). Much time is taken up before facilities engineering and construction commences in gaining commitments from investors that can require fund-raising of tens of billions of dollars. To secure such investments usually requires a clear fiscal design with incentives for investors to accelerate returns on their investments, long-term off take agreements with large gas utilities in gas consuming markets, with take-or-pay provisions and clear price indexing terms.

Issuing upstream leases to promote natural gas exploration in regions where no transportation infrastructure has been built or will not be commissioned until many years into the future requires careful consideration of the time allowed for investors to hold gas discoveries without developing them and exploration leases without drilling them. However, once sufficient downstream infrastructure capacity is in place, further upstream developments have much fewer time challenges to overcome.

In the U.S. oil and gas industry, leases awarded do not expire while a leaseholder is still producing gas from a reservoir. In some countries this is not the case and this has worked well for many countries in accelerating industry activity (e.g. Malaysia with production periods of just twenty years from first production and dependent on a declaration of commerciality). The majority of countries now impose time limits for production periods and it is not unusual for producing fields to be surrendered to governments under such terms. Use–it-or-lose it concerns are addressed by such regulations and they help to prevent acreage or discoveries lying fallow for many years. Most IOCs have signed up to such restrictions around the world.

These issues lead to the following considerations regarding **production period durations**:

- Leaseholders should be granted limited but specified periods to hold a gas field prior to declaring commerciality, but this should be linked to whether or not infrastructure capacity exists to move gas to markets and whether the resource holder is in a position to build the required infrastructure. If the resource holder states that they are unable to build such infrastructure, in many countries those fallow, undeveloped resources are returned to state ownership after a relatively short period of time.
- How long should this holding or appraisal period be? Probably no more than ten years (and some governments would argue substantially less), at which point they have to decide whether to develop a discovery (i.e. to declare commerciality) or hand it back to the state. If it declined to do so it would be required to relinquish the lease back to the state. Once infrastructure exists with available capacity and third-party access provisions, it would be realistic for such a holding period to be reduced to something of the order of five years or less.
- Contract durations for upstream gas field developments in many countries are 25 to 30 years from when production commences. In some countries it can be as low as 20 years.
- Should extensions be granted to the production term for leaseholders that have developed large fields and have substantial reserves left in the ground? Extensions can cause more problems than they solve as they are frequently used by IOCs as points of negotiation later in the life of assets to secure extensions in return for investment commitments. In the years leading up to the negotiable extension period investments can become stalled, waiting on the outcome of negotiations.
- Perhaps linking extensions to mandatory relinquishments of a percentage of remaining reserves would focus the IOCs on more extensive development capital investment during the initial production period, subject to prudent oil field management practices to avoid damaging reservoirs by attempts to produce them too rapidly. Such prudent reservoir management practices would be regulated and monitored by Alaska Oil and Gas Conservation Commission in order to avoid loss of recovery of potential reserves.
- Extensions to production periods should also be carefully defined to avoid being used for mid-term bargaining.

It is also important to establishing an appropriate term (duration) for the **exploration and appraisal periods** associated with a lease, and associated relinquishments and commitments to be imposed on investors. Most countries have exploration periods clearly defined and divided into phases linked to periods in which IOCs agree to complete specified work programs backed up with monetary guarantees. These periods and phases are also associated with mandatory relinquishments. In certain Gulf of Mexico states there are incentives introduced aimed at accelerating drilling once a lease has been awarded (i.e., production royalty rates are set lower for discoveries made from wells drilled early in the exploration period than later in the period). These issues lead to the following considerations regarding exploration period durations and relinquishments:

- How much time should be granted for exploration phases? In many countries the contract areas are large (many thousands of square kilometres), so periods of exploration of up to 10 years are not uncommon. Periods should be shorter if lease areas are small and/or access to them is not limited to seasons due to weather considerations.
- Linking fiscal rates to the timing of drilling within the timeframe of the exploration period; discoveries from early wells receive the benefit of lower rates on a specified fiscal instrument.
- Having mandatory relinquishments at certain specified dates (e.g. 50% of all areas not declared commercial halfway through the exploration period) encourages IOCs to conduct exploration work quickly and thoroughly in order not to hand back prospective areas for re-licensing.
- Relinquishments also help to stimulate competition and more activity and give the state the opportunity to raise bid bonuses on re-licensing relinquished areas.
- It may be necessary to specify what work program should be completed and in what timeframe to adequately appraise a discovery before commerciality can be declared or a potentially commercial gas reserve can be held by a leaseholder pending midstream infrastructure. Solitary exploration wells on their own often do not confirm substantial quantities of reserves. Adding appraisal wells can significantly add to the confidence of the volumes of potentially commercial reserves present in a discovery. Specify appraisal obligations in lease terms can be beneficial to governments in long-term planning and resource development.

XIII. Targeted Investment Instruments to Promote Strategically Desirable Behaviour from Producers

Targeting Investment credits to specific desirable investments can be effective at encouraging desired responses from producers. There are a number of project types that could have long-term benefits for the oil and gas industry in Alaska and to the Alaska natural and commercial environment in general. Many of these require additional investments to which some operators may need incentives to persuade them to adopt. Investment credits to be offset against other fiscal instruments, such as those already offered by Alaska for upstream investments in general, could be increased or restricted to projects such as:

- Enhanced recovery projects
- Carbon capture and sequestration (CCS)
- Methane hydrates
- Deep tight-gas reservoirs

In offering investment credits the state takes the risk of projects proving not to be commercially viable after the investments have been made and the credit have been taken or traded. An alternative to consider is to offer “negative” royalties or a reduction in royalty rates instead once projects enter production or reach certain production milestones. Such instruments are essentially fiscal payments from the state to the IOCs to be added to the IOC’s revenue stream once the high- cost, high-risk projects start to generate revenues and have proved to be commercial, thereby removing substantial risk from the state.

Projects selected to receive preferential tax incentives for a period of time could include:

- Strategic infrastructure projects.
- Enhanced and tertiary recovery projects.
- Carbon capture and sequestration projects.
- Exploitation of methane hydrates reservoirs.
- Deep, tight-gas reservoirs, etc.

Such targeted fiscal Instruments could include:

- Investment credits (already used more broadly in Alaska’s upstream fiscal design).
- “Negative” royalties or a reduction in royalty rates (less risky than investment credits as they are only paid out when revenues are generated by the projects). Such instruments can also be of limited duration rather than royalty reliefs applied over the life of a field production project.
- Tax holidays to encourage investors to commit to costly infrastructure developments. These should be structured carefully and probably targeted at downstream gas treatment or transportation infrastructure projects to avoid too much shelter to profitable upstream production projects. Tax holidays are usually issued with some time commitments from the government, which for the sake of fiscal credibility, it is prudent for the government to honour.

XIV. Cost Control Instruments

Many governments have suffered substantial fiscal revenue reductions in recent years as a consequence of massive budget and schedule overruns by IOCs in large international gas development projects. However, trying to link IOC cost-control performance to the rates applied by fiscal instruments is not easy, but there is recognition that agreeing to fixed fiscal terms with IOCs with favourable cost recovery structures appears to be a recipe for encouraging poor cost control. Each project and reservoir has its own cost issues and it is very difficult to apply historical industry marks to all projects in a region.

Targeting fiscal instruments to inhibit cost gold-plating by IOCs to counter fiscal instruments linked to profitability measures is desirable. However, it is quite difficult to structure fiscal elements that reward investors for good cost control, budgeting and low finding and development costs. Poor performance in this regard is a particular issue and risk for progressive fiscal elements linked to a project's return on investment measured by R-factors or IRR. They are vulnerable to IOCs overstating costs or failing to control them. The effect of such actions is to reduce apparent profitability and enable the producer to stay within a lower tax-rate tranche of the fiscal element. If such instruments are to be used it would probably be prudent for Alaska to review its cost audit powers and procedures.

- In the context of production-sharing agreements Malaysia found one innovative way to do this by providing a higher split of unused cost oil allocation to the IOCs than they could achieve from the profit split for a project at the same R factor. This encourages IOCs to maximize the unused cost oil allocation (i.e. reduce cost) to gain a larger revenue share.

- In mineral-interest systems a mechanism that provides greater accelerated depreciation or capital cost uplift for large projects could be offered in return for remaining inside specified, industry average, unit finding and development costs or operating/lifting costs (US$/boe basis) or achieving first production within so many years of drilling a discovery well. Defining the cost thresholds can be a challenge. Accelerated depreciation is difficult to apply in the Alaska fiscal design as costs for the production tax value are expensed and depreciation for Alaska CIT is applied to worldwide income. However, a cost uplift allowance (e.g., different rates for different categories of costs) to royalty granted only to those projects that achieved specified unit cost performance targets (e.g., benchmarked against "average" Alaska projects for say the previous three-years on a rolling average basis) could be effective at improving IOCs' cost-control performance.

- Nigeria provided fiscal incentives for many years to IOCs that minimize costs and maximize reserve additions in its joint-venture relationships. However, the reserve-addition component proved difficult to monitor and verify and appears to have been widely manipulated by the IOCs (it was involved in Shell's reserve restatements in 2004).

- If R-factor or IRR profitability measures are to be used to drive fiscal rates, then robust cost-control measures and cost-auditing powers need to be included in the fiscal rules and rigorously applied to avoid cost manipulation.

- Tailor rules for cost and revenue ring-fencing and rules for loan interest and financing cost deductions such that terms are favourable for investors with good cost performance track records and for those investors in infrastructure projects that fit with the state's strategic objectives. Alternatively increasing R-factor thresholds for taxes (i.e. higher tax rates would be paid later) for leaseholders that perform substantially better than average in Alaska projects in terms of unit finding and development and/or lifting costs.

- Alaska has already attempted to limit cost-escalation impacts on fiscal revenues by freezing operation costs deduction (under production taxes) for Prudhoe Bay and Kuparuk at 2006 levels plus 3% inflation for three years. The author is not aware of the background to such limits in the case of these specific fields, but it may be worth considering how to adapt such a mechanism to a more generic cost-control fiscal instrument that could be applied more broadly to producing assets in the future. These measures themselves do not limit cost inflation and could in some circumstances act as regressive elements. However they do place pressure on investors (specifically operators) to pay close attention to cost control.

XV. Domestic Market Obligations (DMOs)

Domestic market obligations (DMO) are applied by several countries to supply either the state or the local market with oil or gas at a specified price (usually discounted). This instrument is now used by several countries and is not necessarily linked to price subsidies within those countries. Governments may sell the gas they receive at a discount from producers at higher prices to a buyer in another country. Price subsidies often end up being painful for a government to remove at a later date and make little sense as part of a progressive fiscal design. Where it does not promote discounted domestic wholesale or retail energy prices, a DMO is an instrument worthy of consideration. This mechanism can simply provide a portion of produced gas to the state at a discounted price. The state may then (and often does) sell the DMO component it receives outside the domestic market at a higher (international) destination market price.

There are some issues to consider.

- Would a DMO be deemed in Alaska as a price subsidy and contravene free market principle, even if local market subsidies are not involved? The state already gives subsidy through lower production taxes rate for in-state gas use.
- Is the local market demand sufficient to justify or benefit from this fiscal element?

- Would a DMO help to develop and diversify local gas and NGL markets?
- What discount, if any, should be applied?
- To which products should DMO apply? Natural gas, LPG, ethane, crude oil?
- Would all Alaska citizens and industries benefit equally from a DMO?

XVI. Fiscal Benefits for Direct Equity Participation by Alaska Corporations

Offering fiscal benefits to Alaska companies taking direct equity shares in upstream projects could promote in-state economic development and employment. Under current free market rules it is probably not possible for the state to tax in-state companies any differently than out-of-state companies. Even if it was possible there are potential issues surrounding how to define and regulate companies as being in-state and avoid the status being manipulated. There is a necessary distinction to be made in this regard between direct equity share and investment. A direct equity share in an upstream project is referring here to a company investing to become an active joint venture partner in that project and thereby creating some technical and administrative employment through its value-adding activities to the development of a field or group of development projects. Such direct equity investments are distinguished from pure financial investments made through funds, royalty trusts and a variety of debt and venture capital mechanisms that may not involve direct activity in the development of the assets involved and may result in only limited, if any, local employment opportunities, etc.

Many countries give benefits to local companies and industry (e.g. Nigeria). Two questions need to be asked before such a benefit could be given serious consideration.

- Should this be part of the Alaska fiscal design?
- Is it acceptable under federal free-market rules and federal constitutional guarantees governing interstate commerce?

Issues to address with respect to this approach include:

- There must be a clear definition of what constitutes a qualifying Alaska company (e.g. shareholdings, number of resident employees, etc.).
- Such incentives could also help an Alaska gas service industry to evolve and develop.
- IOCs could be rewarded fiscally for partnering on an equity basis with local participants in upstream leases.
- A training/skills development levy could be included as an upstream fiscal instrument to promote improved skills and availability of better technology for Alaska's oil and gas industry and training establishments.

- Benefits would have to be tailored to meet U.S. free-market/anti-trust regulations.
- Such rules could prove to be very popular in Alaska as they could boost employment and further disseminate value from natural gas production within the state.

XVII. Reward IOCs for Partnering or Investing in Local Companies

There are constitutional issues that restrict such an approach in Alaska. However, there are several alternative ways in which this is achieved internationally, for example:

- Introducing a mandatory requirement for X% Alaska partners in new lease awards.
- Offering a fiscal incentive to IOCs that involve local equity content in the joint venture holding a lease. For example the "negative" royalty concept offered in Philippines is only paid out once revenue is generated by a project.
- Fiscal benefits could be on a sliding scale linked to the percentage of local equity content.
- Offering higher levels of tax credit is more risky for the state as it could involve pre-revenue payouts by the state to investors.
- Benefits could also be linked to capital spent with Alaska-based contractors and suppliers (i.e. those employing staff in Alaska).
- Such benefits would need to be structured in order not to breach free market restrictive-practice rules nor best practice procurement regulations.

XVIII. Provide Choice of Fiscal Designs for a Limited Period of Time Upon Declaration of Commerciality

- Once the choice is made by the investor it is final and cannot be reversed. In offering such a choice the government is providing some assurance of partial fiscal stability in that it will honour the investor's choice for the project in question. Peru has introduced such an element of choice.
- For a specific fiscal element an IOC group (i.e. at the whole project level) could chose between a production-based fiscal design (i.e. tax rates go up progressively as either daily production or cumulative production passes defined thresholds) or a profitability-based fiscal design linked to IRR or R-factor.
- For high-cost developments the profitability design may provide an early return on investment. On the other hand in a high-price environment a production-based design might result in a lower overall tax burden.

- The element of choice increases flexibility from an IOC's perspective, which is more likely to attract investment.
- Such schemes can however increase the level of administration for the tax authority to calculate and monitor the tax burden of many projects applying a range of fiscal designs.
- Placing the choice in the hands of the investor at the time of declaration of commerciality provides the IOC with some alternatives that may encourage positive investment decisions. Of course, the state could be sacrificing some long-term revenue by providing such a choice in return for perhaps securing more investment commitments.

XIX. Vary Tax Rates Linked to Size of an Equity Holding

Varying tax rates linked to the size of an entity's equity holding can provide a mechanism for taxing organizations with large equity holdings at a higher rate than small-interest holders. Most large IOCs prefer to hold large equity interests in projects. If there is an objective to target taxes toward the larger projects and companies with larger production volumes and revenue streams, one possibility is to apply a higher tax rate to equity holdings above a certain level (minimum threshold holding between about 20% and 40%). This approach is taken in Azerbaijan.

- At what equity level should the upper tax rate apply?
- Lower rate incentives given to smaller equity holdings could apply up to a certain level of profitability – i.e. linked to an R-factor or IRR.
- Rules would be needed to exclude multiple affiliates being involved in single lease to reduce minimum holdings.
- This approach can increase overhead costs if all licences are held by large number of small equity participants.
- It can also promote a more diversified holding of strategic infrastructure.

In Alaska's production tax while there is only one BPT rate, credits and other components are phased out based on production, creating different effective tax rates for different sizes of producers. In some ways this follows the federal income tax model that has few nominal rates, but with various deductions and credits being phased out with income, a much greater number of effective rates.

XX. Introduce Tax Incentives and Fiscal Mechanisms for IOCs Committing to Build Strategic Gas Processing and Gas Storage Infrastructure in Alaska

Upstream and downstream storage facilities are an essential part of modern natural gas supply chains. For fiscal purposes it is important to establish whether gas storage is built downstream of first valuation point (in which case it is a deductible cost), or if it is built upstream on the

North Slope (which would imply that the hoped for gas pipeline would have capacity variations such that storage makes sense) whether it is a production facility or not.

Gas storage reservoirs in Alaska closely located to a pipeline could add value to Alaska gas at periods of peak (winter) demand, when it may be difficult for operational reasons to increase production from natural reservoirs. IOCs prepared to build such storage should be provided with some fiscal incentives.

There are possible scenarios in which natural gas storage may be beneficial at the proximal end of a gas line depending on the nature of the gas sales contracts (long-term, medium-term, short-term, or a combination of all three contract types). All of these alternatives are yet to be established. Gas-consuming markets in North America are seasonal and price spikes tend to occur in winter (for heat and power consumption), together with some summer spikes for air conditioning. If there is capacity in the gas line to move gas in winter to supply peaks it could be beneficial for producers and the state. Gas producers do not want to cut back production in summer and usually produce some gas into storage for sale when demand and prices materialize in winter.

The ideal way for the producer to move natural gas off-peak into storage is to hold gas storage capacity close to the markets. However, there can also be benefits in holding gas in storage along the whole supply chain. For instance, there is a lot of gas storage onshore Gulf of Mexico -- more than is required for the Gulf states. Much of that gas is ultimately shipped to the major consuming markets to the north, northeast and on occasions west, depending on prevailing demand in those markets. Major gas producers putting gas through an Alaska gas line could benefit from holding capacity in natural gas storage facilities in Canada, the northern Midwest and potentially also in Alaska. This could enable producers to sell some gas to their storage holding affiliates at low off-peak prices with the affiliates later selling that gas on into consuming markets at peak prices. Alaska could benefit in tax revenue terms from gas storage in the state, located upstream of the point of production. If all the storage is in Canada and the Lower 48 it could be more difficult for Alaska to benefit from onward sales of gas at higher prices out of storage inventory as upstream fiscal revenues.

XXI. Third-Party Access (TPA) and Use-It or Lose-It Rules need to be Carefully Crafted

In some gas markets, strategic infrastructure (pipelines, storage facilities, gas processing plants, LNG facilities) and/or capacity in that infrastructure are controlled by a small number of major IOCs and gas utilities that have been granted full or partial exemption from third-party access (TPA) in order to secure their commitments to invest in building that infrastructure. These exemptions are often ultimately granted, after lengthy negotiations, even though national or regional regulations specify that such infrastructure should involve unrestricted TPA rights. Without such exemptions many IOCs or utilities are reluctant to take the risks of building expensive infrastructure from which other shippers of gas may ultimately benefit more than they do, without taking the high upfront investment risks.

If TPA exemptions are ultimately granted in order to secure investment they can in the long-term strengthen rather than weaken the control that dominant IOCs and/or gas utilities have over the local gas chains. Such a situation can significantly restrict competition in the industry and restrict access for smaller producers and stifle investment and further development.

FERC already regulates requirements for third-party access to gas pipelines, especially the Alaska gas pipeline which is covered by its own set of federal laws. Such laws prohibit full or partial exemption from third-party access for an Alaska gas pipeline. Moreover, the Alaska Gasline Inducement Act (AGIA) and the legislatively approved exclusive license (August 2008) to TransCanada reconfirms third-party access requirements, though FERC is the ultimate controlling authority for TPA concerning an interstate gas pipeline. AGIA also dictates some very specific terms for access and capacity expansion of the gas pipeline in order for the license holder (TransCanada) receiving certain agreed cash incentives from Alaska. Although federal regulations and the AGIA are clear on unfettered TPA access to a gas pipeline, there may arise situations in which gas processing, gas treatment, storage facilities, or other infrastructure components become essential elements to ensure efficient supply of gas for specific supply chain. In such cases it may be prudent for the TPA rules applied by FERC and the AGIA provisions to be diluted to an extent.

It is important to take into account that in spite of strong TPA access regulations in the Lower 48 and Europe, many companies building strategic peripheral infrastructure (such as gas treatment plants and gas storage facilities) tying into the transmission system apply for, and often secure, exemptions (full or partial) from TPA in return for their large capital commitments (e.g. the precedent set by FERC's ruling on TPA for the Hackberry LNG receiving terminal in Louisiana).

In December 2002 FERC ruled that this proposed LNG import terminal could be built without complying with the open-access requirements that have been strictly applied to all parts of the gas transmission chain previously as part of ensuring open competition in the deregulated gas market. This "Hackberry Decision", as it is known, has encouraged proposals to build new receiving terminals without developers risking having to offer capacity to third-parties at market rates (Figure 2.6.1).

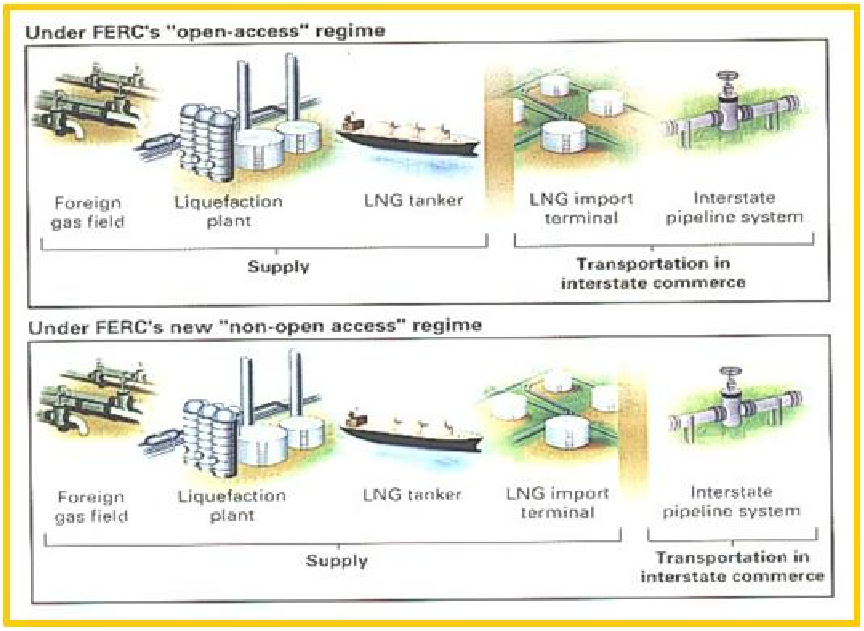

Figure 2.6.1 Third-party access compromise by FERC in Louisiana with respect to LNG receiving (gas treatment) terminal (figure source: Oil and Gas Journal, 10 November 2003).

In some cases TPA exemption is a reasonable commercial compromise by governments wishing to develop infrastructure to expand market capacity. However, in making such decisions it is essential for governments to consider at an early stage the long-term strategic implications of derogation of TPA regulations. Investing companies will always plead that they are a special case in attempts to secure even partial or limited period exclusivity.

- Tax incentives could be linked to guaranteed ***third-party access*** (TPA), up to a minimum percentage capacity.
- At what level should minimum TPA access rights be set for strategic infrastructure, irrespective of tax incentives?
- Policies and provisions for TPA should be carefully structured to incentivize investors without providing them excessive market power or stranglehold level of control over a supply chain's critical infrastructure.
- If TPA exemptions are awarded then transparent and workable tariff schemes for third-parties and use-it-or-lose-it rules/conditions should accompany any TPA exemption granted to infrastructure capacity.
- Harsh and prompt fiscal penalties should be included for abuses of TPA provisions, to discourage such attempts by the infrastructure operators.

XXII. Offer Tax Holidays or Time-Limited Reliefs to Encourage Investors to Commit to Costly Infrastructure and/or Field Developments [issue modelled in Section 4]

Such incentives can be risky for governments in volatile markets and in rapidly depleting reservoirs and need to be targeted carefully and offered for limited and clearly specified time frames.

- Tax exemptions should be focused carefully on specific sectors of the supply chain to avoid exempting highly profitable revenue streams.
- Exemptions could be granted for natural gas revenues, but excluded for oil and NGL revenues associated with a project.
- In some reservoirs production depletes rapidly over a short period. In such cases although a 5-year tax holiday may only represent 20% of the field life on a time basis, it may cover 50% of liquid revenues.
- Tax holidays, however, are more targeted than permanent reliefs which extend over an entire project life. They may have made sense when issued (e.g. 50% relief on royalty rate) but in changing markets they can sacrifice a large component of fiscal revenue in a subsequently high-price market.
- Once a royalty relief or other types of investment credits designed to compensate for the regressive impacts of certain fiscal elements have been offered and investment commitments made by producers under such provisions, it would damage the fiscal credibility of the state if they were to be removed or diluted before the producer had received the benefits.

XXIII. Training Bonuses and Technology Transfer are Subordinate Elements in Many Upstream Fiscal Designs

Payments made by producers to states or local communities for training or access to technology or research findings can provide useful benefits in developing local skills, community infrastructure and local industry standards.

- Many IOCs are prepared to agree to such payments sometimes even without any concessions made by the government on revenue-related fiscal elements. Such benefits can be optimized to meet a particular local skills requirement at an early stage of a project.
- They can help to align local communities to specific industry infrastructure developments.

XXIV. Benefits of Long-Term Natural Gas Sales Contracts for Financing

Final investment decisions by equity investors for most large international upstream gas field development and supply chain infrastructure projects do not get sanctioned until there is usually more than one long-term contract, often with stringent take-or-pay provisions agreed to by the gas buyer. Long-term gas sales contracts are not the norm in U.S. gas supply, but might be useful in reducing risk and securing investment in some Alaska gas development projects in the future. Hence the benefits and drawbacks of long-term gas sales contracts should be evaluated in the context of the Alaska gas line and future gas field developments in Alaska.

In long-term natural gas sales contracts it is necessary to establish how commodity price (market) risk is to be addressed. In many cases prices in long-term contracts are indexed to benchmarks and in some cases to a basket of competing fuels. Both buyer and seller are taking on market risks. If prices are fixed over long periods (now rare), then both the buyer and seller are taking on price risks. Some contracts include re-opener clauses (often linked to specific dates or after certain periods of time) providing the parties to meet and discuss pricing amendments in the light of changes in the market conditions (supply/demand) or market prices. As the state crafts its fiscal design for natural gas it has to bear in mind that changing market and destination market price could have significant impacts on upstream producers and the profitability of their production.

- The requirement for long-term sales contracts is one of the main reasons why it is impossible to focus fiscal design for natural gas solely on the upstream sector. For the upstream component to go ahead it depends on midstream infrastructure capacity and a long-term sales contract on viable commercial terms with a financially robust customer also being in place.
- This sales contract and the tariff cost of transportation, and probably a gas treatment plant fee, will influence the netback gas price and upstream profitability.
- Upstream fiscal instruments will depend heavily on the terms and performance of such gas sales contracts.

In Alaska currently, fiscal design destination values used to calculate both production tax and royalty liabilities are the higher of publicly reported or assessed market values (price discovery based upon benchmark price reports) and what the producer/gas supplier actually sold the gas for in each transaction/delivery. For such rules to be effective it is important that long-term sales contracts, particularly those between affiliates, have provisions for transparent price discovery for natural gas and NGL sales.

XXV. Integrated Projects have Facilitated Multi-Billion-Dollar Investment Commitments by Major IOCs in Several Countries in Recent Years

Integrated upstream/downstream infrastructure projects appeal to equity investors both for pipeline and LNG supply chains. Qatar, Sakhalin, Angola and Papua New Guinea are some examples. IOCs prefer integrated projects because they prefer to control the infrastructure on which their upstream production is going to rely upon for several decades to deliver it to distant markets. The fiscal structures of integrated projects can become quite complex and are often not conducive to third-party access. Alaska should explore whether in the long term integrated projects may attract investment to future strategic infrastructure projects such as a new gas liquefaction plant.

In the context of the U.S., FERC has the sole authority to set and regulate interstate gas pipeline tariffs, and it does so on each pipeline without regard to upstream development costs or profits. Indeed, federal law requires as a rule a legal distance between pipe companies and field developers, even if they have the same parent corporation. In some countries affiliates of a single company owning infrastructure and passing a commodity through it in competition with other users of that facility are obliged to adopt "Chinese walls" isolating the affiliate responsible for the facility's operation from the affiliate responsible for the commercial trade passing through it. Many are sceptical as to how effective such rules are in avoiding potential market manipulation. For multibillion-dollar investments many countries are forced to consider some derogation of the third-party-access rules that would otherwise limit one company's ability to own upstream and midstream facilities in one supply chain. This has happened in recent years in the Lower 48 in respect of LNG receiving terminals (e.g. the so-called Hackberry ruling 2005)

Integrated projects raise complex issues for taxation authorities:

- Should the downstream infrastructure be operated as tolling facilities with tariffs providing set levels of return to investors with all profits passed upstream to the gas field development? Such an approach is preferred by many countries (e.g. Trinidad and Tobago and Egypt for LNG) as it enables them to take a greater share of revenue through upstream fiscal designs.

- The alternative is for the upstream to sell the feed gas at a modest price to the processing plant or downstream company. Only modest revenue streams are then involved in upstream fiscal design. The midstream company then sells the gas on at market prices and most of the revenue stream is taxed at the downstream level. If the downstream fiscal design involves tax holidays and only modest corporate taxes the IOCs are able to secure a much greater share of the economic rent from such fiscal mechanisms.

- In either case there is also the issue of other revenue streams being sold along other supply chains (e.g. oil, condensate, C5+, LPG, ethane, etc.). How should all of the revenue streams be consolidated effectively in a fiscal design?

Key Issues with Relevance for Alaska from the Twenty-five Issues Discussed

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.
- Strengthen tools which limit ability to hold title to undeveloped discovered gas resources, by clarifying what constitutes development and the obligations of investors.
- 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.
- Overall political stability (as defined in section 4.3); benefits of operating in supply chains that involve only U.S. dollar revenues and cost.
- Experienced and competitive service sector and workforce.
- A new gas fiscal design that is responsive to industry requirements (once unveiled).
- Welcoming business environment for most non-U.S. multi-national companies, although the U.S. is more reticent about Russian and Chinese state-owned companies taking equity positions in U.S. companies and projects.