Alaska's Oil and Gas Competitiveness Report 2015

Alaska Oil and Gas Competitiveness Review Board

– Tom Hendrix, Chairman

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http://dor.alaska.gov/OilGasCompetitivenessReviewBoard

This publication is exclusively available online.

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1. Introduction

This report is the product of the Alaska Oil and Gas Competitiveness Review Board (O&GCRB) and the Alaska Department of Revenue (DOR). It was written and provided to the Alaska Legislature to satisfy the statutory report obligation found in AS 43.98.050(6)(A)

In this report, we will consider how Alaska's fiscal regime compares to comparable jurisdictions around the world. To be a good steward of its resources, Alaska should define policies that encourage responsible exploration and development and manage the impacts of those policies to maximize the benefits of oil and gas production for all Alaskans. In fact this is a constitutional mandate.

Fiscal systems are not the only criteria oil and gas producers use to make investment decisions. Factors such as operating costs, economic and political stability, and availability of labor and lands for exploration play a role as well. Alaska's position in the global marketplace is unlikely to stay static with time; rather, it will evolve with changes in oil and gas prices, perceived geologic potential, anticipated cost structure and outside competition. This publication intends to present a clearer view of these other important criteria that are used by investors when comparing Alaska with the rest of the world.

Oil and Gas Competitiveness Review Board history and goals

The concept of Alaska's O&GCRB originated with SB 21, the More Alaska Production (MAP) Act, passed by the Alaska legislature in 2013. The intent of the MAP Act was to reform Alaska's oil and gas production tax. Along with production tax reform, the legislature created a board, the O&GCRB, to establish and maintain salient oil and gas exploration, development, and production data and advise the Alaska legislature on the state's oil and gas fiscal system, labor pool, and regulatory competitiveness.

The O&GCRB board is made up of two public members, three administration department heads, a commissioner from the Alaska Oil and Gas Conservation Commission, three oil and gas subject matter experts, and two industry trade group representatives. The idea for Alaska's O&GCRB was, at least in part, modeled after a similarly tasked board in Alberta, Canada.

Alaska peer group selection

Since the early days of petroleum development of the North Slope, Alaska has been a North American leader in oil production. However, new technologies and new discoveries mean oil and gas companies have a long list of opportunities around the globe when deciding where to invest capital and resources. Fiscal structure is a significant factor producers consider when making those investment decisions. In order to stay competitive with other jurisdictions where investors may consider investing private capital in oil and gas projects, it is critical that Alaska consider both domestic and international competition when selecting a peer group to benchmark its competitiveness.

In most jurisdictions, the sovereign right to explore for and produce hydrocarbons and other minerals belongs to the national or local government. This is true on federal and state lands in the United States, although outside of Alaska, the majority of land and mineral interests are privately owned by individuals. Whether lands are publicly or privately owned, oil and gas companies have historically shared a variety of attributes that make it beneficial for mineral owners to offer them significant rights and a share of the profits from exploration and production. The benefits offered by oil and gas compainies include:

1. A willingness to take large risks and expose significant private capital searching for hydrocarbons.

2. Technical expertise in exploration, development and production including technology and resources that are otherwise not easily available.

3. Massive capital investment that is often required to develop oil and gas fields and a willingness to invest those funds years in advance of revenue and cash flow.

4. Highly trained and experienced people capable of managing major projects associated with oil and gas development.

5. Access to refineries and distribution systems to refine, upgrade and market produced oil and gas.

Simply turning over rights to a for-profit international oil company (IOC) in return for cash (and in some cases, a minor share of the revenue being generated) is usually not an arrangement that is beneficial to the economic health of the jurisdiction that owns the resource. Under early agreements between IOCs and regional jurisdictions, local workers did not receive training or meaningful experience leading to advancement, and the immediate export of oil and gas meant there was no benefit to local industry. Beginning in the 1950s, governments began working to develop fiscal schemes that offered more long-term benefit, with issues of control, involvement of citizens beyond low-level roles and development of local industry and infrastructure beginning to change significantly in the 1960s and continuing to evolve through the present day.

One goal of this report is to select a reasonable peer group of jurisdictions that will allow a representative comparison of Alaska's position in the world with respect to oil and gas exploration and development. It is important to balance the competing needs for a peer group that is diverse and representative of the competition yet is not such a long list of peers that readers of this report are overloaded with too much confusing information. In addition, it is reasonable to consider this list or any other list as a list that may evolve and change over time as world oil and gas exploration and production, global markets, the industry and our understanding of all of the above evolve and change. We believe the criteria discussed in this report can provide a logical framework to show the value of using this group of peers, and specifically this set of peers.

Figure 1-1 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. We preferred a geographic affinity: a location in the Arctic, in North America or Europe, or in the Pacific region.

We also looked for jurisdictions with similar size resource potential, discussed in Chapter 2. We favored jurisdictions with some history of 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. And all of the jurisdictions mentioned in this list have often been used by others before when comparing Alaska's oil and gas resources and fiscal system.

Figure 1-1. Peer group jurisdiction and fiscal regime type and geographic affinities. (figure update complete)

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 OCS	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
U.K.	Federal	Concession		X		

2. Hydrocarbon endowment

A region's production history and future production potential are important elements to consider when establishing or reviewing a petroleum fiscal system. It seems logical that Alaska's fiscal system peer group should include jurisdictions that have a similar resource base and production volumes, referred to in this report as the hydrocarbon endowment.

This section of the report focuses on the comparison of Alaska's hydrocarbon endowment for conventional oil and does not address other resource types, such as natural gas and viscous or "heavy" oil. While these resource types will possibly be important contributors if Alaska's overall production is to increase, there is no available source of worldwide unconventional resource comparisons. Note that in addition to statistics for natural gas resources, reserves and production are provided here because they are important components of the resource base in jurisdictions outside Alaska. Estimates are for the conventional natural gas resource and should not be completely dismissed as irrelevant.

Production volumes

The Energy Information Agency (EIA), an agency of the U.S. Department of Energy, is used throughout this report as our primary source for oil and gas production and proved reserves for both North America and the rest of the world (Figures 2-1 and 2-2). In the case of Canadian provinces, data were gathered from Canada's National Energy Board (NEB). The EIA provides annual estimates of the United States' proved reserves of crude oil and natural gas based on filed responses to Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, which includes data from about 1,200 domestic operators. The purpose of this report is not to explain or offer the definitive cause for these production trends. There are a number of possible explanations for changes in production. Primarily, we provide these numbers as a basis for discussion.

First, let's compare Alaska oil production with other North American peers for the last six years available (Figures 2-1 and 2-3). This group of North American producers includes all the largest-volume oil-producing jurisdictions in North America. In each of the last six years, Alaska's oil production has declined. Meanwhile in that same period, the U.S. Gulf of Mexico's oil production saw an early increase and recent decline, California's production has held relatively constant. Meanwhile, Alberta, Oklahoma, North Dakota, and Texas have all seen significant increases in the last six years, with production in Texas and North Dakota up sharply.

Like Alaska, Australia, Norway and the U.K. have all experienced continuous production declines over the last six years, possibly reflecting the maturity of the basins where production occurs in those countries.

Natural gas production for the North American peer group over the last six years (Figure 2-2) shows somewhat different trends. Alaska has experienced relatively stable natural gas production. Similarly, California, Oklahoma, and Texas have also seen relatively stable natural gas production.Over the same period, the U.S. Gulf of Mexico has seen a significant decline in production, a drop of almost 40 percent. Only North Dakota has a significant production increase in the recent few years, even though there production is still low compared to others in the selected peer group.

Figure 2-1. Annual oil production history for Alaska and its peer group jurisdictions. Complete annual data are only available through 2013.

Jurisdiction	Annual Oil Production					
	2008	2009	2010	2011	2012	2013
Units	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]	[Mbbl/d]
United States[1]						
Alaska[2]	729	703	652	610	590	544
California	649	664	686	686	686	686
North Dakota	172	218	310	419	666	860
Oklahoma	184	183	189	209	254	319
Texas	1,109	1,094	1,169	1,449	1,979	2,543
U.S. Alaska OCS[2]	0.00	0.00	0.00	0.00	0.00	0.00
U.S. GOM OCS	1,157	1,562	1,552	1,317	1,267	1,254
Canada[3]						
Canada-Alberta	2,292	2,461	2,477	2,657	2,870	3,093
Canada-total (includes Alberta)	3,195	3,275	3,306	3,493	3,692	3,965
Rest-of-the-World[4]						
Australia	586	592	604	531	519	445
Norway	2,464	2,353	2,135	2,007	1,902	1,826
U.K.	1,584	1,510	1,406	1,167	1,009	916

[1]Data source for Alaska crude oil production is the Alaska Department of Revenue "Revenue Sources Book" for consistency with other DOR work. Data source for all other U.S. state crude oil production outside Alaska is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

[2]The only oil production allocated to the Alaska Outer Continental Shelf (OCS) is a small fraction of the production from Northstar field. This production is insignificant when compared to the rest of Alaska and its peer group and is not broken out in EIA reports. Because of the units precision used in this table, Alaska OCS production appears as zeros, but the actual production was positive but less than 0.005 MMbbl/d.

[3]Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) Statistical Handbook available at http://www.capp.ca/library/statistics/handbook/Pages/default.aspx. Data series includes natural gas liquids.

[4]Data source for Rest-of-the-World production is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

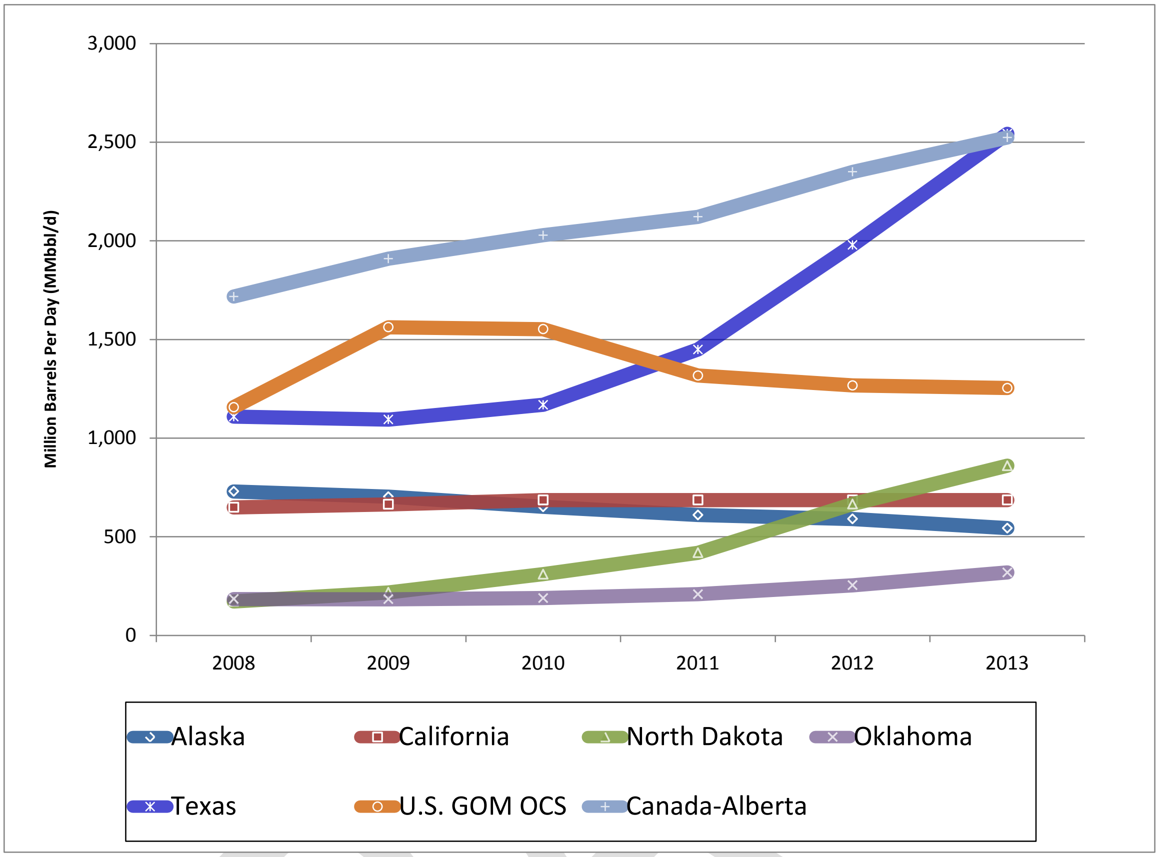
Figure 2-2. Annual natural gas production history for Alaska and its peer group jurisdictions. Complete annual data are only available through 2013.

Jurisdiction	Annual Natural Gas Production					
	2008	2009	2010	2011	2012	2013
Units	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]
United States[1]						
Alaska[2]	1,022	1,025	968	917	901	866
California	772	720	750	652	640	NA
North Dakota	122	135	193	227	418	NA
Oklahoma	4,869	4,900	4,676	4,808	5,145	NA
Texas	17,921	17,520	17,210	18,169	18,840	NA
U.S. Alaska OCS[2]	0.0	0.0	0.0	0.0	0.0	0.0
U.S. GOM OCS	6,323	6,655	6,151	4,965	3,889	NA
Canada[2]						
Canada-Alberta	5,265	4,866	4,644	4,346	4,247	4,159
Canada-total (includes Alberta)	6,931	6,452	6,261	6,148	5,987	6,012
Rest-of-the-World[1]						
Australia	4,329	4,570	4,364			
Norway	9,597	10,011	10,290			
U.K.	6,764	5,718	5,447			

[1]Data source natural gas production is the Departement of Energy, Energy Information Agency (EIA) at http://www.eia.gov/

[2]Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) Statistical Handbook available at http://www.capp.ca/library/statistics/handbook/Pages/default.aspx.

Figure 2-3. Oil production history for Alaska and its North American peers.



Proved reserves

EIA defines "proved reserves" as "those volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." Reserves estimates change from year to year as new discoveries are made, existing reserves are produced and prices, technologies change, and companies modify development schedules for undeveloped reserves. Discoveries include new fields, identification of new reservoirs in old fields, and extensions. Extensions are reserve additions that result from additional drilling and exploration in previously discovered reservoirs. Extensions typically account for a large percentage of "discoveries" within a given year. While actual discoveries of new fields and reservoirs are important indicators of new resources, they usually account for a small percentage of reserve additions in a given year. Revisions occur primarily when operators change their estimates of what they will be able to produce from the properties they operate using existing technology and prices.

While several factors influence proved reserves, crude oil and natural gas prices are particularly important. Higher prices typically increase estimates (positive revisions) as operators consider a broader portion of the resource base economically producible, or proved. Lower prices generally reduce estimates (negative revisions) as the economically producible base contracts.

Scheduling changes can also result in some undeveloped reserves being removed and others added. When an undeveloped resource development project is more than 5 years out, it is outside the limit, based on SEC rules, to be considered "proved reserves." When a project moves into the 5-year window it is added to "proved reserves."

Alaska's proved reserves and peers

On the list of top producing states in the U.S., Alaska's proved oil reserves are greater than only Oklahoma, they are roughly equivalent to California and are less than North Dakota and Texas (Figure 2-4). Continuing improvements in technology and changing economics of producing unconventional oil from the Williston Basin only recently increases North Dakota's reserves to a level that exceeded Alaska. Similarly, if unconventional oil development were ever to become economic on the North Slope, Alaska proved reserves could also increase dramatically. It is always important to keep in mind the importance of commodity price in determining how oil and gas may move in and out of the "proved reserves" classification. Recent price declines may disproportionately affect states with large volumes of shale oil production. Low prices may result in the reclassification of large volumes of proved reserves to potential reserves, reversing the increases some states recently experienced.

Proved oil reserves in Norway are much greater than Alaska's but are still within a range that does not preclude them from consideration for an Alaska peer group. Australia's oil reserves are similar in size, and the U.K.'s oil reserves are only somewhat lower.

Proved reserves in both Norway and the United Kingdom have declined in recent years. However, significant new discoveries in Norwegian waters of the North Sea that were announced in the past year may reflect a change in fortune for the basin. At the time of this writing, it remains unclear if they are large enough to reverse the declining trend of oil reserves in the North Sea.

Figure 2-4. Estimates of proved reserves and undiscovered resources in Alaska and its peer group jurisdictions. (needs work)

Jurisdiction	Oil + NGL Proved Reserves	Natural Gas Proved Reserves
[Units]	[MMbbl]	[BCF]
United States[1,2,3]		
Alaska (onshore & state submerged)	2,898	7,383
California	2,878	2,023
North Dakota	5,683	6,081
Oklahoma	1,469	28,900
Texas	12,004	97,921
U.S. Alaska Arctic OCS	-	-
U.S. GOM OCS	4,950	8,303
Canada[4,5,6,7]		
Canada-Alberta (conventionl)		
Canada-Alberta (unconventional)		
Canada-Total (includes Alberta)	173,110	68,170
Rest-of-the-World[5,6]		
World total	1,433	43,037
Australia	1,433	43,037
Norway	5,825	73,806
U.K.	2,979	8,616

Undiscovered oil resource estimates

Insert text here.

Natural gas, viscous oil and other unconventional resources

As stated earlier, we chose to focus the attention of this publication on Alaska's conventional oil and the fiscal systems the state has put in place to capture revenue from it. But it is important to keep in mind that Alaska also has other significant hydrocarbon resources. The state has large quantities of other classes of hydrocarbon resources including natural gas, viscous oil, shale oil, shale gas, coalbed methane, and gas hydrates.

Natural gas

Alaska has a huge resource base of discovered and undiscovered gas (217.91 trillion cubic feet). Expensive and time-consuming exploration programs will be required to extend the natural gas reserves and identify new commercial gas fields. Much of northern Alaska's conventional natural gas remains unexploited awaiting construction of an export pipeline or development of some other export option. Any capital spending to identify new natural gas reserves will only be made by companies expecting long periods of time bef ore payback on investment. All of the options to construct infrastructure to exploit northern Alaska gas will likely be expensive and technically challenging. Two possible scenarios for export of northern Alaska gas are a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada or shipping liquefied natural gas (LNG) from tidewater. No clear decision has yet been announced on any option.

Viscous oil

Alaska has a large discovered and delineated potential for the production of viscous oil, sometimes referred to as "heavy oil." Viscous oil delineation and test production has been occurring for decades. Schrader Bluff (including West Sak) and Ugnu reservoirs in the Kuparuk River, Milne Point, and Prudhoe Bay units have recently been estimated to contain a total of 23 to 36 billion barrels of viscous oil in place.[4] This compares to a previous estimate of 18 to 40 billion barrels in place in the loosely described "Kuparuk River area."[5] Additional in-place volumes in the Schrader Bluff reservoir at Eni's Nikaitchuq Unit are estimated at 800 to 930 million barrels (AOGCC Conservation Order 639).[6]

Current production of viscous oil flows from six Participating Area (PA) developments in four North Slope units: Kuparuk River, Milne Point, Nikaitchuq and Prudhoe Bay. The combined in-place resources under active development total 5.5 to 7.4 billion barrels. These developments are expected to recover 1.0 to 1.2 billion barrels, with overall recovery factors of 15 to 20 percent.[7]

Other unconventional resources

Alaska has significant potential in the form of several other types of unconventional resources. Notable among these are coalbed methane, methane hydrates, and shale oil.

Coalbed methane

Coalbed methane is a form of natural gas extracted from coal beds. In recent decades it has become an important source of energy in the United States, Canada, and other countries. Coalbed methane is distinct from natural gas produced from a typical sandstone or other conventional gas reservoir because the methane is stored within the coal by a process called adsorption. The methane is in a near-liquid state, lining the inside of pores within the coal (called the matrix). The open fractures in the coal (called "cleats") can also contain free gas or be saturated with water. The adsorbed gas is extracted along with fluid from a well completed in the coal seam (300 to 5,000 feet below ground). Adsorbed gas is released when sustained fluid production reduces the pressure within the coal seam. As formation water is produced from the coalbed, both gas and "produced water" come to the surface through tubing.

Methane hydrates

Another unconventional resource, methane hydrates, is a huge potential hydrocarbon resource in Alaska, as well as in many locations throughout the world. In 2008, the USGS completed the first assessment of the undiscovered technically recoverable gas hydrate resources on the North Slope of Alaska. Using a geology-based assessment methodology, the USGS estimates that there are about 85 TCF of undiscovered, technically recoverable natural gas resources within gas hydrates in northern Alaska.[8] This untapped resource is a significant addition to Alaska's resource base and will possibly prove to be an important component to gas production in the future.

Shale oil

Some explorers in Alaska have begun considering unconventional resource, specifically shale oil, exploration and development in Alaska. Lease acquisitions and test well well drilling has begun in northern Alaska and has brought considerable attention to the possibility of producing oil and gas from shale in Alaska. The technology necessary to produce oil and gas from shale in the Lower 48 has evolved in the past few years and is now accepted as relatively mainstream. Many oil and gas exploration and production companies of all sizes are participating in the rush to exploit this newly emergent resource. Alaska is now receiving attention as a possible new frontier in this resource play. It remains unclear whether Alaska's shale resource plays can prove productive or if the technology applications and methods used to produce shale oil in the Lower 48 will translate reasonably well to an Arctic environment.

[1] http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment.aspx

[2] http://energy.usgs.gov/OilGas/AssessmentsData/WorldPetroleumAssessment.aspx

[3] The USGS also does unconventional resource assessments for resource types not included in this report, including coalbed methane, source rock oil and gas (shale oil and gas), continuous tight sands, and gas hydrates.

[4] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

[5] Werner, M.R., 1987, West Sak and Ugnu sands; Low-gravity oil zones of the Kuparuk River area, Alaskan North Slope, in Tailleur, I., and Weimer, P., eds., Alaskan North Slope Geology, v. 1: Bakersfield, California, Pacific Section, Society of Economic Paleontologists and Mineralogists and Alaska Geological Society, p. 109-118.

[6] Alaska Oil and Gas Conservation Commission, Conservation Order 639 and production records.

[7] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

[8] USGS, 2008, Assessment of Gas Hydrate Resources on the North Slope, Alaska, 2008, USGS FS08-3073, 2 pp.

3. Lease sales

The State of Alaska offers its oil and gas mineral estate for exploration and development primarily under two programs: conventional oil and gas leases (AS 38.05.180) and exploration licenses (AS 38.05.131 – 134). The Alaska Department of Natural Resources (DNR) is charged with preparing and scheduling a five-year proposed oil and gas leasing program. A detailed description of the state's leasing programs and schedule, including location information for lease sales that will be held in the next five years, is updated annually and is available to view or download from the DNR Division of Oil and Gas website.[9]

Conventional oil and gas leases

In 1998, DNR changed the way it offered state lands for competitive bid oil and gas leasing for the North Slope, North Slope Foothills, Beaufort Sea and Cook Inlet areas. These are the areas designated by the state as having moderate to high potential for oil and gas development. So-called "areawide leasing" became the standard for lease sales so that the state could provide stability and predictability in the lease sale program. In 2004, the Alaska Peninsula was added to the list of areas offered by the state under the areawide leasing program. Under areawide leasing, the state offers all available state-owned land within these five areas for lease by competitive bidding at annually scheduled lease sales. Before areawide lease sales, DNR used a nomination process and wrote best interest findings for each sale.

Conducting annual areawide sales is more cost-effective because it allows companies to plan for and develop their exploration strategies and budgets years in advance and to bid on any available acreage within an entire region. A regular schedule of areawide lease sales allows for quick turnaround of expired or terminated leases, or leases contracted out of units, for reoffer in the next annual sale. The result is more efficient exploration leading to earlier development. It also allows smaller companies and individuals the opportunity to acquire leases in areas of less interest to the major oil companies.

Leasing methods

Alaska has several leasing method options designed to encourage oil and gas exploration and maximize state revenue, as described in AS 38.05.180(f). These methods include combinations of fixed and variable bonus bids, royalty shares, and net profit shares. Minimum bids for state leases are generally $5 or $10 per acre. Fixed royalty rates are generally 12.5 percent or 16 and two-thirds percent, although some have been as high as 20 percent. A sliding scale royalty has also been used on occasion. Lease terms are set at 5, 7, or 10 years, depending on geographical location.

Several months before a scheduled sale, a geologic and economic evaluation of the sale area is prepared to determine the bidding method, leasing method and the lease terms for the sale. Public notice of the sale is sent out to an extensive mailing list maintained by the Division of Oil and Gas. Leases in areawide sale areas must be offered by competitive bidding. Leases will be issued to the highest responsible qualified bidder.

Historical lease sale data

The state has conducted annual areawide sales each year since 1998, totaling 68 sales.[10] Reviews of sale results, summed by year, indicate the levels of participation and interest from bidders for leasing in Alaska over the past decade. Figure 3-1 includes data for leases sold, acres sold, bonus bids received, and participation by bidder class for the period 2000 through 2014. During that time, over 2,700 tracts totaling 9.3 million acres of state land have sold, resulting $237.6 million in bonus bids received.

Figure 3-2 shows participation levels by bidder class as percent of total tracts sold in State of Alaska competitive oil and gas lease sales, 2000 through 2014. For example, in 2000 the major oil companies bidding alone acquired 13 percent of all tracts sold by the Alaska DNR in all of the competitive oil and gas lease sales summed for the year, major and/or active independent companies bidding together as a consortium acquired 44 percent, active independent oil companies bidding alone acquired 26 percent, and very small companies and/or individuals bidding alone or together as bidder consortiums acquired 17 percent of tracts sold, totaling 100 percent. In general, recent lease sales have seen active independent oil and gas companies acquiring the greatest share of leases in DNR lease sales.

Exploration licenses

Exploration licensing supplements the state's oil and gas leasing program and encourages oil and gas exploration on DNR administered lands outside of the known oil and gas provinces in the North Slope, Beaufort Sea, Cook Inlet, Alaska Peninsula, and North Slope Foothills areawide sale areas. The DNR is currently administering five existing and two proposed licenses (Figure 3-3). The holder of an oil and gas exploration license has the exclusive right to explore an area between 10,000 acres and 500,000 acres in size for a term of up to 10 years. Rather than an up-front bonus payment to the state, as is done in competitive leasing, a licensee must commit direct expenditures for exploration. Because a license has no annual rental payments, the only money guaranteed the state is a one-time $1 per acre licensing fee, which is paid upon acceptance. However, the state is provided all of the geological and geophysical information acquired by the licensee, and so it can gain a better understanding of an area's resource potential.

Each application for an exploration license must go through a public notice and written finding process to determine whether issuance of a license is in the state's best interest. DNR first issues a notice of intent to evaluate the exploration license proposal and solicits any competing proposals for the area. The department then requests public comment on the proposal(s) and goes through a best interest finding process similar to that for oil and gas leasing to determine whether issuing a license for the area is in the best interest of the state. If competing proposals are submitted for an area, the applicants must submit sealed bids. The successful bidder is determined by the highest bid in terms of the minimum work commitment dollar amount.

[9] "Five-Year Program of Proposed Oil and Gas Lease Sales," January 2014: http://dog.dnr.alaska.gov/

[10] 1998 to 2014 areawide sales: 16 were in the North Slope, 17 in Cook Inlet (added in 1999), 14 in Beaufort Sea (added in 2000), 13 in North Slope Foothills (added in 2001), and eight in Alaska Peninsula (added in 2005).

Figure 3-1. Alaska DNR competitive oil and gas lease sale results summary with all lease sales summed together by year. Source: Alaska DNR, Division of Oil and Gas. (figure update complete)

Year	Total Tracts Sold	Total Acres Sold	Total High Bonus Bids Received [$ MM]	Avgerage Winning Bid Per Acre	Number of Lease Sales Held	Major Oil Company Tracts Acquired	Major &/or Independent Consortium Tracts Acquired	Active Independent Tracts Acquired	Small Co. & Individual Investor Tracts Acquired
	Annual Totals, All Sales					Annual Total, Tracts Acquired by Bidder Classification			
2000	183	753,252	$ 11.066	$ 14.69	3	24	80	47	31
2001	322	1,432,604	$ 21.087	$ 14.72	4	30	68	145	81
2002	92	329,737	$ 4.398	$ 13.34	4	4	32	40	16
2003	123	326,630	$ 5.671	$ 17.36	4	5	-	87	31
2004	162	558,757	$ 13.564	$ 24.28	4	11	4	126	21
2005	104	420,660	$ 2.514	$ 5.98	3	33	-	38	33
2006	363	1,319,855	$ 30.158	$ 22.85	6	42	29	140	152
2007	85	247,256	$ 3.748	$ 15.16	5	15	-	8	62
2008	115	348,135	$ 8.383	$ 24.08	5	1	1	81	32
2009	85	314,838	$ 8.150	$ 25.89	4	-	-	76	9
2010	203	818,849	$ 11.954	$ 14.60	6	1	-	9	199
2011	342	981,694	$ 25.898	$ 26.38	5	72	-	209	65
2012	160	406,541	$ 17.837	$ 43.87	5	77	3	103	24
2013	115	260,583	$ 8.251	$ 31.66	5	-	-	117	2
2014	335	759,701	$ 64.968	$ 85.52	5	-	2	319	14
Totals	2,789	9,279,091	$ 237.645	$ 380.366	68	315	219	1,545	772

Figure 3-2. Participation levels by bidder class as percent of total tracts sold in Alaska DNR competitive oil and gas lease sales, 2000 through 2014. (figure update complete)

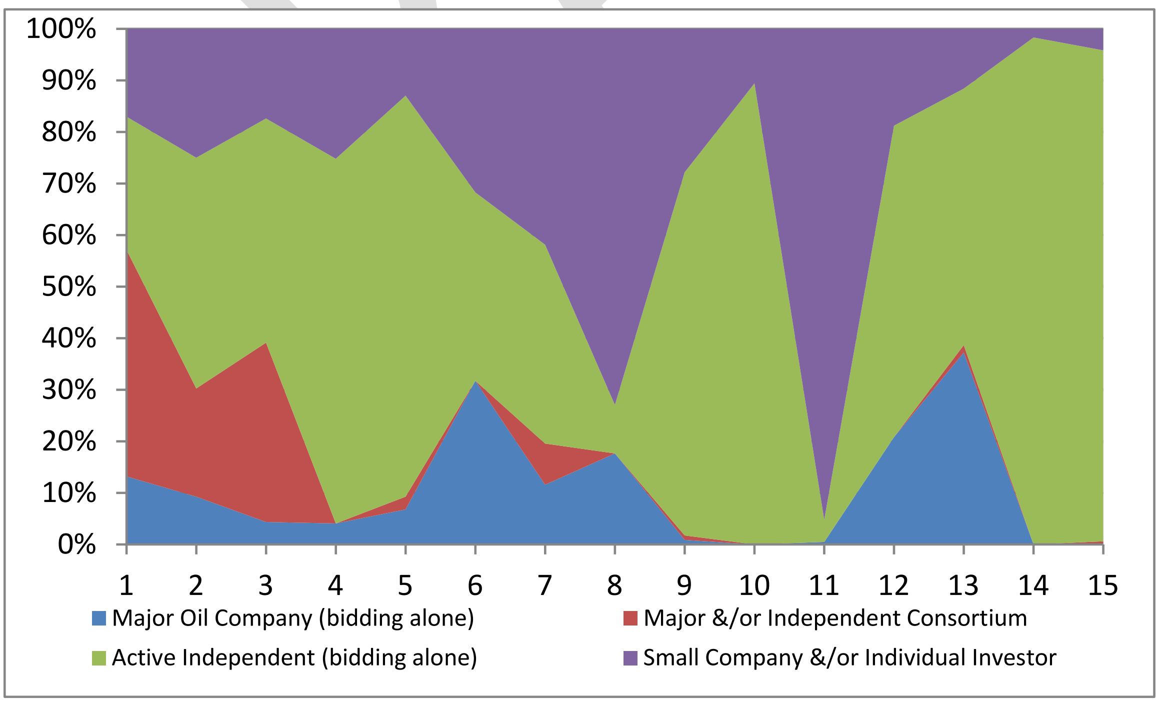


Figure 3-3. Existing and proposed oil and gas exploration licenses administered by the Alaska DNR in January 2015. (figure update complete)

Location	ADL	Status	Licensee	Acres	Work Commitment	Effective Date	Term
Healy Basin	390606	Active	Usibelli Coal Mine Inc.	204,883	$500,000	1/1/2011	10 Yrs
Susitna Basin IV	391628	Active	Cook Inlet Energy LLC	62,909	$2,250,000	4/1/2011	10 Yrs
Susitna Basin V	391794	Active	Cook Inlet Energy LLC	45,764	$250,000	4/1/2012	5 Yrs
Tolsona	392209	Active	Ahtna, Inc.	43,492	$415,000	12/1/2013	5 Yrs
Southwest Cook Inlet	392536	Active	Cook Inlet Energy LLC	168,581	$1,501,000	10/1/2014	4 Yrs
Houston-Willow Basin	391282	Application	LAPP Resources Inc.	21,080	$500,000	Proposed	(10 Yrs)
North Nenana	392535	Application	Rocky Riley	25,600	$500,000	Proposed	(5 Yrs)

4. Exploration and development activity

Drilling activity in Alaska

Exploratory wells

Development and service wells

Drilling rig counts

Figure 4-1. Exploratory wells and wellbores in Alaska (statewide). Includes all exploration wells that were completed, suspended or abandoned between 1999 and 2013. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel). Source: Alaska Oil and Gas Conservation Commission.

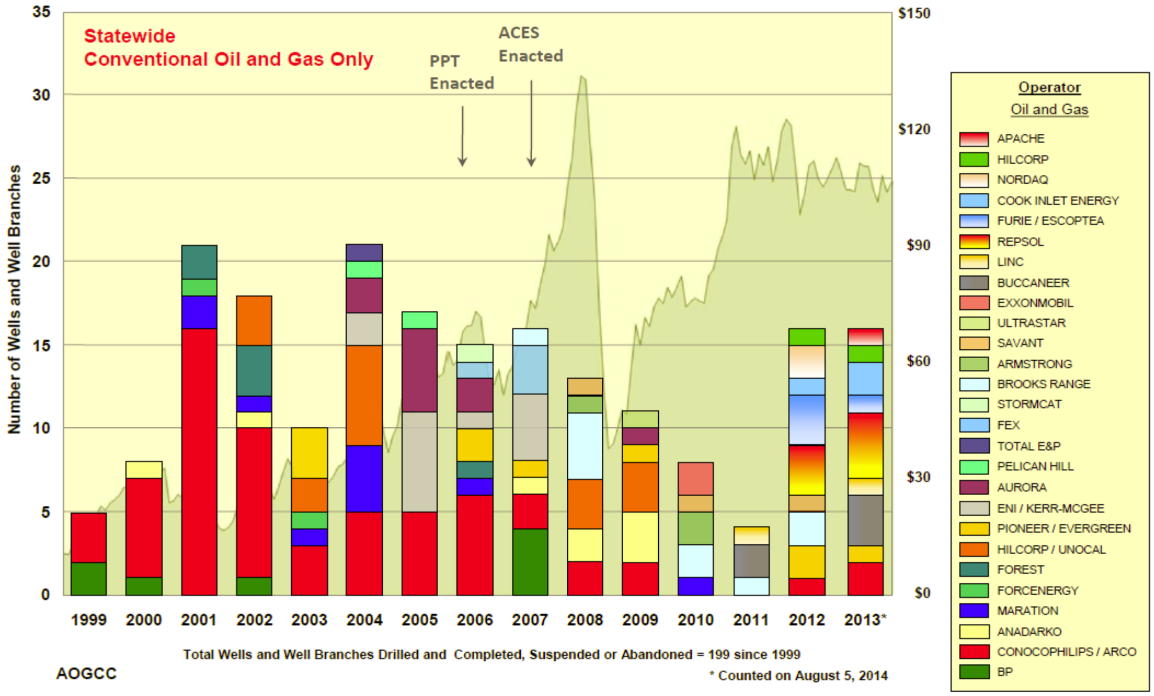


Figure 4-2. Development and service-class wells and wellbores in Alaska (statewide). Includes all development and service wells that were completed, suspended or abandoned between 1999 and 2014. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel). Source: Alaska Oil and Gas Conservation Commission.

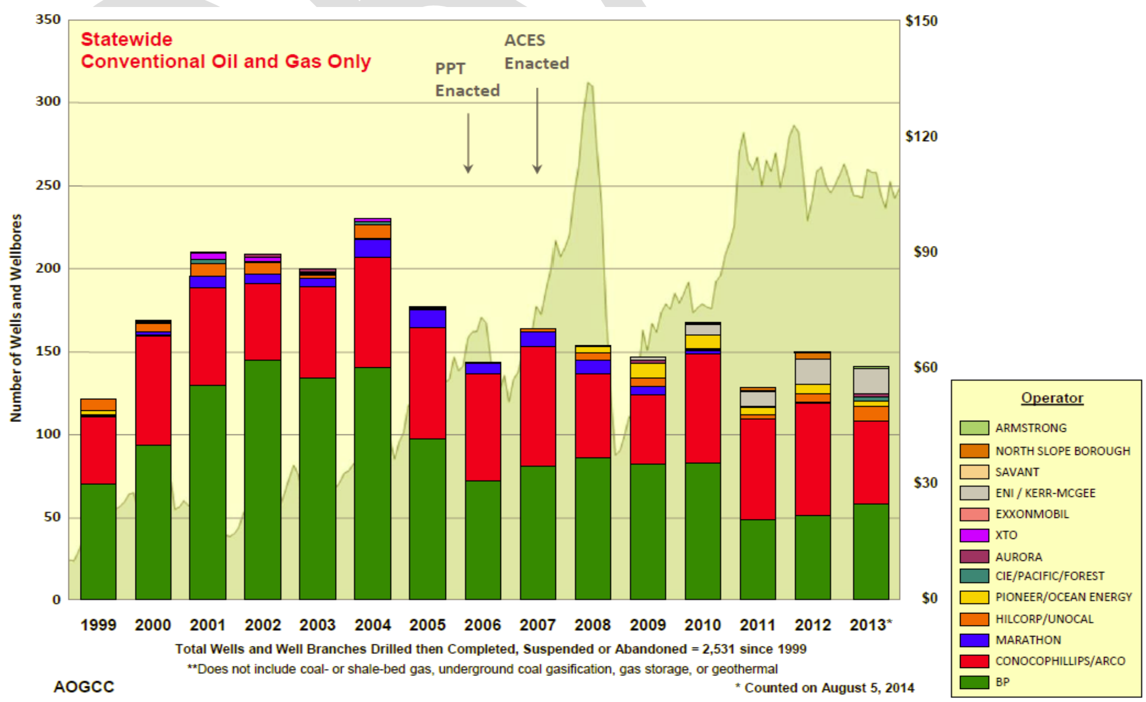


Figure 4-3. Alaska's combined active drilling rigs and workover rigs for each quarter from 2005 through 2012. Source: Alaska Oil and Gas Conservation Commission.

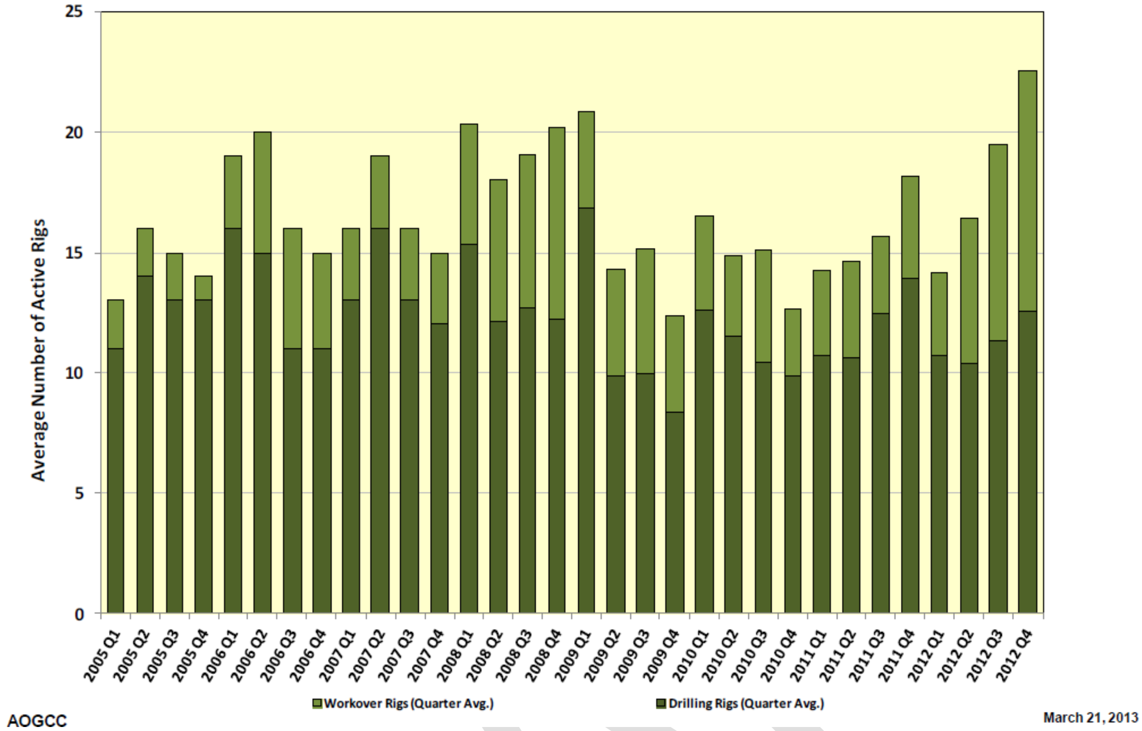


Figure 4-4. Number of Alaska's well workover activities by calendar year, North Slope only, from 2003 through 2010.* Solid line represents West Coast spot price for Alaska North Slope crude oil (dollars per barrel). Source: Alaska Oil and Gas Conservation Commission.

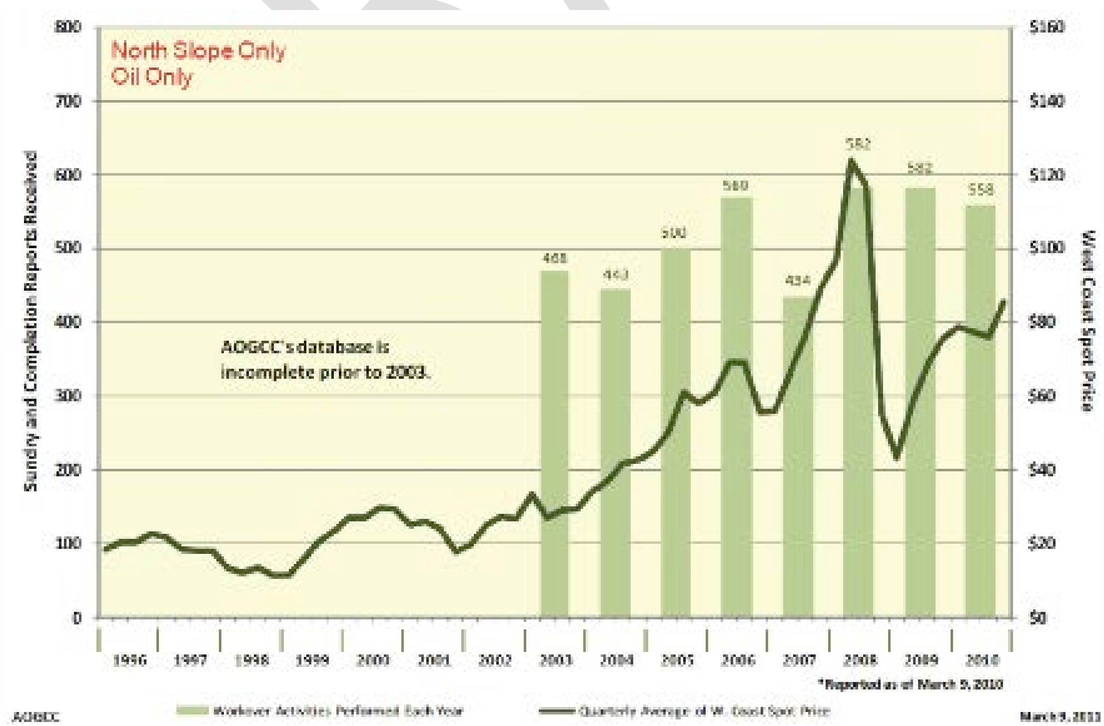
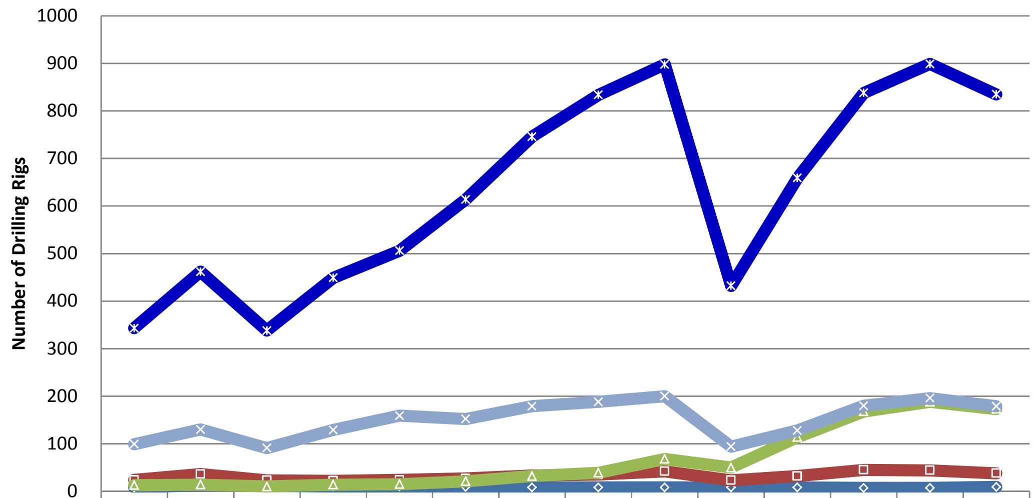


Figure 4-5. Number of drilling rigs by state Source: Baker Hughes.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Alaska	8	13	11	10	10	9	8	8	8	8	8	7	7	9
California	24	36	23	22	24	27	33	35	42	23	32	45	44	38
North Dakota	13	14	10	14	15	21	32	39	68	50	114	168	188	173
Oklahoma	99	130	91	129	159	152	179	188	200	94	128	180	196	179
Texas	343	462	338	449	506	614	746	834	898	432	659	838	899	835

Investment in North Slope oil and gas

5. Status of the oil-and-gas-related infrastructure in Alaska

The oil and gas infrastructure is well established in Alaska. In important aspect is that much of it is privately controlled by the working interest owners of Cook Inlet and North Slope assets, whether single owner operators or combined working interest owners. In addition, oil and gas resources are brought to market by consortiums like the Alyeska Service Company for the Trans-Alaska Pipeline System, or through individual or consortium owned common carrier pipelines regulated by the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska for oil, condensates or dry gas. The list of regulated pipelines and tariffs can be found at http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm. (A table can be inserted of tariffs and years)

North Slope

The infrastructure of the North Slope, while permitted for development and regulated for seasonal operation by the state of Alaska, is exclusively privately owned. The state maintains access to the North Slope via the Dalton Highway for road traffic and via shipping regulations and pilotage, when required, for landings from the Beaufort to land. Entry from the Dalton Highway into Deadhorse, Alaska is restricted and controlled. Once departing Deadhorse, all transportation on the privately maintained roads must be approved by the North Slope unit operators. Similarly, once marine cargo is landed at a facility, any transport of that cargo beyond the landing must be approved by the owner/operators of the specific infrastructure being used. A final restriction applies to air traffic over the North Slope. While air traffic has the right of free passage within restrictions established by the FAA, the use of private landing strips is restricted to those who have approval for the facility.

The North Slope infrastructure was recently updated into the "Alaska Department of Natural Resources 2014 North Slope Infrastructure Atlas", an atlas based on data from many sources, including working interest owners and operators as recent as 2014. The atlas depicts the following:

- Pads and wells
- Processing facilities and pipelines
- Transmission and Utility Corridors
- Roads, air strips and fields, and coastal landings
- Bridges and culverts
- Borrow sites and mine sites

It is important to note that the current atlas does not include the new development at Point Thomson or the expansion of infrastructure from the Alpine field into the federal lands of NPRA.

The infrastructure of the North Slope is being expanded to the east with the development of Point Thomson and the 70,000 bbl/day carrier line for gas condensate. Future infrastructure development will reflect expansion of operations and production at Point Thomson or at other leases held with access to the new line and infrastructure that will join with TAPS.

The infrastructure of the North Slope is being expanded to the west with the development into NPRA for CD-5 and additional pads, as well as the exploration and development of the Greater

Moose's Tooth unit. The newly constructed bridges across the channels of the Coleville River and gravel roads will allow for efficient development of the NPRA resources. This advancement will continue under federal regulatory control, but will depend on the state infrastructure in place.

Future development of the Beaufort Sea is being planned as companies, including Repsol and Hilcorp explore leases in both state and federal waters. While plans are announced and some exploratory drilling has been completed, decisions that will create infrastructure remain speculative.

A private road joining the village of Nuiqsut with the Alpine Development Road was constructed by the Kuukpik Corporation to allow support of the village by a road system.

Infrastructure deficiencies

Presently, there are no significant infrastructure deficiencies identified on the North Slope as the industry has invested in maintaining the infrastructure developed over the more-than-37 years of production. Maintaining the infrastructure to state and federal regulatory standards and in insuring minimal down time in production is reflected in the continued increase in employment on the North Slope regardless of the decline in production.

One important point is the competitive challenge is in the handling of the produced liquids required to be handled in the production of oil (Figure 5-1). Since 2010, the ratio of water production to oil and natural gas liquids (NGL) has been greater than 75% water to less than 25% oil and NGL's produced. Increasing water production, in part due to water flooding and enhanced recovery methods employed by North Slope operators, will either require greater and greater water handling capability or eventually may lead to a continued decline in oil and NGL production.

Figure 5-1. Graph of the North Slope liquids production since the discovery of Prudhoe Bay field in 1969. Liquids production may be a significant factor in the workforce level and investment in maintenance and technology to sustain North Slope production at or above a nominal decline rate.

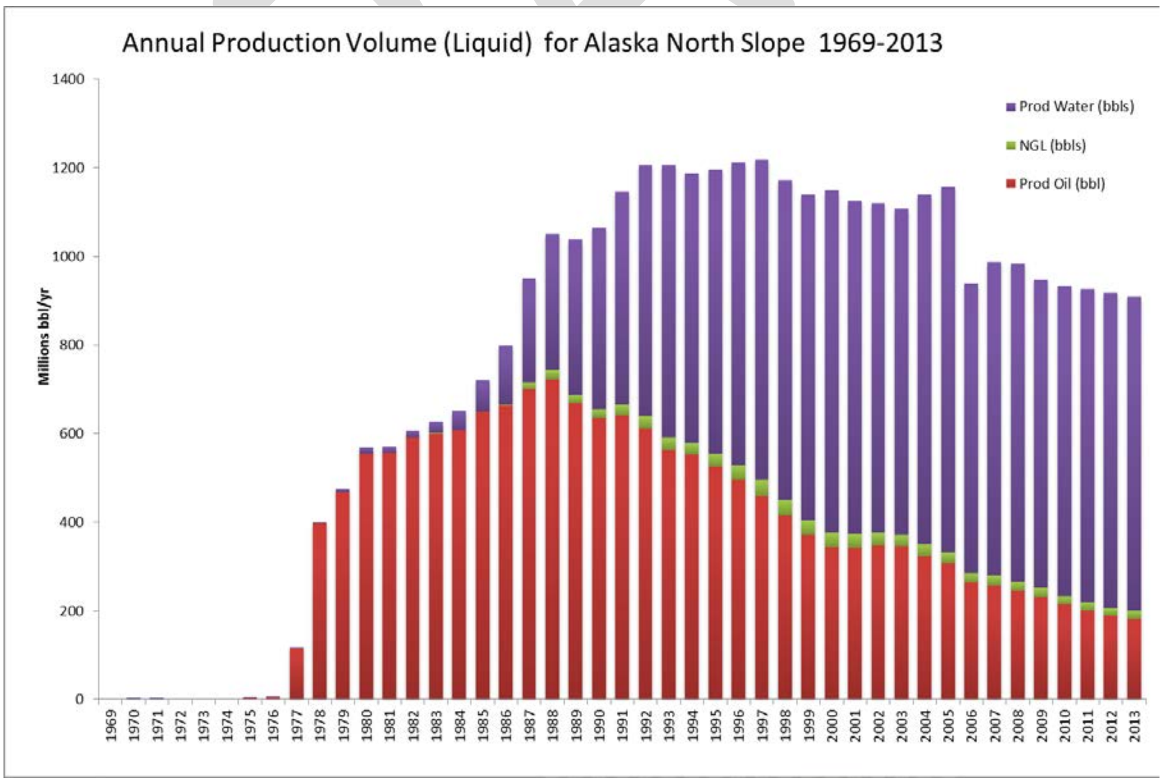
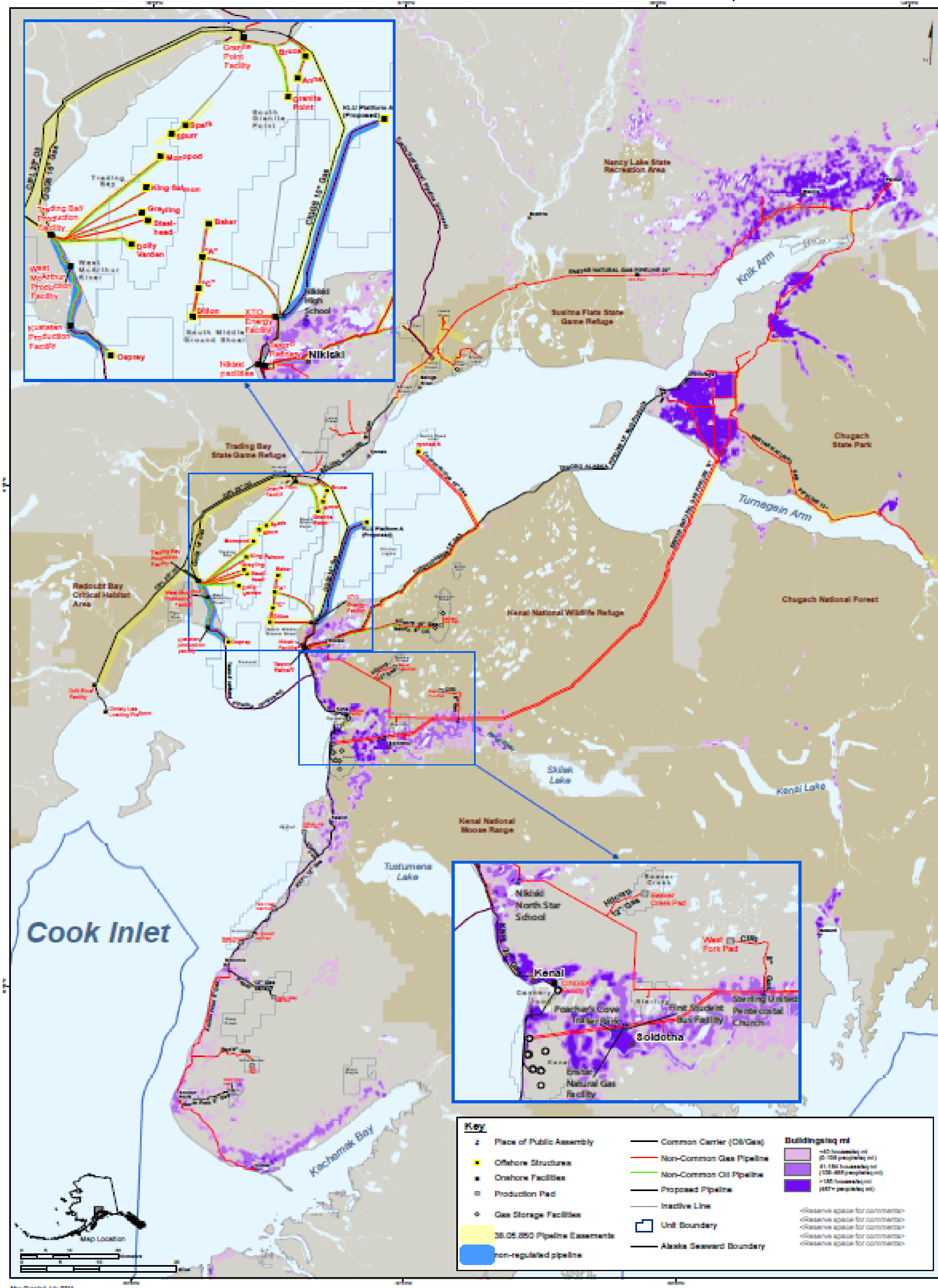


Figure 5-2.

Petroleum Systems Integrity Office: Cook Inlet Area Pipelines and Related Facilities



Cook Inlet

The oil and gas fields of Cook Inlet and the surrounding area have been in production since 1960 on federal, state and private lands. Figure 5-2 is a map published by the Alaska DNR Petroleum Systems Integrity office. Additionally, a map of the existing oil and gas pipelines in Cook Inlet is available at http://dog.dnr.alaska.gov/GIS/Cookinletpipelines.htm. Tariff rates and ownership of common-carrier pipelines in Cook Inlet are available through Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA), and are posted at: http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm. Cook Inlet has 34 recognized units or fields. Of these, 32 are or have had a history of production of natural gas, oil or both. All are connected to infrastructure to bring the produced oil or gas to processing facilities. The inlet has 16 platforms with 2 shut in and others either producing natural gas and/or oil or being reworked to increase their production capability. The inlet includes oil pipelines and dockage for refining at the Tesoro refinery on the east side at Nikiski and the oil loading terminal on the west side at Drift River. The Nikiski Alaska Pipeline is the sole oil carrying pipeline to transport refined product from the Tesoro refinery to Anchorage, allowing fuel distribution from the Port of Anchorage to the Ted Stevens International Airport.

Natural gas pipelines cross the inlet from production platforms and onshore producing fields to common carrier lines on both the east and west side of Cook Inlet. This allows for natural gas to be transported from the production areas to markets in Southcentral Alaska. Pipeline corridors run from Homer and Anchor Point, along the west coast of the Kenai Peninsula to Nikiski and further north and east to Anchorage, gathering the Kenai and Swanson River fields. Additional pipeline corridors carry gas from the Drift River to Anchorage, Palmer and Wasilla. The Cook Inlet Gas Gathering System (CIGGS) joins both pipeline corridors to allow for flexibility in flow direction to prevent from service disruption.

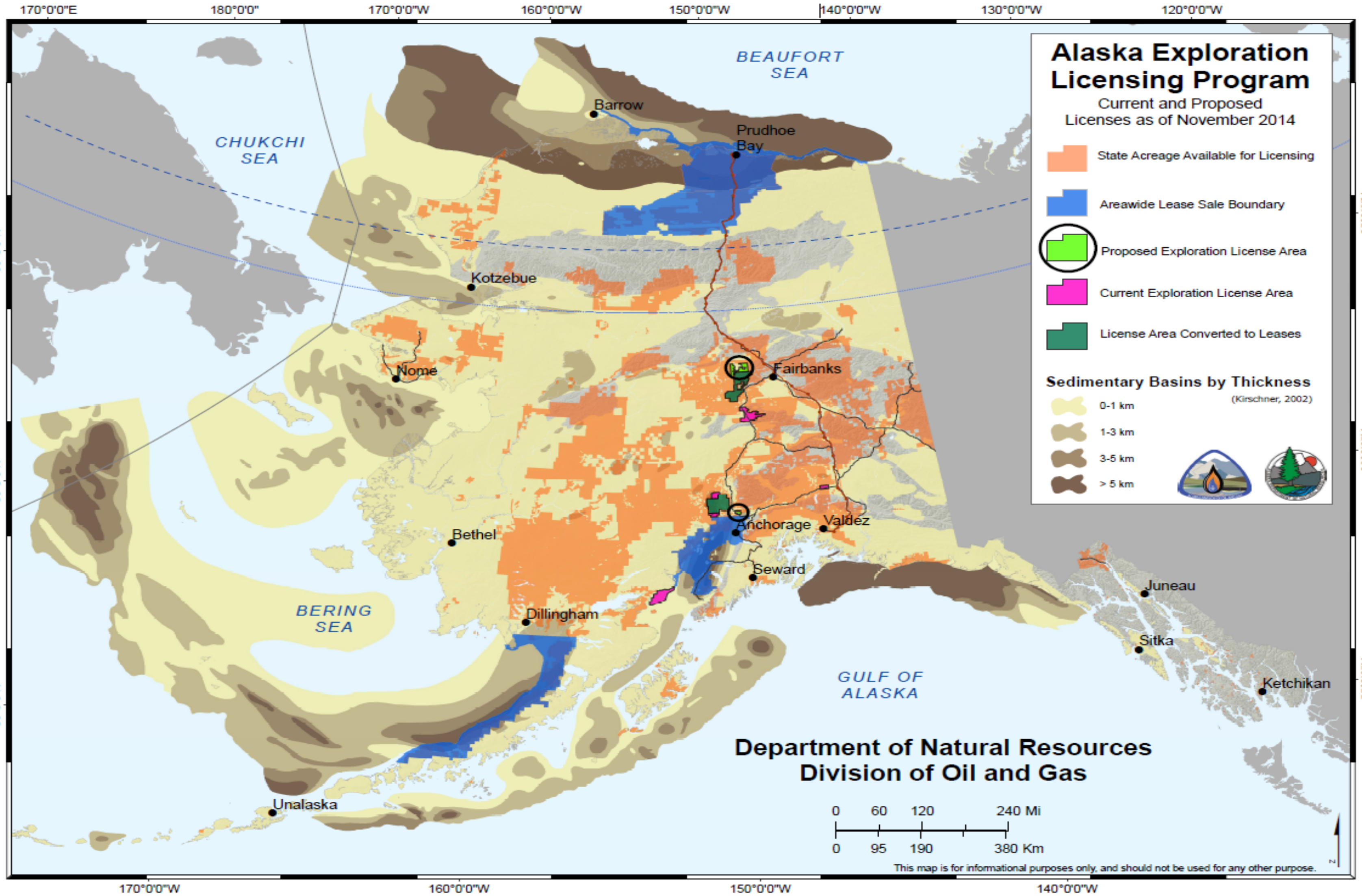
During a period of concern for natural gas supply, a series of gas storage facilities were developed. The importance of gas storage was realized with the stopping the export of liquefied natural gas and shutdown of the Nikiski LNG facility. This removed the flexibility of directing natural gas to domestic market during periods of increased demand (winter) and continuing export during periods of low demand (summer). Currently, the Cook Inlet Natural Gas Storage facility is in operation as well as other storage pools associated with different fields. Gas storage has subsequently declined in demand with the increased drilling of wells, the re-working of wells that have led to increased gas production throughout Cook Inlet's gas producing units and fields.

Frontier basins and exploration license areas

Surface access remains a challenge, but not necessarily a deficiency in exploring for oil and gas resources outside of the state areawide sale areas. Exploration license areas (Figure 5-3) are areas of state land, outside the areawide sale areas, that are available for proposals to explore for oil or gas. Generally these areas are lacking in infrastructure and require review for the exploration to be in the best interest of the state. The finding will detail mitigation measures to protect the environment and regulate activities, thus establishing standards for exploration and methods of access and infrastructure.

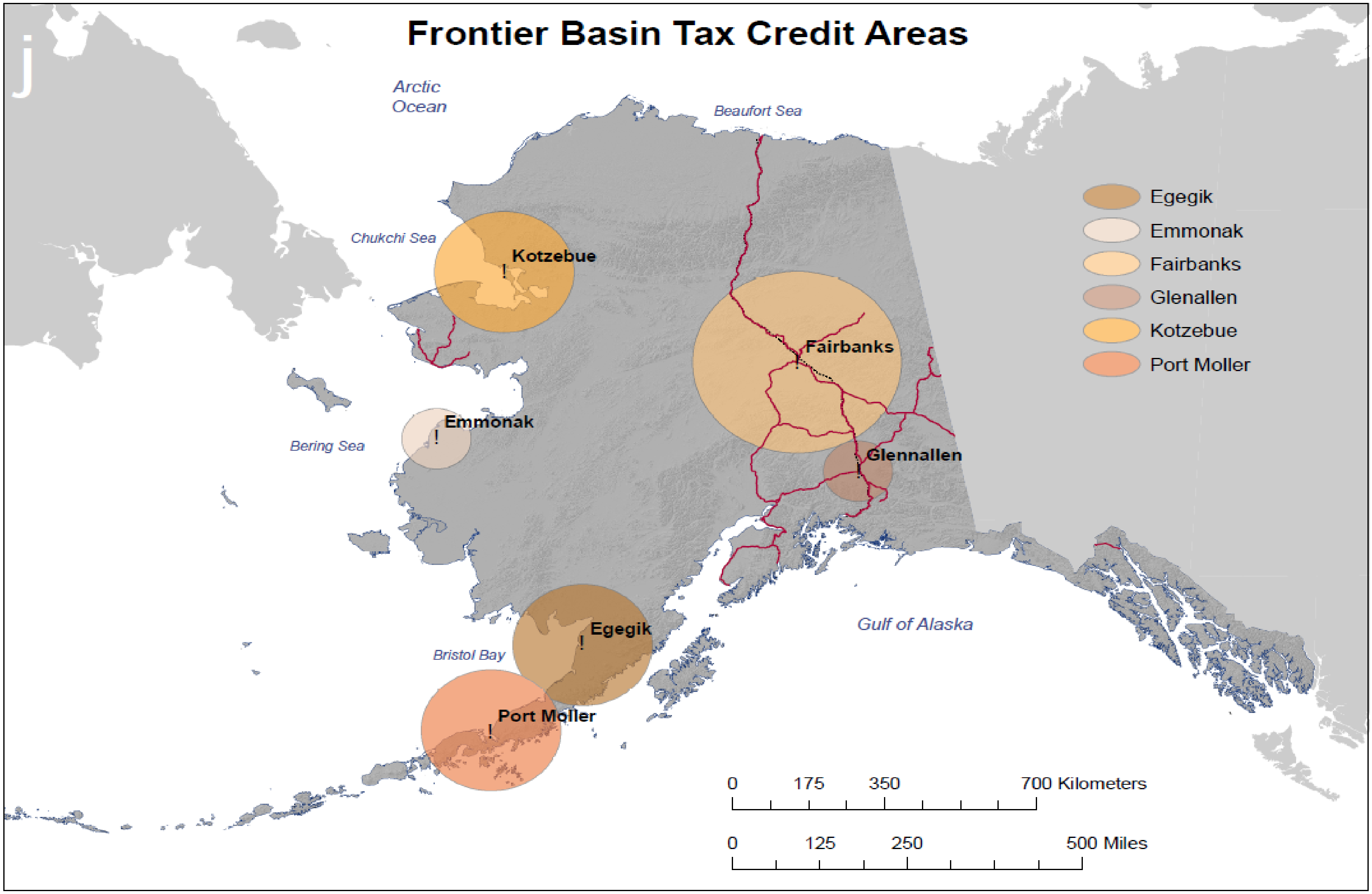
Six frontier basins (Figure 5-4) that were established by the State of Alaska for exploration tax credits similarly lack the necessary infrastructure to efficiently access the exploration locations. However, unlike exploration licenses which apply only to state lands, the Frontier Basins include federal, state and private lands. The regulation of infrastructure is more varied based on the surface owner and the standards by which surface infrastructure will be managed. Access remains a challenge based on ownership, but to qualify it as a deficiency is not merited.

Figure 5-3.



Alaska Exploration Licensing Program
Current and Proposed Licenses as of November 2014
State Acreage Available for Licensing
Areawide Lease Sale Boundary
Proposed Exploration License Area
Current Exploration License Area
License Area Converted to Leases
Sedimentary Basins by Thickness
(Kirschner, 2002)
0-1 km
1-3 km
3-5 km
> 5 km
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
GULF OF ALASKA
Barrow
Prudhoe Bay
Kotzebue
Nome
Fairbanks
Anchorage
Valdez
Bethel
Seward
Dillingham
Juneau
Sitka
Ketchikan
Unalaska
Department of Natural Resources
Division of Oil and Gas
0 60 120 240 Mi
0 95 190 380 Km
This map is for informational purposes only, and should not be used for any other purpose.
170°0'0"E
180°0'0"
170°0'0"W
160°0'0"W
150°0'0"W
140°0'0"W
130°0'0"W
120°0'0"W
65°0'0"N
60°0'0"N
55°0'0"N

Figure 5-3.


Frontier Basin Tax Credit Areas
Arctic Ocean
Beaufort Sea
Chukchi Sea
Bering Sea
Bristol Bay
Gulf of Alaska
Kotzebue
Emmonak
Fairbanks
Glennallen
Egegik
Port Moller
Egegik
Emmonak
Fairbanks
Glenallen
Kotzebue
Port Moller
0 175 350 700 Kilometers
0 125 250 500 Miles

6. Status of Labor and Employment in Alaska

Insert text here.

Workforce development efforts in Alaska

Insert text here.

7. Regulatory environment and permitting structure

In Alaska there is broad spectrum of authority various government agencies have to prohibit, regulate, and condition activities related to oil and gas. In addition to existing laws and regulations applicable to oil and gas activities, the state's standard oil and gas lease contract requires that leases are subject to all applicable state and federal statutes and regulations in effect on the effective date of the lease. Leases are subject to all future laws and regulations in effect after the effective date of the leases to the full extent constitutionally permissible and are affected by any changes to the responsibilities of oversight agencies.

The lease also requires that the lessee keep the lease area open for inspection by authorized state officials. Multiple state agencies may monitor field activities for compliance with each agency's terms. In addition, each lessee or permittee must post a bond before beginning operations.

Plans of Operations

An oil and gas lease grants the lessee exclusive rights to drill for, extract, remove, clean, process, and dispose of oil, gas, and associated substances. The lease and regulations require a plan of operations (for a lease, a group of leases and for a unit) to be approved before any activities or operations may be undertaken on or in the leased area. Plan of operations applications are reviewed for compliance with statue and regulation, as well as terms of the oil and gas lease. Plan of operations applications prior to approval are available for public review and comment for no less than 30 consecutive days.

Plans of operations include how the applicant will meet a series of mitigation measures laid out in the best interest finding specific to that area. Mitigation measures address issues concerning private property; water and air quality; facilities and operations; habitat, fish, and wildlife; harvest activities; fuel and other hazardous substances; and access. Local government organizations and other agencies may be consulted to implement mitigation measures. Exceptions to these mitigation measures may be requested and granted upon a showing by the lessee that compliance with the mitigation measure is not practicable and that the lessee will undertake an equal or better alternative to satisfy the intent of the mitigation measure. Additional conditions on approval and project specific stipulations may also be imposed in the approval of a plan of operations.

Deviations that fall outside of an approved plan require the submission and approval of an amendment to the plan. Submission to the Division of an update on the status and/or completion of plan components are required every subsequent November 1 and May 1 throughout the life of the plan. This information is also used to guide the Division during field inspections to ensure that operations are conducted in conformance with the terms and conditions contained in the plan approval. It also used to facilitate the Divisions continuing hard look at past, current and ongoing surface activities statewide when looking at the approval of proximal plans of operations, associated amendments, and other activities.

Geophysical Exploration Permit

A geophysical exploration permit may be issued by the Division. Seismic surveys related to oil and gas development are the most common activity authorized by this permit. Submission of seismic exploration and stratigraphic test data to the state is a permit condition; however the permittee may request that geological and geophysical data be kept confidential. If the permit period (typically one year) is extended, the director may modify existing terms or add new ones. A permit remains in effect for the term issued, but may be revoked for cause, with 30 days' notice.

Regulatory Upgrades to Increase Competitiveness and Serve Alaskans
The Division has recently undertaken a comprehensive, active and critical approach to upgrading the state regulatory environment and permitting structure conducive to encouraging increased investment while protecting the interests of the people of the state and the environment.

Recent upgrades to the plan of operations and geophysical exploration permit applications and approval processes include the development and implementation of efficiencies such as the use of a single application form, the co-development of the application form, adjudicator guidance for approval, and the approval decision template to provide for a linear framework, and the alignment of applicant data submission to be found in the same portion of each application and in the same manner. These updates ensure the submission of a complete application, adherence and easy identification of applicant compliance with statue, regulation and lease terms, allow for straightforward assessment of multiple plans of operation in full and section by section, and allow for the public to view for comment on plan components in an up-front and consistent fashion.

At this time the plan of operations and geophysical exploration permit updates are being introduced to industry and a review period is underway to allow for industry operators and contractors to view and comment on the draft materials prior to full implementation of the new system. Subsequent components staged for update, review and implementation include the associate mapping products required in the application process, the associated amendment request submission and approval, and the status and completion reporting components.

In addition, information compiled routinely from the biannual plans of operations status and completion reports, combined with additional sources from multiple agencies, will be provided as a summary of current and ongoing surface activities on oil and gas leases on an annual basis and is a new component of the Division's annual report for 2014.

Competitiveness

Outside of Alaska there are areas of significant size where individuals own the mineral interest and the financial, environmental, and additional requirements for development are often internal, confidential agreements between the surface and/or mineral estate owner and the operator. Much like a private owner, the State of Alaska also has the position of serving both as promoter of the resource potential for development and as the regulatory body. The importance variance from the established peer group is that the State of Alaska must develop its resources in the best interest of the state for the maximum benefit of all Alaskans and therefore must weigh the current and potential multiple uses of the land with the potential impacts and benefits from oil and gas development through a public process.

In maintaining that balance, the state has developed and codified a transparent and public regulatory environment through the Alaska Lands Act, AS 38.05 with specific sections for oil and gas leasing, unitization, and exploration. This begins with the establishment of the best interest finding which layouts the regulatory concerns and provides potential operators with the issues and components of operations requiring mitigation. An applicant will be able to demonstrate how they intend to mitigate the identified concerns through submission of a mitigation measure analysis required as part of their plan of operations application. The public can weigh in on both the scope of work identified in the plan application as well as how the operator will meet the voiced concerns implemented by the mitigation measures developed at the time of lease disposal.

The best interest findings provide all potential industry players, as well as Alaskans, with the regulatory roadmap for development. The plan of operations process then refines requirements specific to an operators plan. This transparent process engages the public to ensure that plan approval balances the needs of Alaskans with those in the industry.

This transparent, public, well-established, and often repeated process provides a clear, consistent and predictable regulatory environment competitive with and maybe advantageous to exclusive, confidential, and one-time agreements with private individuals. This has proven effective in the development of the North Slope and Cook Inlet oil and gas fields since discovery and provides the opportunity for continued successful development of the state's lands and oil and gas resources.

8. Alaska's oil and gas fiscal system

Alaska's fiscal system for oil and gas has four major revenue raising components:

1. Royalty
2. Property tax
3. State corporate income tax
4. Production tax

Each of the components have been part of the oil and gas fiscal system since the 1970s, when oil began flowing from the North Slope, although there have been changes made to the various components over the years. In this section, we provide a brief summary and overview of the four major components of the fiscal systems.

Alaska's fiscal system for oil and gas also has special incentives, generally in the form of tax credits. The number of incentives that may decrease revenue, at least in the short-term, has grown considerably over the past 10 years as the fiscal system has changed. Due to the number of incentives, the credits applied in recent years and their important impact on the total revenue picture for the state, we follow our discussion of the components of the fiscal system with a special section describing the incentives in oil and gas royalty and taxation.

In addition to the revenue raising components mentioned above, over which the state has control, there is an additional fiscal element controlled only by the federal government: federal corporate income tax. The federal corporate income tax rate component of all U.S. state and federal fiscal regimes is assumed to be 35 percent. The interaction between the elements that the state controls, royalty, taxes and credits, and federal income tax complicates any effort to materially modify the overall fiscal system in favor of those taxpayers that pay federal taxes on Alaska income.

Alaska's Fiscal System Elements

Oil and gas that is produced onshore in the state of Alaska or offshore within state boundaries is subject to the four components of the Alaska's fiscal system listed above, that are revenue-raising in nature. Together the four components typically provide between 80 and 90 percent of the state's general fund budget, as shown in Figure 8-1. Provided below is a summary of each of the individual components. We also provide some background and a brief history of the changes to what is currently the one of the largest revenue raising components, the state's production tax.

Royalty

In natural resource extraction, royalties generally represent the portion of minerals apportioned to the lessor by a lessee who has leased the property to produce the minerals. Currently in Alaska, the majority of leases for oil and gas extraction are on land where the state has title to the mineral estate. Therefore, in Alaska, most of the royalties for oil and gas extraction are apportioned—or paid—to the state. Although leases have varying royalty rates, most of the state leases in Alaska have royalty rates of 12.5%. This means that the State of Alaska receives approximately 12.5% of all oil and gas produced on state leases. The state royalty may be paid in kind or in value at the state's discretion. When royalties are paid "in kind," the state receives its royalty in barrels (or cubic feet for natural gas); when royalties are paid "in value," the state receives its royalty in dollars.

The federal government also leases land in Alaska for oil and gas extraction, and the state receives a portion of the royalties collected on these leases. In the National Petroleum Reserve-Alaska (NPR-A), the state receives 50 percent of the royalties collected by the federal government. In federal offshore leases that are greater than three miles from shore and less than six miles from shore, the federal government pays the state 27 percent of the royalties it collects from these properties.

Royalties are a significant component of Alaska's fiscal system, often accounting for 30 percent or more of the unrestricted oil and gas revenue paid to the state. Because royalties are paid without regard to oil and gas prices or whether there is any profit associated with oil and gas production, it is considered a regressive element of Alaska's fiscal system.

Property 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 within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.

The property tax is a relatively small component in Alaska's fiscal system, generating revenues of $100 million or more in recent years. The tax is an important component of local governments that have oil and gas property, however, as up to $400 million per year is split among fewer than 10 local governments.

Like royalties, property tax is a regressive element in Alaska's fiscal system, as it is collected without regard to prices or profit.

Corporate income tax

Alaska's corporate income tax 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. The corporate income tax rate is graduated with the top tax rate of 9.4% levied when net incomes exceed $222,000 for the year.

Oil and gas corporate income tax revenues have comprised about 10% of the state's unrestricted petroleum revenues in recent years. In addition to mirroring the federal tax code with regard to tax credits, there are several state tax credits applicable to the corporate income tax. These will be discussed in detail in the "Tax Credits" section of this chapter.

Production tax

Among the largest revenue raising components of Alaska's fiscal system for oil and gas is the production tax. The current production tax was passed by the legislature in 2013 as Senate Bill 21. Like its predecessor production tax system, SB 21 taxes the net profits of production, after all operating and capital expenses have been deducted. The current production tax also offers credits for taxable barrels of oil produced, for exploration and for companies that produce less than 100,000 barrels of oil per day. Prior to the implementation of a net profits-based production tax, Alaska taxed production based on the gross value of oil and gas as adjusted by an economic limit factor.

The state production tax is less complex than its predecessor production tax system, ACES. The new system has one tax rate for North Slope production: 35 percent. Also for purposes of taxation, production on the North Slope is divided into two groups: (1) production from existing fields; and (2) new production. New production, if it meets certain criteria, is eligible for a 20 percent or 30 percent gross value reduction (GVR). The starting point for calculating the production tax on new production is 80 or 70 percent of the gross value of the oil or gas. This production is also allowed a $5 per taxable barrel credit against their tax liability. Production from existing fields does not receive a GVR, but instead of the $5 per barrel credit, this production receives a per-barrel credit that ranges from $0 to $8 per barrel, depending on the wellhead value.

The basic tax calculation of the state 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%

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

Minimum tax, production from existing fields = 4% of Value before Costs are subtracted

Additional fiscal elements

Lease bonuses and rentals are two additional components that contribute minor amounts of revenue to the state. However, in some jurisdictions these two fiscal components can contribute materially to government take, so they are worth discussing here.

Bonuses are cash payments received by the state, usually at a lease sale, to win the execution of an oil and gas lease. Normally the state's sale terms establish the bonus payment as the bid variable so that the bidder offering the highest bonus bid wins the lease being offered. Since 2000, annual revenues from lease bonus payments have ranged from as low as about $250,000 in 2007 to as high as $1.4 million in 2001.

Lease rentals are periodic cash payments received by the state to maintain an oil and gas lease and the rights granted under it. Alaska's statutorily established rates per acre for oil and gas leases are as follows:

(1) First year: $1
(2) Second year: $1.50
(3) Third year: $2
(4) Fourth year: $2.50
(5) Fifth year and greater: $3 annually

Most State of Alaska lease contracts state that rental paid for a lease in advance, at the beginning of the year, for a lease, can be claimed as a credit against royalty payments due under the lease for that year. Thus, on Alaska state land, even relatively small production volumes result in refunding of most rental payments through credits against royalty.

Tax credits and Royalty Incentives

Tax credits have also played a large role in Alaska's oil and gas fiscal system. Most of the tax credits in current law were implemented with the change to a production tax on net profits. The tax credits were intended to incentivize certain activities, such as oil and gas exploration and development. Over the past eight years, the tax credits program has expanded. In 2010, many new tax credits were introduced for the non-North Slope areas of the state. The credits appear to have been successful in incentivizing the activity sought, especially in Cook Inlet, where the number of companies exploring for and drilling wells, has increased significantly since 2010.

There are currently three major categories of tax credits available against the Alaska production tax. AS 43.55.023 offers credits for certain exploration expenditures, well lease expenditures, and expenditures leading to net operating losses. AS 43.55.024 offers several types of credits, including per-taxable barrel credits and credits to producers of oil and/or gas that produce fewer than 50,000 btu equivalent barrels of oil and/or gas per day. AS 43.55.025 offers credits for exploration expenditures that meet certain criteria related to distance from existing units or wells and for the first persons to drill wells in certain areas of the state. These three categories of tax credits make up the majority of the tax credits used against or in connection with the oil and gas production tax.

There are several credit programs targeted specifically at oil and gas corporate income tax in Alaska. Two of the credits under this program pertain to natural gas. AS 43.20.023 provides a credit of 25 percent of qualified expenditures for exploration and development of non-North Slope natural gas reserves. This credit was extended and expanded in the 2010 legislative session. A second oil and gas corporate income tax credit provides a credit for the costs incurred to establish a natural gas storage facility or LNG storage facility. Over the past two years, two more credit programs were established under the corporate income tax system. An oil and gas industry service expenditures credit was added to incentivize in-state manufacturing or modification of oil and gas tangible person property. Another credit was added in 2014 to assist in-state refineries with qualified infrastructure expenditures.

Figure 8-2 summarizes the tax credits in current law that are applicable to the oil and gas production tax and the state corporate income tax and the amount of credits used in each of the past 3 years. We note that there has been an increasing use of tax credits in general, especially those authorized at AS 43.55.023, over the 3-year period.

There are several royalty incentives in current law. Many of them are tailored to a specific project, economic criteria, or lease type. For example, there is a licensing program that allows for more favorable lease terms for explorers to gain access to large tracts of state land. For economically-challenged projects, the DNR commissioner can modify royalty terms to incentivize production.

Figure 8-1. Alaska General Fund Revenue Sources, FY 2011.

Figure 8-2.

9. Fiscal system comparisons

We began this report by presenting information comparing Alaska with a group of peers based on non-fiscal criteria that oil and gas companies may consider. In the previous section we presented Alaska's fiscal regime. In this section we will compare Alaska's fiscal regime with a peer group. Before we begin our comparison, it may be helpful to discuss the basic styles of worldwide fiscal regimes. This publication is not intended to provide an exhaustive treatment of petroleum fiscal regimes, but it will provide a brief introduction to the basic types of fiscal arrangements.

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 generous 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 9-1). 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 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 production sharing contracts (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 an 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 and 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 minerals leases 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 block.

The U.S. Outer Continental Shelf (OCS) mineral leases represent a tax/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 (PRT), Norway’s Supplemental Petroleum Tax (SPT), Brazil’s Special Participation (SP), Australia’s Petroleum Resource Rent Tax (PRRT) and Alaska’s ACES production tax. In the case of the U.K., Norway and much of offshore Australia, no royalty at all is now 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 book their “net” reserves, which are 100 percent of the gross reserves less royalty.

Elements of comparison and definitions

In Figure 9-2 terms are used to classify some of the categories of government take commonly found in concession fiscal regimes. To clarify their use for the purpose of this publication we will provide definitions for several of the high value terms used here.

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 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 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.

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. Corporate income tax on oil and gas often is 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 net tax in this document refers to the resource tax on the value of the resource net 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 (JVs) 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 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

Figure 9-2 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. We will use the elements presented in Figure 9-3 and in Chapter 5 of this report in our discussion of several other jurisdictions with which we believe the state competes for corporate investment.

In this report we compare Alaska 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 should also 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.

California

California (Figure 9-4) is a state with resource potential and historic production similar to Alaska’s. 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 9-5) has historically experienced lower production volumes than Alaska; however, its production has now surpassed Alaska. 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 9-6) 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 9-7) 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. 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 9-8) 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 the 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 corporate tax, 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 9-9) has only 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 corporate tax, 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 9-10) 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 corporate tax 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 corporate income tax rates are is 16.5 percent, lower than the 35 percent U.S. corporate income tax. The Alberta provincial corporate income tax rate is 10 percent.

Northwest Territories

Northwest Territories, Canada (Figure 9-11), 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 Alberta provincial corporate income tax rate is 11.5 percent.

Canada Federal Offshore Beaufort Sea

Canada federal offshore Beaufort Sea (Figure 9-12) 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 9-13) 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 9-14) 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.

United Kingdom

The United Kingdom (Figure 9-15) 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.

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, we sought out those with the most reasonable parallels to Alaska. 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

We considered including a number of states located in the western U.S. However, most of the states we excluded from the peer group have significantly smaller oil and gas endowment and smaller production volumes than Alaska and the other states included in the list. 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, we considered including several provinces of Canada in Alaska's fiscal system peer group. But with the exception of Alberta, the resource endowment and historical production was 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. We excluded many countries 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 on the west coast of the U.S. and the economic barrier is high 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.

Iraq

To offer an example of how this exclusion logic might be applied, we will look at the country of Iraq in detail.

Iraq was excluded based in part on the significant differences between its fiscal regime and Alaska's. Iraq's current fiscal regime is based on a technical service contract. Since 2008, Iraq has offered IOCs the opportunity to bid competitively on service contracts for large legacy fields, each producing between 200,000 and 1 million barrels of oil per day. Contracts are awarded through a competitive bidding process whereby IOCs bid a combination of the production plateaus they believed they could achieve and the per-barrel fees they would accept. The contracting IOC is paid a remuneration fee bid per barrel from a schedule based on a factor equal to the ratio of the cumulative revenue divided by total expenditures. The contractor must then pay a 35 percent corporate income tax and allow for a 25 percent carried interest for the Iraq NOC.

Iraq is also eliminated based on its geographic location. Very little of the production from the Middle East makes it to the west coast of the U.S. due to high transportation costs.

The EIA reports Iraq's reserves at 115 billion barrels of oil and 46 TCF of natural gas. Alaska's reserve base is tiny in comparison: 3.5 billion barrels of oil and 9 TCF of natural gas. IOCs are interested in Iraq despite low service contract payments because the huge production volumes and reasonably certain cash flow from projects in Iraq benefit many companies' overall portfolio mix. Holding existing contracts also places a contractor in a position to win future contracts over the mid- to long term. Alaska simply could not guarantee the same volume assurances over a similar time period.

Figure 9-1. Petroleum legal arrangement classifications. (figure update complete)

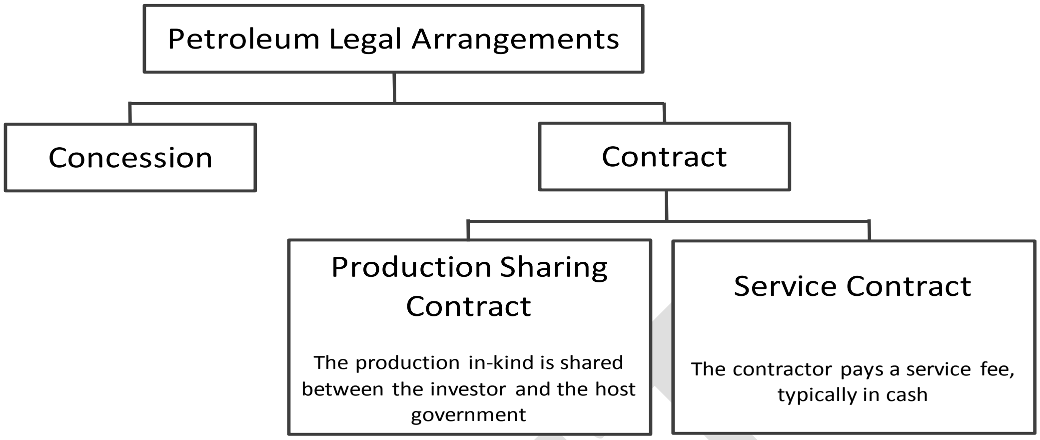


Figure 9-2. Petroleum fiscal regime peer group highlights. (figure update complete)

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 9-3. Alaska fiscal system highlights (needs work).

Royalty: Generally 12 ½ or 16 ⅔ percent, most production pays at 12 ½ 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.

Corporate Income Tax: The U.S. federal corporate income tax rate is 35 percent.

The state corporate income tax 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 corporate income tax 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%

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% 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 9-4. California fiscal system highlights.

Royalty:	Federal lands: Most production pays at 12 ½ percent. Natural gas rate is same as oil. Private lands: Generally 16 ⅔ or 25 percent, most production pays at 16 ⅔ 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.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The state corporate income tax 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 9-5. North Dakota fiscal system highlights.

Royalty:

North Dakota state lands: Most production pays at 16 ⅔ percent. Natural gas rate is same as oil.
Federal lands: Most production pays at 12 ½ 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.

Corporate Income Tax:

The U.S. federal corporate income tax rate is 35 percent.

The state corporate income tax 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 11 ½ 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 6 ½ 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 9-6. 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.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The state corporate income tax 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% for the first 48 months of production. Deep wells drilled between 15,000 and 17,499 feet will be levied at 4% for 48 months and deep wells drilled below 17,500 feet will be levied at 4% 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% 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% 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 workovers 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 9-7. Texas fiscal system highlights.

Royalty:	Private lands: Rate range between 12 ½ 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.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent.
	Texas has no state corporate income tax, 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% 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% if the average price is $22 or less to 0% if the average price is more than $30 per barrel. A certified orphan well put back in production is eligible for a 100% 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 9-8. 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.
Corporate Income Tax:	The U.S. federal corporate income tax 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 9-9. U.S. Beaufort Sea and Chukchi Outer Continental Shelf (OCS) fiscal system highlights.

Royalty:	12 ½ 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.
Corporate Income Tax:	The U.S. federal corporate income tax 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 9-10. 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.
Corporate Income Tax:	In Alberta, the Canadian federal corporate income tax 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 corporate income tax 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 9-11. 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.
Corporate Income Tax:	In Northwest Territories the Canadian federal corporate income tax 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 corporate income tax 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 9-12. 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.
Corporate Income Tax:	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 9-13. 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.
Corporate Income Tax:	The Australian federal corporate income tax 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 corporate income taxes.
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 9-14. 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.
Corporate Income Tax:	The Norwegian federal ordinary corporate income tax 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 7 ½ percent for a period of four years, 30 percent total. Hydrocarbon tax is not deductible against corporate income taxes.
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:	7 ½ 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%.
	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% to 90% of the tax value of the exploration tax refund (i.e., 65% to 70% 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 9-15. 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.
Corporate Income Tax:	The United Kingdom federal corporate income tax 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% from 24 March 2011 and previously 20%) on UK exploration and production activities that is in-addition to corporate income tax. 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 United Kingdom 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 United Kingdom and its territorial waters.
Incentives and Credits:	The United Kingdom offers incentives for certain activities and ventures, including a Ring Fence Expenditure Supplement (RFES) and certain research and development allowances.

10. Summary

Alaska is fortunate to be endowed with abundant natural resources, especially oil and gas. Additionally, the state is well positioned geographically to market those resources to a large area of the world. It is the responsibility of Alaska's government to continuously review its competitiveness in critical categories related to oil and gas exploration and production compared to similarly positioned jurisdictions.

In this report, we establish a logical peer group for comparison. Our peer group selection is largely tied to three elements, production and reserves, geographic location, and fiscal system type. We hope clearly enumerating our criteria here adds a framework to the discussion and improves the outcome of any review of the Alaska's competitiveness. We have also presented and discussed information on lease sales, permitting, infrastructure, permitting and workforce availability. Certainly there can be criteria that others may wish to add to this list and we are open to the ideas others will bring to future discussions related to competitiveness.

While it is important for Alaskans to look at Alaska's fiscal regime from the state's perspective, focused on state revenue, to help understand potential risks to Alaska's revenue stream, it is equally important that we consider the perspective of industry investors in Alaska. Most oil companies look at more than one jurisdiction when making decisions on where to invest, and they will only invest in a place where they believe there are resources to find and where there is reasonable certainty those resources eventually can be produced and sold at a reasonable profit. If we look at natural resource development from both the industry and landowner perspectives, we will improve the long-term benefit to Alaskans from those resources.

Ongoing work and future deliverables (needs work)

The Alaska O&GCRB is a relatively newly constituted board with the potential to establish the necessary framework to the continuing conversation the state is engaged in on the topic of maximizing the benefits of our oil and gas resources for the people of Alaska. the O&GCRB is looking at several tasks that they hope to accomplish over the short- to intermediate-term.

Subject to available funding and resources, we hope to survey a broad range of oil and gas exploration and development companies to better understand Alaska's relative strengths and weaknesses 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 that would represent companies not active in Alaska.

Another project the O&GCRB is considering is establishing an online "dashboard" of critical data elements that would….

Appendices

Alaska Oil and Gas Competitiveness Review Board members:

Insert list of names of board members here.

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Alaska Oil and Gas Competitiveness Review Board (O&GCRB) web page:
http://dor.alaska.gov/OilGasCompetitivenessReviewBoard

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