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March 3, 2016

The Honorable Benjamin Nageak and the Honorable David Talerico
Alaska State Representatives
Co-Chairs, House Resources Committee
State Capitol Rooms 126 and 104
Juneau, AK 99801

Dear Co-Chairs Nageak and Talerico:

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue during our presentation to the House Resources Committee on February 22, 2016 and February 25, 2016 regarding HB 247. Please see questions in italics and our responses immediately below the questions.

The following follow-up questions are from the February 22, 2016 hearing:

1. *Provide a breakout of non-North Slope capital expenditure and well lease expenditure credits since FY 2013 by oil versus gas expenditures, to the extent possible.*

The following table provides detail on which type of hydrocarbon production was supported by refunded non-North Slope credits for FY 2013, FY 2014, and FY 2015. This analysis was performed by company, and includes all refunded credits (analysis at a more detailed level would present confidentiality issues).

Some companies are producing or targeting gas exclusively; no companies are producing oil exclusively. For those companies producing both oil and gas or conducting general exploration, it is difficult to itemize the amount of credit attributable to one type of hydrocarbon; for these companies we have included their credits in the "both oil and gas" category.

Non-North Slope Refunded Tax Credits: Amount and Share Attributable to Oil versus Gas			
Fiscal Year	**Gas Only**	**Both Oil and Gas**	**Oil Only**
FY 2013	$84.5 million (78%)	$24.2 million (22%)	Zero
FY 2014	$122.1 million (39%)	$190.0 million (61%)	Zero
FY 2015	$130.5 million (32%)	$273.6 million (68%)	Zero

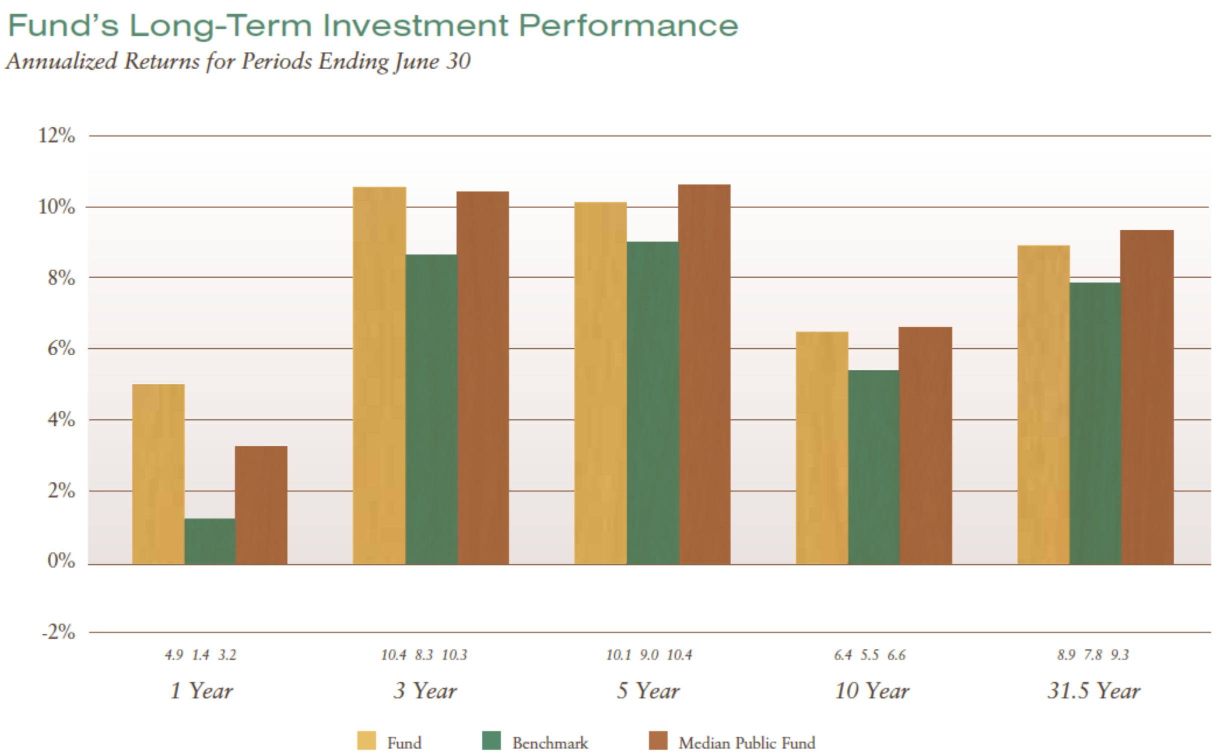
2. *Provide the most recent Competitiveness Review Board report.*

   The full report, "Alaska's Oil and Gas Competitiveness Report 2015," is available on the Department's website at http://dor.alaska.gov/OilGasCompetitivenessReviewBoard.

   More recently, the Department of Revenue issued a research report titled "Peer Group Comparison of Alaska's Oil and Gas Fiscal System," which is attached. This research report excerpts key portions of the Competitiveness Report that discuss comparable fiscal regimes, and adds context for the current environment.

3. *Provide information about actual Permanent Fund investment returns, and how they compare to the forward-looking projection of about 7% annual returns.*

   The following chart presents historical investment performance for the Alaska Permanent Fund, as of the close of FY 2015, along with comparisons to performance benchmarks and other public funds. Over the 10-year period ending June 30, 2015, the average annual return for the Permanent Fund was 6.4%. These returns are presented in nominal terms, i.e. before accounting for inflation.



4. *Provide information about production tax revenue at prices up to $135 per barrel.*

   The Department has prepared sensitivity analysis for revenues over the next ten years at a range of oil prices, based on the Fall 2015 forecast, and that analysis is attached. Page 5 of the analysis shows unrestricted oil and gas production tax revenue for a range of oil prices from $20 to $130.

5. *Provide information about production and projects that were added to the state's revenue forecast following passage of SB 21.*

   Several companies indicated increases to their planned spending in Alaska following passage of SB 21. In general, following passage of SB 21, there has been an increase in the overall spending forecast, and an increase in production forecasts for FY 2017 and beyond. The increased investment and production were primarily related to increased activity at existing fields, such as drilling more wells or extending into new production areas. Note that correlation does not necessarily equal causation; it is difficult to say how production or lease expenditures may have changed without SB 21, and some of these increases may have been planned prior to passage of SB 21.

   In terms of specific projects added to the forecast, production from Badami and Eider was forecasted to end between FY 2014-2016 prior to passage of SB 21 but is now expected to continue for many years. The new developments Lookout (Colville River Unit) and Nuna (Ooogaruk Unit) have been added to our forecast. A new Participating Area was added to the forecast in the Kuparuk Unit, and additional drilling activity and production were added to the forecast in the Prudhoe Bay Unit. Again, it is difficult to say whether or not these projects would have proceeded without SB 21.

The following follow-up question was from the February 25, 2016 hearing:

1. *How will HB247 impact the Interior Energy (aka Fairbanks LNG) Project?*

   According to the January 2016 Interior Energy Project "Quarterly Report to the Alaska State Legislature," the Interior Energy Project would purchase gas from either the North Slope or Cook Inlet basins. Gas would then be liquefied and transported to the Fairbanks area via either rail or trucking, where it would enter a local distribution system.

   From a standpoint of the state's production tax, gas sold to the Interior Energy Project as currently envisioned would be taxable when sold to the project, which would occur either at the North Slope or at Cook Inlet, prior to the liquefaction facility.

   Several provisions of HB 247 have the net effect of reducing the portion of the state's budget that funds credit purchases. To the extent these changes to state support are reflected in future gas price contracts, the Interior Energy Project could see higher purchase prices for natural gas, and thus higher end-user prices. Given that the exact project has not yet been selected, it is not possible at this time to quantify the impact on those prices.

   Section 31 of HB 247 would stipulate that the Gross Value at Point of Production for oil or gas cannot be reduced below zero. Presumably, any producer committing gas to the Interior Energy Project would enter into contracts that provided a positive gross value, so this provision is unlikely to materially impact the Interior Energy Project.

   Section 37 of HB 247 would change how lease expenditures are allocated for a municipal entity that owns a portion of a gas field, uses a portion of its gas to generate its own power, and sells a portion of its gas to other parties. This provision would impact the Interior Energy Project only if it entered into gas supply contracts with a municipal entity subject to this provision. In such a case, the municipal utility limitation could cause the municipality to require higher sales prices for its natural gas.

I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,

Randall J Hoffbeck

Randall Hoffbeck
Commissioner

Attachments:

Peer Group Fiscal System Comparison white paper

Estimated General Fund Unrestricted Revenue under Fall 2015 forecast, and production tax / royalty forecast detail, at ANS Prices of $20 to $130 per Barrel

Peer Group Comparison of Alaska’s Oil and Gas Fiscal System

Alaska Department of Revenue

Introduction

With the ongoing discussion and debate over proposed legislation that will significantly change the oil and gas fiscal regime in Alaska, it seems appropriate to provide some perspective and high-level analysis of how Alaska’s existing fiscal regime compares to other jurisdictions. The Department of Revenue (DOR) has recently worked with the Alaska Oil and Gas Competitiveness Review Board (O&GCRB) on a report that established peer group jurisdictions and preliminary methodologies for comparison of Alaska’s competitiveness in attracting oil and gas exploration and development capital investment when compared with other resource-rich jurisdictions[1]. This report summarizes the fiscal regime comparisons included in that report.

In this discussion of Alaska’s fiscal regime it is important to keep in mind that Alaska’s production tax is, at its core, a net tax. No other state in the Lower-48 states uses a net tax. Instead, in states with production taxes, a gross tax is applied. If we convert the production taxes Alaska collects to a gross tax equivalent based on the total barrels of oil produced, Alaska taxed at an equivalent rate of between four and five and a half percent. As oil prices declined in the last two years the gross tax equivalent has fallen to about 0.64 percent for 2015.

Alaska Peer Group Selection

When looking at Alaska’s competitiveness, the O&GCRB feels that it is important to consider a variety of criteria in comparison to other resource-rich jurisdictions. Resource potential as determined by proved reserves and estimated undiscovered resources, are often the most important criteria investors consider when investors are considering where to allocate limited capital. Reserves and undiscovered resource estimates are known to be difficult to quantify and are best portrayed as a wide distribution of possible outcomes. Even so, resource potential is often the clearest criteria for comparison and is often considered first by investors.

Other competitiveness criteria are less easy to quantify for comparison, including the assessment of a jurisdiction’s fiscal system, regulatory environment, permitting structure, industry labor resources, and the status and availability of oil-and-gas-related infrastructure. To varying degrees, data sets related to these competitiveness criteria tend to have significantly less consistency in character between jurisdictions. Even within Alaska there are significant differences between the North Slope and Cook Inlet in our ability to quantify and characterize these competitiveness criteria.

After significant analysis and review by the O&GCRB, they selected a group of relevant peer jurisdictions they considered to be most closely comparable to Alaska over many of those criteria. The jurisdictions that seem to most closely compare to Alaska for many of the important criteria, and are selected here to comprise the relevant peer group for Alaska, include four U.S. states, two provinces of Canada, two regions of the U.S. outer continental shelf and four foreign countries.

After peer group selection and analysis, another priority of the Board is to poll a broad range of oil and gas exploration and development companies to better understand Alaska's perceived relative strengths and weaknesses

[1] Alaska Oil and Gas Competitiveness Review Board, 2015, “Alaska’s Oil and Gas Competitiveness Report 2015,” 91 pages,
http://dor.alaska.gov/Portals/5/Alaska's%20Oil%20and%20Gas%20Competitiveness%20Report%202015.pdf

with our global peers. We plan to survey a representative group of large to small companies, including existing producers and lease owners, as well as other companies, such as service companies, that would represent companies not active in Alaska. This undertaking will take funding. We have prepared a draft RFP for the survey effort, with a budget for up to $300,000, to be considered by DOR and the Alaska Legislature. An effective survey of this type could take up to nine months, just to collect the survey data. Then additional time will be required to compile and analyze the collected data. It is paramount to be able to compare our strengths and weaknesses against other peer jurisdictions to insure that we are getting the greatest benefit from Alaska's resources while continuing to attract investment to the state.

In their analysis the O&GCRB determined that oil and gas fiscal systems are widely believed to be one of the important criteria to consider when ranking a jurisdiction's competitiveness.

Figure 1 lists the Alaska peer group selected for this report and some of their basic geographic characteristics. We narrowed the list in part by focusing primarily on concession-type (tax and royalty) fiscal arrangements, generally similar to Alaska's fiscal regime. We also preferred a geographic affinity: a location in the Arctic, in North America or Europe, or in the Pacific region.

Other preferable similarities included jurisdictions with similar size reserves and undiscovered resource potential and favored jurisdictions with a history of significant hydrocarbon production. Throughout this report we will compare Alaska to all or portions of this peer group and present data to show the logic of using this comparison group. While, in the past, all of the jurisdictions mentioned in this list have been used as peers in comparing Alaska's oil and gas resources and fiscal system, it is wise to regularly review the peer group and each individual jurisdiction in the group, as well as previously excluded jurisdictions, for relevance based on current information, especially now with the enactment of SB 21 tax legislation in 2014. The Board acknowledges the possibility that the peer group selected for future reports may be different than the group selected for this report as the Board's analyses and understanding evolves.

For a more comprehensive discussion of the peer group selection process and more of the logic behind the group selected, please see the O&GCRB document referenced above[1].

Fiscal Regime Styles

There are nearly as many types of contractual arrangements between governments and oil and gas companies as there are jurisdictions with mineral resources to recover. Among the many general types of agreements, the basic differences tend to be in various approaches to the four following areas:

- **Ownership:** "Are the hydrocarbons owned by the oil company in the ground or at the wellhead or elsewhere, or are they owned by the state throughout?"
- **Payment:** "Is payment made by companies receiving hydrocarbons by lifting hydrocarbons they own, or in lieu of payment for cost and profit recovery?"
- **Profit drivers:** "Is the contract structured such that the oil companies are fully exposed to price risk, or are their returns fundamentally driven by payments based on the amount of money invested?"
- **Operational freedom:** "How do contractual and administrative terms affect the degree of freedom with which companies can operate and vary their investment decisions within the country?"

It should be noted that there is no one best approach. None of the specific approaches discussed is necessarily more or less beneficial to all jurisdictions than the others, as the specific levels of payments and handling of risk can and do vary greatly from country to country and contract to contract.

Typically there are taken to be three "headline" styles of petroleum regimes: concessions, production sharing contracts (PSCs) and service contracts (Figure 2). Typically, under a concession arrangement, the fiscal components are handled separately from the award of rights to explore and produce, while under PSCs and service contracts the fiscal structure tends to be tightly interwoven with the underlying contracts specifying each party's rights.

However, as with any generalization, care must be taken as it is possible to construct any of the headline regime styles to look and act very much like another. In particular, the financial returns from each may be very similar, notwithstanding more obvious differences. Indeed, when countries look to update or modify their petroleum contractual or fiscal regime, they are always "benchmarking" it against those of other countries, and aspects are "borrowed" from one to another regardless of the headline contract style involved.

Complexity

An important consideration with all types of fiscal systems is the issue of complexity. Fiscal regimes need to be complex enough to properly compensate governments and mineral owners, and project investors and developers over the entire life of a project, as well as fairly treat a broad spectrum of different project types and sizes that may fall under the same system. On the other hand, fiscal systems that are overly complex can discourage investment when investors can't reasonably forecast their possible profits, costs, timing, and risks in a particular jurisdiction. The system that attracts investment most successfully is likely to be the least complex system that still properly allocates costs and benefits at the lowest risk possible.

Production Sharing Contracts

The first PSCs were signed in 1967 with Indonesia. These contracts are also known as production sharing agreements (PSAs) in some locations. The two parties to the PSC are the owner-country usually in the form of a national oil and gas company (NOC) and an international oil and gas company (IOC). Unlike tax and royalty systems, PSCs generally transfer title to the produced hydrocarbons at the export point (as opposed to at the wellhead in tax/royalty systems, under which the resource in the ground is owned by the state). PSCs typically differ from service contracts in that reimbursement to the IOC is in-kind and the parties to the PSC own the rights to their share of the oil.

In general, PSCs divide gross production into what is frequently referred to as cost oil (oil or gas applied to reimburse costs) and profit oil (that in excess of cost oil) with the contractor receiving its compensation from cost oil and a share of the remaining profit oil.

Service Contracts

A service contract is a type of agreement whereby an IOC performs exploration and/or production services for the host government within a specified area for a fee. The host government maintains ownership at all times of the hydrocarbons produced, and usually the IOC (contractor) does not acquire any rights or title to the oil and or gas, except where a contractor is paid its fee in kind (oil or gas) or is given a preferential right to purchase production from the host government. Pure service agreements between a host government and an IOC are rare. These forms of arrangement are used in Iran, Saudi Arabia, the Philippines, and Kuwait, but are not used by governments in North America or Europe.

Concession Contracts

The current tax and royalty schemes grew out of concession systems commonly seen in the early part of the 20th century. The concept of tax and royalty fiscal regimes is easy to describe in that the government owners of the mineral lease tracts for exploration and development directly to an oil and gas company contractor group either through negotiations or through some sort of competitive bidding. An initial cost typically includes acreage rental payments plus fixed or variable royalties. The government authorities tax the contractor group members based on their profitability from the leased tract (block).

The OCS mineral leases represent a tax and royalty scheme. While most OCS leases contain a competitive bid and fixed royalty payments, tax/royalty schemes can include work commitments, variable royalties, net profit interests, etc.

A number of countries with tax/royalty regimes include, in addition to corporation tax, various forms of “rent” or taxes to capture a greater share of the economic benefit arising from operations, whether these result simply from highly profitable fields or from windfalls such as high petroleum prices. Examples include the U.K.’s Petroleum Revenue Tax, Norway’s Supplemental Petroleum Tax, Brazil’s Special Participation, Australia’s Petroleum Resource Rent Tax and Alaska’s ACES production tax, now replaced by SB 21. In the case of the U.K., Norway and much of offshore Australia, no royalty at all is levied and the countries rely on “rent” and income taxes for virtually their entire share of profits.

Leases granted under a tax/royalty style arrangement are quite different from the old style concession agreements, even though the term “concession” may still be used (as well as “permit” or “license”). While details vary from one jurisdiction to another, they all contain significant term provisions, usually involving relinquishment of some part of the acreage at various stages such that only the immediate producing area remains held for a long time (typically the life of production). In some jurisdictions, minimum work obligations will also apply to different holding periods. Operators are generally able to report their “net” booked reserves[2], which are 100 percent of the gross reserves less royalty.

Elements of Fiscal Regime Comparison and Definition of Terms

When comparing concession fiscal regimes a number of terms are used that apply to different types of government take. To clarify the use of those terms in this report, we present their definitions below.

Royalty

The landowner's share of production, generally considered to be free of expenses of production. The landowner's royalty was historically frequently set at 1/8th of production, but it may be any fractional share or percentage of production.

Royalty may be payable in-kind (where the royalty owner is entitled to a share of the oil or gas as produced) or in-value (where the royalty owner is paid in money for the value or market price of his share of the production).

Rental Fee (Delay Rental)

A lease covenant or term which provides for a flat sum periodic payment to the lessor by the lessee for the privilege of holding or maintaining a mineral lease and deferring the commencement of drilling operations or the commencement of production during the primary term of the lease. A lessee's failure to make the rental payment to the landowner in a timely fashion can result in the termination of the lease.

[2] Booked oil and gas reserves are estimated quantities of hydrocarbons that have a high degree of certainty, usually 90%, of existence and exploitability. In other words reserves are estimated quantities of hydrocarbons that a company believes to exist in a particular location and can be exploited. According to the Securities Exchange and Commission (SEC), oil companies are required to report their booked reserves to investors through supplemental information to the financial statements. It is important to note oil still in the ground is not considered an asset until it is extracted or produced. Once the oil is produced, oil companies generally list what isn't sold as products and merchandise inventory.

Property/Ad Valorem Tax

A tax based on the assessed/appraised fair market value of real or personal property imposed by a governmental jurisdiction. The property/ad valorem tax is typically payable by the owner of the real or personal property, so lease operators are not automatically responsible for a property tax liability of a working interest owner. In Texas (and in some other states), this tax becomes payable only when minerals are producing (as opposed to non-producing), and are billed and collected once per year. Sales tax rates shown in Figure 9-2 are assumed to be for capital expenditures only. This treatment will understate the total sales tax revenue for those states that impose general sales tax to the extent that there are other taxable inputs (i.e., non-capital goods used in operations and production).

Corporate Income Tax

A tax levied by a government directly on a corporation's income. CIT on oil and gas is often associated with targeted incentives and credits, such as depreciation of assets and credits for certain activities and ventures.

Net Tax/Profit Share

The use of the term net tax in this document refers to the resource tax on the value of the resource net of most costs of production.

Gross/Severance Tax

The use of the term gross tax in this document refers to the resource tax on the value of the resource before subtraction of most costs of production.

Indirect sales/Value-Added Tax

A sales tax is a type of indirect consumption tax on oil and gas operations by which a tax is levied on final sales or on the receipts from sales. A value-added tax (VAT) is a similar type of indirect tax on oil and gas operations by which a tax is levied on a product whenever value is added often at many stages of production, marketing and at final sale.

Participation/Joint Venture

Typical joint ventures (JV) for development share the risks and benefits from oil and gas development and are associated with concession regimes. The national oil company (NOC) partner (participating in a project on behalf of the government that owns the resource) may receive a relatively large initial payment for the execution of the JV and the contractor group partners may carry 100 percent of exploration costs and potentially all costs "to the tanks" for first oil. Subsequent capital and operating costs are shared in the proportions of the JV ownership. Management decisions for the field and staffing of the JV are also shared with the host government, typically via the NOC as the JV partner. There is nonetheless a clear separation between the government as a taxing and licensing authority and the government-owned IOC JV partner. Some portion of the exploration and development "carried costs" are typically reimbursed by the NOC partner to the contractor group either in cash or oil. Ownership of the crude government share of the crude oil is independent of the contractor group ownership. The contractor group is typically entitled only to book reserves for their share of the JV's gross reserves less any government royalty and potentially the reimbursable costs if they are repaid from crude oil.

Peer Group Jurisdictions' Fiscal Systems

Figure 3 includes the highlights of the fiscal regime Alaska offers oil and gas companies interested in doing business in Alaska compared to a group of peer jurisdictions. The information presented in Figure 3 through Figure 16 will be used to compare Alaska to several other jurisdictions with which we believe the state competes for oil and gas industry investment.

In this report, Alaska's fiscal regime, summarized in Figure 4, is compared only to other concession-based fiscal regimes largely because of the difficulty of making clear comparisons with the fundamentally very different contract-based fiscal regimes.

Alaska's peer comparisons selected here include a representative group of states and provinces in the U.S. and Canada. Companies doing business in the U.S. and Canada can relatively easily shift the location of their operations and corporate focus to any fiscal regime they see as more beneficial in either of these two countries. However, most of the onshore states and provinces have much lower undiscovered resource potential than Alaska, and do not offer the attraction of conventional "elephant-size" prospects like Alaska does.

California

California (Figure 5) is a state with resource potential and historic production similar to Alaska. Issues regarding regulations and environmental concerns make California a reasonable addition to the peer group for Alaska. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

North Dakota

North Dakota (Figure 6) has historically experienced lower production volumes than Alaska; however, its production now surpasses Alaska, largely on the strength of shale oil production in the last five years. Capital and operating costs are generally assumed to be lower than Alaska. Infrastructure is well established and much more extensive than in Alaska.

Oklahoma

Oklahoma (Figure 7) has experienced lower production volumes than Alaska for more than 25 years, and its production is stable to slightly increasing in recent years. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

Texas

Texas (Figure 8) is the perennial powerhouse of oil production and potential in the U.S. Production volumes are higher than in Alaska, and its production has been steadily increasing in recent years, largely on the strength of shale oil production. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

U.S. Gulf of Mexico Outer Continental Shelf

The Gulf of Mexico OCS (Figure 9) is another material oil and gas supply source for the U.S. Oil production volumes in the Gulf of Mexico are higher than in Alaska, but were down in 2010, likely due to BP's Macondo well blowout and spill that occurred that year. Offshore infrastructure is well-established and extensive. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska. There is no state or local CIT, property tax, severance tax, production tax or sales tax.

U.S. Beaufort and Chukchi Sea Outer Continental Shelf

The Beaufort Sea and Chukchi Sea OCS (Figure 10), off Alaska's northern coast, has seen very minimal historic production (from the Northstar field), but has several discovered accumulations and significant potential. There is no infrastructure in the Alaska OCS. Our assumption is that costs will be high and environmental restrictions and permitting hurdles will be greater than onshore Alaska. The U.S. OCS fiscal system has significantly lower overall government take because there is no state or local CIT, property tax, severance tax, production tax or sales tax. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska.

Alberta

Alberta, Canada (Figure 11) has greater production volumes, reserves, and resources than Alaska, a large portion of which is heavy oil and oil sands. However, anecdotal evidence indicates that costs are lower there than in Alaska.

In Alberta, as in the rest of Canada, fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. In Canada, oil and gas corporations are taxed at the same rate as other corporations. Corporations are taxed by the Canadian federal government and by one or more provinces or territories. The basic rate of federal CIT is 26.5 percent, but this rate may be reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. Canada's federal CIT rate is 16.5 percent, lower than the 35 percent U.S. CIT. The Alberta provincial CIT rate is 10 percent.

Northwest Territories

Northwest Territories, Canada (Figure 12), unlike Alberta, has no production history; however, potential is significant. Currently, the Canadian federal government manages oil and gas resources in the Northwest Territories; therefore, the fiscal system is very similar to the Canadian federal offshore Beaufort Sea described below. Costs here are assumed to be similar to Alaska and infrastructure is limited. The Northwest Territories' fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. The Northwest Territories' provincial CIT rate is 11.5 percent.

Canada Federal Offshore Beaufort Sea

Canada's federal offshore Beaufort Sea (Figure 13), like the Northwest Territories, has no production history; however, its potential is significant. Costs here are assumed to be similar to offshore Alaska, and infrastructure is limited.

Australia

Australia (Figure 14) is included in Alaska's peer group because it has a concession-based fiscal regime and easy access to Pacific Rim markets. In recent years, some Australian oil and gas companies have become interested in Alaska and are now actively pursuing projects here.

Norway

Norway (Figure 15) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime. Like Alaska, the Norway's North Sea basin is generally considered mature by oil and gas industry standards.

United Kingdom

The U.K. (Figure 16) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime. Like Alaska, the U.K.'s North Sea basin is generally considered mature by oil and gas industry standards.

Excluded Jurisdictions

The list of peers for Alaska's oil and gas fiscal regimes is short. This is to facilitate, to the extent possible, more direct, logical comparisons. Of the hundreds of jurisdictions and fiscal regimes in the world, only those with the most reasonable parallels to Alaska were selected for inclusion in the peer group. This meant excluding the vast majority of jurisdictions. The logic for excluding jurisdictions from the peer group is the same as the logic used to determine which jurisdictions to include.

Excluded States and Provinces

A number of other states located in the western U.S. were considered for inclusion in the peer group. However, most of the states excluded from the peer group have significantly smaller oil and gas endowment and smaller production volumes than Alaska and its peer group. States that were considered but excluded are Colorado, Kansas, Montana, New Mexico, South Dakota, Utah, and Wyoming. Despite their exclusion from the peer group, their fiscal systems are similar to the states that were included, so they are not totally unrepresented in the chosen peer group.

Similarly, several provinces and offshore federal waters of Canada were considered for inclusion in Alaska's fiscal system peer group. But, with the exception of Alberta, sufficient data were unavailable or the resource endowment and historical production were too small to warrant comparison.

Fiscal System Exclusions

Internationally, many jurisdictions are excluded from the Alaska peer group because their fiscal regime is not a pure concession-type fiscal system. It is unlikely that Alaska would ever consider moving to a production sharing contract or a service contract fiscal regime and therefore, it is logical that these countries are excluded from Alaska's peer group. This exclusion group based on fiscal system type is comprised of countries such as Indonesia, New Guinea, Myanmar, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, and Venezuela.

Geographic Location Exclusions

A second criterion for excluding some foreign countries is their geographic location. Many countries were excluded based on their location away from the Arctic region or the Pacific basin. The logic for this is that the refineries that Alaska's oil supplies are all located in Hawaii or on the west coast of the U.S. and the economic barrier may be higher for them to shift their supply source to other countries outside the Pacific basin. The exclusion group based on geographic location is comprised of countries such as South Africa, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, Venezuela, and Argentina.

Production History Exclusions

A third criterion for excluding certain countries is the resource base and production history. Filtering fiscal systems in this way will exclude jurisdictions with a resource base or production history that is longer than Alaska's, such as Russia and many Middle Eastern countries, or where production history, reserves and undiscovered resource are much less, as in most U.S. states, most Canadian provinces, Thailand, Vietnam, Greenland, and Iceland.

Figure 1. Peer group jurisdiction and fiscal regime type and geographic affinities.

Jurisdiction	Jurisdiction Type	Type of Fiscal Regime	North America	Europe	Pacific	Arctic
Alaska	State	Concession	X		X	X
California	State	Concession	X		X	
North Dakota	State	Concession	X			
Oklahoma	State	Concession	X			
Texas	State	Concession	X			
U.S. GOM[1] OCS[2]	Federal	Concession	X			
U.S. Alaska OCS	Federal	Concession	X			
Alberta	Province	Concession	X			
Canada-Northwest Territories	Federal	Concession	X			X
Canada-Beaufort Sea	Federal	Concession	X			X
Australia	Federal	Concession			X	
Norway	Federal	Concession		X		X
United Kingdom	Federal	Concession		X		

[1]Gulf of Mexico (GOM)

[2]Outer Continental Shelf (OCS)

Figure 2. Petroleum legal arrangement classifications.

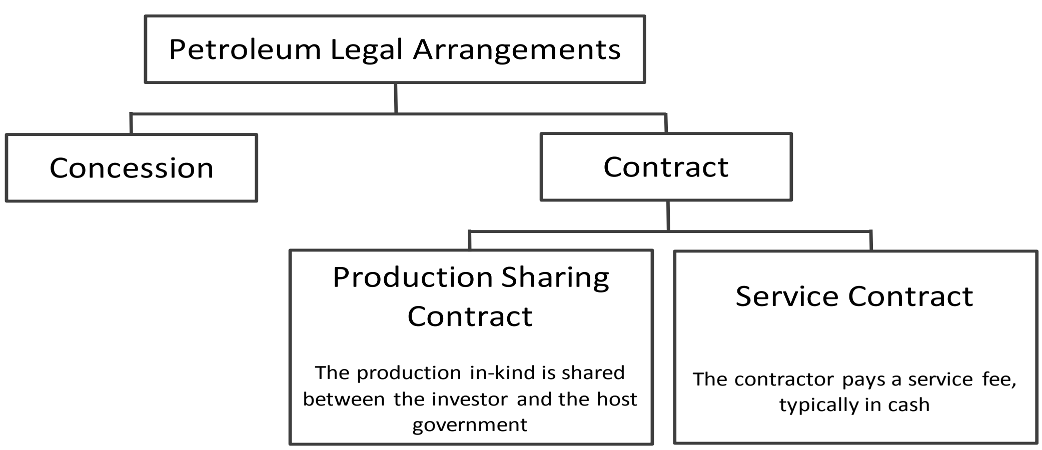


Figure 3. Petroleum fiscal regime peer group highlights.

Jurisdiction	Royalty (% of Gross Production)	Rental Fees ($ per Acre)	Property /Ad Val. Tax	Federal Corp. Income Tax Rate	State/ Province Corp. Income Tax Rate	Net Tax / Profit Share (net of costs)	Gross / Severance Tax	Indirect Sales / VAT Tax Rate	Partici-pation
U.S./States									
Alaska	State: 12½% - 16⅔% Federal: 12½%	State: $1 - $3 Federal: $1.50 - $2	Yes	35%	9.4%	North Slope: 35% and up	Gross minimum tax may apply	none	-
California	Federal: 12½% Private: 16⅔% - 25%	Federal: $1.50 - $2 Private: $5 - $30	Yes	35%	8.84%	-	$0.1063/bbl. $0.1063/MCF	7%	-
North Dakota	State: 16⅔% Private: 12½% - 25%	State: $0 - $1 Private: $1	None	35%	6.4%	-	5% - 11.5%	5%	-
Oklahoma	Private: 12½% - 20%	Private: $1	Yes	35%	6%	-	7.2% (reduced at low prices)	4.5%	-
Texas	Private: 12½% - 30%	Private: $3.50	Yes	35%	1% of Net Taxable	-	$0.0063/bbl. $0.0667/MCF plus 0 - 4.6% oil and liquids and 7.5% gas value	6%	-
U.S. GOM OCS	Federal: 18¾%	Federal: $7 - $16	None	35%	-	-	-	none	-
U.S. Alaska OCS	Federal: 12½%	Federal: $2.50 - $20	None	35%	-	-	-	none	-
Canada/Provinces									
Alberta	Province: 0% - 40%	Province: $1.35	None	16.5%	10%	-	-	5%	-
Northwest Territories	Province: 1% - 5%	work commitment, no rental	None	16.5%	11.5%	-	-	5%	-
Canada - Beaufort Sea	Federal: 1% - 5%	work commitment, no rental	None	26.5%	-	-	-	5%	-
International									
Australia - Deepwater	none	Federal: $0 - $1	None	30%	-	40%	-	10%	-
Norway	none	Federal: $20 - $80	None	28%	-	50%	-	25%	20%
U.K.	none	Federal: $0.1 - $30	None	30%	-	32%	-	20%	-

Figure 4. Alaska fiscal system highlights.

Royalty:	Generally 12½ or 16⅔ percent, most production pays at 12½ percent. Higher royalty rates on some private lands do exist, but generally private rates are not lower than state rates. Natural gas royalty rate is the same as oil on state and federal lands. Most production in Alaska is on state-owned lands.
Rental Fee:	Alaska state lands: 1st year - $1, 2nd year - $1.50, 3rd year - $2, 4th year - $2.50, and 5th and subsequent years - $3 per acre. Rental is creditable against royalties. Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property/ad valorem tax:	The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The property tax is assessed annually and the tax rate is 20 mills. Oil and gas property that is also within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is graduated with the top tax rate of 9.4 percent levied when net incomes exceed $90,000 for the year. The CIT for oil and gas uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operation's (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property.
Net Tax/Profit Share:	The Alaska state production tax is fundamentally different than all other federal and state jurisdictions in the U.S., in that it is a "net" tax, after most costs and expenses are subtracted from revenue. This aspect of Alaska's fiscal regime remains unchanged despite changes made to the state's oil and gas production tax that went into effect in 2014. The production tax formula consists of two primary pieces: a base tax rate of 35 percent. With the 2014 tax changes, variable credit mechanism was created, with the value of the credit changing with an inverse relationship to the value of the oil produced. A company's tax liability may be reduced by credits that are included in the production tax system. Additionally, Alaska has a 4 percent gross minimum tax that may apply in some circumstances (see Gross/Severance Tax section below). The basic tax calculation of Alaska's production tax is as follows: **Production Tax Liability = [(Value – Costs) * Tax Rate] – Credits** **Value, production from existing fields** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value **Value, new production** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value * 80 or 70 percent **Costs** = Operating and Capital Expenditures **Tax Rate** = 35 percent

Credits, production from existing fields = Value of $0 to $8 per taxable barrel of oil produced

Credits, new production = Value of $5 per taxable barrel of oil produced

Gross/Severance Tax: **Minimum tax, production from existing fields** = 4 percent of Value before costs are subtracted

Indirect Taxes: None.

Incentives and Credits: Alaska offers, by most accounts, generous incentives targeted in several ways. See Figure 8-2 for details on many of Alaska's credit incentives. In addition to tax credits listed in Figure 8-2, Alaska offers special incentives for Cook Inlet and other "non-North-Slope" oil and natural gas production, royalty modification, natural gas storage.

Royalty modification, or reduction, on State of Alaska leases may be considered if an operator shows the state that a development project is uneconomic if developed without royalty modification.

In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 5. California fiscal system highlights.

Royalty:	Federal lands: Most production pays at 12½ percent. Natural gas rate is same as oil. Private lands: Generally 16⅔ or 25 percent, most production pays at 16⅔ percent. The majority of production in California is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Federal lands: \$1.50 per acre delay rental for years 1 – 5 and \$2 per acre thereafter. Private lands: \$5 to \$30 per acre, assumed to be \$20 per acre.
Property/ad valorem tax:	Property tax, administered by counties, is based on the lesser of the market value of the property and the Proposition 13 tax cap value. The rate is assumed to be 1 percent. This rate reflects a statewide average for counties and school districts.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 8.84 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	An Assessment Tax applies at \$0.14062 per barrel oil or per 10,000 cubic feet natural gas.
Indirect Taxes:	7¼ percent sales tax.
Incentives and Credits:	In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 6. North Dakota fiscal system highlights.

Royalty:	North Dakota state lands: Most production pays at 16⅔ percent. Natural gas rate is same as oil. Federal lands: Most production pays at 12½ percent. Natural gas rate is same as oil. Private lands: Most production pays at 18 ¾ percent. The majority of production in North Dakota is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	North Dakota state lands: $1 per acre (during exploration period only). Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 6.4 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	The overall tax is comprised of two pieces, 1. Severance Tax and 2. Oil Extraction Tax, that sum together for a total tax rate of 11½ percent, before incentives and credits. The Severance Tax is 5 percent of gross value and is effectively an irreducible minimum tax that is unaffected by any incentives or credits offered by the state. The Oil Extraction Tax starts at 6½ percent of gross value, but may be lower if production qualifies for incentives or credits offered by the state.
Indirect Taxes:	5 percent on all capital goods brought into the state.
Incentives and Credits:	North Dakota offers incentives for certain types of activities and ventures. These programs include lower Oil Extraction Tax (OET) for very-low-production volume (stripper) wells and when WTI oil price minus $2.50 falls below an inflation adjusted “Trigger” price, recently at $46.78. To encourage horizontal oil wells the

OET is reduced to 2 percent for the earlier of 75,000 barrels produced, 18 months, or $4.5 million in gross production revenue. To encourage production in the Bakken Formation, the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, or 18 months.

In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 7. Oklahoma fiscal system highlights.

Royalty:	Private lands: Rate range between 12½ and 20 percent, average assumed to be 18¾ percent. Virtually all production in Oklahoma is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Private lands: assumed to be $1 per acre delay rental.
Property/ad valorem tax:	Oklahoma assesses a Franchise Tax at $1.25 per $1,000 invested, to an annual maximum of $20,000 per corporate entity.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 6 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	1.2 to 7.2 percent total, broken down in four pieces. 1. Petroleum Excise Tax at 0.095 percent rate; 2. Energy Resources Board Fee at 0.1 percent rate; 3. Marginal Well Fee at $0.0035 per barrel oil and $0.00015 per thousand cubic feet natural gas; and 4. Gross Severance Tax assessed based on price as follows: 7 percent if the statewide average price of Oklahoma oil equals or exceeds $17.00 per barrel oil or $2.10 per mcf natural gas, 4 percent if the statewide average price of Oklahoma oil is less than $17.00 but is equal to or exceeds $14.00 per barrel oil or is less than $2.10 but is equal to or exceeds $1.75 per mcf natural gas, 1 percent if the statewide average price of Oklahoma oil is less than $14.00 per barrel oil or $1.75 per mcf natural gas.
Indirect Taxes:	4.5 percent on goods and services.
Incentives and Credits:	Oklahoma offers incentives for certain types of activities and ventures. Beginning July 1, 2012, in lieu of an incentive rebate for horizontally drilled and ultra-deep wells, a reduced tax rate shall be levied. Horizontal wells will be levied at 4 percent for the first 48 months of production. Deep wells drilled between 15,000 and 17,499 feet will be levied at 4 percent for 48 months and deep wells drilled below 17,500 feet will be levied at 4 percent for 60 months. Upon expiration of the incentive terms of 48 and 60 months, the Gross Production Tax Rate will be levied at the 7 percent base rate. Additionally, exemptions are available from the Gross Production Tax levied on oil and gas produced from certain wells. The exemption is equal to 6/7ths of the 7 percent Gross Production Tax and is rebated back to producers of qualified wells. Producers are eligible to file claims for refund on a July through June fiscal year basis. Wells qualifying for the exemption are as follows: horizontally drilled wells, the reestablished production of a well that was non-productive for one year, production enhancements such as work overs and recompletions, wells drilled and completed at a depth of 12,500 feet or greater, wells classified as "New Discovery", wells meeting the criteria as being "Economically at Risk", and wells that are drilled and completed based on 3-D seismic technology. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 8. Texas fiscal system highlights.

Royalty:	Private lands: Rate range between 12½ and 30 percent, average assumed to be 25 percent. Virtually all production in Texas is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	Private lands: assumed to be $3.50 per acre delay rental, exploration period only. University lands: $25 per acre at the time of the bid, then $5 per acre annually thereafter. Rental is creditable against royalties.
Property/ad valorem tax:	Property taxes assessed at 2.5 percent, levied on the fair market value of reserves as determined by discounted present value. This rate reflects a percent average for counties and school districts.
CIT:	The U.S. federal CIT rate is 35 percent. Texas has no state CIT, however it does levy a Corporate Franchise Tax at 1 percent of “net taxable earned surplus.”
Net Tax/Profit Share:	None.
Gross/Severance Tax:	Oil Production Tax is 4.6 percent plus Regulatory Tax at $0.001875 per barrel plus Oil Field Clean-Up Fee at $0.00625 per barrel oil. The oil severance tax may be reduced if production qualifies under certain incentives. Gas Production Tax is 7.5 percent plus Oil Field Clean-Up Fee at $0.000667 per thousand cubic feet natural gas.
Indirect Taxes:	6 percent on goods and services.
Incentives and Credits:	Enhanced Oil Recovery (EOR) projects are taxed at 2.3 percent of the market value. Oil produced from well bores certified by the Texas Railroad Commission as 2-year or 3-year inactive well bores is exempt from the tax for 10 years. Producers are eligible for a production tax credit for crude oil from low producing wells ranging from 100 percent if the average price is $22 or less to 0 percent if the average price is more than $30 per barrel. A certified orphan well put back in production is eligible for a 100 percent exemption from the oil production tax and the oilfield cleanup fee. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

Figure 9. U.S. Gulf of Mexico Outer Continental Shelf (OCS) fiscal system highlights.

Royalty:	18 ¾ percent (2008 terms). Natural gas pays the same royalty rate as oil.
Rental Fee:	If water depth <200 meters: \$7 per acre for years 1 – 5 and \$16 per acre for years 6 – 10. If water depth >200 meters: \$11 per acre for years 1 – 5 and \$16 per acre for years 6 – 10.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than \$5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 10. U.S. Beaufort Sea and Chukchi Outer Continental Shelf (OCS) fiscal system highlights.

Royalty:	12½ percent (recent lease sales). Natural gas pays the same royalty rate as oil.
Rental Fee:	1st year - $2.50, 2nd year - $3.75, 3rd year - $5, 4th year - $6.25, 5th year - $7.50, 6th year - $10, 7th year - $12, 8th year - $15, 9th year - $17, and 10th year - $20 per acre.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than $5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 11. Alberta (Canada) fiscal system highlights.

Royalty:	0 to 40 percent. Royalties in Alberta are the primary vehicle by which the province assesses its portion of economic rent. Unlike in the Alaska and other U.S. states, royalty rates in Alberta and other jurisdictions in Canada are not set in the lease contract, leases in Alberta simply state that the royalty is established by the provincial government. This leaves the royalty subject to change as government deems appropriate.
Rental Fee:	C$3.50 per hectare (approx. $1.35 per acre) per year.
Property/ad valorem tax:	None.
CIT:	In Alberta, the Canadian federal CIT rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Alberta provincial CIT for oil and gas is 10 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	Alberta has established programs whereby royalty rates are lowered to incentivize several different types of activities and ventures. These programs include special terms for low production volume wells, low price conditions, horizontal wells, deep gas wells, oil sands projects and coalbed methane, shale gas, solution gas, condensate, and natural gas liquids (NGL) production. The corporate tax rate is 3.0 percent for firms that qualify as "small businesses." In addition to provincial incentives, the Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 12. Northwest Territories (Canada) Onshore fiscal system highlights.

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental Fee:	None. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	In Northwest Territories the Canadian federal CIT rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Northwest Territory provincial CIT for oil and gas is 11.5 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Net Tax/Profit Share:	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 13. Canada Federal Offshore Beaufort Sea fiscal system highlights.

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental Fee:	None. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	In Canada the basic rate of federal corporate tax is 26.5 percent. Offshore areas are not subject to any federal corporate tax abatement and pay taxes at the full federal rate. For Canadian income tax purposes, a corporation's worldwide taxable income is computed in accordance with the common principles of business (or accounting) practice, modified by certain statutory provisions in the Canadian Income Tax Act. In general, no special tax regime applies to oil and gas producers. Depreciation, depletion or amortization recorded for financial statement purposes is not deductible; rather, tax-deductible capital allowances specified in the Income Tax Act are allowed.
Net Tax/Profit Share:	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Gross/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 14. Australia Federal Offshore fiscal system highlights.

Royalty:	See Production Tax.
Rental Fee:	Various application, permit and annual fees apply, up to about $1 per acre. Work expenditure commitments may apply.
Property/ad valorem tax:	None.
CIT:	The Australian federal CIT rate is 30 percent. Facilities depreciation is based on prescribed "effective life."
Net Tax/Profit Share:	The Petroleum Resource Rent Tax (PRRT) applies seaward of the territorial sea boundary, with the some exceptions. The PRRT is levied at 40 percent of taxable profit (income) after payout. Taxable profit is determined by deducting from assessable receipts, the total of deductible expenditures, plus certain expenditures. Payout occurs when a project has earned a return allowance equal to Australia's long-term bond rate plus an allowance of 5 percent or 15 percent depending on the specific project. PRRT is deductible in calculating CIT.
Gross/Severance Tax:	None.
Indirect Taxes:	All sales within Australia are subject to goods and services tax (GST) at the rate of 10 percent. Both Australian-resident and non-resident entities engaged in the oil and gas industry may be subject to GST on services and products supplied. All commercial transactions have a GST impact. Certain exported products and services and other transactions may qualify for exemptions.
Incentives and Credits:	None.

Figure 15. Norway Federal Offshore fiscal system highlights.

Royalty:	None.
Rental Fee:	Various rentals and annual fees apply, from about $20 to $80 per acre depending on the status of the lease block.
Property/ad valorem tax:	None.
CIT:	The Norwegian federal ordinary CIT rate is 28 percent. Expensing of certain costs is allowed. Depreciation of certain asset classes is based on a straight-line depreciation schedule. Additional tax elements apply.
Net Tax/Profit Share:	Special Tax, sometimes referred to as the “Hydrocarbon Tax,” is assessed at a 50 percent rate. Uplift of all capital expenses is at a rate of 7½ percent for a period of four years, 30 percent total. Hydrocarbon tax is not deductible against CIT.
Gross/Severance Tax:	None
Indirect Taxes:	Exempt. Norway’s value added tax (VAT) generally does not apply to goods and services used in offshore oil and gas operations.
Incentives and Credits:	7½ percent "uplift" of capital expenses under Special/Production Tax (described above). Losses may be carried forward indefinitely for offshore activity and may be transferrable in some cases. Interest on such losses is set by the Ministry of Finance annually; for 2011 the rate was 1.9 percent. Effective from 1 January 2005, an upstream company may also be refunded the tax value of exploration expenses for each tax year loss, including direct and indirect expenses related to exploration activities on the NCS (except for financing costs). The refund is made on 22 December in the year following the tax year for which the expenses were incurred. For example, NOK100 million spent on exploration expenses in 2012 may result in a cash refund of NOK78 million on 22 December 2013. The refund of exploration costs has opened up the opportunity for third parties to fund exploration activities. The claim on the state can also be pledged. In general, banks may typically be willing to fund 80 percent to 90 percent of the tax value of the exploration tax refund (i.e., 65 percent to 70 percent of the exploration cost basis).
State Participation:	Unlike all other jurisdictions discussed in detail in this report, Norway retains the right to exercise a participation interest in offshore oil and gas blocks. Various interest shares have been exercised, in recent bidding rounds about 20 percent participation. These participation interests are managed by a state-run company, Petoro.

Figure 16. United Kingdom Federal Offshore fiscal system highlights.

Royalty:	None.
Rental Fee:	1st and 2nd years - $0.10 per acre, 3rd through 6th years - $0.60 per acre, then escalating to a maximum of about $30 per acre in the 15th year. There is a mandatory 75 percent relinquishment at the end of Year 3 and a further 50 percent at the end of the primary term in Year 6.
Property/ad valorem tax:	None.
CIT:	The U.K. federal CIT rate is 30 percent. Taxable income is ring-fenced for upstream oil and gas activities. Additional tax elements apply.
Net Tax/Profit Share:	Supplementary Charge is tax (32 percent from 24 March 2011 and previously 20 percent) on UK exploration and production activities that is in-addition to CIT. Taxable profits for supplementary charge purposes are calculated in the same manner as ring-fence trading profits but without any deduction for finance costs. Finance costs are defined very broadly for this purpose and include the finance element of lease rentals and any costs associated with financing transactions for accounts purposes.
Gross/Severance Tax:	None.
Indirect Taxes:	The standard rate of value added tax (VAT) in the U.K. is 20 percent, with reduced rates of 5 percent and 0 percent. The VAT is potentially chargeable on all supplies of goods and services made in the U.K. and its territorial waters.
Incentives and Credits:	The U.K. offers incentives for certain activities and ventures, including a Ring Fence Expenditure Supplement and certain research and development allowances.

Title:	**Estimated General Fund Unrestricted Revenue under Fall 2015 forecast, and production tax / royalty forecast detail, at ANS Prices of $20 to $130 per Barrel**
Preparer:	Dan Stickel, Assistant Chief Economist, Economic Research Group
Date:	December 24, 2015
Purpose:	To show estimated unrestricted revenue, and production tax / royalty revenue, for FY 2016 through FY 2025 at a range of prices.
Data Source:	DOR Fall 2015 forecast model.
Key Assumptions:	Fall 2015 production, lease expenditures, and non-oil revenue are held constant in this analysis. The only variable changed is ANS price. Additional production would likely increase revenue from amounts shown here.
History:	First version based on Fall 2015 forecast. In addition to unrestricted revenue at a range of prices, this year's analysis also includes detailed forecasts for production tax and royalty revenue.
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

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This table presents revenue estimates at a range of ANS prices, holding all other variables constant. Analysis assumes that the given price is in place for the current year and for all years shown. Only production tax, royalties, and corporate income tax are adjusted for purposes of this analysis. Users should be cautioned that changes in any number of variables may cause revenue to vary significantly from amounts shown. These variables include but are not limited to production, lease expenditures, and netback costs. In addition, revenues may vary from amount shown due to changes in company decision making, company specific tax calculation issues, month to month variation in price or production, and changes in non-oil revenue.

Production tax estimates do not include refundable production tax credits which are paid for via appropriation in the operating budget.

Estimated GFUR at various prices, Fall 2015 forecast, $million

Prepared 12/24/2015 by Dan Stickel based on Fall 2015 forecast

Price	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Official Forecast	$ 1,593	$ 1,796	$ 2,021	$ 2,130	$ 2,111	$ 2,173	$ 2,132	$ 2,077	$ 2,061	$ 2,046
$ 20	$ 913	$ 885	$ 903	$ 911	$ 915	$ 915	$ 913	$ 916	$ 920	$ 924
$ 25	$ 997	$ 964	$ 982	$ 987	$ 987	$ 981	$ 974	$ 973	$ 972	$ 971
$ 30	$ 1,085	$ 1,044	$ 1,061	$ 1,064	$ 1,057	$ 1,047	$ 1,036	$ 1,031	$ 1,025	$ 1,020
$ 35	$ 1,172	$ 1,123	$ 1,139	$ 1,140	$ 1,127	$ 1,112	$ 1,097	$ 1,088	$ 1,079	$ 1,070
$ 40	$ 1,265	$ 1,202	$ 1,218	$ 1,216	$ 1,198	$ 1,178	$ 1,158	$ 1,146	$ 1,131	$ 1,121
$ 45	$ 1,405	$ 1,376	$ 1,312	$ 1,293	$ 1,292	$ 1,252	$ 1,219	$ 1,203	$ 1,184	$ 1,172
$ 50	$ 1,616	$ 1,586	$ 1,585	$ 1,495	$ 1,463	$ 1,388	$ 1,309	$ 1,270	$ 1,236	$ 1,224
$ 55	$ 1,795	$ 1,780	$ 1,691	$ 1,678	$ 1,645	$ 1,611	$ 1,543	$ 1,447	$ 1,360	$ 1,330
$ 60	$ 1,985	$ 1,986	$ 1,950	$ 1,916	$ 1,840	$ 1,734	$ 1,667	$ 1,633	$ 1,590	$ 1,520
$ 65	$ 2,141	$ 2,111	$ 2,080	$ 2,036	$ 1,962	$ 1,879	$ 1,803	$ 1,733	$ 1,642	$ 1,621
$ 70	$ 2,383	$ 2,238	$ 2,205	$ 2,155	$ 2,085	$ 1,995	$ 1,918	$ 1,842	$ 1,777	$ 1,721
$ 75	$ 2,719	$ 2,372	$ 2,356	$ 2,294	$ 2,211	$ 2,112	$ 2,025	$ 1,941	$ 1,875	$ 1,818
$ 80	$ 3,180	$ 2,597	$ 2,545	$ 2,475	$ 2,371	$ 2,228	$ 2,132	$ 2,041	$ 1,972	$ 1,910
$ 85	$ 3,649	$ 2,944	$ 2,791	$ 2,719	$ 2,590	$ 2,386	$ 2,266	$ 2,151	$ 2,070	$ 2,002
$ 90	$ 4,027	$ 3,298	$ 3,129	$ 3,059	$ 2,904	$ 2,633	$ 2,449	$ 2,288	$ 2,198	$ 2,107
$ 95	$ 4,501	$ 3,794	$ 3,613	$ 3,533	$ 3,344	$ 3,041	$ 2,827	$ 2,522	$ 2,370	$ 2,232
$ 100	$ 4,976	$ 4,149	$ 3,959	$ 3,876	$ 3,671	$ 3,342	$ 3,111	$ 2,885	$ 2,701	$ 2,520
$ 105	$ 5,446	$ 4,648	$ 4,443	$ 4,352	$ 4,118	$ 3,758	$ 3,472	$ 3,147	$ 2,948	$ 2,750
$ 110	$ 5,824	$ 5,010	$ 4,791	$ 4,695	$ 4,450	$ 4,066	$ 3,785	$ 3,507	$ 3,284	$ 3,062
$ 115	$ 6,299	$ 5,515	$ 5,278	$ 5,166	$ 4,899	$ 4,483	$ 4,146	$ 3,773	$ 3,532	$ 3,292
$ 120	$ 6,774	$ 5,876	$ 5,631	$ 5,514	$ 5,231	$ 4,791	$ 4,459	$ 4,133	$ 3,867	$ 3,604
$ 125	$ 7,245	$ 6,381	$ 6,124	$ 5,991	$ 5,679	$ 5,208	$ 4,821	$ 4,398	$ 4,115	$ 3,834
$ 130	$ 7,625	$ 6,742	$ 6,478	$ 6,343	$ 6,011	$ 5,516	$ 5,134	$ 4,759	$ 4,451	$ 4,146

Key Fall 2015 forecast assumptions included in this analysis

	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
ANS production (ths bbl/day)	500.2	504.9	497.7	487.6	460.5	423.9	391.1	359.8	329.2	302.1
ANS total lease expenditures ($ million)	$6,889	$6,465	$6,507	$6,032	$5,592	$5,327	$5,012	$4,723	$4,429	$4,162
ANS total lease expenditures per barrel	$38	$35	$36	$34	$33	$34	$35	$36	$37	$38

Source: DOR Fall 2015 forecast model
Notes:

This table presents revenue estimates at a range of ANS prices, holding all other variables constant. Analysis assumes that the given price is in place for the current year and for all years shown. Only production tax, royalties, and corporate income tax are adjusted for purposes of this analysis. Users should be cautioned that changes in any number of variables may cause revenue to vary significantly from amounts shown. These variables include but are not limited to production, lease expenditures, and netback costs. In addition, revenues may vary from amount shown due to changes in company decision making, company specific tax calculation issues, month to month variation in price or production, and changes in non-oil revenue.

Estimated Royalty Revenue at various prices, Fall 2015 forecast, $million

Prepared 12/24/2015 by Dan Stickel based on Fall 2015 forecast

Unrestricted Oil & Gas Royalty

Price	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Official Forecast	$ 650	$ 758	$ 840	$ 901	$ 869	$ 884	$ 843	$ 794	$ 753	$ 711
$ 20	$ 168	$ 185	$ 182	$ 173	$ 159	$ 140	$ 124	$ 108	$ 93	$ 79
$ 25	$ 252	$ 263	$ 259	$ 247	$ 228	$ 205	$ 184	$ 164	$ 144	$ 126
$ 30	$ 333	$ 342	$ 335	$ 321	$ 297	$ 269	$ 243	$ 219	$ 195	$ 173
$ 35	$ 413	$ 420	$ 412	$ 395	$ 366	$ 333	$ 303	$ 274	$ 246	$ 220
$ 40	$ 494	$ 499	$ 488	$ 469	$ 435	$ 397	$ 362	$ 329	$ 297	$ 266
$ 45	$ 576	$ 578	$ 565	$ 543	$ 505	$ 461	$ 422	$ 384	$ 348	$ 313
$ 50	$ 657	$ 658	$ 642	$ 617	$ 574	$ 525	$ 482	$ 439	$ 398	$ 359
$ 55	$ 739	$ 738	$ 720	$ 692	$ 644	$ 589	$ 541	$ 495	$ 449	$ 406
$ 60	$ 821	$ 818	$ 798	$ 767	$ 714	$ 654	$ 601	$ 550	$ 500	$ 453
$ 65	$ 903	$ 898	$ 875	$ 842	$ 784	$ 719	$ 662	$ 606	$ 552	$ 500
$ 70	$ 984	$ 977	$ 953	$ 917	$ 854	$ 784	$ 722	$ 662	$ 603	$ 547
$ 75	$ 1,066	$ 1,057	$ 1,031	$ 992	$ 925	$ 849	$ 783	$ 718	$ 655	$ 594
$ 80	$ 1,148	$ 1,137	$ 1,108	$ 1,067	$ 995	$ 914	$ 843	$ 774	$ 706	$ 642
$ 85	$ 1,229	$ 1,216	$ 1,186	$ 1,142	$ 1,065	$ 979	$ 904	$ 830	$ 758	$ 689
$ 90	$ 1,311	$ 1,296	$ 1,263	$ 1,217	$ 1,135	$ 1,044	$ 964	$ 886	$ 809	$ 736
$ 95	$ 1,393	$ 1,376	$ 1,341	$ 1,292	$ 1,206	$ 1,109	$ 1,025	$ 942	$ 861	$ 784
$ 100	$ 1,474	$ 1,455	$ 1,419	$ 1,367	$ 1,276	$ 1,174	$ 1,085	$ 997	$ 912	$ 831
$ 105	$ 1,556	$ 1,535	$ 1,496	$ 1,442	$ 1,346	$ 1,239	$ 1,145	$ 1,053	$ 964	$ 878
$ 110	$ 1,637	$ 1,615	$ 1,574	$ 1,517	$ 1,416	$ 1,304	$ 1,206	$ 1,109	$ 1,015	$ 926
$ 115	$ 1,719	$ 1,694	$ 1,652	$ 1,591	$ 1,486	$ 1,369	$ 1,266	$ 1,165	$ 1,067	$ 973
$ 120	$ 1,800	$ 1,774	$ 1,729	$ 1,666	$ 1,556	$ 1,434	$ 1,327	$ 1,221	$ 1,118	$ 1,020
$ 125	$ 1,881	$ 1,853	$ 1,807	$ 1,741	$ 1,627	$ 1,499	$ 1,387	$ 1,277	$ 1,170	$ 1,068
$ 130	$ 1,962	$ 1,933	$ 1,884	$ 1,816	$ 1,697	$ 1,564	$ 1,447	$ 1,333	$ 1,221	$ 1,115

Restricted Oil & Gas Royalty

Price	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Official Forecast	$ 288	$ 332	$ 368	$ 401	$ 387	$ 385	$ 360	$ 335	$ 315	$ 295
$ 20	$ 80	$ 80	$ 78	$ 75	$ 68	$ 59	$ 51	$ 44	$ 37	$ 31
$ 25	$ 112	$ 114	$ 112	$ 108	$ 99	$ 87	$ 76	$ 67	$ 58	$ 51
$ 30	$ 148	$ 149	$ 146	$ 141	$ 130	$ 115	$ 102	$ 90	$ 80	$ 70
$ 35	$ 183	$ 183	$ 179	$ 174	$ 162	$ 143	$ 128	$ 114	$ 101	$ 89
$ 40	$ 219	$ 218	$ 213	$ 207	$ 193	$ 171	$ 153	$ 137	$ 122	$ 109
$ 45	$ 255	$ 253	$ 247	$ 241	$ 224	$ 199	$ 179	$ 161	$ 144	$ 128
$ 50	$ 291	$ 288	$ 281	$ 274	$ 255	$ 228	$ 205	$ 184	$ 165	$ 148
$ 55	$ 327	$ 323	$ 315	$ 307	$ 286	$ 256	$ 230	$ 208	$ 187	$ 167
$ 60	$ 363	$ 358	$ 350	$ 341	$ 318	$ 284	$ 256	$ 231	$ 208	$ 187
$ 65	$ 399	$ 393	$ 384	$ 375	$ 349	$ 313	$ 282	$ 255	$ 230	$ 206
$ 70	$ 435	$ 428	$ 418	$ 408	$ 381	$ 341	$ 308	$ 279	$ 251	$ 226
$ 75	$ 471	$ 463	$ 452	$ 442	$ 412	$ 370	$ 334	$ 302	$ 273	$ 246
$ 80	$ 507	$ 499	$ 487	$ 475	$ 444	$ 398	$ 360	$ 326	$ 295	$ 266
$ 85	$ 543	$ 534	$ 521	$ 509	$ 475	$ 427	$ 386	$ 350	$ 317	$ 286
$ 90	$ 579	$ 569	$ 555	$ 543	$ 507	$ 455	$ 412	$ 374	$ 338	$ 305
$ 95	$ 615	$ 604	$ 589	$ 576	$ 538	$ 484	$ 439	$ 398	$ 360	$ 325
$ 100	$ 651	$ 639	$ 624	$ 610	$ 570	$ 512	$ 465	$ 421	$ 382	$ 345
$ 105	$ 687	$ 674	$ 658	$ 643	$ 601	$ 541	$ 491	$ 445	$ 403	$ 365
$ 110	$ 723	$ 709	$ 692	$ 677	$ 633	$ 569	$ 517	$ 469	$ 425	$ 384
$ 115	$ 759	$ 744	$ 726	$ 710	$ 664	$ 598	$ 543	$ 493	$ 447	$ 404
$ 120	$ 795	$ 779	$ 760	$ 744	$ 696	$ 626	$ 569	$ 516	$ 468	$ 424
$ 125	$ 831	$ 814	$ 795	$ 777	$ 727	$ 655	$ 595	$ 540	$ 490	$ 444
$ 130	$ 867	$ 849	$ 829	$ 811	$ 759	$ 683	$ 621	$ 564	$ 512	$ 464

Total Oil & Gas Royalty

Price		FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Official Forecast		$ 938	$ 1,090	$ 1,208	$ 1,302	$ 1,256	$ 1,269	$ 1,203	$ 1,129	$ 1,068	$ 1,006
$	20	$ 248	$ 265	$ 260	$ 248	$ 227	$ 199	$ 175	$ 152	$ 130	$ 110
$	25	$ 364	$ 377	$ 371	$ 355	$ 327	$ 292	$ 260	$ 231	$ 202	$ 177
$	30	$ 481	$ 491	$ 481	$ 462	$ 427	$ 384	$ 345	$ 309	$ 275	$ 243
$	35	$ 596	$ 603	$ 591	$ 569	$ 528	$ 476	$ 431	$ 388	$ 347	$ 309
$	40	$ 713	$ 717	$ 701	$ 676	$ 628	$ 568	$ 515	$ 466	$ 419	$ 375
$	45	$ 831	$ 831	$ 812	$ 784	$ 729	$ 660	$ 601	$ 545	$ 492	$ 441
$	50	$ 948	$ 946	$ 923	$ 891	$ 829	$ 753	$ 687	$ 623	$ 563	$ 507
$	55	$ 1,066	$ 1,061	$ 1,035	$ 999	$ 930	$ 845	$ 771	$ 703	$ 636	$ 573
$	60	$ 1,184	$ 1,176	$ 1,148	$ 1,108	$ 1,032	$ 938	$ 857	$ 781	$ 708	$ 640
$	65	$ 1,302	$ 1,291	$ 1,259	$ 1,217	$ 1,133	$ 1,032	$ 944	$ 861	$ 782	$ 706
$	70	$ 1,419	$ 1,405	$ 1,371	$ 1,325	$ 1,235	$ 1,125	$ 1,030	$ 941	$ 854	$ 773
$	75	$ 1,537	$ 1,520	$ 1,483	$ 1,434	$ 1,337	$ 1,219	$ 1,117	$ 1,020	$ 928	$ 840
$	80	$ 1,655	$ 1,636	$ 1,595	$ 1,542	$ 1,439	$ 1,312	$ 1,203	$ 1,100	$ 1,001	$ 908
$	85	$ 1,772	$ 1,750	$ 1,707	$ 1,651	$ 1,540	$ 1,406	$ 1,290	$ 1,180	$ 1,075	$ 975
$	90	$ 1,890	$ 1,865	$ 1,818	$ 1,760	$ 1,642	$ 1,499	$ 1,376	$ 1,260	$ 1,147	$ 1,041
$	95	$ 2,008	$ 1,980	$ 1,930	$ 1,868	$ 1,744	$ 1,593	$ 1,464	$ 1,340	$ 1,221	$ 1,109
$	100	$ 2,125	$ 2,094	$ 2,043	$ 1,977	$ 1,846	$ 1,686	$ 1,550	$ 1,418	$ 1,294	$ 1,176
$	105	$ 2,243	$ 2,209	$ 2,154	$ 2,085	$ 1,947	$ 1,780	$ 1,636	$ 1,498	$ 1,367	$ 1,243
$	110	$ 2,360	$ 2,324	$ 2,266	$ 2,194	$ 2,049	$ 1,873	$ 1,723	$ 1,578	$ 1,440	$ 1,310
$	115	$ 2,478	$ 2,438	$ 2,378	$ 2,301	$ 2,150	$ 1,967	$ 1,809	$ 1,658	$ 1,514	$ 1,377
$	120	$ 2,595	$ 2,553	$ 2,489	$ 2,410	$ 2,252	$ 2,060	$ 1,896	$ 1,737	$ 1,586	$ 1,444
$	125	$ 2,712	$ 2,667	$ 2,602	$ 2,518	$ 2,354	$ 2,154	$ 1,982	$ 1,817	$ 1,660	$ 1,512
$	130	$ 2,829	$ 2,782	$ 2,713	$ 2,627	$ 2,456	$ 2,247	$ 2,068	$ 1,897	$ 1,733	$ 1,579

Mining Rents and Royalties

Price	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Unrestricted	$ 16	$ 16	$ 17	$ 17	$ 18	$ 18	$ 18	$ 19	$ 19	$ 20
Restricted	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7
Total	$ 23	$ 23	$ 24	$ 24	$ 24	$ 25	$ 25	$ 26	$ 26	$ 27

Source: DOR Fall 2015 forecast model
Notes:

This table presents revenue estimates at a range of ANS prices, holding all other variables constant. Analysis assumes that the given price is in place for the current year and for all years shown. Only royalties are adjusted for purposes of this analysis. Users should be cautioned that changes in any number of variables may cause revenue to vary significantly from amounts shown. These variables include but are not limited to production, lease expenditures, and netback costs. All amounts are in $millions and are inclusive of bonuses, rents, and interest. "Restricted Royalty" includes funds to the Permanent Fund and School Fund only.

Estimated Production Tax Revenue at various prices, Fall 2015 forecast, $million

Prepared 12/24/2015 by Dan Stickel based on Fall 2015 forecast

Unrestricted Oil & Gas Production Tax										
Price	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Official Forecast	$ 172	$ 188	$ 277	$ 296	$ 296	$ 318	$ 307	$ 287	$ 293	$ 301
$ 20	$ 79	$ 10	$ 12	$ 11	$ 10	$ 9	$ 8	$ 7	$ 6	$ 5
$ 25	$ 79	$ 10	$ 14	$ 13	$ 12	$ 11	$ 9	$ 9	$ 7	$ 6
$ 30	$ 86	$ 11	$ 16	$ 15	$ 14	$ 13	$ 11	$ 11	$ 10	$ 8
$ 35	$ 94	$ 12	$ 19	$ 18	$ 14	$ 14	$ 13	$ 14	$ 12	$ 11
$ 40	$ 106	$ 13	$ 21	$ 20	$ 16	$ 15	$ 14	$ 15	$ 14	$ 16
$ 45	$ 118	$ 93	$ 38	$ 23	$ 41	$ 25	$ 16	$ 17	$ 16	$ 21
$ 50	$ 183	$ 158	$ 177	$ 106	$ 111	$ 83	$ 45	$ 30	$ 18	$ 25
$ 55	$ 216	$ 207	$ 141	$ 149	$ 158	$ 177	$ 154	$ 97	$ 46	$ 49
$ 60	$ 259	$ 268	$ 258	$ 248	$ 218	$ 170	$ 153	$ 163	$ 159	$ 128
$ 65	$ 316	$ 297	$ 292	$ 275	$ 252	$ 233	$ 212	$ 190	$ 143	$ 165
$ 70	$ 459	$ 327	$ 323	$ 302	$ 288	$ 267	$ 249	$ 225	$ 209	$ 200
$ 75	$ 696	$ 364	$ 379	$ 349	$ 326	$ 302	$ 278	$ 251	$ 238	$ 233
$ 80	$ 1,058	$ 492	$ 473	$ 437	$ 399	$ 335	$ 307	$ 277	$ 266	$ 260
$ 85	$ 1,428	$ 741	$ 623	$ 589	$ 531	$ 410	$ 364	$ 314	$ 295	$ 287
$ 90	$ 1,707	$ 999	$ 867	$ 837	$ 756	$ 575	$ 469	$ 379	$ 354	$ 327
$ 95	$ 2,082	$ 1,398	$ 1,256	$ 1,218	$ 1,109	$ 901	$ 769	$ 539	$ 458	$ 387
$ 100	$ 2,458	$ 1,656	$ 1,508	$ 1,470	$ 1,348	$ 1,120	$ 975	$ 828	$ 720	$ 611
$ 105	$ 2,829	$ 2,058	$ 1,897	$ 1,853	$ 1,708	$ 1,454	$ 1,258	$ 1,017	$ 898	$ 777
$ 110	$ 3,109	$ 2,322	$ 2,149	$ 2,104	$ 1,953	$ 1,679	$ 1,493	$ 1,305	$ 1,165	$ 1,024
$ 115	$ 3,485	$ 2,731	$ 2,541	$ 2,482	$ 2,314	$ 2,014	$ 1,777	$ 1,497	$ 1,344	$ 1,190
$ 120	$ 3,861	$ 2,995	$ 2,800	$ 2,739	$ 2,558	$ 2,240	$ 2,012	$ 1,784	$ 1,611	$ 1,437
$ 125	$ 4,234	$ 3,403	$ 3,197	$ 3,123	$ 2,920	$ 2,574	$ 2,297	$ 1,976	$ 1,790	$ 1,602
$ 130	$ 4,515	$ 3,668	$ 3,457	$ 3,383	$ 3,164	$ 2,800	$ 2,533	$ 2,263	$ 2,057	$ 1,849

Source: DOR Fall 2015 forecast model
Notes:

This table presents revenue estimates at a range of ANS prices, holding all other variables constant. Analysis assumes that the given price is in place for the current year and for all years shown. Only production tax is adjusted for purposes of this analysis. Users should be cautioned that changes in any number of variables may cause revenue to vary significantly from amounts shown. These variables include but are not limited to production, lease expenditures, and netback costs. All amounts are in $millions. Production tax estimates include hazardous release surcharge and do not include refundable production tax credits which are paid for via appropriation in the operating budget.

The Department's Fall 2015 forecast model calculates production tax using an aggregate estimate of taxable value of oil produced, and company-specific estimates of lease expenditures and credits applied in calculating tax liabilities. In certain isolated instances, this approach can produce slight inconsistencies when calculating production tax at prices other than the forecast price. For instance, FY2018 production tax is calculated to be slightly higher at $50/barrel than at $55/barrel. Users should be aware of this deficiency when using numbers presented in this table.