A Comparison of Fiscal Regimes

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October 18, 2007

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A COMPARISON OF FISCAL REGIMES

Cambridge Energy Research Associates (CERA) has been requested by ExxonMobil to consider how the current and proposed fiscal regimes in Alaska compare with other fiscal regimes for both oil and gas developments around the world.

APPROACH

When comparing fiscal regimes, most analyses focus on the level of "state take" as a tool for ranking. This is an oversimplification. Ranking by state take is only a proxy for what really influences investment decisions—the value creation resulting from the deployment of investors' capital.

More useful, detailed fiscal analyses can be obtained by applying different fiscal regimes to an example model field and comparing the resulting development economics and levels of state take. However, this approach still oversimplifies the situation by assuming a world devoid of varying climates, topographies, and reservoir conditions, not to mention market conditions (including distance to liquid markets).

By contrast, in forming our opinion, CERA has considered which countries' oil and gas resources face technical and commercial challenges similar to Alaska's. We have selected conceptual development plans for sample oil and gas fields that are appropriate to each environment—in a range of sizes and at a range of product prices. These analyses are generated using the data and tools of our parent company, IHS Inc., and allow a true "apples-to-apples" comparison of what is left to the concessionaire.

Our approach in the comparison of fiscal terms is to consider what share of the barrel is left to the concessionaire in each jurisdiction. State take competes with capital and operating costs and the time value of money for the remainder. Unless this share of the barrel compensates the risks of exploration, development, production, and eventual decommissioning, the oil and gas resources will not be developed.

In its document *Guiding Principle for New Production Tax System*, the State of Alaska ranks the Marginal Government Take (including federal taxes) under its ACES plan at 68 percent—in line with an average for "all fiscal regimes" of 67 percent. Although it does not specify what regimes have been included, this latter figure is very similar to CERA's own analysis of a wide range of fiscal regimes performed for its 2005 Special Report *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures*. Among these regimes were a variety of operating environments including Algeria, China, Libya, Qatar, and other low-cost operating countries that are very dissimilar to Alaska for the purposes of valid comparison. The pre-tax profitability of activities in such countries leaves more room than a high-cost environment for government take without undermining the attractiveness of investment in exploration and development of their hydrocarbon resources.

How, then, should we select suitable peers against which to compare both current and proposed Alaskan fiscal regimes? CERA selected a peer group consisting of basins—typically situated in offshore or arctic-like environments or where their remoteness from markets results in significant costs—that are comparable to those experienced in Alaska.

KEY FINDINGS

The mean government take of the relevant peer group across a range of oil and gas prices and field sizes, to the extent that this is the appropriate measure, is 57 percent. This compares to a range of 70–75 percent for Alaska under the ACES proposals and 65–71 percent under the existing Petroleum Profits Tax regime.* These figures are based on the undiscounted government take as a percentage of the undiscounted net revenue. This suggests that the current regime favors the government (the combination of federal and state) over the leaseholder when compared to competing opportunities. The ACES proposals worsen this position.

In CERA's opinion a more appropriate measure of the attractiveness of a fiscal regime is the rate of return on development and the profit-to-investment ratio of development (a measure of the capital efficiency and therefore a guide to where a company should direct its capital). These measures indicate that Alaska is not competitive with other similar regimes.

*The range for Alaska depends on the underlying lease royalty rates ranging from 12.5 percent to 20 percent.

CHOOSING THE RIGHT PEER GROUP

To select relevant peers for Alaska, CERA began by identifying countries and basins in which the cost structure was comparable to that found in Alaska. Our assessment excluded field operating costs, but did include the price penalties of quality differentials (such as might apply to heavy, sour crudes) and the costs of bringing products to market. These costs can be calculated as capital sums—such as the cost of a pipeline from Alaska to liquid North American markets for both oil and gas or the costs of building liquefied natural gas (LNG) liquefaction, shipping and regasification. We have employed the convention of using tariff equivalents since this avoids complex issues of allocating capital to fields that share the same infrastructure. However, we have not included the capitalized liability of capacity bookings. Thus, if a field would cost $12 of capital expenditure (capex) per barrel to develop, the pipeline tariff to get it to market were $6 per barrel, and the crude quality resulted in a $5 per barrel discount to West Texas Intermediate (WTI), our analysis would treat it as having a $23 per barrel total cost.

CERA selected from among those countries and basins where these total costs exceeded $20 per boe for reserves with a scale exceeding 200 million boe. The list therefore excludes some high-cost regions such as the US Lower 48 where the scale of resource is simply not comparable to Alaska and also a number of LNG producers where the underlying costs of feed gas are low (including economic credit for associated liquids, e.g., Qatar, Nigeria, and Australia).

A feature of many of these high-cost basins is that long lead times between discovery and development result from the challenge of developing the fields profitably. Long lead times also limit the scope for fiscal take that does not recognize the time value of money without damaging the economics of the project.

Taking into account these criteria, CERA's selected peer group (illustrated in yellow on Figure 1) includes the following regimes:

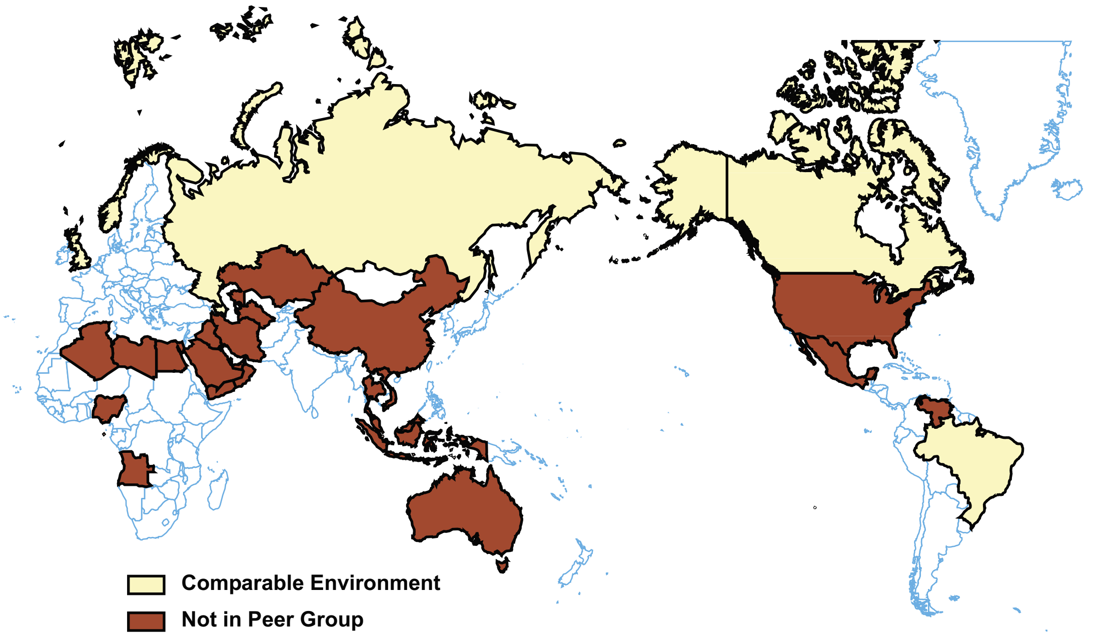
- Azerbaijan offshore
- Brazil deepwater (Campos Basin)
- Canada (Alberta oil sands in situ production, Atlantic coast offshore—Newfoundland and Nova Scotia—and gas from the Northwest Territories)
- Norway arctic offshore
- Russia (East Siberia, Sakhalin)
- UK West of Shetlands

The fiscal terms that we examined for each peer are included in Appendix 1 along with the representative field development examples for each.

Countries and regions that did not make the peer group because their cost structures and risk profiles differed too significantly from Alaska's are shown in red in Figure 1.

Figure 1

Choosing the Right Peer Group



Source: Cambridge Energy Research Associates.
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PLACING ALASKA IN ITS PEER GROUP

CERA has ranked the fiscal regimes by assessing the full cycle exploration and development economics of a range of field sizes at a range of oil and gas prices. The example developments have been analyzed by applying the costs of developing a field in each operating environment to a standard production profile for each field size. In our analysis, we chose

- oil fields of 100 million barrels, 200 million barrels, and 500 million barrels
- gas fields of 1 trillion cubic feet (Tcf), 5 Tcf, and 10 Tcf
- WTI oil prices of $40, $60, and $80 per barrel
- gas prices in each end market of $7, $10, and $13 per million British thermal units (MMBtu)

We applied costs of transportation to markets in which these prices could be accessed and the "costs" of quality differentials for heavy or sour crudes where these are typical of a basin or play.

The economics were run in real terms to exclude the requirement to make assumptions about escalation rates for oil and gas prices and costs. We used costs based on 2007 market conditions for each hydrocarbon province. The relative ranking of each province would not change by using nominal economics.

Furthermore, we have assumed fiscal stability in all markets. For example, we have made no attempt to predict the outcome of the review of royalties currently under way in Alberta, Canada.

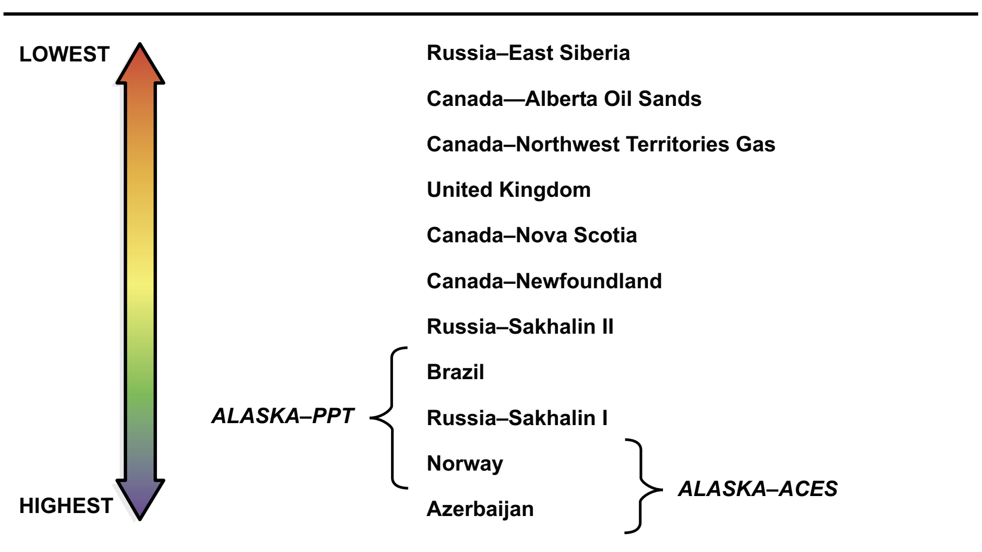
Figures 2–4 rank the attractiveness of activity under the existing and proposed regimes for Alaska versus the peer group.

Based on ranking by government take, Alaska's fiscal regime lies towards the bottom of the peer group. But as we have explained, this oversimplifies the question. Companies do not invest on the basis of a notional share of the returns; they focus on the cash returns and value creation.

Figures 3 and 4 show the rankings based on real rate of return and the profit to investment ratio (calculated using a 10 percent real discount rate).

Figure 2

Government Take



Source: Cambridge Energy Research Associates.
Note: Bracket displays range of positions for Alaska regimes depending on royalty level.
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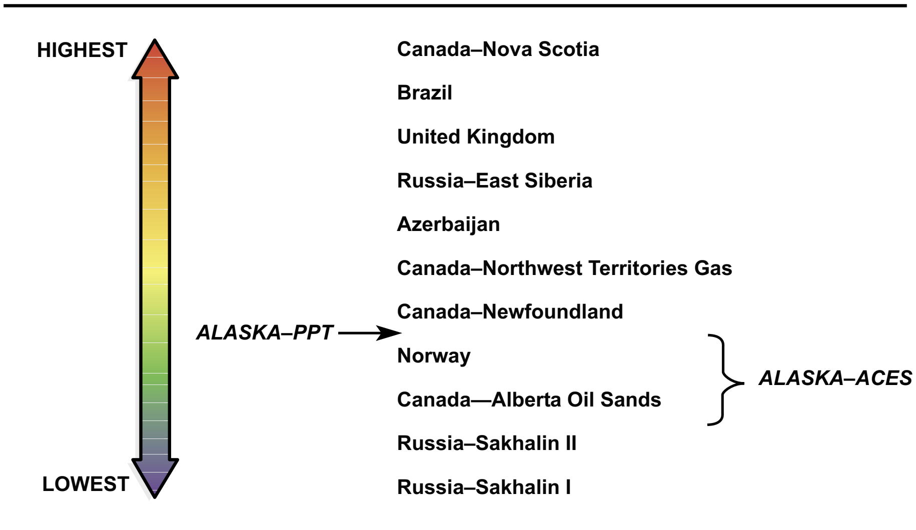
Figure 3

Full Cycle Rate of Return



Source: Cambridge Energy Research Associates.
Note: Bracket displays range of positions for Alaska regimes depending on royalty level.
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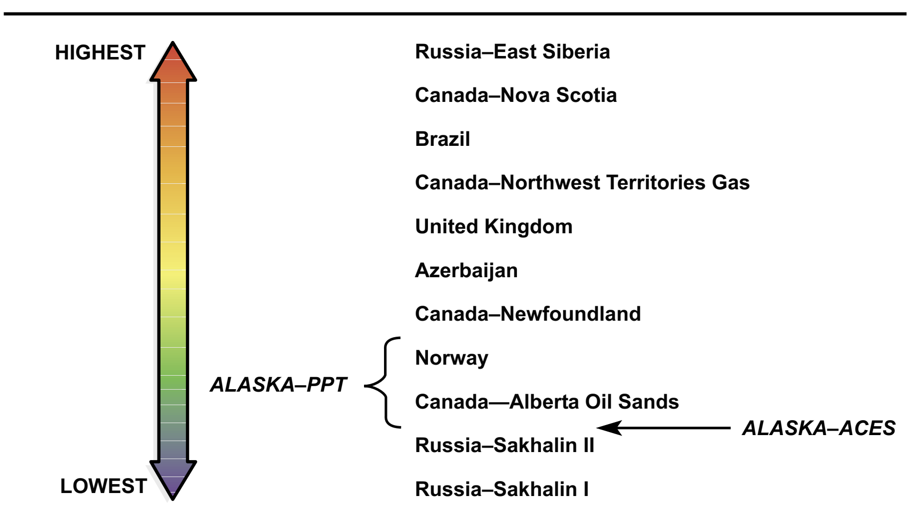
Figure 4

Profit-to-investment Ratio
(10 percent real DCF)



Source: Cambridge Energy Research Associates.
Note: Bracket displays range of positions for Alaska regimes depending on royalty level.
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However, this analysis covers only the development of hydrocarbon resources—it excludes the risks and costs of abortive exploration. The other important factor is whether the value created through successful exploration is sufficient to support the costs and risks of exploration. Companies will not typically invest in exploration unless they expect to create significant value. One of the commonest ways of measuring the value expected to be created through an exploration program is to calculate the expected monetary value (EMV) of the exploration prospects covered by the program. In its simplest form, this can be calculated as

$$EMV = Value_{Success} \times Probability_{Success} - Cost_{Exploration} \times Probability_{Failure}$$

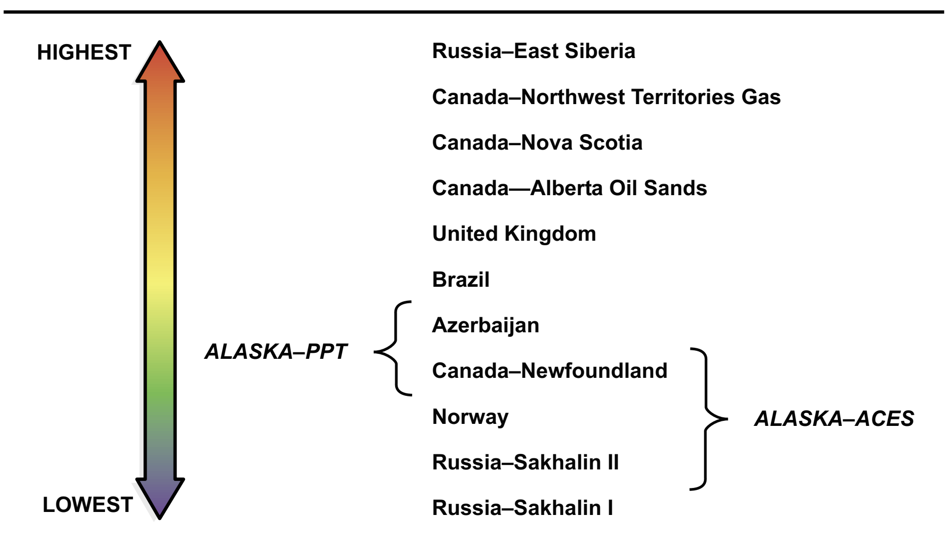
It is important to stress that the aggregate shows results for a portfolio rather than assigning value to any individual prospect (where the outcome is often binary—either zero or high value). Furthermore, one can also calculate an "exploration cover ratio"—the result of dividing $Value_{Success}$ by $Cost_{Exploration}$. When exploring in a frontier basin, it is not uncommon to seek exploration cover ratios of 10 and more. Figure 5 ranks Alaska's peer group by their exploration cover ratios.

The Alberta oil sands have been included in this comparison even though the resource has been discovered. In situ production operations do still rely on some delineation of the resource to optimize development.

By any of the measures shown, Alaska's current fiscal regime lies in the bottom half of its peer group, and the proposed ACES regime would only cause Alaska's position to fall.

Figure 5

Exploration Cover Ratio



Source: Cambridge Energy Research Associates.
Note: Bracket displays range of positions for Alaska regimes depending on royalty level.
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APPENDIX-1

Alaska–Generic Gas Development

Onshore development. Fully winterized drilling facilities and all production facilities and pipelines raised above ground to protect the permafrost. Infrastructure (including airstrip and roads) constructed only during winter. Sweet gas and no associated liquids result in minimum processing, and 200 kilometer (km) pipeline connecting to the main pipeline is included. Six years from discovery to first production and up to 23 years production life.

Alaska–Generic Oil Development

Onshore winterized development similar to gas example. Associated gas disposal at zero cost. Oil stabilization and 200 km pipeline to Trans-Alaska Pipeline System line.

Alaska–Petroleum Profits Tax (PPT) Regime

Royalty

Royalty rates vary depending on the terms under which a lease was granted. We have run the economics at 12.5 percent and 20 percent royalty rates to account for different terms.

Property (Ad Valorem) Tax

The property tax is assumed to be 2 percent per year of the replacement cost of the assets. We have assumed that the cost is equal to the cumulative development capital less the accumulated book depreciation where book depreciation is assumed to be figured using a straight-line method over the life of the project.

Miscellaneous Fees

There are minor fees of no significance to the economics and thus have not been modeled.

Petroleum Profits Tax

Taxable income for the PPT in Alaska is defined as the total gross revenues less deductions for royalties, tariffs, operating expenses, and capital expenditures. The base PPT tax rate is 22.5 percent, but it increases .25 percent for every $1 per barrel that the taxable income divided by the production exceeds $40 per barrel, up to a maximum PPT tax rate of 47.5 percent. A 20 percent credit to PPT is given for each dollar of capital spent in Alaska operations. This credit may be carried forward indefinitely.

There is a minimum PPT payable of 4 percent of gross revenues less transportation expenses if the oil price exceeds $25 per barrel, 3 percent if it is between $20 and $25 per barrel, 2 percent if it is between $17.50 and $20 per barrel and 1 percent if it is between $15 and $17.50 per barrel. There is no minimum payment if the price is at or below $15 per barrel.

Alaska State Income Tax

Taxable income for the Alaska state income tax is a complex calculation based on the percentage of worldwide income that was earned in Alaska. Effectively, the taxable income is the same as for US federal income tax, and the tax rate is 9.4 percent.

US Federal Income

The US federal income tax is 35 percent of gross revenues less royalty, property, and severance taxes; miscellaneous fees; PPTs, Alaska state income taxes; transportation expenses; operating expenses; and depreciation of capex. The depreciation rules are as follow:

- Exploration dry holes are expensed.
- Bonuses are subject to cost depletion, which utilizes a unit-of-production method.
- Geological and geophysical costs are depreciated on a 2-year straight-line basis with only half of the first year's depreciation allowable.
- Intangible drilling capital is depreciated on a 5-year straight-line basis using the half-year rule in the first depreciable year; however, 70 percent of the capital may be expensed in the first depreciable year.
- Development tangible capital is depreciated on a double declining balance basis over 7 years using the half-year rule in the first depreciable year.

Alaska–Clear and Equitable Share Plan (ACES): Proposed Changes from PPT Regime

Royalty, Property Tax, and Miscellaneous Fees

No Change.

Petroleum Profits Tax

Taxable income for the PPT in Alaska is defined as the total gross revenues less deductions for royalties, tariffs, operating expenses, and capital expenditures. The base PPT tax rate is 25 percent, but it increases .2 percent for every $1 per barrel that the taxable income divided by the production exceeds $30 per barrel, up to a maximum PPT tax rate of 50 percent. A 20 percent credit to PPT is given for each dollar of capital spent in Alaska operations, but this credit must be split over 2 years. This credit may be carried forward indefinitely.

There is a minimum PPT payable of 10 percent of gross revenues less transportation expenses.

Alaska State Income Tax

No Change.

US Federal Income Tax

No Change.

Azerbaijan–Generic Gas Development

Offshore development in the Caspian (based around Shah Deniz development concept scaled up and down appropriately for fields in the range 1 Tcf to 10 Tcf) employing 8-leg jacket for gas processing and drilling facilities. Processing includes amine treatment of sour gas and there is a 200 km pipeline to the shore. Five years from discovery to first production and up to 34 years production life.

Azerbaijan–Generic Oil Development

Offshore development. Wells drilled from artificial islands, with production facilities on barges, including water injection. Gas disposal at zero cost and 130 km offshore pipeline for oil. Up to 9 years from discovery to first production and a 28-year production life.

Azerbaijan–Production-sharing Agreement

State Participation

State is assumed to take a 10 percent interest upon commencement of the development and production period and repays its share of carried exploration and appraisal (E&A) costs with interest (8 percent assumed) from its share of production.

Royalty

None.

Cost Recovery

Under the terms of recent production-sharing agreements (PSAs) recoverable costs are expensed and recovered immediately from production according to the following schedule:

- All operating costs, including contributions to the abandonment fund, are recovered from 100 percent of gross production.
- All capital costs (including E&A costs and development costs) are recovered from a negotiable percentage (50 percent assumed here) of production remaining after the recovery of operating costs.
- Unrecovered costs may be carried forward indefinitely for recovery in subsequent years, but not beyond the duration of the contract.

Profit Sharing

Production (after cost recovery) is shared between the state and the contractor on an incremental sliding scale based on an R factor (a proxy for rate of return), with the contractor's share ranging from 55 percent down to 10 percent in the most profitable case.

Income Tax

Paid by the State Oil Company of Azerbaijan Republic on the contractor's behalf from its share of production at a special rate of 25 percent.

Brazil–Generic Oil Development

Subsea wells tied back to a newbuild floating production, storage, and off-loading (FPSO) facility in about 1,000 meters (m) of water. Includes a pipeline to the shore and zero cost gas disposal. Development is modeled after Block 1-RJS-597 with costs adjusted to optimize for field sizes from 100 million barrels to 500 million barrels. Producing field life of up to 15 years.

Brazil–Deep Water > 400 Meters Fiscal Terms

State Participation

None.

Royalty

A production royalty is payable to the state and levied on gross revenue. The standard rate of 10 percent has been assumed here.

Special Participation Fee

The concessionaire is subject to payment of a special participation fee (SPF). The SPF is calculated quarterly and levied on net revenue before income tax from each field under the concession agreement. Net revenue for SPF is gross revenue from the field less signature bonuses, royalty, research and development expenses, operating costs, E&A costs, a quarterly allowance, depreciation of development costs over 10 years straight-line, and abandonment costs (amounts set aside for future abandonment or current costs). Losses may be carried forward indefinitely. There is no provision for the carry-back of losses. The rate of SPF is linked to production and the year of production as defined in the 1998 Fiscal Decree.

Income Tax

Income tax is levied on gross revenue less operating costs, royalty, research and development expenses, special participation fee, depreciation of all capex (assumed to include bonuses) over 10 years straight-line, and abandonment costs (IHS assumption). Losses may be carried forward indefinitely, but they cannot exceed 30 percent of the company's taxable income for a tax period. There is no carry-back provision. The basic rate of corporate income tax is 15 percent, increased by a surtax of 10 percent on taxable profits exceeding R$240,000.

A Social Contribution Tax (SCT) is imposed on Brazilian-source corporate income. The taxable base and deductions are identical to those for income tax, and the rate of SCT is 9 percent. Effective January 1, 1997, SCT is not deductible in calculating the tax base for either income tax or SCT itself. Losses for SCT purposes are subject to the same tax rules as for the income tax purposes.

Thus, the effective income tax rate is 34 percent (15 percent basic rate + 10 percent surtax + 9 percent SCT).

Other Taxes

Local taxes include a Municipal service tax (ISS), excise tax (IPI), municipal sales tax (ICMS), social contribution for welfare programs (COFINS), and Social Integration Program (PIS) contribution.

Canada–Alberta Oil Sands Generic Development

In situ production of oil sands in Alberta. Integrated upgrader produces synthetic crude selling at approximately WTI prices.

Canada–Alberta Fiscal Terms

Bonus and Other Payments

None included in this analysis.

State Participation

None.

Royalty

The *Oil Sands Royalty Regulation, 1997* provides for royalty to be determined on a project basis and applies to all new investment in oil sands whether they are new projects or expansions of existing projects. Before payout the applicable royalty is 1 percent of the gross revenue of the oil sands project. After a project reaches payout, the Crown's royalty share calculation is equal to the greater of 1 percent gross revenue and 25 percent net revenue. A return allowance is calculated on the balance of cumulative costs less cumulative revenues based on the Canadian government's long-term bond rate.

The analysis excludes the impact of the royalty credit implemented by Alberta under the *Innovative Energy Technologies Program.*

Provincial Income Tax

Levied on gross revenue less operating and E&A costs, depreciation of capital costs (on a 30 percent declining balance basis), and the greater of resource allowance (see below) or royalty. Losses may be carried forward for a maximum of 7 years. Since April 2004 the provincial income tax rate is 10 percent, having been gradually reduced from 15.5 percent over a 5-year period from 2000.

Federal Income Tax

Federal income tax is levied on gross revenue less operating costs, E&A costs, royalty, and depreciation of development costs at 30 percent on a declining balance basis. Noncapital losses may be carried forward for a maximum of 7 years; capital losses may be carried forward indefinitely.

The basic federal corporate income tax rate in Canada is 38 percent. However, corporations liable for provincial income tax receive abatement equal to 10 percent, reducing the basic rate of federal income tax to 28 percent. The rate had been reduced to 21 percent in 2004 and will be further reduced to 19 percent between January 2008 and 2010.

Large Corporations Tax

Large corporations tax is effectively a minimum tax that may be reduced by the surtax. Large corporations tax is levied on the capital employed in Canada in excess of C$50 million. The rate is 0.0625 percent for 2007. This is ignored in the analysis as it will not apply after 2008.

Canada–Generic Gas Development–Northwest Territories

Arctic type onshore development modeled after proposed Lake Parsons development with two well pads separated by 15 km, elevated equipment, high winterization factor for drilling rig and sour gas processing facilities. Pipeline of 45 km to gas processing facility. Five years from discovery to first production (i.e., assumes main export line already exists) and field life up to 49 years.

Canada–Northwest Territories Fiscal Terms

Royalty

A royalty is levied at 1 percent of gross revenue for the first 18 months, followed by 2 percent for the following 18 months, etc. up to a maximum of 5 percent. After project payout, royalty is paid at a rate of 5 percent of gross revenue, or 30 percent of net revenue, which ever is greater.

Provincial Income Tax

Provincial income tax in both the Northwest Territories and Nunavut is levied at a rate of 11.5 percent (reduced from 12 percent effective July 1, 2006) of the taxable income as assessed for federal tax, resulting in a combined federal and provincial income tax of 33.62 percent for 2007.

Federal Income Tax

As for the other provinces.

Canada–Generic Oil Development–Newfoundland

Offshore development modeled after the Hibernia offshore development (adjusted for field size range). Gravity base structure with extra concrete included for ice protection. Offshore-loaded crude and zero cost gas disposal. Onshore infrastructure includes facilities for permanent residence and airstrip.

Canada–Newfoundland Fiscal Terms

Bonus and Other Payments

A signature bonus in the form of an up-front competitive bid may be required when applying for a license but has not been assumed here. There are no further bonuses or other payments.

Royalty

The *2003 Royalty Regulations* provide for royalty rates starting at 1 percent and rising to 7.5 percent after 200 million barrels of production for leases issued after November 30, 2001.

Tier I Incremental Royalty is levied at 20 percent of net revenue after Tier I payout is reached. The Tier I payout is reached when the project reaches a 5 percent rate of return plus a long-term government bond rate (assumed to be 6 percent). As basic royalty paid is creditable against Tier I royalty payable, the effective royalty rate will be equal to or greater than the basic royalty.

Tier II Incremental Royalty is levied as an incremental 10 percent of net revenue after Tier II payout occurs. The Tier II payout occurs when the project reaches a rate of return of 15 percent plus a long-term government bond rate (assumed to be 16 percent). Tier I royalty paid is an allowed cost for the purposes of calculating the Tier II payout.

For royalty purposes the allowed costs are uplifted by 1 percent for capital costs, 10 percent for operating costs, 5 percent for exploration costs, and 1 percent for decommissioning costs.

Provincial Income Tax

Provincial income tax is levied on gross revenue less operating costs, E&A costs, and depreciation of capital costs at 30 percent per year on a declining balance basis. Losses may be carried forward 7 years. The provincial income tax rate is 14 percent.

Federal Income Tax

As for the other provinces.

Canada–Generic Gas Development–Nova Scotia

Modeled after the Deep Panuke development (adjusted for field size range) involving two platforms bridged with accommodation and processing facilities in 44 m water depth. Drilling is conducted in two phases with the second phase deploying subsea tie back of wells and acid gas reinjection. A 120 km pipeline to shore. Six years from discovery to first production and a field life of up 23 years.

Canada–Nova Scotia Fiscal Terms

Bonus and Other Payments

A signature bonus in the form of an up-front competitive bid may be required when applying for a license but has not been assumed here. There are no further bonuses or other payments.

Royalty

Royalty is levied on the revenue due to an interest holder arising from its interest in a field. Royalty is calculated on a monthly basis and is determined by a sliding scale linked to dates of field payout (i.e., profitability).

In summary, the royalty rate is 2 percent of gross revenue until a first rate-of-return threshold is reached, after which it becomes 5 percent until a second rate-of-return threshold. After the second rate-of-return threshold has been reached, the royalty rate is the maximum of 5 percent of gross revenue and 20 percent of net revenue until a third rate-of-return threshold is reached, after which the royalty rate becomes the maximum of 5 percent of gross revenue and 35 percent of net revenue. If the resource being developed has been designated by the minister as the first to be developed in a high risk area, the 35 percent rate is reduced to 20 percent.

Provincial Income Tax

Provincial income tax is levied on gross revenue less E&A costs, operating costs, a capital cost allowance in the case of acquisitions, and depreciation of development capital at 30 percent per year on a declining balance basis.

The rate of provincial income tax is 16 percent.

Federal Income Tax

As for the other provinces.

Norway–Generic Gas Development

Modeled after the Ormen Lange development in the Barents Sea (adjusted for the range of field sizes). Utilizes subsea development tied back to shore by 108 km multiphase pipeline in 1,000 m of water. Seven years from discovery to first production and up to 32-year field life.

Norway–Generic Oil Development

Modeled after the offshore Goliat development (adjusted for the range of field sizes). Utilizes subsea wells tied back to a fifth generation newbuild semisub with offshore loading of crude and zero cost gas disposal. Eight years from discovery to first production and a 15-year producing life.

Norway–Royalty Tax Terms

Bonus and Other Payments

None assumed.

State Participation

State takes a direct financial interest (DFI) from day one. It is paid its share from the beginning and therefore has not been modeled as a fiscal impost. State participation of 20 percent has been assumed, reflecting some of the preliminary awards of the Eighteenth Licensing Round.

Royalty

None.

Carbon Dioxide Tax

Carbon dioxide (CO_2) tax is levied on the volume of petroleum flared, on the volume of natural gas vented, and on CO_2 separated from petroleum and vented on platforms or other installations used for production or transportation of petroleum. CO_2 tax is deductible for income tax and special petroleum tax. The intention is to abolish this tax and replace it with tradable “Emissions Quotas.”

Income Tax

The taxable base for income tax is gross revenue less exploration costs, operating costs, royalty, CO_2 tax, and depreciation of development costs (6 years straight-line). Losses from 2002 onward may be carried forward with interest (calculated as a risk-free interest plus a margin after deducting income tax at the prevailing income tax rate). The income tax rate is 28 percent.

Special Petroleum Tax

The taxable base for Special Petroleum Tax (SPT) is the same as for income tax but includes an extra allowance in the form of an uplift equal to 5 percent of the capital investment (excluding exploration costs) rolled up annually to a maximum 130 percent of development costs. Unused uplift can be carried forward. The SPT rate is 50 percent.

Russia–Generic Gas Development–East Siberia

Modeled after Kovykta onshore development (adjusted for range of field sizes). Production from two well pad locations to a central processing facility with compression which feeds to a 250 km pipeline connecting to the main Gazprom export pipeline.

Russia–Generic Oil Development–East Siberia

Modeled after Ardalin onshore development (adjusted for range of field sizes). The onshore production facility is positioned 30 km from field infrastructure and feeds to an 85 km pipeline connecting to main Transneft export pipeline.

Russia–East Siberia Fiscal Terms

State Participation

None.

Minerals Production Tax

The Minerals Production Tax is based on gross sales revenue less tariffs. The tax rate is 16.5 percent. As of January 2007 a holiday of up to 15 years or until oil production from the field exceeds 25 million metric tons per year.

Property Tax

Property tax is levied on cumulative capex less cumulative capex depreciation as for profits tax purposes. The rate of property tax is 2 percent.

Land and Pollution Taxes

Modeled to be equivalent to 0.1 percent of operating costs.

Single Social Tax

Introduced on January 1, 2001, the Single Social Tax (SST) is levied on the “salary fund.” We understand the “salary fund” is 6 percent of operating costs. The rate of SST is 36.4 percent, but taking into account life insurance (1 percent) the rate of SST will be 37.4 percent.

Income Tax

The income tax rate is 24 percent as of January 1, 2002.

Russia–Generic Gas Development–Sakhalin Offshore

Developed with subsea wells tied back to production facilities onshore; $500 million on local infrastructure upgrade. Onshore pipeline to coastal terminal for gas export via assumed existing LNG facilities.

Russia–Generic Oil Development–Sakhalin Onshore

Production and injection wells tied back 30 km to central facility. Crude stabilization and zero cost gas disposal before export through 226 km pipeline to coastal terminal.

Russia–Sakhalin I PSA Indicative Example

Bonus and Other Payments

We have modeled a $45 million production bonus. Also $100 million payable to Sakhalin Development Fund, over 5 years ($20 million per year) after the first development plan is approved.

State Participation

None.

Royalty

Royalty of 8 percent is levied on gross production.

Cost Recovery

All recoverable costs are expensed and recovered immediately from revenue from gross production less royalty. Cost recovery ceiling is 85 percent.

Profit Sharing

Production remaining after royalty and cost recovery is shared between the state and the contractor as specified in the PSA. The profit sharing has been assumed to be on a sliding scale with state share of 70 percent after a 28 percent rate of return has been achieved.

Income Tax

The income tax rate is 35 percent.

Deductions and Depreciation

Capex is depreciated over 3 years straight-line. Bonuses are tax deductible. Losses are carried over for 15 years.

Russia– Sakhalin II PSA Indicative Example

Bonuses

There is a signature bonus payable; however, no signature bonuses have been modeled. No discovery or production bonuses are payable.

State Participation

None assumed in the context of this analysis.

Royalty

Royalty of 6 percent is levied on gross production.

Cost Recovery

All recoverable costs are expensed and recovered immediately from revenue from gross production less royalty. There is no cost recovery ceiling.

Profit Sharing

Production remaining after royalty and cost recovery is shared between the state and the contractor as specified in the PSA. The profit sharing has been assumed to be on a sliding scale with state share of 70 percent after a 24 percent rate of return has been achieved.

Other Payments

Exploration costs incurred by the Russian party are paid in quarterly installments of $4 million until $80 million has been paid. When 17.5 percent internal rate of return has been reached, another $80 million is disbursed in the same manner.

Income Tax

The income tax rate is 32 percent.

Deductions and Depreciation

Capex is depreciated over 3 years straight-line. Bonuses are tax deductible. Losses are carried over for 15 years.

United Kingdom–Generic Gas Development

Modeled after the Lagan development west of the Shetland Islands (adjusted for the range of field sizes). Utilizes a tension leg platform in 620 m water depth and a 380 km pipeline to St. Fergus in Scotland.

United Kingdom–Generic Oil Development

Modeled after the Rosebank development offshore west of the Shetland Islands (adjusted for the range of field sizes) with subsea wells in 1,100 m water tied back to an FPSO. Oil is offloaded to tankers.

United Kingdom–Fiscal Terms

Royalty

None.

Income Tax

The Corporation Tax is 30 percent of corporate taxable Income, which is defined as gross revenues less all capex and operating expenses in the year they are spent. Losses may be carried forward indefinitely and earn interest at the rate of 6 percent per year for the first 6 years of carry-forward.

Supplementary Corporation Tax

The tax rate is 20 percent of corporate taxable income, as defined above. Losses may be carried forward and earn interest in the same manner as the corporation tax.