Alaska's Oil and Gas Competitiveness Report 2015

Alaska Oil and Gas Competitiveness Review Board

February 27, 2015

This report is available exclusively online and can be downloaded at the Board's website provided by the Department of Revenue:

http://dor.alaska.gov/OilGasCompetitivenessReviewBoard

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Executive Summary

The Oil and Gas Competitiveness Review Board (Board) is tasked with the important job of identifying critical criteria, collecting and analyzing historical, current and forecast data, and providing written findings regarding the competitive position of Alaska for oil and gas exploration and development.

The Board embarked on a series of meetings to address the statutory requirements that it was tasked with. Acknowledging the relatively short period of time allowed for research and analysis of a subject as complex as Alaska's oil and gas competitiveness, the critical importance of oil and gas to the State's revenue stream obligated the board to making sure the report was delivered on the schedule identified in statute. Testimony and input was invited from a number of experts within the administration on the topics enumerated above. This document is the initial report from the Board to fulfill its statutory obligations.

Alaska's crude oil production is down by more than 50 percent from its peak in 1989, it's proved reserves have also declined over a similar time frame, but estimated undiscovered oil and gas resources are much greater than any other state in the U.S. Thus, it seems that Alaska's resource potential is great compared to the Lower-48, but not our current production performance. Similarly, our production performance, as well as our resource potential, compared to international oil and gas resource-rich jurisdictions is ranked below many OPEC countries, but is still respectably ranked.

When looking at Alaska's competitiveness, it is important to consider a variety of criteria in comparison to other resource-rich jurisdictions. As we just touched on, proved reserves, as well as estimated undiscovered resources, are important pieces of information. Historic drilling rates and rig activity are reasonable leading indicators of the near-term trend of production growth and proved reserves additions. These data sets are those that tend to have more comprehensive coverage worldwide. This makes quantitative comparisons more appropriate.

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

After our initial review of a variety of comparison criteria, a group of relevant peer jurisdictions were selected that appear to be most closely comparable to Alaska over many of those criteria. The jurisdictions that seem to most closely compare to Alaska for many of the important criteria, and are selected here to comprise the relevant peer group for Alaska, include four U.S. states, two provinces of Canada, two regions of the U.S. outer continental shelf and four foreign countries.

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

As we review our competitiveness we need to consider the items that the State of Alaska has control of, or can influence, such as permitting, infrastructure, labor, lease costs, taxation, royalties and access to resources. We need to be able to do a grounded comparative analysis of our fiscal structure versus our peers. One of our thoughts moving ahead is to build a dashboard of critical measurements for Alaskans to easily review using principally, but not limited to items that are currently being measured by various state and federal agencies that can be compiled and provided on a single website. Our goal is to track past, current and projected future statistics and projections for a group of key diagnostic criteria that will help interested parties view specific progress or trends related to the oil and gas industry in Alaska compared to peer jurisdictions. These measures could be items like number of wells being drilled, production, resource pricing, permitting and other pertinent trending data. This will be maintained on a recurrent basis so interested parties have a baseline to current view of the industry.

To prepare for future statutorily required deliverables, significant additional work by the state and the Board remains to be done in the area of collecting the necessary data and performing meaningful analysis of the data to better understand the competitive relationships between Alaska and other resource-rich jurisdictions. Additionally, the Board is tasked with providing a better understanding of the competitive comparisons of different areas within Alaska, as well.

The next required deliverable from the Board is a report to the Alaska State Legislature due on or before January 15, 2017. For the January 2017 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. the state's tax structure and rates on oil and gas produced south of 68 degrees North latitude;

2. a tax structure that takes into account the unique economic circumstances for each oil and gas producing area south of 68 degrees North latitude;

3. a reduction in the gross value at the point of production for oil and gas produced south of 68 degrees North latitude that is similar to the reduction in gross value at the point of production in AS 43.55.160(f) and (g); and

4. other incentives for oil and gas production south of 68 degrees North latitude.

The Board's final statutorily required deliverable is a report to the Alaska State Legislature due on or before January 31, 2021. For the January 2021 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. changes to the state's fiscal regime that would be conducive to increased and ongoing long-term investment in and development of the state's oil and gas resources;

2. alternative means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources; and

3. a review of the current effectiveness and future value of any provisions of the state's oil and gas tax laws that are expiring in the next five years.

1. Introduction

Oil and Gas Competitiveness Review Board history and goals

The concept of the Alaska Oil and Gas Competitiveness Review Board (Board) 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 to improve Alaska's competitiveness against other oil and gas producing jurisdictions around the globe. Along with production tax reform, the legislature created the Board to establish and maintain salient data regarding oil and gas exploration, development, and production and advise the Alaska legislature on the state's oil and gas fiscal system, labor pool, and regulatory competitiveness.

The 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 Board was, at least in part, modeled after a similarly tasked board in Alberta, Canada.

The Board met for the first time on October 15, 2014 and was tasked with presenting this report in early 2015. The limited time statutorily allowed this group to research and write this report has constrained this report to establishing a framework within which, over time we hope to refine and possibly expand the criteria, methodology and analysis of Alaska's competitiveness within a reasonable peer group.

This report is the product of the Board 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).

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.

In this report Alaska's fiscal system and other competitiveness criteria will be compared to similar oil and gas producing jurisdictions around the world. While much attention in Alaska is focused on fiscal systems, they are not the only criteria oil and gas producers use to make investment decisions. Factors such as resource volumes and potential, capital and operating costs, economic and political stability, access to infrastructure, availability of labor, efficiency of permitting, and access to lands for exploration all play important roles.

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 is the first in a series of mandated reports by the Board that attempts to establish a set of important criteria that are used by investors when comparing Alaska to other oil and gas producing areas of the world and select a group of reasonable peers for future analysis and comparison. It was extremely challenging to research and analyze these important factors in sufficient depth in a single report in the short period of time that was available. As a result, it is the goal of the Board to continue to refine the list of important competitiveness criteria and factors and discuss and analyze them in more depth in future reports. Additionally, because of further research and analysis and changes in our understanding of resource potential and economics, the group of peers may evolve and change in future reports.

Alaska peer group selection

Alaska has been a North America leader in oil production since production began on the North Slope in the 1970s. However, new technologies and new discoveries have provided oil and gas companies with a long list of opportunities around the globe when deciding where to invest capital and resources. Fiscal structure is one of the significant factors that explorers and producers consider for their project portfolio when making 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. 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 companies 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 is not otherwise 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 or governments. 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. At first glance this may seem like a relatively straight-forward task, but comparing broadly different areas of the world on the basis of many widely different criteria rapidly becomes quite complex. For example the similarities may seem stretched when comparing Alaska to Texas, North Dakota or any of the other Lower-48 states on exploration and development costs, infrastructure, environmental challenges, or "upside" resource potential. A peer group that is diverse and representative of the competition is critical to a meaningful comparison. To gain the most benefit from a peer group comparison, the peers need to share a core group of similarities to the competitive markets that Alaska faces. It is reasonable to expect the peer group list to 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 a peer group comparison and specifically this set of peers at this time.

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's fiscal regime. We also preferred a geographic affinity: a location in the Arctic, in North America or Europe, or in the Pacific region.

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

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

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

[1]Gulf of Mexico (GOM)

[2]Outer Continental Shelf (OCS)

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 oil and gas peer group should include jurisdictions that have a similar resource base and production volumes, referred to in this report as the hydrocarbon endowment. Beyond historic production, proved reserves and undiscovered resource volumes considered for this report, it may be important to broaden the discussion into related areas of study. Further refinement around this issue could involve discussion of economic field size distributions, basin maturity, exploration success ratios, and whether recent additions to proved reserves and undiscovered resource are conventional or unconventional.

This section of the report focuses on the comparison of Alaska's hydrocarbon endowment for conventional oil and does not address other energy 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 from which to draw meaningful comparisons of worldwide unconventional resources.

In considering hydrocarbon endowment and Alaska's peer group, it is important to recognize the physical differences of each region, the location of the resources with regards to infrastructure, and the level of investment required for exploration, development, production, and transportation. In each case, the geology, geography, size of the resource, and proximity to market are factors that make comparison of limited shelf life. For example, Alaska has proved conventional oil reserves that led the nation's production in the 1980's and 1990's. Development of unconventional oil sources along with continued decline in North Slope production has changed Alaska's position during the past decade. However, without transport via the Trans-Alaska Pipeline System (TAPS), the proved reserves would have remained as contingent resources, like the vast quantities of stranded North Slope natural gas are. Similarly, without existing surface infrastructure and advances in hydraulic fracturing and horizontal drilling the vast reserves of unconventional resources in the lower 48 states would not have been realized. These points are important to consider in evaluating the competitiveness of each peer to the other.

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 portion of the report is to provide these numbers as a basis for discussion, not to attempt to explain or offer an opinion on the causes of these production trends.

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	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	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 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/.

[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.

Alaska's oil production in comparison with its North American peers for the last six years is presented in Figure 2-3. This group of North American producers includes all the largest-volume oil-producing jurisdictions in North America. In general, Alaska holds a place in the low to midlevel, and in each of the last six years, Alaska's oil production has declined. Meanwhile, Alberta, Oklahoma, North Dakota, and Texas have all seen significant production increases in the last six years, with production in Texas and North Dakota up sharply due to expanded development of unconventional oil resources, including shale oils and tight sand structures. The U.S. Gulf of Mexico oil production saw an early increase and recent decline over the same time period, California's production has held relatively constant.

When we compare Alaska with the international peer group (Figure 2-4) the most striking thing to note is that unlike the peer group of states, Alaska, along with Australia, is at the bottom of the oil production history graph. In addition Alaska, Australia, Norway and the United Kingdom (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 2-5) shows significantly different trends than oil production, primary of which is that Alaska is very close to the bottom of the production volume graph. Alaska and California have experienced a slight decline in natural gas production in recent years. Oklahoma, Texas, and North Dakota have seen increases in natural gas production due to the ramp-up in production of shale and unconventional resources. 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 their production is still low compared to others in the selected peer group.

When comparing Alaska's natural gas production to international peers (Figure 2-6), Alaska is by far the lowest producing jurisdiction of the group. Australia and, to some degree Norway, have upward production trends in the time period. Canada and the U.K. have declining trends.

Figure 2-3. Oil production history for Alaska and its North American peers. (Note that figures 2-3 and 2-4 have different vertical scales.)

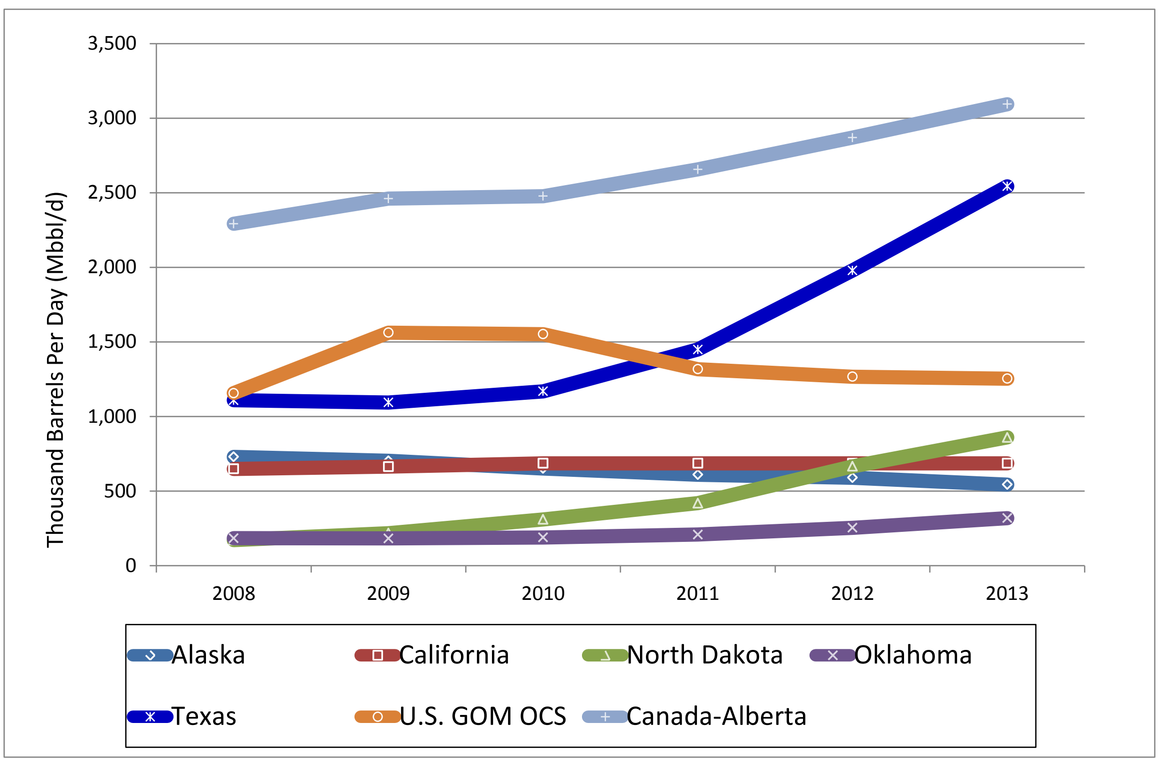


Figure 2-4. Oil production history for Alaska and its international peers. (Note that figures 2-3 and 2-4 have different vertical scales.)

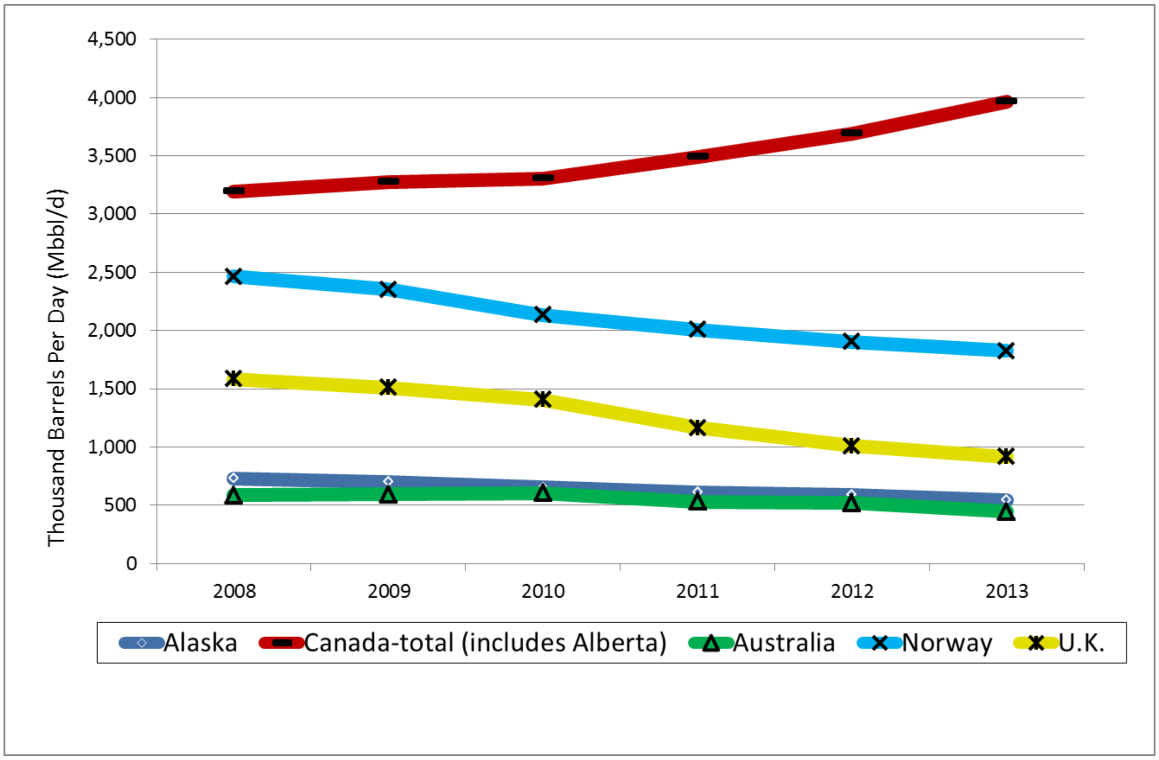


Figure 2-5. Natural gas production history for Alaska and its North American peers. (Note that figures 2-5 and 2-6 have different vertical scales.)

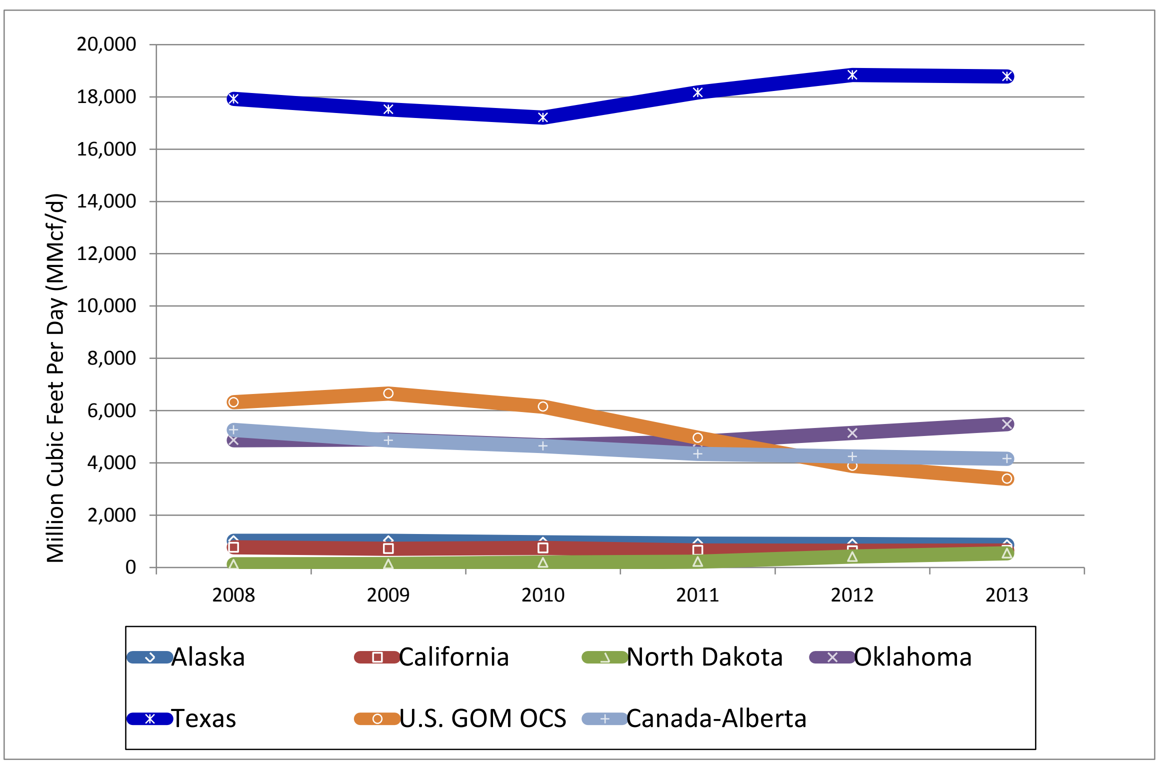
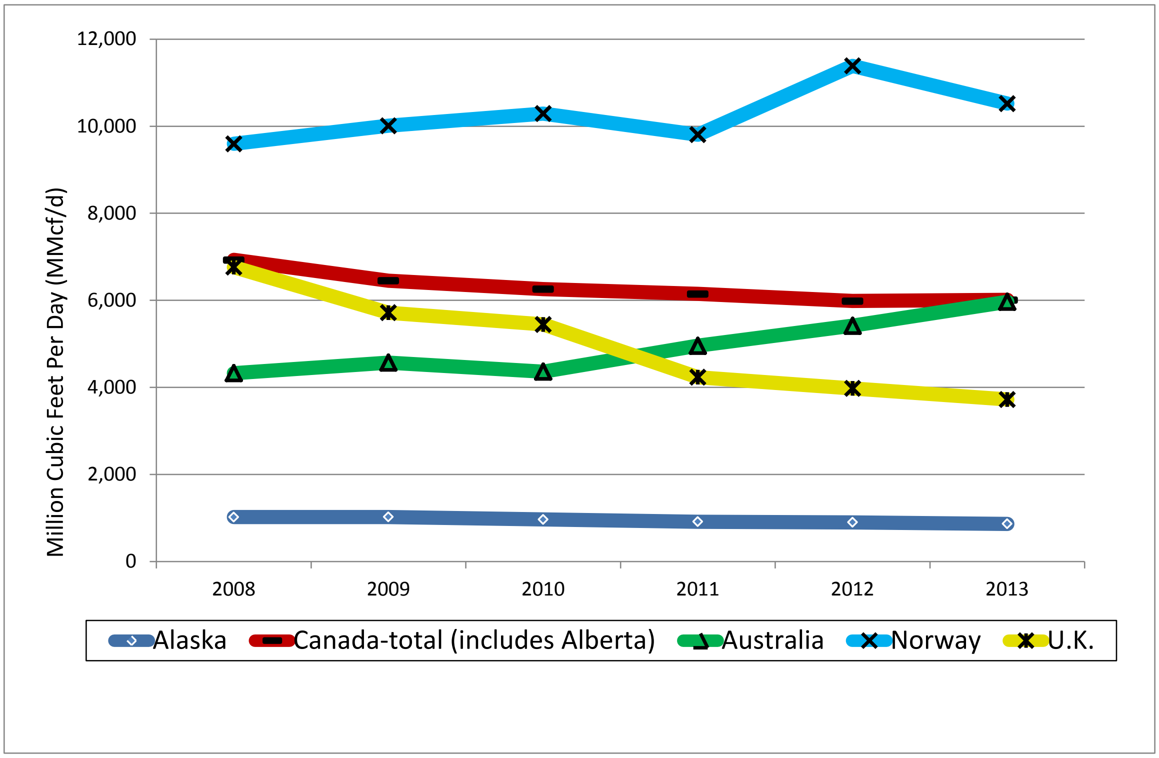


Figure 2-6. Natural gas production history for Alaska and its international peers. (Note that figures 2-5 and 2-6 have different vertical scales.)



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, technologies change, companies modify development schedules for undeveloped reserves and prices change. Discoveries include new fields, identification of new reservoirs in old fields, and extensions of existing reservoirs. 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 profitably 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 five years from achieving production, it is outside the limit, based on SEC rules, to be considered “proved reserves." When a project moves into the five-year window its reserves are added to "proved reserves."

Proved reserves: Alaska and its peers

EIA maintains an annual assessment of the U.S. crude oil and lease condensate proved reserves and the U.S. total natural gas proved reserves for the period 1983-2013. Figures 2-7 and 2-8 are a graphical comparison of Alaska with U.S. onshore, offshore and total reserves for liquid hydrocarbons (oil and condensate) and natural gas over a thirty year period, from 1983 through 2013. Figure 2-9 is a tabular comparison of Alaska and its North American peer group for proved reserves and undiscovered resource estimates of oil and natural gas. This table also provides the historical trends changing reserves estimates.

Compared to top producing U.S states, Alaska's proved oil reserves are only greater than Oklahoma. They are roughly equivalent to California and are less than North Dakota and Texas (Figure 2-11). Continuing improvements in technology and changing economics of producing unconventional oil from the Williston Basin only recently increased North Dakota's reserves to a level that exceed Alaska's. Texas and Canada have also experienced dramatic increases in proved reserves because of improved economics of unconventional oil and gas production. If unconventional oil resource development was ever to become economic on the North Slope, Alaska's proved reserves also would increase dramatically.

It is worthwhile keeping in mind the importance of commodity price in determining how oil and gas may move into and out of the "proved reserves" classification. Recent price declines may disproportionately affect states with large volumes of relatively expensive to produce oil reserves, such as that from shale oil. Low prices may result in the reclassification of large volumes of proved reserves to potential reserves, reversing the reserve increases some states recently experienced as a result of greater than $100 per barrel oil prices.

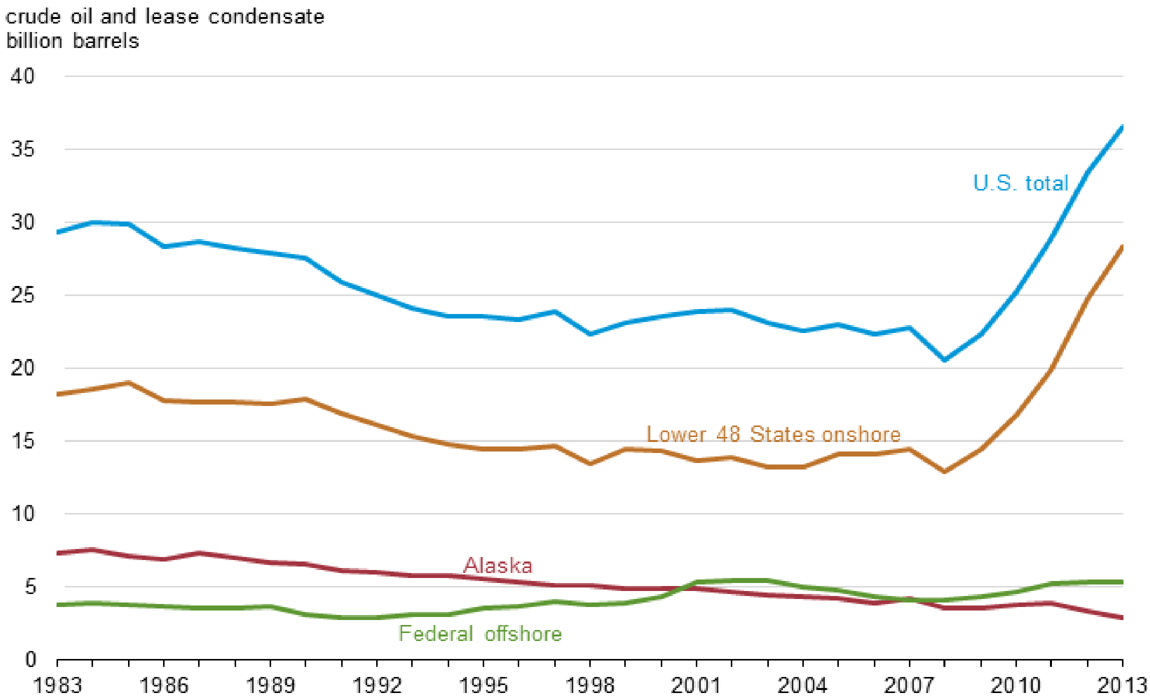
Within the international peers, proved oil reserves in Norway are much greater than Alaska's, but are still within a range that does not preclude them from consideration for an Alaska peer group. Australia's oil reserves are similar in size, and the U.K.'s oil reserves are only slightly lower.

Proved reserves in both Norway and the U.K. have declined in recent years. However, significant new discoveries in Norwegian waters of the North Sea that were announced in the past few years may reflect a change in fortune for the basin.

Alaska's proved reserves of natural gas are constrained by the definition of "proved reserves." Given the contingent resources of natural gas on the North Slope, estimated in excess of 35 TCF. This stranded natural gas resource is an area of significant economic interest. The Alaska LNG project is working on feasibility studies to bring the North Slope gas to tidewater. Based on the findings of these studies and if successfully constructed, the transport of this contingent resource would meet the definition of proved reserves and change Alaska's position to second in the nation. It is also important to note that the North Slope natural gas, and most of the gas attributed to our international peer group, is a conventional natural gas source versus a combination of conventional and unconventional sources that constitute proved reserves in the Lower-48 peer group.

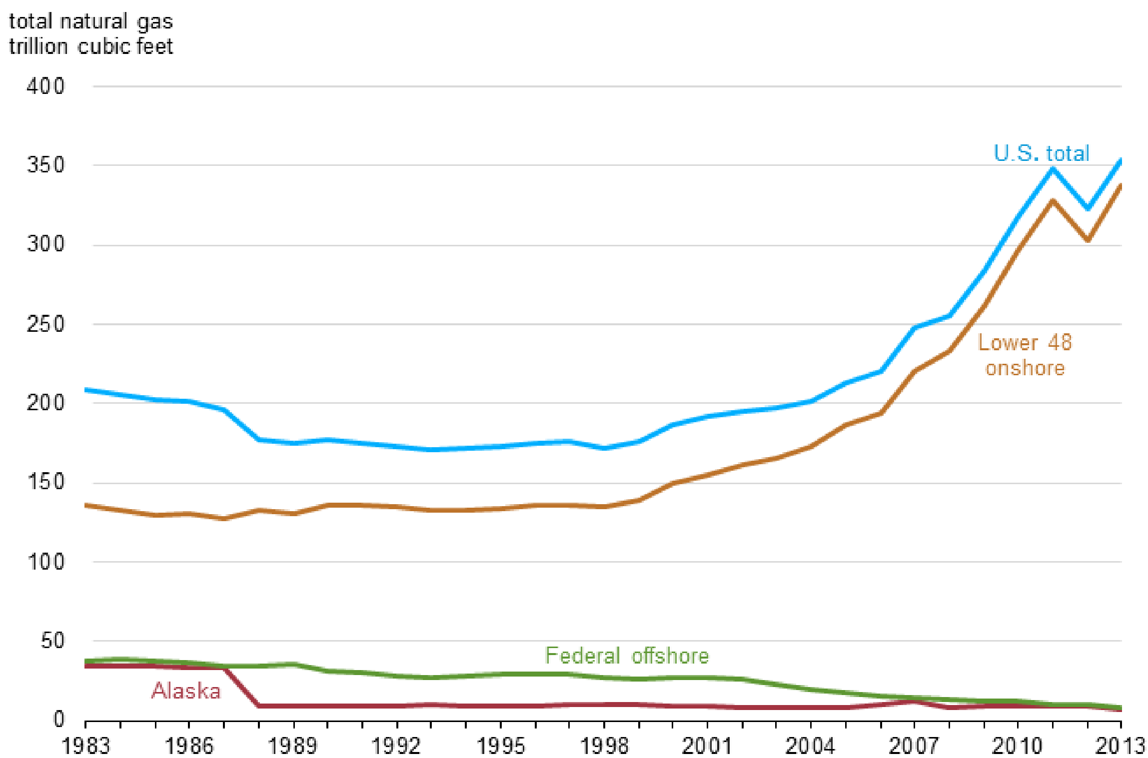
Another key factor in analyzing Alaska's North Slope reserves is that they are currently located almost exclusively on state and Native corporation lands and do not include federal lands in National Petroleum Reserve-Alaska (NPR-A) or the 1002 area of Arctic National Wildlife Refuge (ANWR)+.

Figure 2-7. EIA estimate of U.S. crude oil and lease condensate proved reserves 1983-2013.



Source: http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

Figure 2-8. EIA estimate of U.S. total natural gas proved reserves, 1983-2013. (Note: Alaska's proved reserves do not include the vast estimates of the North Slope as they are not "recoverable under existing economic and operating conditions."



Source: http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf.

Figure 2-9. Estimates of proved reserves and undiscovered resources in Alaska and peers.

Jurisdiction	Oil + NGL Proved Reserves	Natural Gas Proved Reserves	Oil + NGL Undiscovered Resource Mean Estimate	Natural Gas Undiscovered Resource Mean Estimate
[Units]	[MMbbl]	[BCF]	[MMbbl]	[BCF]
United States[1,2,3,4]				
Alaska (onshore & state submerged)	2,898	7,383	16,750	123,826
California	2,878	2,023	3,748	7,349
North Dakota	5,683	6,081	6,536	1,464
Oklahoma	1,469	28,900	790	10,244
Texas	12,004	97,921	8,174	55,468
U.S. Alaska Arctic OCS	-	-	23,750[3]	108,180[3]
U.S. GOM OCS	4,950	16,535	43,310	169,160
Canada[5,6]				
Canada-Alberta (conventionl)	1,781	31,900	1,196	15,916
Canada-Alberta (unconventional)	167,170	-	-	-
Canada-Total (includes Alberta)	173,110	68,170	4,043	42,990
Rest-of-the-World[6]				
Australia	1,433	43,037	46,746	114,000
Norway	5,825	73,806	12,881	183,000
U.K.	2,979	8,616	6,329	23,377

[1]Data source for U.S. reserves is the Departement of Energy, Energy Information Agency (EIA) at *http://www.eia.gov/dnav/pet/pet_crd_cplc_a_EPCCOND_R01_MMbbl_a.htm* and *http://www.eia.gov/dnav/ng/ng_enr_sum_a_EPG0_R11_BCF_a.htm.*

[2]Data source for U.S. undiscovered resource estimates is the U.S. Geological Survey (USGS) at *http://pubs.usgs.gov/dds/dds-030/.*

[3]Alaska current mean undiscovered resource estimates from the U.S. Geological Survey and Bureau of Ocean Energy Managment were compiled by the Alaska Department of Natural Resources, Division of Oil and Gas. The USGS estimates undiscovered resource by assessment areas (generally conforming to sedimentary basin outlines), but does not estimate resources by state. For this publication the Department of Revenue performed a rough allocation of the U.S.G.S. resource estimates to individual states for use in this table.

[4]Data source for U.S. Gulf of Mexico Outer Continental Shelf undiscovered resource is "Assessment of Undiscovered Recoverable Oil and Gas...", 2011; at *http://www.boem.gov/2011-National-Assessment-Factsheet/.*

[5]Data source for Alberta reserves at *http://www.aer.ca/data-and-publications/statistical-reports/st98*

[6]Data source for Canada (total) and Rest-of-the-World undiscovered resource estimates is the U.S. Geological Survey (USGS) at *http://pubs.usgs.gov/dds/dds-030/*

Undiscovered oil resource estimates

The U.S. Geological Survey (USGS) is used throughout this report as our source for undiscovered resource estimates for both North America and the rest-of-the-world.[1,2] The USGS assesses the recoverability of undiscovered conventional oil and gas resources, as shown in Figure 2-9.[3] Figures 2-12, 2-13, 2-14, and 2-15 graphically compare the current estimates of

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

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

3 The USGS also conducts 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.

Alaska's liquid hydrocarbon and natural gas undiscovered conventional resources and proved reserves with its North American and international peer groups. Several conclusions can be drawn from these graphs. These data show that Alaska's reserves are significantly less than undiscovered resource potential, unlike the U.S. states in the peer group, but similar to the Gulf of Mexico and Australia. Most of the U.S. states have roughly equal reserves and undiscovered resources, implying a higher overall level of exploration and development maturity than Alaska. A second observation is that the overall level of undiscovered conventional oil resource is much greater than any of the U.S. states and some of its international peers. It is, however, less than the Gulf of Mexico and Australia. A third observation is that Alaska's natural gas potential, as defined by undiscovered resource, is outranked in the peer group only by the Gulf of Mexico and Norway. Gas resource estimates for U.S. states are all far below Alaska.

The USGS analysis estimates how much undiscovered conventional oil and gas is technically recoverable and the difference between what is proved reserves and technically recoverable. For the onshore United States, the "assessment units" defined in the USGS analysis does not conform to any state or political jurisdictional boundary. Instead, the "assessment units" are based more on geologic divisions, such as the Permian Basin (Texas and New Mexico) and Williston Basin (North Dakota, South Dakota, Montana, Manitoba and Saskatchewan). In this way the USGS avoids dividing otherwise single coherent continuous plays between two or more assessment units. The international undiscovered resource assessment more closely adheres to national boundaries to define the "assessment units" or the geographic limits of the area analyzed. Understanding how much undiscovered technically recoverable resource might be present serves as a basis for calculating how much might be ultimately economically developed.

Technically recoverable resources are those that could be potentially produced using current technology and industry practices. Economically recoverable resources are those that can be sold at a price that covers the costs of discovery, development, production and transportation to the market. Figure 2-9 shows the significant differences in undiscovered resources between Alaska and the Lower-48 states and many of its international peers.

USGS assessments are meant to provide a means to estimate quantities of undiscovered conventional oil, gas and natural gas liquids that have the potential to be added to reserves (proved and otherwise) in some specified future time span. These estimated petroleum volumes reside in fields whose sizes exceed a minimum cutoff value that the USGS establishes for each assessment unit. The term "undiscovered conventional resource" as used in this report is understood to mean short approximations of this objective. Note that the USGS assessment of undiscovered resource has no stated or implied estimate of timing of development or volumes produced.

The USGS defines both heavy oil and shale oil as unconventional and considers those resources separately from its conventional resource estimates. While the USGS provides undiscovered resource estimates for nations in a relatively straightforward manner, its use of assessment units that do not adhere to state boundaries presented a barrier to clear comparisons for this study. To circumvent this barrier, we approximated undiscovered resources by state by visually estimating the areas of the assessment units contained within the state boundaries and prorating the total based on the estimated area allocations.

The USGS assessment effort ranks Alaska's undiscovered resource potential in a relatively high position compared to other parts of the world. Alaska's onshore undiscovered conventional petroleum resource is estimated to be approximately 17 billion barrels of oil. When the estimate for offshore undiscovered petroleum resource is added in, Alaska's total undiscovered resources top 40 billion barrels of oil. The USGS characterizes these estimates as representing a "significant potential for energy and mineral resource that is unmatched by any other onshore region of the U.S."

Figure 2-10. Estimates of proved oil reserves for Alaska and North American peers.

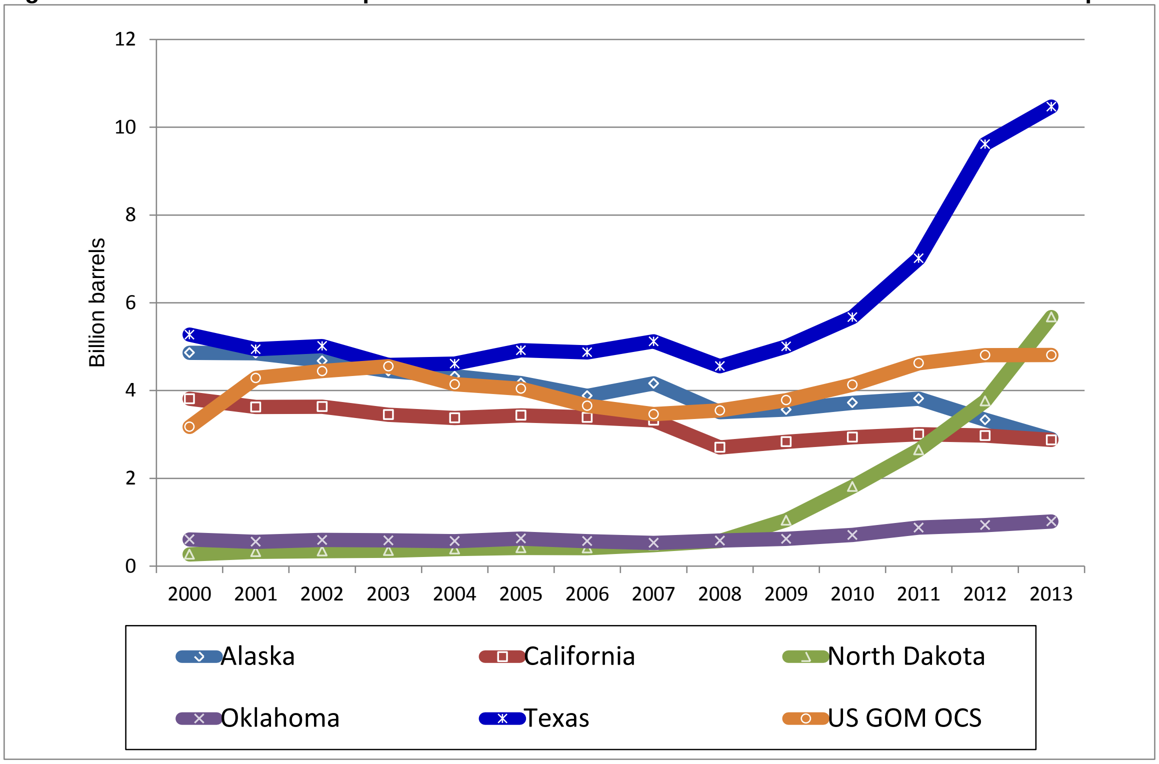


Figure 2-11. Estimates of proved oil reserves for Alaska and international peers.

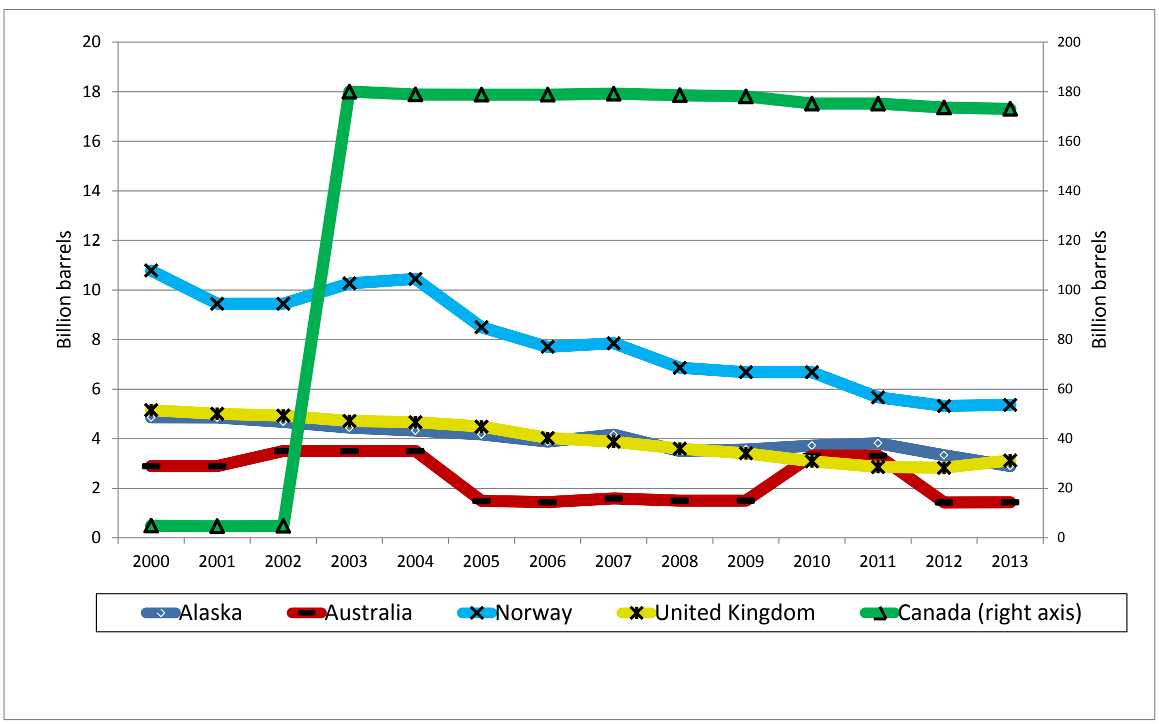


Figure 2-12. Comparison of proved reserves and undiscovered liquid hydrocarbon resource between Alaska and North American peers. (Note that for scaling purposes, the bar representing Canada's reserves is truncated.)

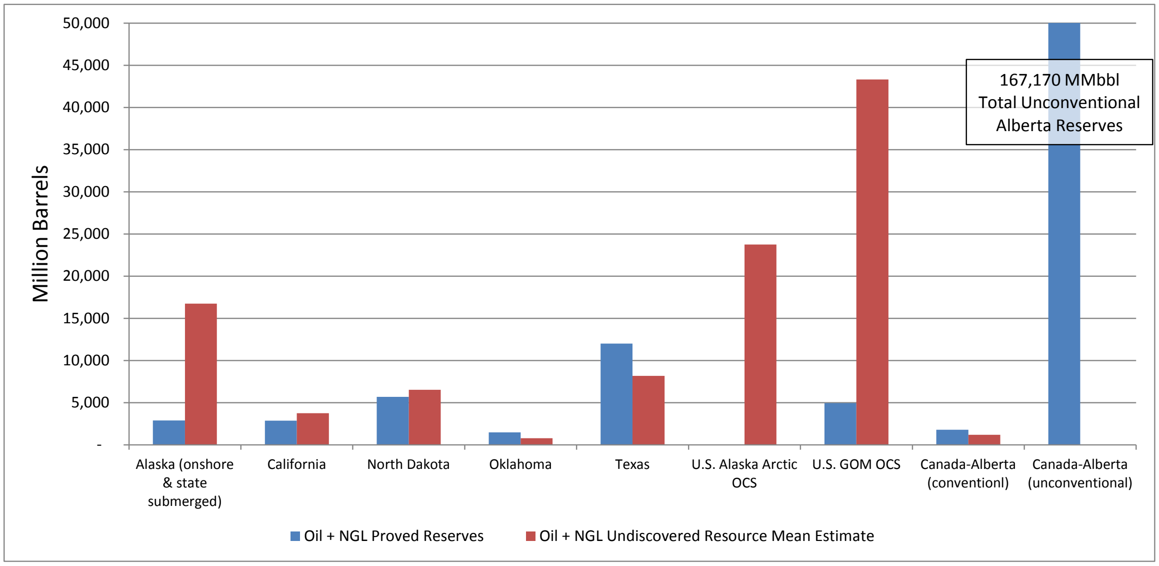


Figure 2-13. Comparison of proved reserves and undiscovered liquid hydrocarbon resource between Alaska and international peers. (Note that for scaling purposes, the bar representing Canada's reserves is truncated.)

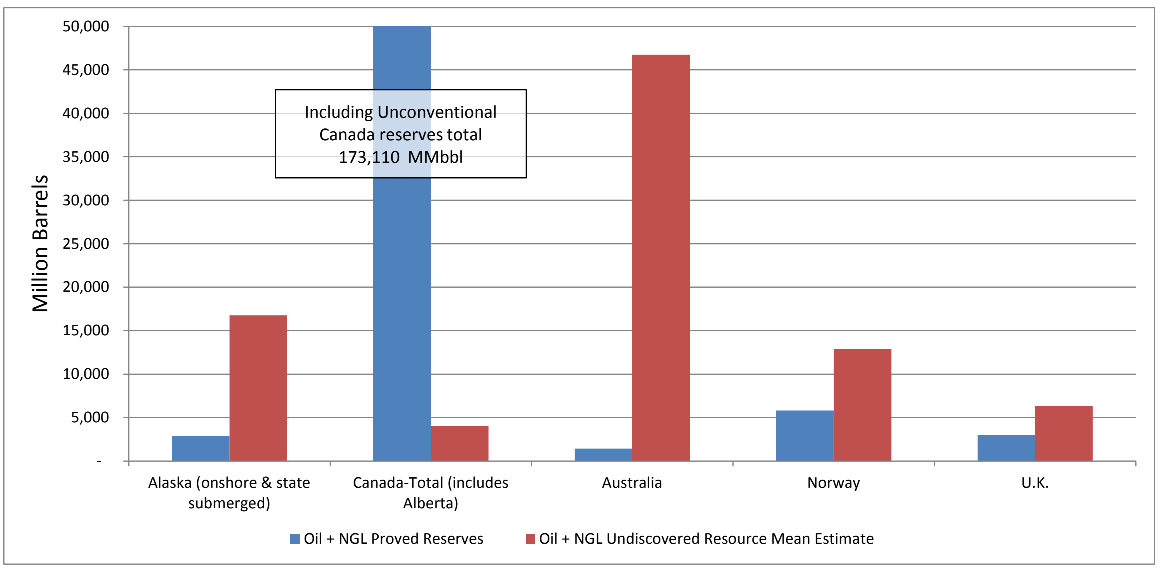


Figure 2-14. Comparison of proved reserves and undiscovered natural gas resource between Alaska and North American peers.

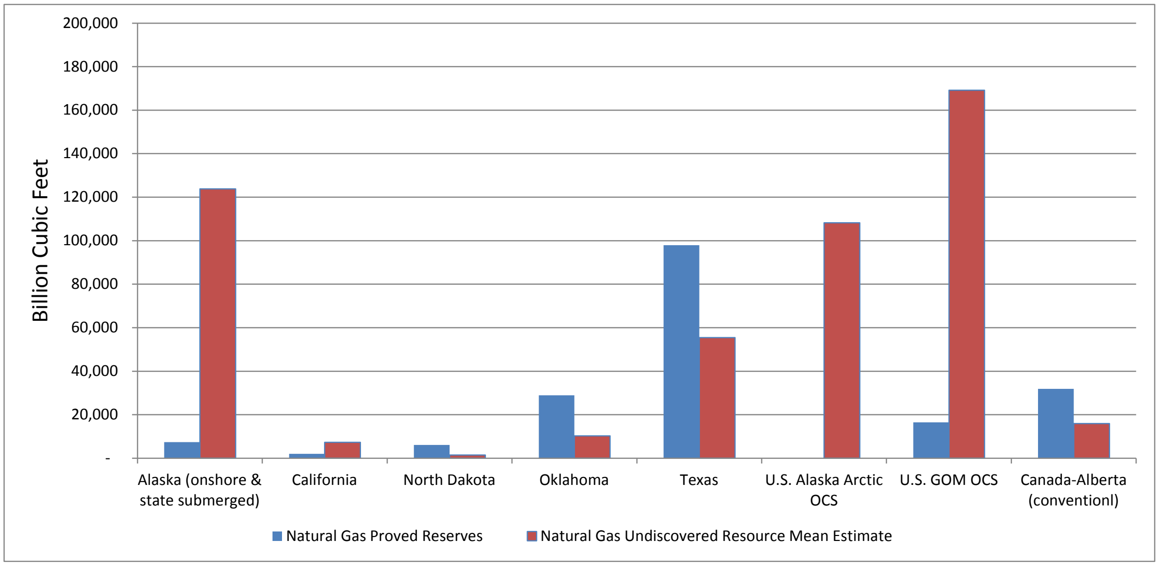
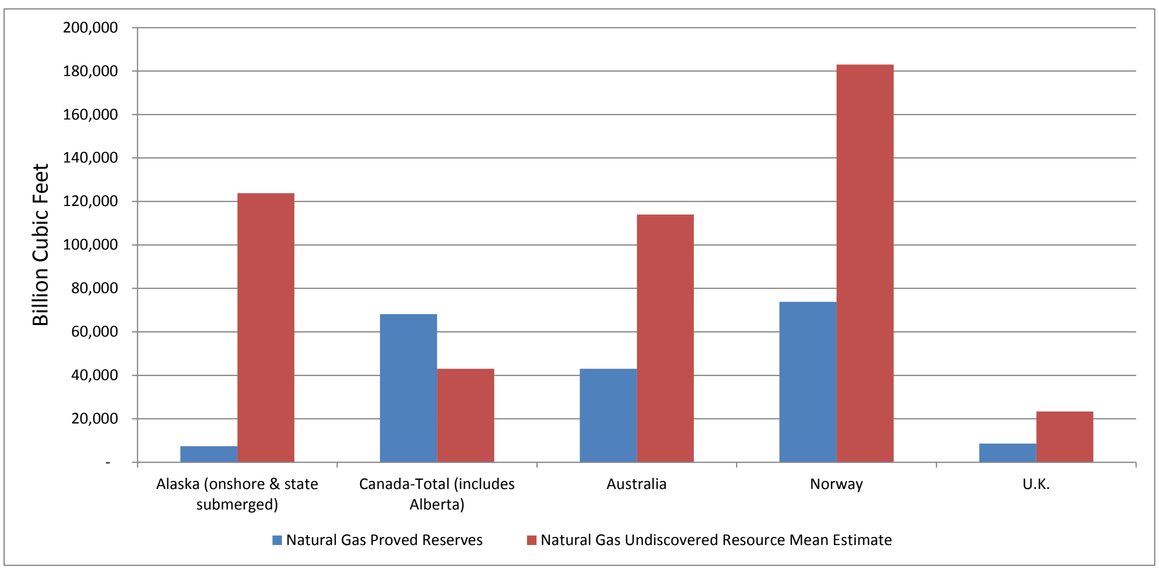


Figure 2-15. Comparison of proved reserves and undiscovered natural gas resource between Alaska and international peers.



Natural gas, viscous oil and other unconventional resources

As stated earlier, the focus of this publication is on Alaska's conventional oil and the fiscal systems the state has put in place to capture revenue from it. However, Alaska also has other significant hydrocarbon resources, including large quantities of natural gas, viscous oil, shale oil, shale gas, coalbed methane, and gas hydrates. While Alaska currently does not receive significant revenue from these hydrocarbon sources, the potential is significant, so a brief summary of these potential resources is warranted.

Natural gas

Alaska has a huge resource base of discovered and undiscovered natural gas (217.91 trillion cubic feet). Much of northern Alaska's conventional natural gas remains unexploited awaiting construction of an economically viable export option, such as an export pipeline or liquid natural gas (LNG) via tankers. Any capital spending to identify new natural gas reserves will only be made by companies expecting long periods of time before payback on investment. All of the options to construct infrastructure to exploit northern Alaska gas will likely be expensive and technically challenging and sensitive to market prices. Two possible scenarios for export of northern Alaska's natural gas have been considered in recent years. The two scenarios are a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada, or shipping liquefied natural gas (LNG) from tidewater. Recent attention has focused on the LNG 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]

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 conventional gas reservoirs 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. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

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[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.

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. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

Shale oil

Some explorers in Alaska have begun considering development of unconventional shale oil and gas resources. Lease acquisitions and test 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 decade 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, much less if they are economically viable or if the technology applications and methods used to produce shale oil in the Lower-48 will translate reasonably well to an Arctic environment, especially considering Alaska's limited infrastructure outside the conventional oil and gas field areas. Alaska currently has no production and receives no revenue from this type of unconventional hydrocarbon.

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

3. Lease sales

Federal

Onshore

Oil and gas leasing on Alaska's federal onshore lands is concentrated in both the Cook Inlet Region (on both sides of the Inlet) and in the NPR-A which is a 22.8-million acre area on Alaska's North Slope. The U.S. Bureau of Land Management (BLM) conducts annual oil and gas lease sales for onshore federal land. Additional information on federal onshore lease sales in Alaska can be found at the BLM online.[9]

Offshore

The Bureau of Ocean Energy and Management (BOEM) conducts federal lease sales for the Outer Continental Shelf (OCS), which are the submerged lands, subsoil, and seabed, lying between the seaward extent of the States' jurisdiction and the seaward limit of Federal jurisdiction, currently known as the Exclusive Economic Zone. The State of Alaska's seaward limits are extended 3 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured. Federal jurisdiction is established as the 200 nautical mile limit, as defined under treaty and accepted principles of international law. For BOEM OCS leasing information please review their Leasing 101.[10]

University, Mental Health Trust, Native corporation, and private lands

In general, University of Alaska (University) property is available for oil and gas leasing. University property is located throughout the state and currently the University has three oil and gas leases on the Kenai Peninsula, one of which is actively producing. The University's oil and gas leases are awarded on a competitive basis or through direct negotiation. All proposed leases are Public Noticed in local area newspapers, listed on UA's website, with notices sent to the University Board of Regents and legislators. The University's terms and conditions for oil and gas leases are driven by current market economics, and as such, each lease is somewhat unique to the lessee. Additionally, the framework of the lease is a combination of the Alaska Division of Oil and Gas lease structure and the Alaska Mental Health Trust Land Office lease structure; which are detailed later in this report. The University's leasing program actively seeks development and production of oil and gas on its property in an effort to continue support of the University Scholars Program and research programs. Information is available through the University Land Management website.[11]

The Trust Land Office (TLO) manages approximately 1 million acres of land and other natural resources owned by the Alaska Mental Health Trust Authority (Trust). The TLO generates revenue through land leases and sales. The Trust's oil and gas resources are principally located in Southcentral and interior Alaska. The TLO regularly offers Trust land for oil and gas leasing and encourages active development of leased lands. Information is available from the TLO website[12] and their Resource Management Strategy.[13]

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9 BLM information on federal onshore lease sales in Alaska http://www.blm.gov/ak/st/en/prog/energy/oil_gas/leasing.html

10 BOEM OCS Leasing 101 http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/5BOEMRE_Leasing101.pdf

11 University of Alaska Land Management http://www.ualand.com/

12 Trust Land Office http://mhtrustland.org/

Alaska Native corporations are private land owners of surface and subsurface oil and gas estates, including lands in the Cook Inlet and the North Slope, as well as lands proximal to state identified frontier basins for which there may be available exploration tax credits. For detailed information on specific privately held Alaska Native corporation lands, please see individual corporations' websites. A list of Alaska Native corporations and links to their individual websites is available online.[14]

In many cases private individual Alaskans own surface, mineral and oil and gas estates in a variety of combinations. These individuals may lease their land for oil and gas and associated development.

These privately structured leases (University, Mental Health Trust, Native corporation, and private individuals) have a variety of different leasing mechanisms, contracts and rules in place and they vary from owner to owner and from lessee to lessee. Agreements between the lessee and the land owner are often held in confidence. Negotiable terms may include a monetary bonus, variations in rental or royalty rates, the primary term and work commitments, among others.

State of Alaska Conventional oil and gas leases

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.[15]

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. Prior to adoption of 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 quicker 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 and production decisions. It also allows smaller companies and individuals the opportunity to acquire leases in areas of lesser 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

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[13] Trust Land Office Resource Management Strategy http://mhtrustland.org/wp-content/uploads/2014/05/Resource-Management-Strategy.pdf
[14] Alaska Native Corporations and links http://www.ncai.org/tribal-directory/alaska-native-corporations
[15] "Five-Year Program of Proposed Oil and Gas Lease Sales," January 2014: http://dog.dnr.alaska.gov/

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 general 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 are issued to the highest responsible qualified bidder.

Historical lease sale data

The state has conducted 68 areawide sales since 1998 in the five areas mentioned above.[16] Reviews of sale results, summarized 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 been awarded, resulting in a cumulative total of $237.6 million in bonus bids received (Figure 3-2).

Figure 3-3 shows participation levels by bidder class as a percent of total tracts leased in State of Alaska competitive oil and gas lease sales from 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, 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. 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 exploration licenses (Figure 3-4). 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 most 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. If DNR finds that an exploration lease is in the State's best interests, the successful bidder is determined by the highest bid in terms of the minimum work commitment dollar amount. Exploration license bidders must all be qualified by DNR for their bid to be accepted.

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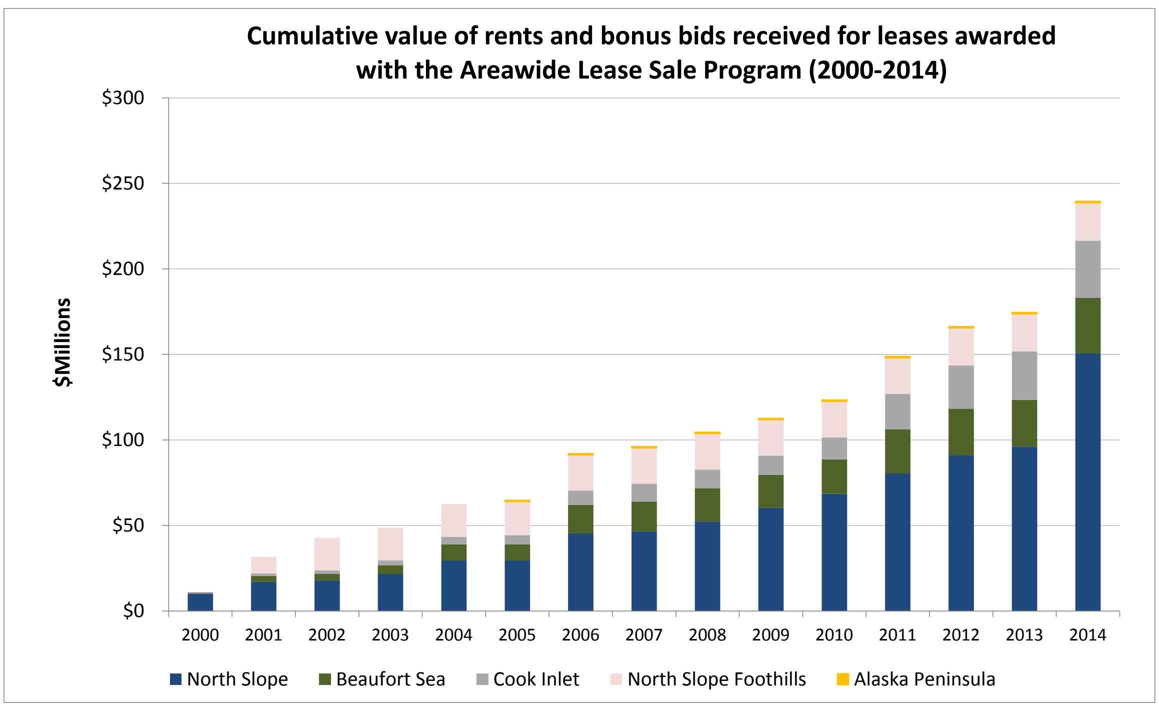
[16] 1998 to 2014 areawide sales: 16 were in the North Slope, 17 in Cook Inlet (added in 1999), 14 in Beaufort Sea (added in 2000), 13 in North Slope Foothills (added in 2001), and eight in Alaska Peninsula (added in 2005).

Figure 3-1. Alaska DNR competitive oil and gas lease sale results summary with all lease sales summed together by year.

Year	Total Tracts Sold	Total Acres Sold	Total High Bonus Bids Received [$ MM]	Average 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	87	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	1,320,022	$ 30.160	$ 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	197	767,858	$ 11.346	$ 14.78	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[1]	335	759,701	$ 64.968	$ 85.52	5	-	2	319	14
Totals	2,778	9,228,267	$ 237.038		68	315	219	1,545	772

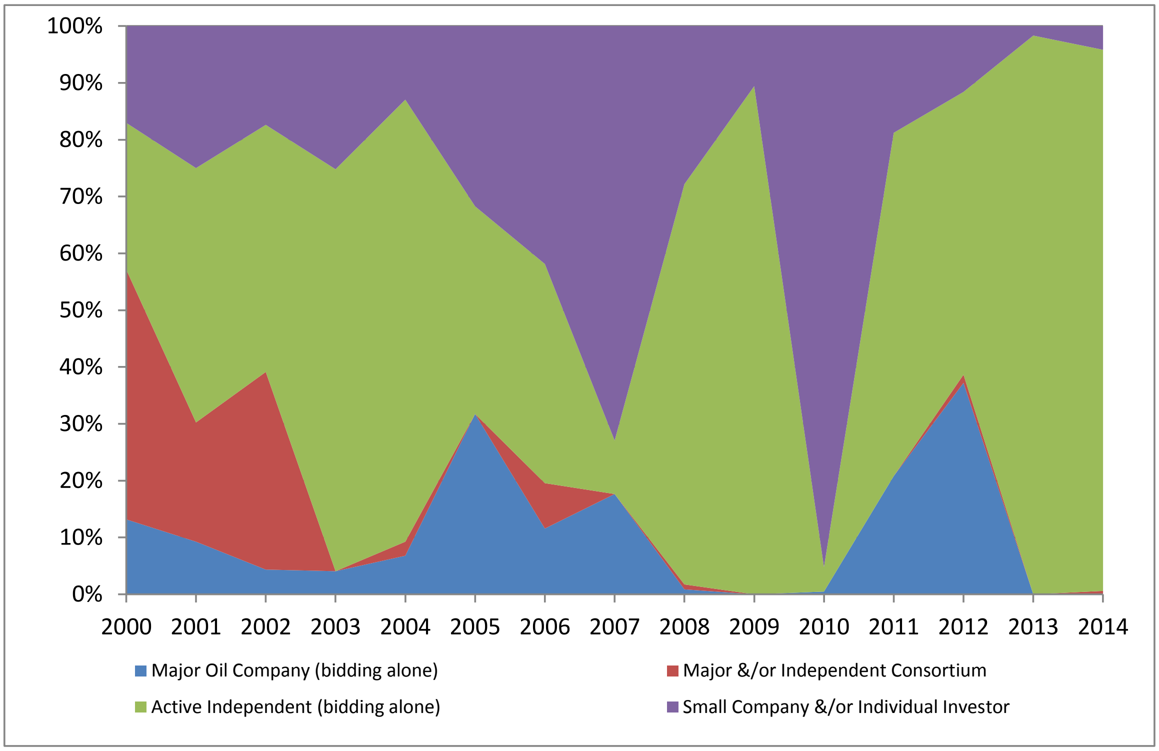
[1]Data based in-part on preliminary sale results, values will likely change when final results are available.
Source: Alaska DNR, Division of Oil and Gas.

Figure 3-2. Cumulative value of rents and bonus bids received for oil and gas leases administered by DNR.



Source: Alaska DNR, Division of Oil and Gas.

Figure 3-3. Participation levels by bidder class as percent of total tracts sold in Alaska DNR competitive oil and gas lease sales.



Source: Alaska DNR, Division of Oil and Gas.

Figure 3-4. Existing and proposed oil and gas exploration licenses administered by the Alaska DNR in January 2015.

Location	ADL[1]	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

[1]ADL is the Alaska Division of Lands case number (lease) prefix or identifier.
Source: Alaska DNR, Division of Oil and Gas.

4. Exploration and development activity

The oil and gas industry worldwide, like many resource extraction industries, is known for its “boom and bust” cycles. There are many different causes of booms and busts. Booms could be brought on by sudden demand for a resource, high sales prices, technology breakthroughs that make the resource extraction more attractive economically, or an easing of regulations on the resource to be extracted. Busts are often caused by the exact opposite of what created the boom in the first place, or they could signal a depletion of the resource in a particular locality.

It is not difficult to identify a booming industry. In the case of oil and gas production, common indicators include the number of active drilling rigs, the number of persons employed, and the number of wells drilled. A booming oil or gas development will attract other companies, increasing competition for leases, drilling rigs, support services and equipment, and housing and office space may be in short supply.

Drilling activity in Alaska

Drilling activity, including the number and type of wells drilled, is an indicator of oil and gas industry activity. The Alaska Oil and Gas Conservation Commission (AOGCC) authorizes and monitors permits to drill for oil and gas and other oil and gas related subsurface activities in Alaska. The AOGCC web site[17] provides detail on the number and types of oil and gas wells drilled in Alaska from 2000 to 2014. We have reproduced below several of the charts that the AOGCC included in their online presentation.

Exploratory wells

Figure 4-1 shows the number of exploratory wells and wellbores that were completed, suspended or abandoned in the years 2000 through 2014. The numbers on each column indicate the number of companies that contributed to the number of wells shown. Figure 4-1 shows a significant amount of exploration well activity in 2001 through 2004, a substantial drop in activity began in 2008 and lasted through 2011and then an increase of exploration activity occurred, back to higher historic levels. It is worthy of note that drilling of exploration wells in Alaska is at a much lower level than our entire selected peer group.

Development and service wells

Figure 4-2 shows the number of development and service wells and wellbores that were completed, suspended or abandoned in the years 2000 through 2014. Like the previous figure, the period from 2000 through 2004 shows a steady, relatively high rate of well development, with a drop in activity beginning in 2005 and continuing through 2011. Development drilling remained low through 2013 and then saw a substantial increase in 2014. As with exploration drilling, drilling of development and service wells in Alaska is at a much lower level than our entire selected peer group, especially in the Llower-48 states.

Drilling rig counts

The number of drilling rigs in an oil and gas jurisdiction is also an indicator of petroleum-related activity. The AOGCC tracks drilling and workover rig activity within Alaska. Figures from the 2011 presentation, shown as Figure 4-3 and Figure 4-4, indicate that well workover activity has been healthy throughout the years shown in the graphs but again, at a much lower level than any jurisdiction within our selected peer group.

[17] The AOGCC web site is found at http://doa.alaska.gov/ogc/

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).

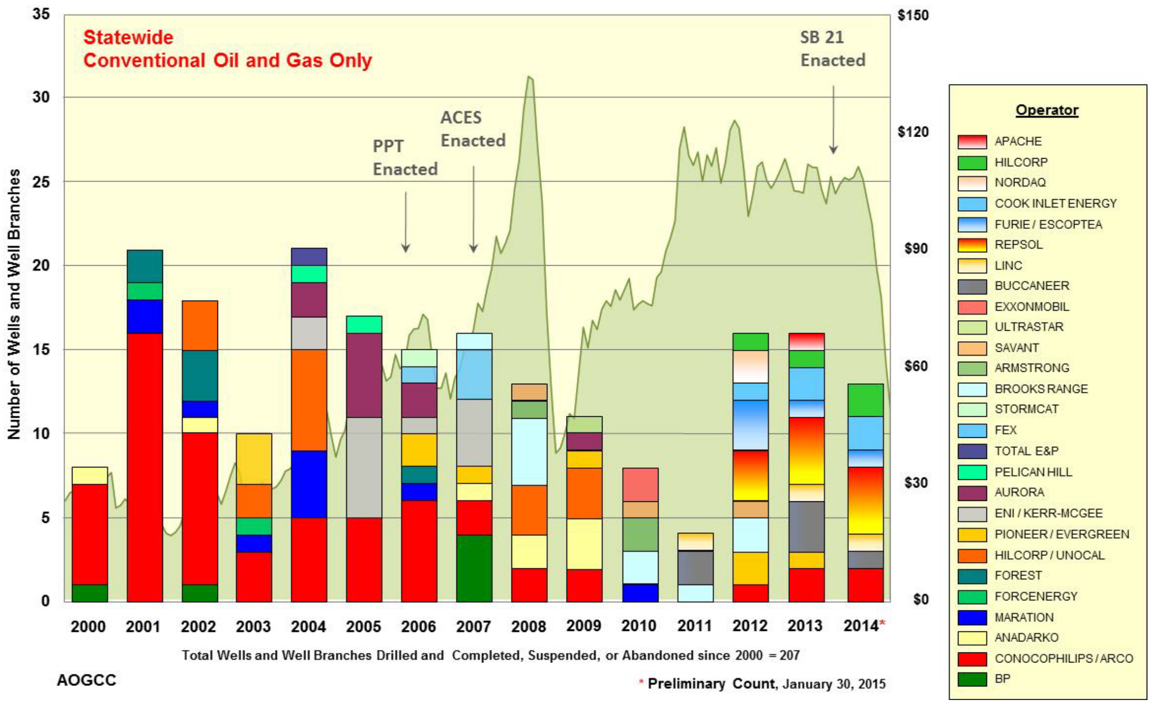


Figure 4-2. Development and service-class wells and wellbores in Alaska (statewide). Includes all development and service wells that were completed, suspended or abandoned between 2000 and 2014. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel).

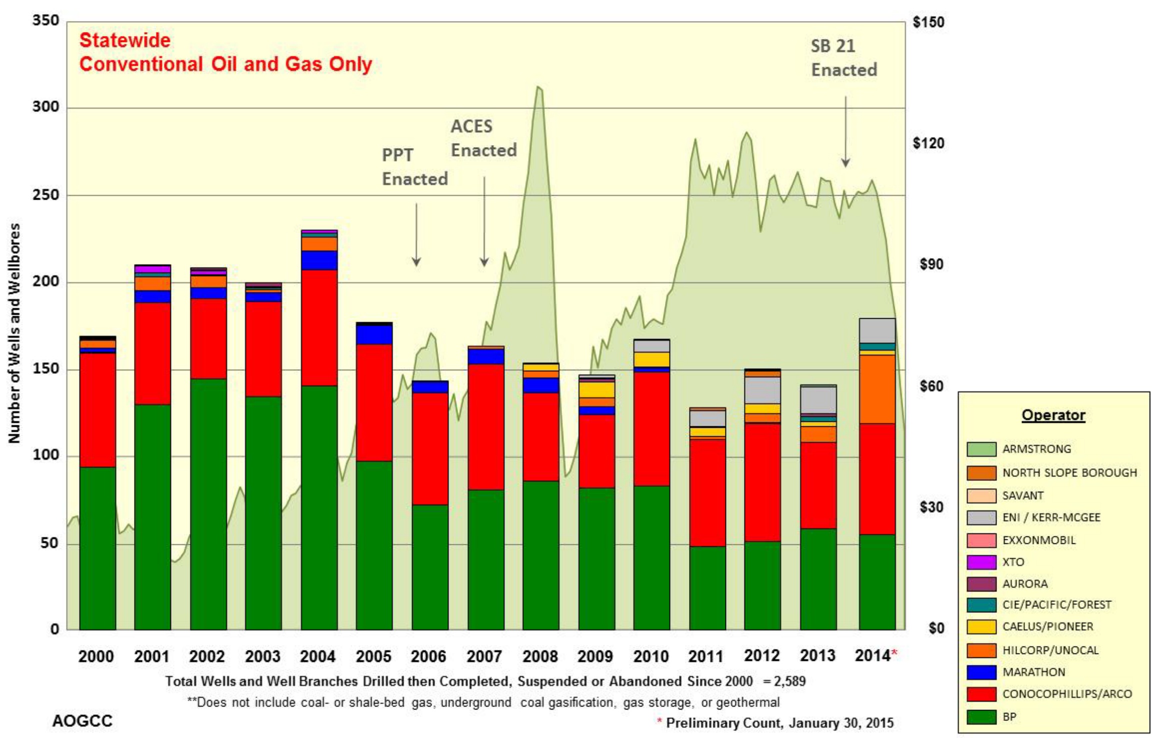


Figure 4-3. Alaska's combined active drilling rigs and workover rigs for each quarter from 2005 through 2014.

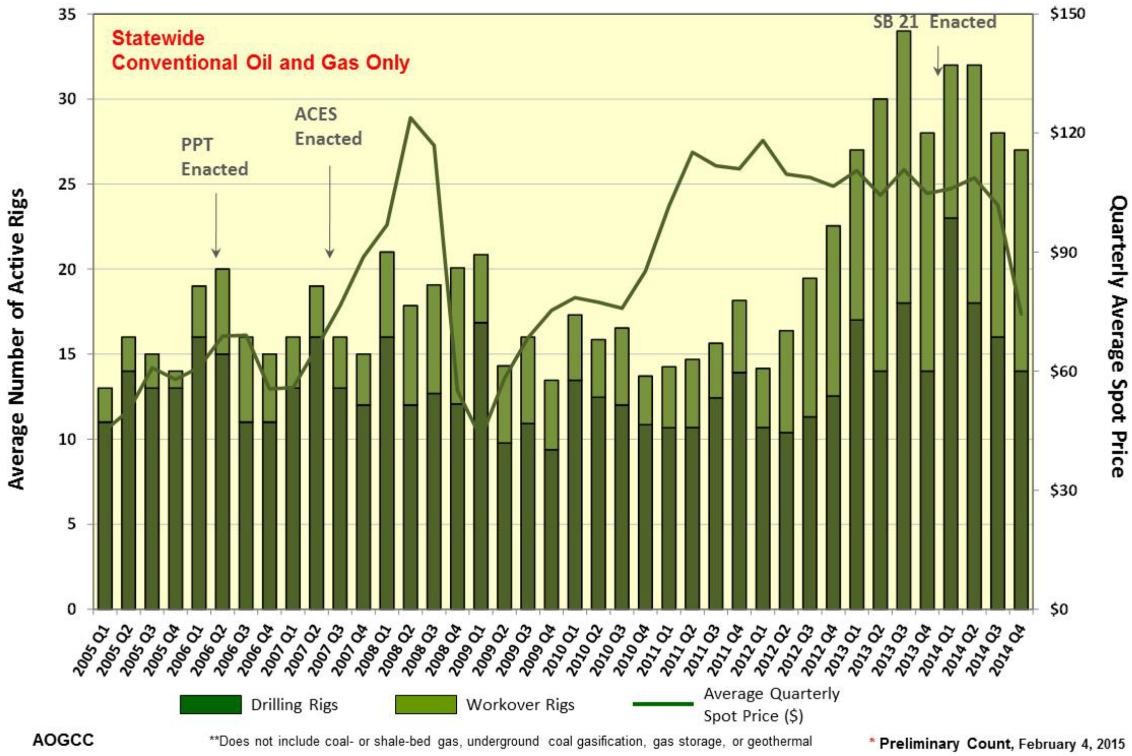
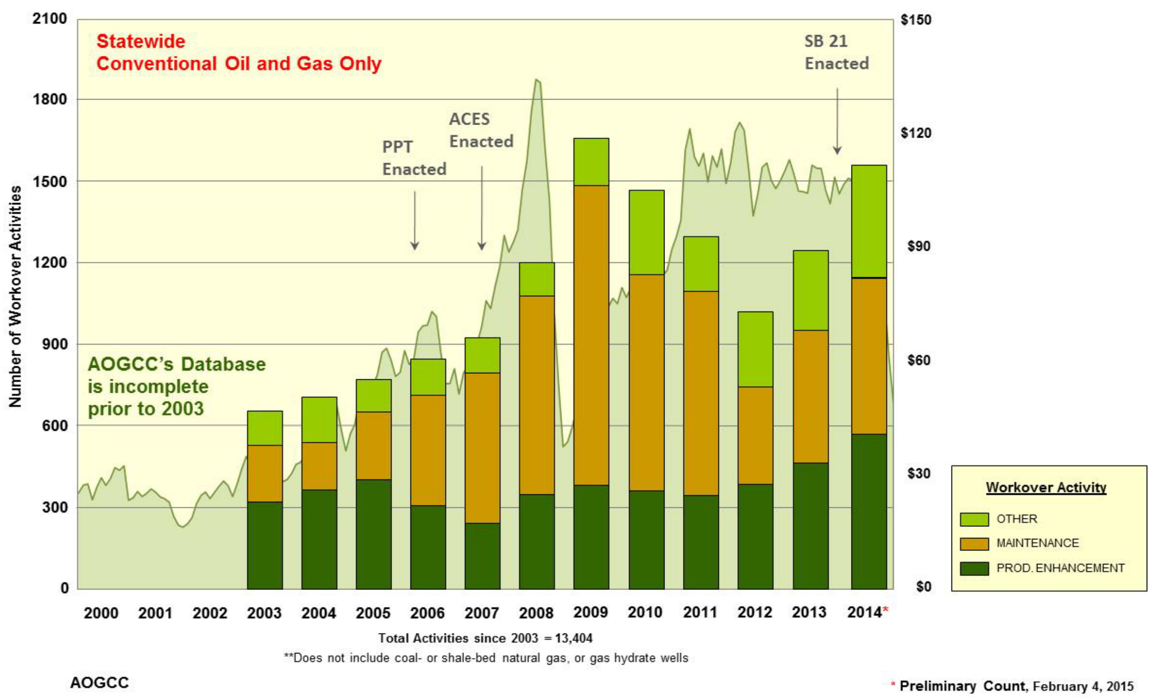
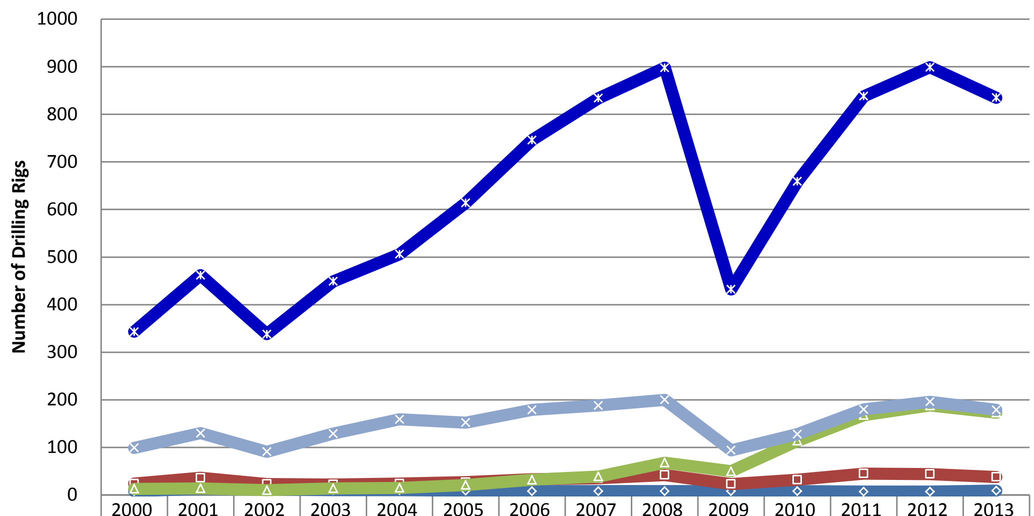


Figure 4-4. Number of Alaska's well workover activities by calendar year, from 2003 through 2014.* Solid line represents West Coast spot price for Alaska North Slope crude oil (dollars per barrel).



Baker Hughes, an oilfield service company that operates in 80 countries, has been providing counts of rotary rigs for the petroleum industry for over 65 years. Although not as detailed as the information provided by the AOGCC, the rig counts provided by Baker Hughes can be viewed relative to other oil and gas provinces over a given time period. Figure 4-5 shows a comparison of annual average rotary rig counts in Alaska and four other oil and gas-producing states from 2000 through 2013. We note that the data show a dip in rig counts in all states except Alaska in 2009, followed by an increase in rig counts in all states except Alaska in 2010. According to Baker Hughes, the annual average rig count for Alaska has remained flat since 2006. In the other four states, rig counts increased at least 28 percent between 2009 and 2010, and in North Dakota, the number of rotary rigs more than doubled.

Figure 4-5. Number of drilling rigs by state.



	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

Source: Baker Hughes.

Investment in North Slope oil and gas

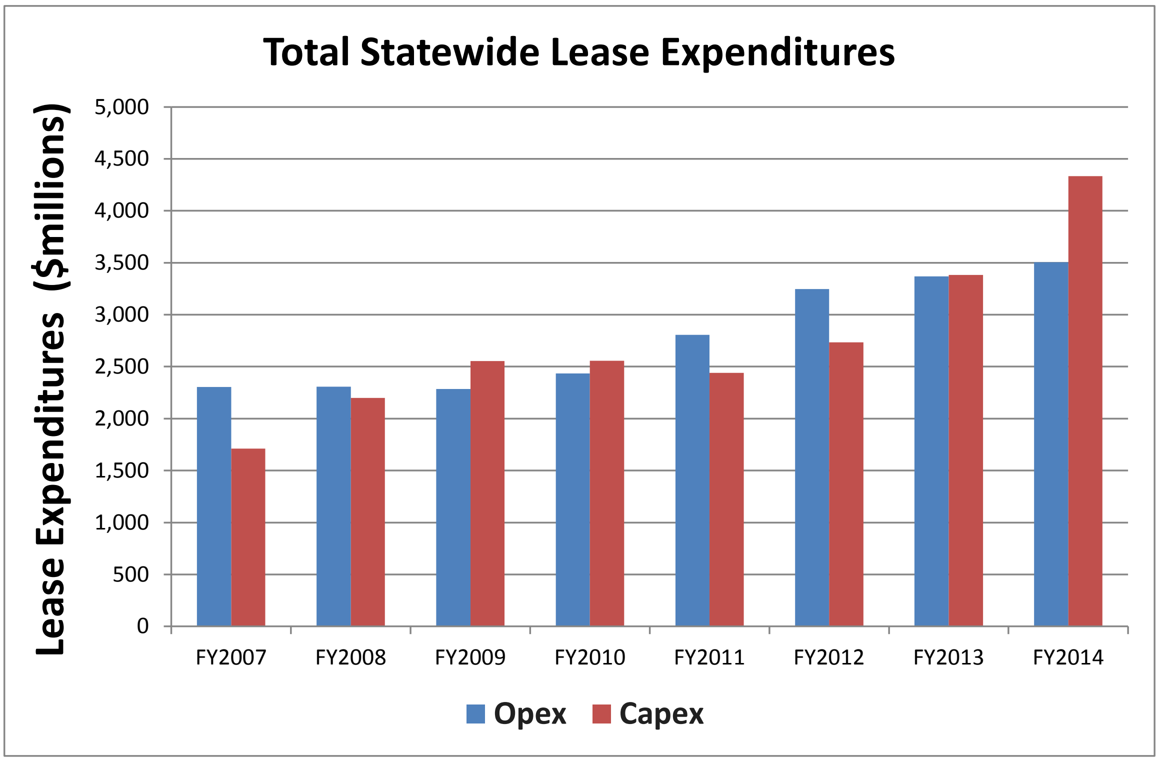
Investment in the oil and gas industry since exploration began in Alaska has been substantial. Exploration, development and production costs have been high throughout the state since oil was first produced at Katalla in 1902. The North Slope of Alaska is remote, and prior to oil and gas development had no roads or facilities close to where the development would be. To date, the area has only one road connecting it with the rest of the state, which is itself remote from the other states in the U.S. The amount of investment that had to occur in order to explore for and develop the North Slope's oil and gas resources, and to transport oil to markets, was an order of magnitude higher than the amount of investment required to produce and transport oil in much of the Lower-48 states. Although Alaska does not have any official records, estimates for the initial development of the major North Slope fields are in the tens of billions of dollars.

Since that time, over 17 billion barrels of oil have been produced and sent through facilities that were constructed in the 1960s and 1970s. In recent years, the aging infrastructure has begun to show signs of the years of wear. Shortly after major pipeline leaks in 2006, BP Exploration (Alaska) Inc. undertook several large-scale projects to improve the integrity of the pipelines, flowlines, and associated facilities. The project cost hundreds of millions of dollars and required a significant increase in the labor force.

Investment can be broken down into capital expenditures and operating expenditures, both of which are deductible under the ACES production tax. Capital expenditures are the type of expenditures most often associated with property development and improvements. With the passage of a production tax on net profits, the State of Alaska began to receive information about the amount of investment in North Slope oil and gas operations. Although much of this information has yet to be audited, it provides some estimates with which to assess investment in oil and gas in Alaska.

Company reported operating and capital expenditures (opex and capex) from 2007 through 2014 is shown in Figure 4-6 and shows that statewide both opex and capex show a long-term trend of increases with noticeable increases in capex in 2013 and 2014.

Figure 4-6. Statewide operating expenditures (opex) and capital expenditures (capex).



Figures 4-7 and 4-8 splits opex and capex spending into two categories, with Figure 4-7 showing spending on the North Slope and Figure 4-8 showing spending in Cook Inlet and non-North Slope areas. North Slope spending reflects the statewide spending seen in the previous figure, because the magnitude of the spending on the North Slope is dramatically higher than spending in Cook Inlet and non-North Slope areas. Spending in the rest of the state when extracted from the statewide data shows much greater variability than the North Slope, but here, too, significant increases in spending have occurred in recent years.

Figure 4-7. North Slope opex and capex.

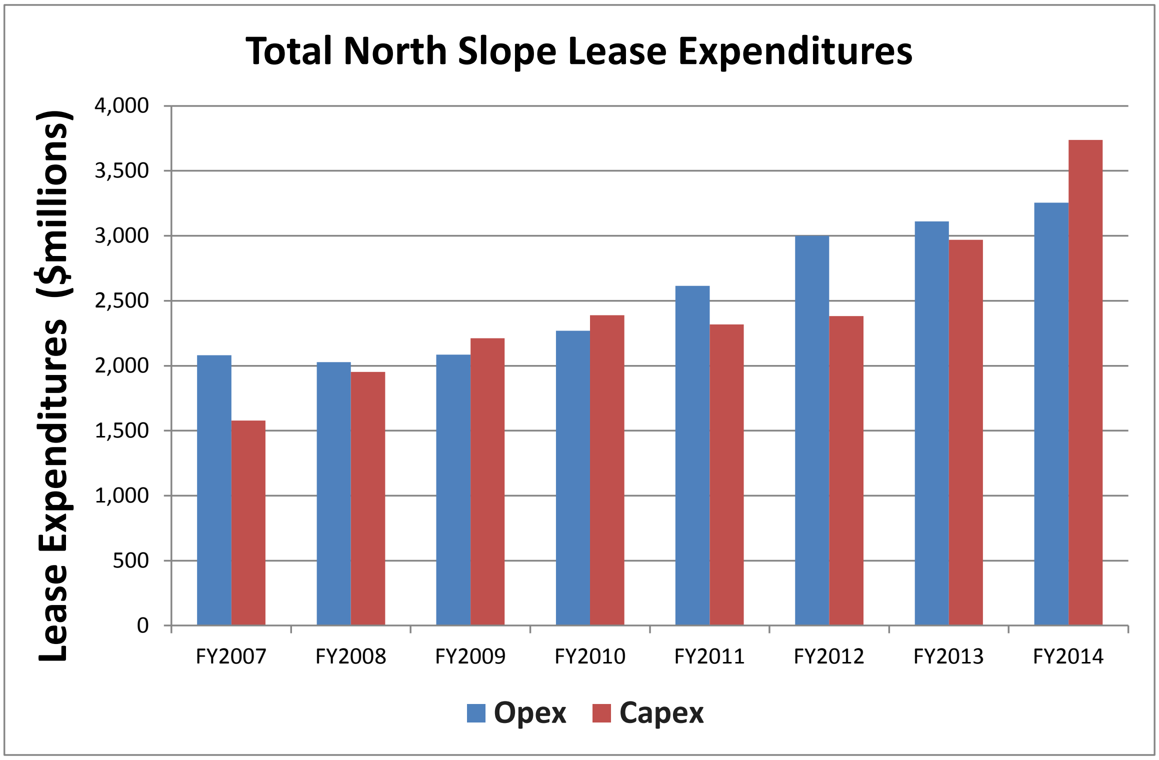
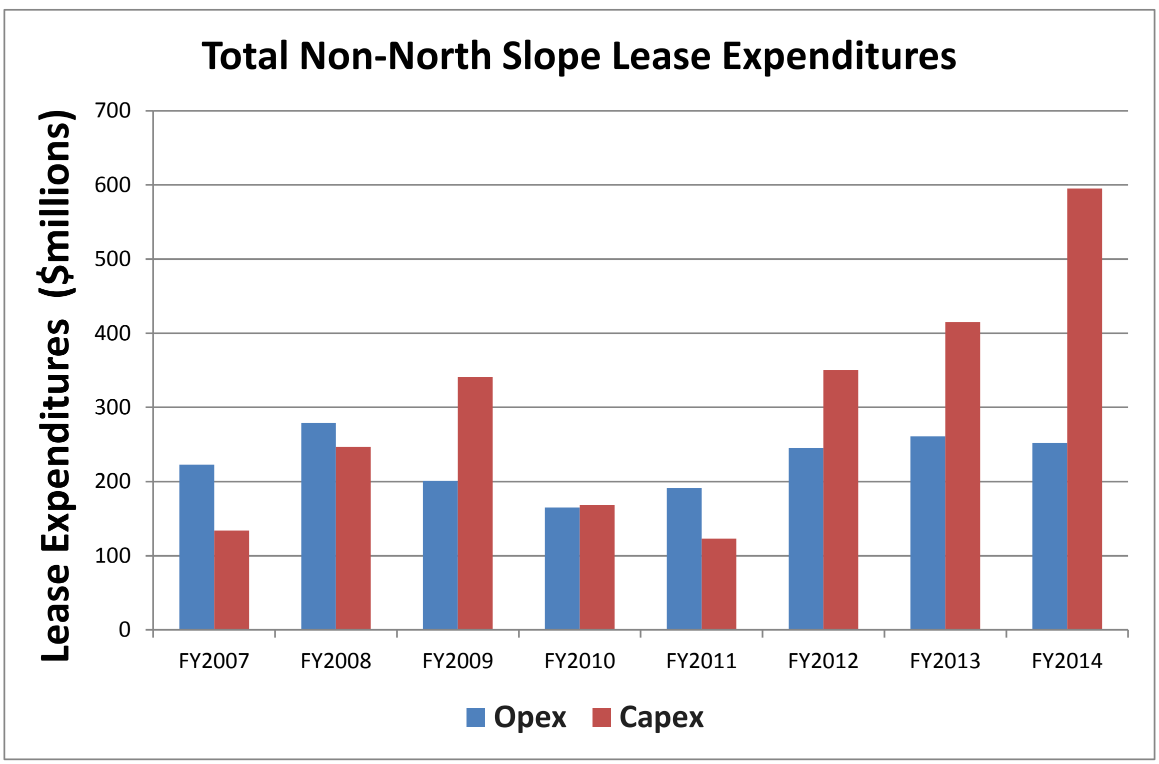


Figure 4-7. Cook Inlet and non-North Slope opex and capex.



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

The oil and gas infrastructure is well established in Cook Inlet and on the North Slope of Alaska, albeit very localized, with production linked to market by pipelines crossing vast areas of undeveloped lands. Infrastructure plays an important role in exploration and development and can have a direct effect on costs and new field economics. Much of Alaska's oil- and gas-related infrastructure is privately owned or 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 infield flowlines, joining with individual or other consortium owned common carrier pipelines, like the TAPS from the North Slope or lines surrounding Cook Inlet. Common carrier oil, condensates or dry gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA).

North Slope

The North Slope oil and gas industry exists because the construction of the TAPS enabled transportation and marketing of the stranded North Slope oils of Prudhoe Bay and other associated fields. This 800 mile pipeline system extends from Pump Station One, in the vicinity of Deadhorse to Valdez. In Valdez, TAPS ends at the Valdez marine terminal where North Slope crude oil is shipped by tanker to U.S. West Coast refineries. The system is operated by the Alyeska Pipelines Service Company[18] and its subsidiaries, while tankers are controlled by the producer companies. To date, over 17 billion barrels of oil have been transported from the North Slope to the West Coast.

TAPS is a common carrier pipeline regulated by both FERC and RCA, with tariffs per barrel for oil transported ranging from $4.37 in 2011 to $6.68 in 2014. Within the North Slope operating fields, six common carrier pipelines bring oil to TAPS with charges in 2014 ranging from $0.36 for the Kuparuk Pipeline to $12.25 for the Badami Pipeline. The list of regulated pipelines and tariffs can be found at the DNR's web site.[19] Common carrier pipeline use is a cost factor to consider in expanding infrastructure on the North Slope.

The oil and gas field-related infrastructure of the North Slope, while permitted for development and regulated for operation by the State of Alaska, is predominately owned and operated by the oil and gas industry. The state maintains access to the North Slope via the Dalton Highway for road traffic, via the Deadhorse airport for air cargo and personnel, and via shipping regulations and pilotage, when required, for landings from the Beaufort Sea. Entry from the Dalton Highway into Deadhorse, Alaska is public, but access on the North Slope beyond the immediate Deadhorse area is restricted and controlled. Within Deadhorse, the transportation and utility infrastructure is managed by the Alaska Department of Transportation and Public Facilities (DOT/PF) and the North Slope Borough. Once departing Deadhorse, all transportation on the privately maintained roads must be approved by the North Slope unit operators. Transport of marine cargo must be done at private landings and docks and approved by the owners/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 use of the facility.

[18] Alyeska Pipelines Service Company is owned by a consortium of companies including the biggest producers of crude oil on the North Slope.

[19] The list of regulated pipelines and tariffs can be found at http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm.

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. 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 new developments at Point Thomson and the expansion of infrastructure from the Alpine field into the federal lands of NPR-A. Maps in this atlas are available by request to the DNR Division of Mining, Land and Water (DMLW), Resource Assessment and Development Section.

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

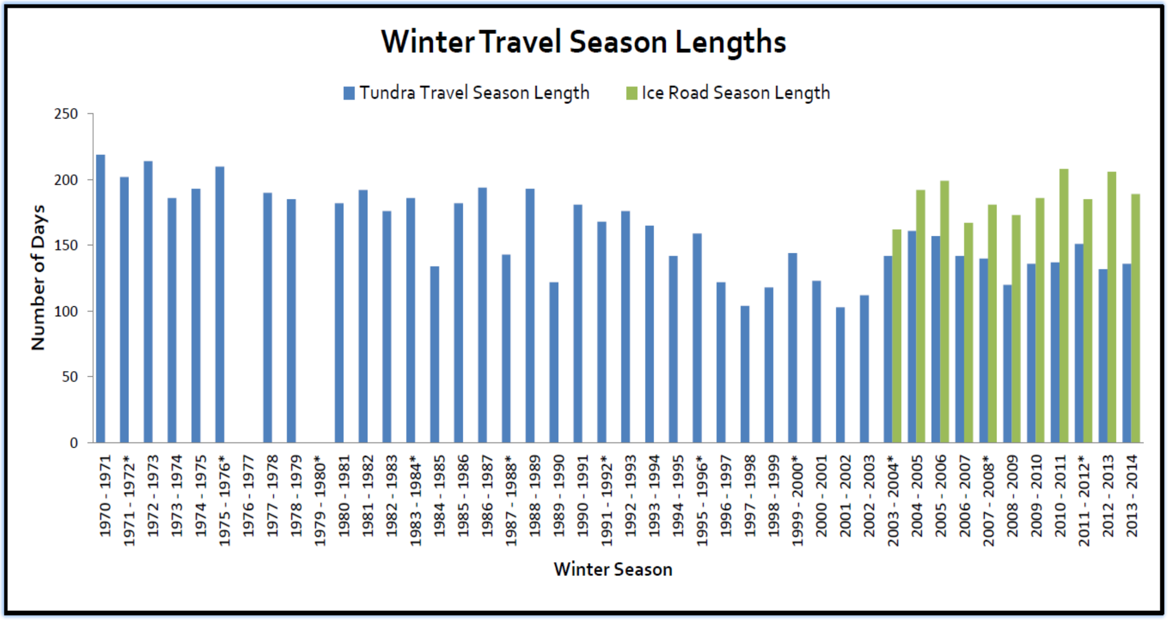
The infrastructure of the North Slope is being expanded to the west with the development into NPRA for Moose's Tooth and potentially to additional pads, as well as the exploration and development of the Greater Moose’s Tooth unit. The newly constructed bridges across the channels of the Coleville River 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 have been announced and some exploratory drilling has been completed, decisions that will create infrastructure are yet-to-be-determined.

In considering the infrastructure of the North Slope, it is important to recognize the advantages of development near existing infrastructure. All production will likely pass through TAPS and exploration and development costs are lower near the Dalton Highway and Deadhorse. Access may require facility sharing agreements to utilize existing infrastructure for new development and production. New operators will need to recognize the risks, liabilities, and opportunities that come with North Slope oil and gas exploration and development. These points are important to consider in judging the competitiveness of Alaska, in accessing state leases, and in investing in development and the associated new infrastructure.

Outside of established infrastructure, the importance of ice roads and ice pads cannot be emphasized enough, as these are critical to development of the oil and gas resources while protecting the tundra. Ice road construction and off-road travel is regulated by seasonal environmental conditions that are monitored by the DMLW, Northern Regional Office (NRO). Tundra opening areas have been established throughout the North Slope. The date of tundra opening has ranged from as early as November 4, to as late as February 20. The tundra is closed when it appears as if thawing conditions have resulted in snow that will be too soft or too limited to permit travel without resulting in damage to the tundra. Once the tundra has been opened in the winter, there are no restrictions on the type of vehicles that may operate on the tundra provided that vehicle operation does not negatively impact the tundra. The general winter off-road travel season has declined over the years (Figure 5-1). With concern for declining winter off-road travel season, NRO has developed best practices for early winter season tundra access. Innovations in ice road construction techniques and low impact vehicles have continued to stem the season's decline.

Figure 5-1. Winter travel season length approved from 1970 through 2014. Note the addition of ice road seasons based on best practices established with research studies beginning in 2003



Infrastructure deficiencies

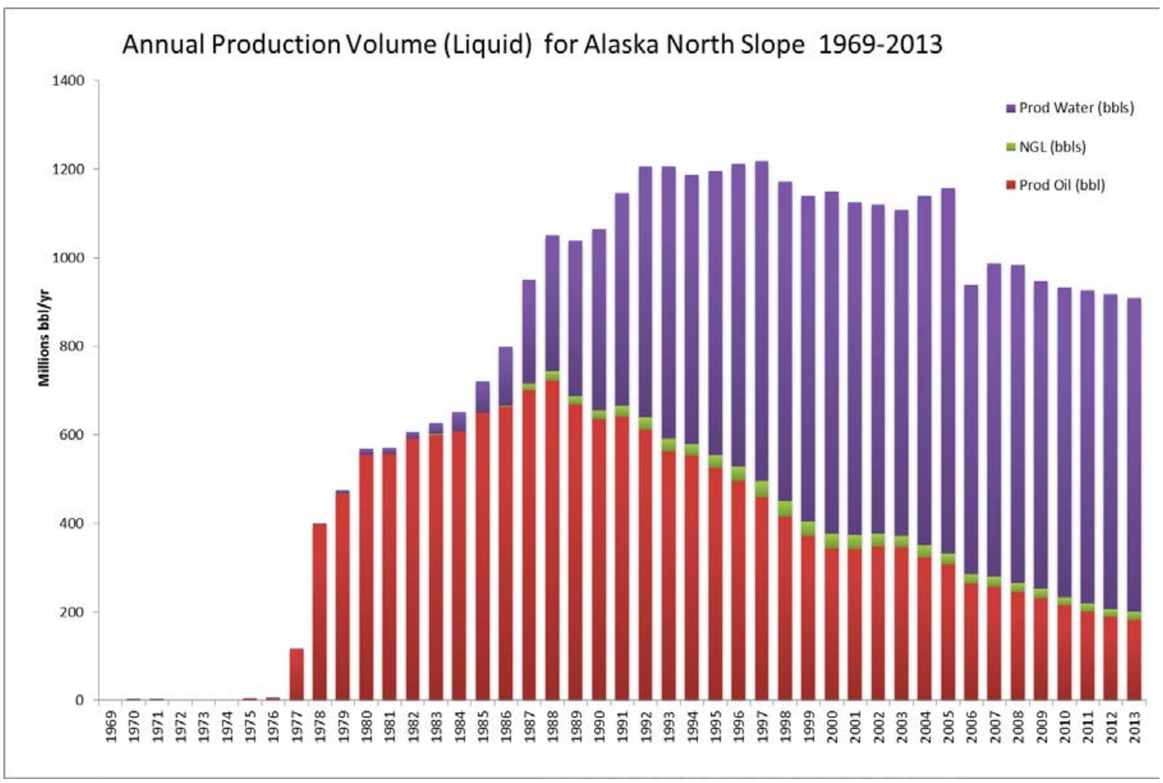
Presently, the existing producers likely see no significant infrastructure deficiency identified in or near existing fields because the operators and the State have invested in developing and maintaining infrastructure over the more-than-40 years of development and production in the area. However, because much of Alaska's resource potential is in remote areas far removed from Prudhoe Bay, infrastructure costs will continue to be a hurdle to bringing new discoveries on-line, unless production rates and overall reserve volumes are of sufficient size to justify the capital expenditures for new infrastructure.

While not a deficiency, but relevant to the tundra travel season, is incident response. Given the history of operation of the North Slope with road less access to infrastructure, a specific challenge remains with access to Roadless infrastructure and facilities during an oil or gas incident. The Northstar, Badami, Alpine, and future Point Thomson pipelines are road less, as are many infield pipelines. Access to a location with a pipeline leak that occurs outside of approved tundra travel times could involve an extended duration, considerable expense and a long outage if a large amount of heavy equipment is required for repair. Even in winter, construction of an ice road will take time. The response capabilities to minor incidents have proven successful, but response to a major spill in road less areas is untested. The challenges of access to respond to incidents, including liabilities and costs involved, should be listed as a factor in considering Alaska's competitiveness.

One important point is the challenge of managing significant and increasing quantities of water produced with crude oil from mature reservoirs (Figure 5-2). 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 increased water handling capability or eventually may lead to accelerated decline in oil and NGL production. Similarly, natural gas production in some fields may also increase over time. As with water, increased use of gas handling facilities on the North Slope is an integral part of maintaining enhanced oil recovery. It is the combination of these approaches that add to the competitive challenge of Alaska, but are integral in sustaining production and managing decline of its mature fields.

With the decline in production of the North Slope over time, the volume in the TAPS and costs of operating and maintaining flow is an additional issue of competitiveness. While the TAPS is not deficient in transporting the oil from the North Slope to Valdez, it is facing challenges with reduced flow and age-related wear. One concern is the level of infrastructure required to keep the oil flowing during all contingencies in all seasons. Alyeska believes that TAPS has sufficient heating capacity for typical flow and average weather conditions. However, the outcome from a combination of atypical conditions is unknown. These might include unusually cold and long-duration weather fronts or upsets that reduce throughput, such as tanker loading problems, mechanical or electrical problems in TAPS or production upsets or facilities shutdowns on the North Slope. In oil, there is a small portion of water that cannot be economically removed. This is the subject of a consent agreement with Pipeline and Hazardous Materials Safety Administration (PHMSA), CPF 5-2011-5001S. Because low temperature operation and restart is a concern involving a single, long upset or a string of incidents, the scenario remains and should be listed as a concern, not as a deficiency, and be considered in the future of Alaska's North Slope oil and gas competitiveness.

Figure 5-2. 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.



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 5-3 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 DNR's website.[20] Figure 5-4 shows the 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).

Cook Inlet has 34 units or fields recognized by DNR. Of these, 32 have 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. Infrastructure 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 additional production from 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 service disruption.

During a period of concern for natural gas supply, a series of gas storage facilities were developed. Currently, the Cook Inlet Natural Gas Storage facility is in operation as well as other storage pools associated with different fields. Gas storage remains available to accommodate excess gas produced with increased drilling of new wells and the re-working of older wells throughout Cook Inlet's gas producing units and fields.

Frontier basins and exploration license areas

Surface access and infrastructure remain a hurdle in exploring for oil and gas resources in frontier basins, defined here as areas away from population centers and existing oil and gas production facilities. Exploration license areas (Figure 5-5) 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 (finding) for the exploration to be in the best interest of the state. A best interest 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 5-6) were established by the State of Alaska for exploration tax credits, in-part because of their lack of necessary infrastructure to efficiently access exploration prospects. However, unlike exploration licenses which apply only to state lands, frontier basins may include federal, state and private lands. The regulation of access and infrastructure may involve multiple regulatory agencies and is determined by the surface owner and the standards by which surface access and infrastructure is managed.

[20] http://dog.dnr.alaska.gov/GIS/Cookinletpipelines.htm

Figure 5-3. Oil and gas infrastructure in the Cook Inlet basin showing pads, platforms, and oil and gas pipelines.

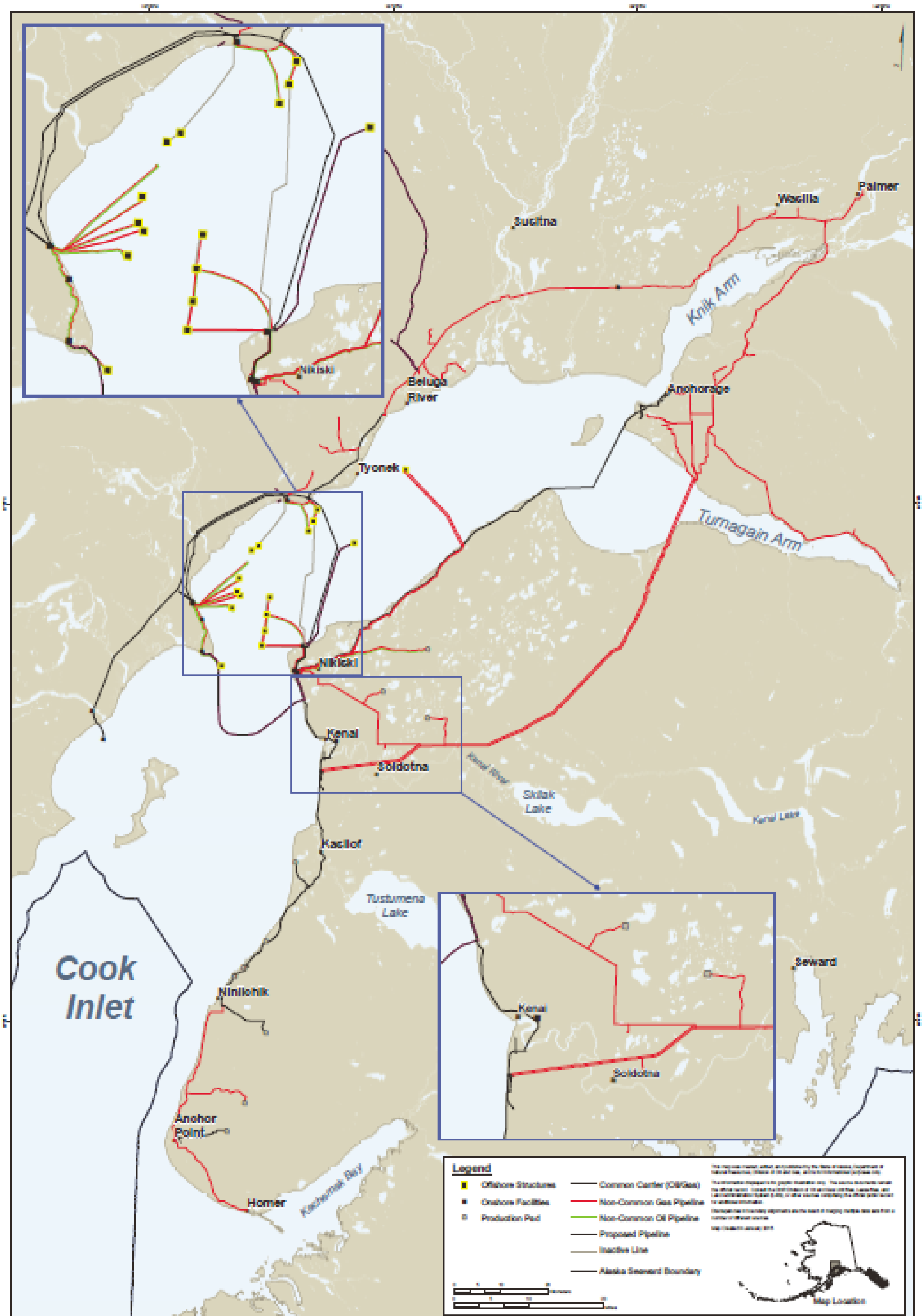


Figure 5-4. Cook Inlet and southcentral Alaska common carrier pipeline tariffs as approved by FERC and RCA.

Pipeline Name	Product	Units	2006	2007	2008	2009	2010	2011	2012	2013	2014
Alaska Pipeline Tariff (Enstar) Value	Dry Gas	$/mcf	$0.99	$1.16	$1.22	$1.16	$1.23	$1.06	$1.24	$0.69	$0.75
Beluga Pipeline Tariff Value	Dry Gas	$/mcf	$0.38	$0.05	$0.03	$0.22	$0.23	$0.21	$0.24	$0.25	$0.25
Cook Inlet Gas Gathering System Tariff Value	Dry Gas	$/mcf	$0.15	$0.15	$0.16	$0.28	$0.25	$0.24	$0.14	$0.23	$0.24
Cook Inlet Pipeline Tariff Value	Oil & Condensate	$/bbl	$4.69	$2.25	$3.16	$4.05	$13.40	$7.07	$6.48	$4.07	$3.15
Kenai Kachemak Pipeline Tariff Zone 1 - Main Line Value	Dry Gas	$/mcf	$0.30	$0.35	$0.26	$0.29	$0.27	$0.25	$0.25	$0.35	$0.29
Kenai Kachemak Pipeline Tariff Zone 2 - Happy Valley Spur Value	Dry Gas	$/mcf	$0.65	$0.85	$1.45	$1.93	$1.19	$0.98	$0.55	$0.23	$0.12
Kenai Kachemak Pipeline Tariff Zone 3 - Kasilof Spur Value	Dry Gas	$/mcf	$0.62	$1.19	$1.18	$1.19	$1.09	$1.19	$1.18	$4.75	$5.46
Kenai Nikiski Pipeline Tariff Value	Dry Gas	$/mcf	$0.05	$0.04	$0.04	$0.08	$0.10	$0.16	$0.08	$0.07	$0.07
North Fork Pipeline Tariff	Dry Gas	$/mcf						$1.95	$1.95	$1.95	$1.95
West McArthur River Pipeline Tariff Value	Oil	$/bbl	$1.11	$1.23	$1.23	$1.23	$1.51	$1.49	$1.48	$2.12	$1.91

Source: http://dog.dnr.alaska.gov/Commercial/PipelineTariffs.htm#cinlet.

Figure 5-5. Alaska's exploration areawide lease sales, existing exploration licenses and areas available for exploration licensing.

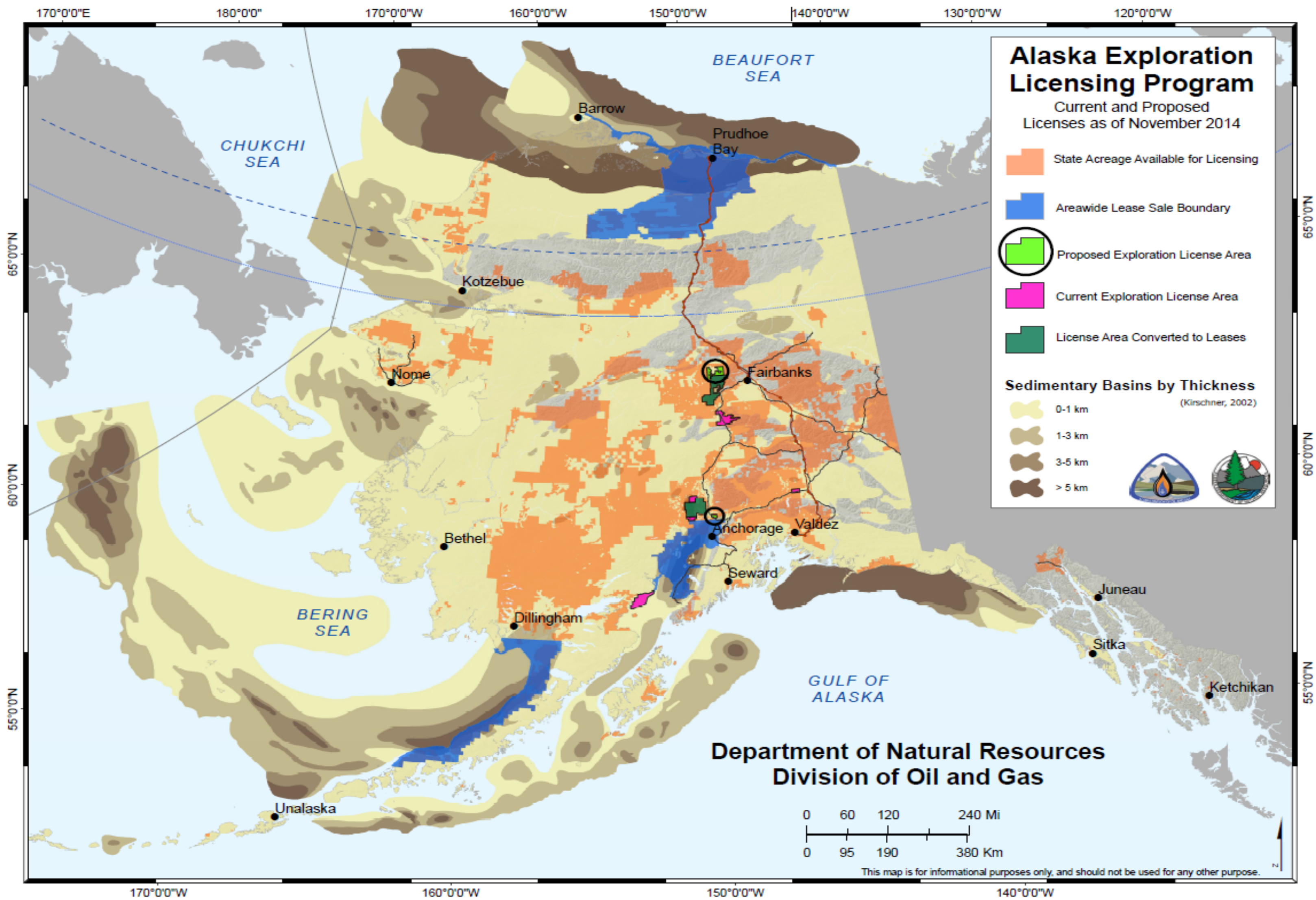
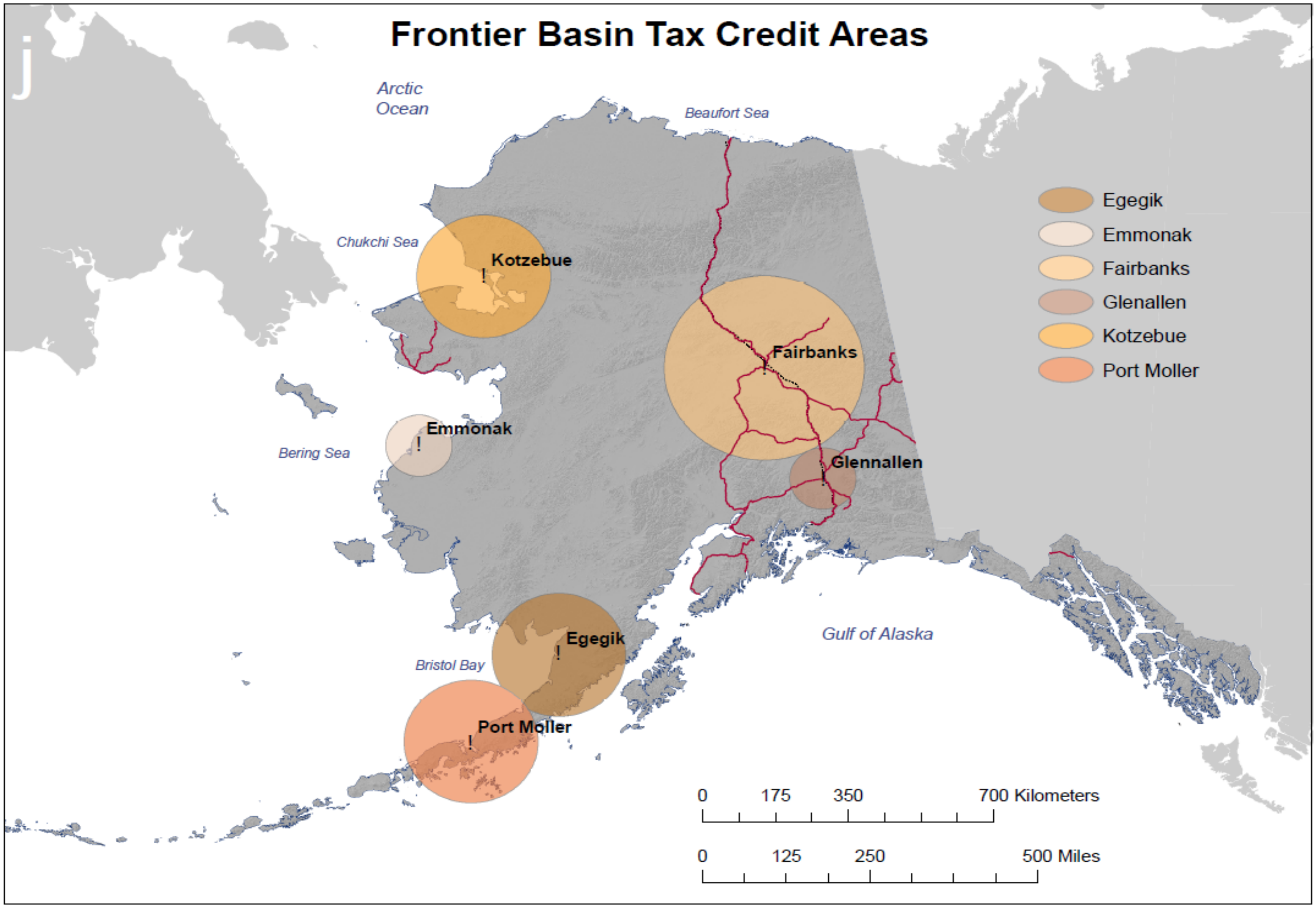


Figure 5-6. Areas in Alaska that may qualify for frontier basin tax credits.



6. Status of labor and employment in Alaska

Over the past decade the oil and gas workforce has grown from 8,000 to 15,000 employees. Total wages earned from oil and gas also rose from about $800 million to approximately $1.9 billion over this same period. Direct industry jobs are projected to increase to about 20,000 over the next five years. There are another estimated 30,000 direct and indirect jobs connected to Alaska’s oil and gas industry activities. This combined workforce of direct and indirect jobs in the state of Alaska is approximately 45,000 workers, earning over $2.65 billion. Oil and gas industry jobs have historically been the highest paying jobs in Alaska, with the average annual income for an oil and gas industry worker at $127,148.

Oil and gas industry firms rely heavily on support contractors involved in transportation, civil engineering, power, industrial service and supply, pipeline construction, and asset maintenance. An estimated 50 – 70percent of the occupational skill sets required for oil and gas industry jobs are the same skills found in the construction and mining industry occupations.

The number of oil and gas industry jobs is at an all-time high for Alaska and for jobs located on Alaska’s North Slope. As the number of oil and gas jobs have grown over the past decade, so too has the number of non-resident workers hired to fill the jobs. Today, more than half of the new industry jobs on Alaska’s North Slope are filled by non-residents. The increase of North Slope jobs over the past decade has occurred during a national economic recession and a significant downturn in oil and gas industry jobs in other states. Dislocated workers, who possess the skill sets necessary for oil and gas industry jobs and specifically for the North Slope jobs, have helped fill the growing demand for qualified workers in Alaska.

Technology and electronic communications have allowed employment information and hiring processes to take place through the internet, which have allowed non-resident workers with appropriate skills and experience to learn about and apply for the same jobs as Alaska residents with the same qualifications, often without resident considerations. There are exceptions where project developers and employers have made residency a consideration and put forth the extra effort to hire Alaskans.

The development of Point Thompson

Over a three-year period ExxonMobil has invested more than $2 billion in the development of Point Thompson. During the 2014 work season approximately 1,200 Alaskans were employed on this project. At 50 percent “Alaskan hire,” this project was far above other projects on the North Slope for use of in-state labor resources. This project helps to illustrate what can be done to increase resident-hire in the oil and gas industry and on the North Slope, in particular.

Workforce development efforts in Alaska

Pipeline construction training plays a critical role in developing a workforce that is ready, safe and has the correct skill set needed for Alaska’s oil and gas industry jobs. For decades the Alaska Department of Labor and Workforce Development (ADOLWD) and Alaska’s pipeline trade unions and their associated apprenticeship programs have delivered training to fill the workforce needs in construction of oil and gas pipelines. Apprenticeship programs provide training for specific skills required for the construction of pipelines and associated jobs in the oil and gas industry. There is a 52 acre training site located in Fairbanks, where workers are trained in practical, hands-on methods of pipeline construction. The Fairbanks Pipeline Training Center is operated by a training trust composed of industry employers and trade unions involved in oil and gas work, which offer specialized training to develop the Alaska's workforce for this important industry. The success of this training is in their comprehensive approach to industry training and developing career awareness, partnering with others to provide pathways into the workforce. These include basic skills training through the ADOLWD Fairbanks Construction Academy, trade apprenticeship programs and working with the school districts to inform Alaska's youth.

Alaska's trade apprenticeship programs have helped to provide new workers to fill the high needs of job growth in the construction, mining and oil and gas industries. These programs are critical to meet industry needs as the skilled workers are aging out. There are more than 2000 apprentices being trained in Alaska to meet the workforce needs for these industries. Apprenticeship programs serve the entire state with training centers located in Fairbanks, Palmer, Anchorage, Chugiak and Juneau.

As a result, the 2014 ADOLWD Alaska Workforce Investment Board adopted the Alaska Oil and Gas Industry Workforce Development Plan 2014 – 2018. School administrators, teachers, guidance counselors and students are focusing on career pathways into the oil and gas industry. These efforts are helping to connect post-secondary degree choices with actual industry needs in Alaska. It is also helping students identify pathways to work through obtaining occupational certificates and gaining of the technical knowledge required by industry jobs. High school graduates are also finding a pathway to high paying jobs through apprenticeship programs, which give them the training to become highly skilled and qualified for the jobs available.

The workforce that underpins Alaska's oil and gas industry needs requires that adequate training opportunities exist and that knowledge of the skills needed are available to those helping guide workforce development. To fill the high demand, high paying jobs found in the oil and gas industry, Alaska must provide avenues of workforce development to meet these demands. This will put Alaska residents to work in these jobs and provide industry confidence that Alaska can substantially help meet future labor demands.

7. Regulatory environment and permitting structure

In Alaska various government agencies have a broad spectrum of authority to prohibit, regulate, and condition activities related to oil and gas. The implementation of regulations varies depending on the land ownership, lease specifics, and agreements between the parties.

Many of the permitting and planning requirements in place in Alaska focus on minimizing the impact of oil and gas development on the environment, specifically concerning water and air quality, habitat, fish, and wildlife, and the placement and preparedness for the storage and spillage of fuel and other hazardous substances. Multiple agencies administer and manage specific permits required to conduct necessary activities such as installing a culvert, building an ice road, and operating a drill rig. These agencies may be engaged at several different levels and throughout the life of a project. They also may require ongoing monitoring and reporting by the permitee, as well as on-site inspections conducted by agency staff. Additional regulations focus on potential impacts to the regional population and economy, subsistence and sport harvest activities, and access to the project areas. Regulations also routinely encourage local and Alaskan hire.

The implementation of these regulations affects the planning and construction of facilities, and the implementation of proposed operations. Multiple agencies may have regulatory authority when operations require permission from additional land owners for access, compensation for land owners, determination that an operator has informed the local population of their plans and received and replied to feedback provided, and the communication of local concerns and issues back to permitting agencies has occurred during plan implementation. Again, which agencies are involved is mostly dependent on the ownership of the lease upon which the activities occur and that of the surrounding land.

Federal

Onshore

The BLM issues permits for geophysical exploration and operation permits to drill oil and gas wells, and authorizations to construct pads and install production facilities on onshore federal leases in Alaska in the NPR-A and Cook Inlet. For the NPR-A the BLM implements 43 Code of Federal Regulations and in the Cook Inlet they implement regulations under the authority of the Mineral Leasing Act of 1920 (MLA). For more information on onshore federal lease regulations please see the BLM webpage.[21]

Offshore

The leasing and operations activities on the OCS are subject to the requirements of some 30 federal laws administered by numerous departments and agencies. In addition to the OCS Lands Act, other laws may apply to OCS exploration, development, and production. For a more detailed explanation of BOEM OCS lease regulations see the BOEM Leasing 101 instructions.[22]

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[21] BLM onshore federal lease regulations http://www.blm.gov/ak/st/en/prog/energy/oil_gas/oil_gas_regs.html.

[22] BOEM Leasing 101 http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/5BOEMRE_Leasing101.pdf

University, Mental Health Trust, Native corporation, and private lands

Depending on the nature and timing of the oil and gas development and ownership of surrounding lands, a variety of state, federal and local regulations, policies, and programs may apply to private leases. Literature specific to each of these private land lease types may provide additional information regarding regulatory programs specific to these private lands.

State of Alaska land management

The majority of past and current oil and gas production in Alaska comes from state leases managed by the DNR. Three agencies within the DNR play specific regulatory roles in the exploration, development, and transportation of oil and gas resources: (1) the Division of Oil and Gas (DOG), (2) the DMLW, and (3) the State Pipeline Coordinator's Office (SPCO). The remainder of this section will focus on oil and gas development on state managed lands.

Division of Oil and Gas

The DOG focuses on state subsurface activities and surface activities required to develop those subsurface resources. The regulatory emphasis is on overall project planning approvals and contract requirements identified in the lease terms. Specifically, individual permits for necessary activities are administered by those agencies that hold the knowledge and expertise to regulate potential environmental impacts, including monitoring and mitigations, and in addition those who also regulate the hydrocarbon resource for conservation, among others.

In addition to existing laws and regulations applicable to oil and gas activities, the DOG'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. In addition, leases are subject to all future laws and regulations that go into effect after the effective date of the lease to the full extent constitutionally permissible.

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.

A comprehensive and detailed summary of governmental (state and federal) powers to regulate DOG oil and gas leases can be found in each best interest finding (BIF), available online.[23]

Plans of operations

An oil and gas lease issued by DOG grants the lessee exclusive rights to drill for, extract, remove, clean, process, and dispose of (sell) oil, gas, and associated substances. The lease and regulations require a plan of operations (for a lease, for 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. Prior to approval, plans of operation applications are required to be made available for a public review and comment period lasting no less than 30 consecutive days.

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[23] Alaska Division of Oil and Gas Best Interest Findings
http://dog.dnr.alaska.gov/Leasing/BestInterestFindings.htm

Plans of operations include descriptions of how the applicant will meet a series of mitigation measures laid out in the BIF 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 management; 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 and project specific stipulations may also be imposed in the approval of a plan of operations.

Subsequent deviations in activities proposed by a lessee that fall outside of an approved plan require the submission to and approval by the DOG of an amendment to the plan. Submission to the DOG of an update on the status and completion of plan components is also required every November 1 and May 1, following plan approval and continuing throughout the life of the plan. Status and completion information is also used to guide the DOG during field inspections to ensure that operations are conducted in conformance with the terms and conditions contained in the plan approval. The status and completion submissions are also used to facilitate the DOG's continuing review of past, current, and planned future surface activities statewide, especially when considering the approval of new proximal plans of operations, associated amendments, and other activities.

Geophysical exploration permit

A geophysical exploration permit may be issued by the DOG. 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

The DOG has recently undertaken a comprehensive, active, and critical approach to upgrading the state oil and gas regulatory environment and permitting structure conducive to encouraging increased investment while protecting the interests of the people of the state and the environment.

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 review and for comment on plan components in a consistent meaningful manner.

At this time the proposed new plan of operations and geophysical exploration permit application 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 associated map products required in the application process, the associated amendment request submission and approval forms, 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 on an annual basis by DOG as a summary of current and ongoing surface activities on oil and gas leases and is available as a component of the DOG's annual report.

Division of Mining, Land and Water

Over the years, exploration operations on the North Slope have changed to reduced overall environmental impacts. In its infancy, gravel roads and pads were constructed to reach areas targeted for exploratory drilling. Often these roads and pads were constructed without proper drainage resulting in excessive ponding and/or drying of the tundra adjacent to the gravel structures. Additionally, dry holes and uneconomic wells resulted in a number of abandoned roads and pads, many of which remain unused to this day. Ice road and pad construction developed out of a need to reduce environmental damage and recognition of the uncertainty in exploration drilling. This approach was supported by industry and was adopted as a mitigation measure in all North Slope lease sales. The Mitigation Measure (5(a)) lease term states the following:

> *"Except for approved off-road travel, exploration activities must be supported only by ice roads, winter trails, existing road systems or air service. Wintertime off-road travel across tundra and wetlands may be approved in areas where snow and frost depths are sufficient to protect the ground surface. Summertime off-road travel across tundra and wetlands may be authorized subject to time periods and vehicle types approved by DMLW…"*

Ice road and off-road travel permits

The NRO has the primary responsibility for issuing ice road and off-road travel permits for North Slope oil and gas activities. Permits are generally issued for five year increments and are typically issued for a broad area (i.e. state land between the Canning and Colville rivers). Permits contain stipulations intended to prevent damage to the tundra vegetation. They also require that if any damage to the tundra does occur, the damaged area must be rehabilitated to the satisfaction of the DMLW. Ice roads and off-road travel activities are requested, evaluated, and approved on an individual basis throughout the season. This allows the individual travel requests to be effectively evaluated with the current snow and soil temperature conditions and other activities occurring in the area.

Ice road construction and off-road travel is regulated by seasonal environmental conditions that are monitored by the NRO. Tundra opening areas and monitoring stations within those areas have been established throughout the North Slope and are visited on a weekly basis prior to a station meeting opening criteria. The tundra is opened to winter off-road travel when the soil temperatures reach -5˚C at a depth of twelve inches (30 cm) and when there is sufficient snow on the ground to protect tundra vegetation. The snow standards differ for the coastal plain and the foothills areas; the coastal areas require a minimum of 6 inches of snow and the foothills areas requires a minimum of 9 inches of snow. The date of tundra opening has ranged from as early as November 4 to as late as February 20. There have even been some years where lack of snow or warm soil temperatures resulted in no tundra opening for a given area. Once the tundra has been opened in the winter, there are no restrictions on the type of vehicles that may operate on the tundra provided that vehicle operation does not negatively impact the tundra. In years of limited snowfall, the tundra may be opened conditionally, with the condition that vehicles must be restricted to areas where snow is deep enough to prevent damage to the tundra vegetation.

The tundra is closed when it appears as if thawing conditions have resulted in snow that will be too soft or too limited to permit travel without resulting in damage to the tundra. Operators are then given 72 hours to move their vehicles and other equipment onto the gravel road system.

The general winter off-road travel season has declined over the years. In 2003, the NRO conducted studies to determine the best methods for opening the tundra and allowing earlier winter access in response to the shortening seasons. These studies resulted in best practices for early winter season tundra access and established the monitoring system that is presently used by the DMLW. Innovations in ice road construction techniques and low impact vehicles have continued to stem the season's decline.

The NRO may approve site specific tundra opening and conventional ice road construction when specialized methods and equipment are employed early in the winter season. Pre-packing snow using summer-approved and/or low impact vehicles has two positive results with regards to reaching tundra opening criteria. First, packing snow decreases the insulation value of the snow and allows the underlying tundra soils to decrease in temperature faster than non-snow packed tundra soils. Secondly, the packed snow trail effectively captures snow during wind and blizzard conditions effectively increasing the snow depth within the trail. Pre-packing allows operators to begin work earlier in the winter season and, coupled with temperature sensors installed within ice or snow road routes, individual ice and snow roads often reach opening standards before general winter tundra travel is opened.

Summer tundra travel is limited to vehicles that have been approved for use by the NRO. Each vehicle must pass a test to verify that it can operate on the tundra during the summer without causing damage to the tundra vegetation. Vehicles are approved in the configuration tested; for example, a vehicle tested with a payload of 1000 pounds would be limited to that payload when operating in the field. A vehicle tested and approved with smooth tracks would require retesting if the vehicle is to be operated with wheels or cleats.

Leases and easements

The DMLW administers land leases within the North Slope oil fields. These leases are primarily occupied by oil and gas support companies including construction, well work, camp operations, and spill response. In some instances, leases are issued to oil production companies for operations that may not be authorized under DOG lease operations approvals. Leases may be located throughout the oil fields, but primarily reside in the state surveyed area of Deadhorse. Tideland leases at primary dock facilities are also managed by the DMLW. These include West Dock and Oliktok.

Easements for fiber optic cables, cell towers, roads, and electrical transmission may be authorized by the DMLW on state land. These easements often support the oil and gas service industry and the general worker population.

Temporary water use authorizations

The DMLW Water Section is tasked with issuing temporary water use authorizations for water extraction. Water is a major component of oil and gas operations for camp operations, reservoir water flooding, and ice road construction.

Other miscellaneous land use permits

The DMLW may issue a wide range of permits for other temporary activities throughout the North Slope. These include barge landings, remediation and rehabilitation projects, research, geotechnical drilling, material site exploration, and storage.

Competitiveness

Outside and within Alaska there are areas of significant size where individuals own the surface and/or mineral estate and all of the financial, environmental, and additional requirements for exploration, development and production are often private confidential agreements between the surface and/or mineral estate owner and the lessee or operator. Additionally, 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 consisting mostly of private lease agreements, 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 BIFs, which define the regulatory concerns of the State of Alaska, and provides potential operators with the issues and components of operations requiring mitigation. An applicant must 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 issuance.

The BIFs 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 operator's plan. This transparent process engages the public to ensure that plan approval balances the needs of Alaskans with those of applicants.

This transparent, public, well-established, and often repeated process provides a clear, consistent and predictable regulatory environment competitive with and maybe more advantageous than exclusive, confidential, and one-time agreements with private individuals. This process 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 oil and gas resources.

Water quality management

The Alaska Department of Environmental Conservation (DEC)[24] Water Division regulates water quality through water quality and wastewater standards found in the Alaska Administrative Code at 18 AAC 70 and 18 AAC 72. These regulations provide specificity for the State of Alaska's implementation of the federal Clean Water Act. The state's water and wastewater regulations are based on the general prohibition principle, such that no person may cause or contribute to a violation of the water quality standards in waters in the state, and discharges to waters in the state must be authorized by an Alaska Pollutant Discharge Elimination System (APDES) permit. These water quality standards apply to both marine and fresh waters and protect water quality for a wide variety of uses, including growth and propagation of aquatic life, which includes marine mammals and their prey.

For waters that are of naturally high quality, the water quality standards include an anti-degradation provision that prohibits any degradation of water quality unless certain conditions are met and uses of the water are protected. The Division's Non-Point Source Water Pollution Control Program regulates storm water pollution of water bodies through review and approval of construction plans and storm water pollution prevention plans from industrial sites.

Industrial wastewater discharges - oil and gas wastewater discharges

Discharges from oil and gas facilities can be categorized generally as onshore and offshore. Offshore typically includes production platforms, exploration jack-up rigs, and geotechnical surveys using water based drilling fluids. Onshore includes well pads, processing facilities, refineries, terminals, and large pipelines including horizontal direction drilling under or into water bodies. Offshore discharges include drilling fluids and drill cuttings, produced water, water flood, domestic wastewater, graywater, desalination, non-contact cooling water, deck drainage and other miscellaneous discharges that are similar to vessels. Onshore discharges do not have discharges of drilling fluids and drill cuttings or produced water as these wastes are commonly disposed into underground injection control wells. Common onshore discharges includes domestic wastewater, excavation dewatering, hydrostatic test water, secondary containment water, and horizontal direction drilling when drilling fluids are used that are, or can be, discharged to a surface water.

Water quality monitoring and assessment

The DMLW Water Division Alaska Monitoring and Assessment program (AKMAP) conducts annual surveys that report on the status of Alaska's water resources with a calculated statistical

[24] The DEC's responsibilities include the permitting and authorization of certain actions relating to oil and gas exploration and production. The main areas DEC regulates include: oil spill prevention and response, pollutant discharges, waste disposal, and air emissions

confidence. This provides resource managers, elected officials, and the public an understanding of the "big picture" of Alaska's water resources. No similar probabilistic sampling surveys are currently providing regional, ecological information on such a large scale within Alaska. The DEC Environmental Monitoring and Assessment Program (EMAP) implementation strategy is DEC's plan to sample and report monitoring data for large regions of Alaska in the near future. The AKMAP has sampled coastal and fresh waters since 2002. The first wetland monitoring occurred in 2011 on the Arctic Coastal Plain.

Air quality management

Oil Exploration and production typically utilize several air permits. The DEC Air Quality Division regulates air quality for the State of Alaska through the air quality standards found in the Alaska Administrative Code at 18 AAC 50 and the vehicle emission standards at 18 AAC 52. The State of Alaska has primary authority for implementation of the federal Clean Air Act on state lands and federal lands.

Minor permits (Alaska Air Quality Minor Permit) are required to change existing air quality permit requirements. The permits ensure smaller new and increased sources of pollution comply with emission standards and do not cause a violation of ambient air quality standards. Minor permits also are the administrative vehicle for a variety of housekeeping tasks related to permits.

New and modified stationary emission units categorized in regulation by the type of source and by its potential emissions require a minor permit. Any new or modified source of air pollutant emissions should be reviewed against the regulatory thresholds. Typical emission units requiring permits include incinerators, coal preparation plants, boilers, stationary engines, or turbines.

Minor permit actions are also used extensively to change the conditions of existing permits, such as to remove an emission unit which has been decommissioned, or to establish limits on new equipment which avoids classification under a more rigorous permit. For example, a unit used intermittently may require a major source permit based on its potential emissions, but those potential emissions can be reduced by legally limiting the operation of the unit through a minor permit.

These permits are often necessary before beginning construction or modification of an air pollution source categorized in regulation. Applicants must provide descriptive information about the emission units and a demonstration that emissions will not interfere with attainment and maintenance of Ambient Air Quality Standards. The application process typically takes four to six months from initial application, including any re-work by the applicant to address incomplete applications and incorrect modeling. There is a minimum 30 day public comment period. Permits are required to be issued or denied within 30 days of the close of the comment period.

These permits can be derailed by incomplete permit applications, lack of representative meteorological data for use in modeling[25], modeling that does not meet the guideline on air quality modeling, controversial projects that draw extensive public comment, or disputes with applicants or their consultants over required limits. To minimize these delays, up front discussions with air permit program staff typically results in the development and review/approval of a modeling protocol which, if followed, ensures acceptable modeling analyses.

A "New Source Review/Prevention of Significant Deterioration (NSR/PSD) construction permit may be required to ensure large new and increased sources of pollution comply with emission

[25]Modeling is required for a complete permit application. Five years of national weather service data or a minimum of one year of site specific representative meteorological data is needed in order to perform refined modeling. The intent is to ensure the worst met conditions for pollutant dispersion is modeled. It is possible to do screening modeling without using actual meteorological data, but that modeling is very conservative. Most applicants will need to do refined modeling to demonstrate compliance with the ambient standards.

standards, do not violate the ambient air quality standards , and do not cause a deterioration of air quality in the area or interfere with improving air quality in a non-attainment area.

What activities require an NSR and/or PSD permit? A new major PSD or NSR source, or a major modification to an existing major PSD or NSR source. A major PSD source has the potential to emit 250 tons per year (TPY) of a regulated pollutant; a major NSR source has the potential to emit 100 TPY of the nonattainment pollutant or any precursor.

A major modification is a physical or operational change that causes a net emission increase greater than a threshold set in regulation. For example, adding a new coal boiler to a central heat and power plant would likely be a major modification; however, simultaneously retiring an existing boiler would reduce the net emission increase and could avoid major modification permitting for the new boiler. A minor permit would be required to document the changes.

A source may be NSR major for a nonattainment pollutant and also PSD major for other pollutants. For example, a source in the Fairbanks nonattainment area could require a major NSR permit for PM2.5 as well as a PSD permit for other regulated air pollutants.

An NSR/PSD permit is required before beginning construction of a major new source or major modification to an existing major source. The application must contain descriptive information about the emission units; and for PSD: demonstrate that the source will apply the best available control technology , provide one continuous year of pollutant monitoring data for the area where the source will be built or modified representative of the year preceding receipt of the application, provide modeling to show the maximum ambient[26] concentration of pollutants expected from the source consistent with the averaging times for the ambient standard of that pollutant using a minimum of one year of meteorological data and demonstrate that growth associated with the project will not impair visibility, soils, and vegetation of the area.

The Clean Air Act "Title V Operating Permit" compiles all currently applicable Clean Air Act and air quality control requirements into a single enforceable document for a given source classified as requiring an operating permit. A permit for an area source that requires a permit only because it is subject to one or more federal standards will only include the applicable federal standard that triggers an operating permit.

A Title V operating permit is needed for any stationary source which has the potential to emit 100 TPY or more of a regulated air pollutant, or 10 TPY of an individual hazardous air pollutant, or 25 TPY of all hazardous air pollutants combined, or which contains an emission unit subject to a Federal New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (a.k.a. Maximum Achievable Control Technology standards).

Because potential to emit is calculated assuming all emission units operate at their maximum rate 24/7, some sources can establish a legal limit to reduce their potential to emit to avoid Title V permitting.

An application is due within 12 months after the source becomes classified as requiring an operating permit. Sources are categorized by the type of regulated activity and by being a major source of emissions. A permit applicant who submits a timely and complete application may operate and continue to operate under that application until the department issues a final permit.

The application process typically takes 12-24 months. There is a minimum 30 day public comment period and a 45-day EPA draft permit review process. Permits are required to be issued or denied within 30 days of the close of the EPA review period.

[26]Ambient air means any location to which the general public has access. In a military context, ambient air can be on base where spouses or children, or other members of the general public (not soldiers or employees) have access.

The main issues that delay permits include disputes with the client or EPA over applicable requirements and monitoring, controversial projects that draw extensive public comment, non-compliance with pending enforcement, new or modified emissions standards promulgated during the review process, and client delays in supplementing applications.

Solid waste disposal

Under the general provisions of Subtitle D of the Resource Conservation and Recovery Act (RCRA), the DEC Division of Environmental Health, Solid Waste Program (SWP) has an approved program for regulation of solid waste disposal in Alaska. The state's solid waste management regulations, based on the federal standards in 40 C.F.R 257 and 40 C.F.R 258, are found in the Alaska Administrative Code at 18 AAC 60. These regulations make a general distinction between municipal and non-municipal disposal facilities and include requirements for the design, operation, closure, and monitoring of those facilities to minimize harm to human health and the environment.

The SWP permits and regulates both municipal and non-municipal disposal facilities in the arctic region of Alaska. Non-municipal facilities are associated with the oil and gas industry and the mining industry. Municipal facilities are found in every community, and at present, every disposal facility on the North Slope and adjacent areas is either permitted or authorized under a plan approval.

Oil and gas solid waste facilities

The SWP regulates oil and gas drilling waste management facilities throughout the State. Drilling waste is generated by oil and gas exploration and production activities. Drilling waste, which consists of drilling mud, cuttings, pigging waste, fluids, and other related wastes, is a solid waste that is excluded from regulation as a hazardous waste through 40 C.F.R 261.4(b)(5). However, drilling waste may include contaminants that pose a significant public health and environmental risk, and as such, drilling waste storage, treatment, and disposal facilities must be designed and operated to minimize the potential for contaminant release. The SWP requires surface water monitoring at permanent oil and gas solid waste facilities and inspects these facilities annually.

Drilling waste is primarily disposed of by underground injection although management can involve surface storage of solid waste prior to injection. The SWP authorizes drilling waste management through several mechanisms, including individual solid waste permits, solid waste general permits, solid waste treatment permits, and temporary storage plan approvals.

Municipal solid waste facilities

Municipal solid waste landfills are subdivided into three classifications based on the average tonnage of waste received each day. The three classifications include:

Class I (greater than 20 tons per day)
The lone Class I landfill on the North Slope is the Oxbow Landfill at Prudhoe Bay. This landfill is designed as a freeze-back landfill, which means that the overall intent is for the disposed wastes to become permanently frozen. The progress towards achieving freeze-back is monitored by periodically measuring the temperature below, within, and around the waste pile.

Class II (5 to 20 tons per day)
The only Class II landfill on the North Slope is located in Barrow. This landfill was opened in July 2007 and is located approximately six miles inland from the coast. Because this landfill is operated in conjunction with a thermal oxidation system incinerator, it receives only incinerator ash and inert wastes. A second landfill in Barrow is in the process of being permanently closed.

Class III (less than 5 tons per day)

There are seven Class III landfills on the North Slope located in the following communities: Atqasuk, Kaktovik, Nuiqsut, Point Lay, and Wainwright.

The specific requirements for design, operation, monitoring, and closure of the landfill vary with the classification: the larger the landfill, the more stringent the requirements. Class I and Class II landfills are inspected at least once per year; permitted Class III landfills are inspected at least once every five years.

Oil spill prevention and response

The DEC Division of Spill Prevention and Response (SPAR) is responsible for protecting Alaska's land, waters and air from oil and hazardous substances spills. SPAR regulates spill prevention through review and approval of spill prevention plans for oil terminals, pipelines, tank vessels, barges, refineries, oil exploration facilities and oil production facilities. SPAR ensures response preparedness through the review and approval of oil discharge contingency plans, inspections, spill response exercises, and drills. Spill contingency plans are required under Alaska Statute AS 46.04.030 and Alaska Administrative Code regulations at 18 AAC 75. They document a facility-wide spill prevention program that ensures personnel, equipment and financial resources are available for the company to adequately respond to spills.

The State of Alaska requires oil spill contingency plans for the following facilities:

- Oil and gas exploration facilities (onshore and off)
- Crude oil transmission pipelines
- Flow lines and gathering lines
- Non-crude oil terminals (over 10,000 barrels)

Contingency plans are valid for five years. During that time major and minor amendments are possible. Major amendments require a public process for review of the changes whereas minor changes do not.

In addition to documenting response capacity, companies are also required to provide proof of financial responsibility as required under Alaska Statute AS 46.04.030. Companies are required to show they have the financial capacity to clean up a spill if it occurs and restore the environment.

Contaminated sites

The DEC Contaminated Sites Program oversees or conducts cleanup of contaminated sites based on their danger to public health and the environment. The contaminated sites cleanup process is governed by Alaska Statutes at Title 46 and Alaska Administrative Code regulations at 18 AAC 75 and 18 AAC 78. Previous exploration and production practices (before environmental permits existed) resulted in several contaminated sites in Alaska. Some exist where existing production is occurring. In cases where remediation is not possible due to active infrastructure, the sites are monitored to ensure contamination is not leaving the site with plans to remove the contamination when the production activity ceases.

8. Alaska’s oil and gas fiscal system

Elements of Alaska's fiscal system

Alaska’s fiscal system for oil and gas has four major components that generate State revenue:

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

Although there have been changes made to the various components over the years, each component has been part of the oil and gas fiscal system since the 1970s, when oil began flowing from the North Slope. In this section, we provide a brief summary and overview of the four major components of the fiscal systems. Note that while major elements of Alaska’s fiscal system apply in the same way to North Slope and non-North Slope areas of the state, this discussion is focused on the North Slope. Subsequent reports by the Board will focus on Cook Inlet and non-North Slope areas, where a number of different statutes and regulations apply.

Alaska’s fiscal system for oil and gas also has special incentives, generally in the form of tax credits to operators. The number of incentives that may decrease revenue to the State of Alaska, 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, and their significant impact on the total revenue picture for the state, the following discussion of the components of the fiscal system concludes 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 CIT. The federal CIT rate component for all U.S. state and federal fiscal regimes is assumed to be 35 percent. The interaction between the elements that the state controls (royalties, taxes and credits) and the very significant federal income tax diminishes any efforts by the State of Alaska to materially modify the overall fiscal system in favor of lessees or operators on Alaska lands.

Oil and gas that is produced onshore in the state of Alaska or offshore within state boundaries is subject to the four revenue-generating components of the Alaska’s fiscal system listed above. Together the four components typically provide almost 90 percent of the state’s general fund unrestricted revenue (GFUR), as shown in Figure 8-1.

Figure 8-2 shows a group of data series related to oil and gas production, taxes and credits, and how they relate to each other. Note that the values for the pie chart in Figure 8-1 may not match the values in the Figure 8-2 data table because the pie chart shows only unrestricted GRUR revenue, while the table includes both GFUR and restricted revenue components.

<u>Royalty, rents and bonuses</u>

In natural resource extraction, royalties generally represent that portion of the revenue from the sale of minerals that is apportioned to the lessor by a lessee who has leased and produced something of value from a property. 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 State of Alaska leases have royalty rates of 12.5 percent. This means that the State of Alaska receives approximately 12.5 percent 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.

In some oil and gas lease sales net profit share (NPS) terms were offered. The NPS term can either be in addition or an alternative to the state's royalty share of net production income. The NPS accounting allows the lessee to recover qualified development and operating costs before the lease enters "payout" and begins remitting a share of income (net profit) to the State of Alaska." In some cases, the NPS rate is greater than 30 percent.

Figure 8-1. Petroleum revenue components of the Alaska General Fund Unrestricted Revenue (GFUR), FY 2014

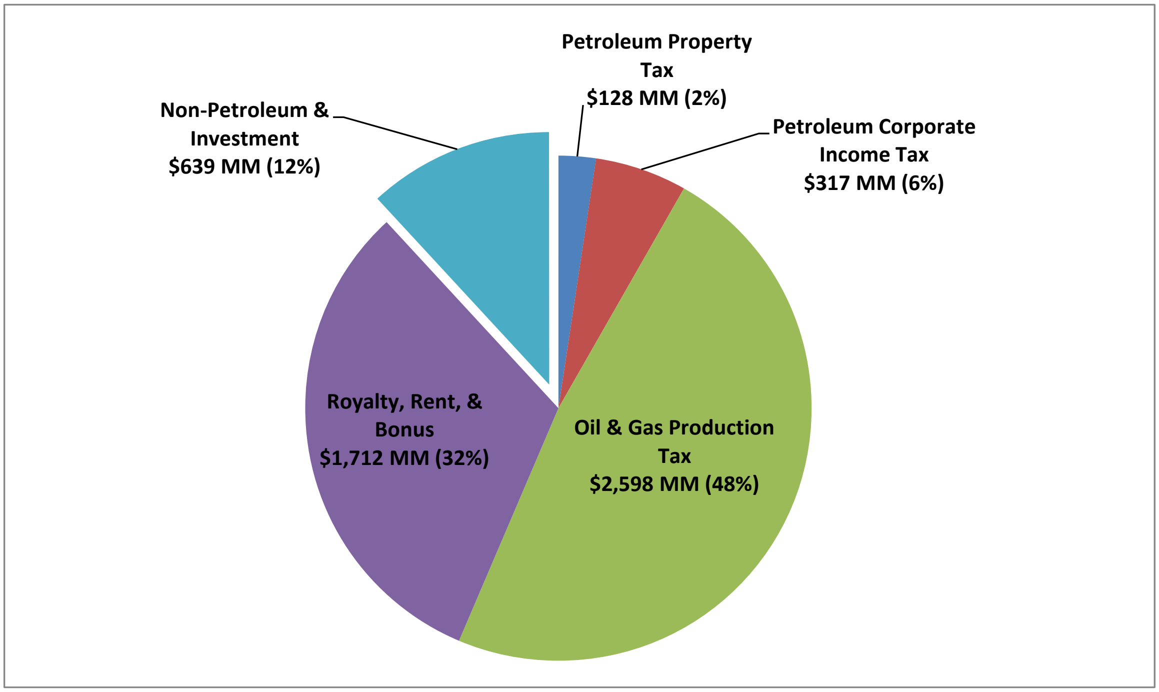

Figure 8-2. Alaska petroleum revenue-related data series, including gross production value, tax revenue streams and credits, FY 2011 through FY 2014.

Statewide Oil and Gas Revenue & Credits	FY 2011 $ MM	FY 2012 $ MM	FY 2013 $ MM	FY 2014 $ MM
Gross Production Value	19,918	23,027	19,787	NA
Royalty Revenue (not including bonus, rents, and interest)	1,821	2,023	1,748	1,685
Oil and Gas Property Tax Liability (total including municipal share)	477	490	530	548
Production Tax Before Credits	4,939	6,509	4,599	3,486
Production Tax Credits - Claimed Against Tax	386	363	549	888
Production Tax Liability After Credits (including Hazardous Release surcharge)	4,553	6,146	4,050	2,598
Credits Claimed as Cash Purchase	450	353	369	593
State Corporate Income Tax petroleum	542	569	435	317

The administration of most leases owned by the State of Alaska and the collection of associated royalties is a DNR responsibility.

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 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.

Oil and gas 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 oil and gas property tax is administered by DOR and is assessed annually. 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 oil and gas property tax is a relatively small component in Alaska's fiscal system, generating revenues of about $100 million per year in recent years. However, the tax is an important component of local governments that have oil and gas property. Up to $400 million per year is split among fewer than 10 local governments.

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

Corporate income tax

Alaska's CIT for oil and gas is administered by DOR and 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 operations' (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property. The CIT rate is progressively graduated to the top tax rate of 9.4 percent levied when net income exceeds $222,000 for the year.

Oil and gas CIT revenues have comprised about 10 percent 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 CIT. These will be discussed in detail in the "Tax Credits" section of this chapter.

Oil and gas production (severance) tax

Among the largest revenue generating components of Alaska's fiscal system for oil and gas is the production tax. The production tax is administered by DOR. The current production tax was passed by the legislature in 2013 as Senate Bill 21 (SB 21). Like the two preceding production tax system, SB 21 taxes the net profits of production, after most 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 current state production tax, SB 21, is less complex than its predecessor production tax system, Alaska Clear and Equitable Share (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 "legacy" 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 "legacy" 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[27]:

Production Tax Liability = [(Value – Costs) * Tax Rate] – Credits

Value

Value of production from existing "legacy" **fields**
= Volume of Non-Royalty Oil & Gas Produced * Wellhead Value
Value of new production
= Volume of Non-Royalty Oil & Gas Produced * Wellhead Value * 80 or 70 percent

Costs = Operating and Capital Expenditures
Tax Rate = 35 percent
Credits

Credits on production from existing "legacy" **fields**
= Value of $0 to $8 per taxable barrel of oil produced
Credits on new production
= Value of $5 per taxable barrel of oil produced

Minimum tax, production from existing "legacy" **fields**
= 0 - 4 percent of Value (depending on oil price) before Costs are subtracted less applicable credits

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 $2.5 million in 2005 to as high as $64.9 million[28] in 2014.

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. Greater than five years: $3 annually

Most State of Alaska lease contracts state that rental paid for a lease in advance, at the beginning of the year, can be claimed as a credit against royalty payments due under the lease

[27] It should be noted that this formula is a basic simplified example of the tax calculation. Numerous location, project, and company specific variations of the tax calculation occur.
[28] Based in-part on preliminary sale results. Final sale results will only be available after leases are issued.

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 are also an important element of Alaska's fiscal regime and have played a large role in the competitiveness of Alaska's fiscal system. Most of the tax credits in current law were implemented with the change to a production tax based 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, and oil production has increased significantly since 2010.

Credits applicable to the oil and gas production tax

There are currently three major categories of tax credits available against the Alaska production tax. AS 43.55.023 offers credits for certain capital 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 100,000 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. Below are more detailed descriptions of credits applicable to the oil and gas production tax in Alaska.

Alternative Credit for Exploration, AS 43.55.025(a)(1)-(4)

The Alternative Credit for Exploration is a transferable credit for expenditures for certain oil and gas exploration activities. Outside of Cook inlet, the credit is 40 percent for seismic costs outside an existing unit, 30 percent for drilling costs greater than 25 miles from an existing unit, 30 percent for pre-approved new targets greater than three miles from an existing well, and 40 percent for pre-approved new targets greater than three miles from a well and greater than 25 miles from an existing unit. The three-mile limit has been dropped for wells in "Frontier Basins," as described under the Frontier Basin Credit below. For Cook Inlet, the credit is 40 percent for seismic costs outside an existing unit, 30 percent of qualified drilling costs greater than 10 miles from an existing unit, 30 percent of costs for pre-approved new targets, and 40 percent of costs for drilling done greater than 10 miles from an existing unit and pre-approved new targets. The credit expires on July 1, 2016, for the North Slope and Cook Inlet; for areas other than the North Slope and Cook Inlet, the credit expires January 1, 2022.

Carried-Forward Annual Loss Credit, AS 43.55.023(b)

This credit is a transferable credit for a carried-forward annual loss, defined as a producer or explorer's adjusted lease expenditures that are not deductible in calculating production tax values for the calendar year. The credit is currently 25 percent of the carried-forward annual loss. Beginning January 1, 2014, the credit for carried-forward annual losses incurred on the North Slope increased to 45 percent of the loss, and certificates for these credits may be taken in a single year. On January 1, 2016, the credits for losses incurred on the North Slope decreases to 35 percent of the loss.

Cook Inlet Jack-Up Rig Credit, AS 43.55.025(a)(5)

This credit is for exploration expenses for the first three wells drilled by the first jack-up rig brought into Cook Inlet. It is only for expenses incurred in drilling wells that test pre-Tertiary strata; all three wells must be drilled by unaffiliated parties using the same rig. The credit is 100 percent of costs for the first well up to $25 million, 90 percent of costs for the second well up to

$22.5 million, and 80 percent of costs for the third well up to $20 million. If the exploration well is brought into production, the operator repays 50 percent of the credit over ten years following production start-up.

Education Credit

See “Credits Applicable to Multiple Tax Programs.”

Exploration Incentive Credit, AS 38.05.180(i)

The exploration incentive credit is a non-transferrable credit for the cost of drilling or seismic work performed under a limited time period established by the DNR Commissioner. Credit may be granted for up to 50 percent of the cost of drilling or seismic work, not to exceed 50 percent of the tax liability to which it is being applied. This credit may also be applied against the state royalty.

Frontier Basin Credit, AS 43.55.025(a)(6)-(7)

The Frontier Basin Credit is for expenses for the first four persons to drill exploration wells and the first four persons to conduct seismic projects within an area designated in AS 43.55.025(o) and (p), also called the “Frontier Basins.” The credit is for the lesser of 80 percent of qualified exploration drilling expenses or $25 million; or for seismic projects, the credit is for the lesser of 75 percent of qualified seismic exploration expenditures or $7.5 million. It includes expenditures incurred for work performed after June 1, 2012 and before July 1, 2016.

Per-Taxable-Barrel Credit, AS 43.55.024(j)

Beginning January 1, 2014, there is a per-taxable-barrel credit for oil production on the North Slope. This credit cannot be transferred, carried forward, or used to reduce the producer’s tax liability to less than zero. In areas that qualify for a gross value reduction (GVR), the credit is five dollar per taxable barrel. Those areas are defined in AS 43.55.160(f) and (g). For areas that do not qualify for a GVR, the credit is on a $10 increment sliding scale. The sliding scale credit is a dollar-per-taxable barrel credit ranging from zero dollars per barrel at gross value at point of production (GVPP) values greater than $150 to $8 per barrel at GVPP values less than $80 per-barrel. The sliding scale credit may not reduce the producers’ tax liability to less than the minimum tax established under AS 43.55.011(f).

Qualified Capital Expenditure and Well Lease Expenditure Credit, AS 43.55.023(a) and (1)

This credit is a transferable tax credit for qualified oil and gas capital expenditures in the State. It can be taken in lieu of exploration incentive credits under AS 43.55.025 and gas exploration credits under AS43.20.043. The credit is 20 percent of eligible expenditures anywhere in the State, or 40 percent for qualified well lease expenditures for areas other than the North Slope. The qualified capital expenditure credit was no longer available for North Slope capital expenditures beginning January 1, 2014.

Small Producer / New Area Development Credit, AS 43.55.024(a) and (c)

The Small Producer Credit is a non-transferable credit for oil and gas produced by small producers, defined as having average taxable oil and gas production of less than 100,000 BTU equivalent barrels per day. The credit is available until the later of 2016 or nine years after the first commercial production of oil and gas on the properties for which the credit applies. The small producer credit is capped at $12 million annually for producers with less than 50,000 BTU equivalent barrels per day. The credits then phases out, reaching to zero for producers with 100,000 or more BTU equivalent barrels per day. The credit may only be used against a tax liability, providing the producer has a positive tax liability before the application of credits. The New Area Development Credit is a credit of up to $6 million per company annually, for oil or gas produced from leases outside Cook Inlet and south of 68 degrees North latitude, providing the producer has a positive tax liability on that production before the application of credits. The credit is available until the later of 2016 or nine years after the first commercial production of oil and gas on the properties for which the credit applies.

Transitional Investment Expenditure Credit, AS 43.55.023(1)

The transitional investment expenditure credit is a non-transferable credit for qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006. It is only available to companies that did not have production in commercial quantities prior to January 1, 2008. The credit may not be used after December 31, 2013. The credit is 20 percent of qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10 percent of the capital expenditures incurred between March 31, 2006 and January 1, 2008.

Credits applicable to CIT

There are several credit programs targeted specifically at oil and gas CIT 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 Cook Inlet and non-North Slope natural gas reserves. This credit was extended and expanded in the 2010 legislative session. A second oil and gas CIT 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 CIT 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. Below are more detailed descriptions of credits applicable to CIT in Alaska.

Gas Exploration and Development Credit, AS 43.20.043

The Gas Exploration and Development Credit is a nontransferable credit for qualified expenditures for the exploration and development of non-North Slope natural gas reserves. The credit is 25 percent of qualified expenditures for investment after January 1, 2010; investments in existing units qualify. The credit is capped at 75 percent of tax liability as calculated before applying other credits.

Gas Storage Facility Credit, AS 43.20.046

The Gas Storage Facility Credit is a non-transferable credit for the costs incurred to establish a natural gas storage facility. The credit is $1.50 per thousand cubic feet of “working gas” storage capacity as determined by the Alaska Oil and Gas Conservation Commission. It does not apply to gas storage related to a gas sales pipeline on the North Slope. To qualify, the facility must operate as a public utility regulated by the Regulatory Commission of Alaska with open access for third parties. It is effective for facilities placed into service between January 1, 2011 and December 31, 2015. The maximum credit is the lesser of $15 million or 25 percent of costs incurred to establish the facility.

LNG Storage Facility Credit, AS 43.20.047

The LNG Storage Facility Credit is a non-transferable credit for the costs incurred to establish a storage facility for liquefied natural gas. The credit is the lesser of $15 million or 50 percent of the costs incurred to establish the facility. It applies to facilities with a minimum storage capacity of 25,000 gallons of LNG and are public utilities regulated by the Regulatory Commission of Alaska (RCA). It is for facilities placed into service after January 1, 2011.

Oil and Gas Industry Service Expenditures Credit, AS 43.20.049

The Oil and Gas Industry Service Expenditures Credit is a credit of 10 percent of qualified oil and gas industry service expenditures that are for in-state manufacture or in-state modification of oil and gas tangible personal property with a service life of three years or more. The credit may be applied to CIT liabilities in amounts up to $10 million per taxpayer per year. The credit is effective for expenditures incurred after January 1, 2014. The credit is not transferable but any amount of the credit that exceeds the taxpayer’s liability may be carried forward up to five years.

Internal Revenue Code Credits Adopted By Reference, AS 43.20.021

Under Alaska’s blanket adoption of the federal Internal Revenue Code, taxpayers can claim all federal incentive credits. Federal credits that refund other federal taxes are not allowed. Multistate taxpayers apportion their total federal incentive credits. In most cases the credit is limited to 18 percent of the amount of the credit determined for federal income tax purposes which is attributable to Alaska.

Education Credit

See "Credits Applicable to Multiple Tax Programs."

Minerals Exploration Incentive Credit

See "Credits Applicable to Multiple Tax Programs."

Veteran Employment Tax Credit, AS 43.20.048

The Veteran Employment Credit is a non-transferable credit for CIT payers that employ qualified veterans in the State. A "qualified veteran" is a veteran who was unemployed for more than four weeks preceding the employment date and who was discharged or released from military service not more than ten years before employment date (for a disabled veteran) or not more than two years before employment date (for a veteran who is not disabled). The credit is $3,000 for a disabled veteran or $2,000 for a veteran who is not disabled for employment for a minimum of 1,560 hours during 12 consecutive months following the veteran's employment date. For seasonal employment, the credit is $1.000 for a veteran employed for a minimum of 500 hours during three consecutive months following the employment date.

Credits applicable to multiple tax programs

Additional credit programs are less targeted and may be applicable under multiple tax programs including those benefiting oil and gas exploration and development in Alaska. Below are more detailed descriptions of these credits applicable to multiple tax programs in Alaska.

Education Credit, AS 21.96.070, AS 43.20.014, AS 43.55.019, AS 43.56.018, AS 43.65.018, AS 43.75.018, AS 43.77.045

The Education Credit is a nontransferable credit applicable to the state CIT. Fisheries Business Tax, Fishery Resource Landing Tax, Insurance Premiums Tax, Title Insurance Premiums Tax, Mining License Tax, Oil and Gas Production Tax, and the Oil and Gas Property Tax. It is a nontransferable credit for contributions to vocational educational programs, accredited Alaska universities or colleges for educational purposes or facilities, annual intercollegiate sports tournaments, Alaska Native educational programs, and facilities that qualify under the Coastal American Partnership. The credit is available for up to 50 percent of annual contributions up to $100,000, 100 percent of the next $200,000, and 50 percent of annual contributions beyond $300,000 up to $10 million. The credit for any one taxpayer cannot exceed $5 million annually across all eligible tax types. The credit at these rates is effective from January 1, 2011 until December 31, 2020, at which point the maximum credit for any taxpayer is $150,000 per year.

Film Production Credit, AS 43.98.030, under AS 21.09.210, AS 21.66.110, AS 43.20, AS 43.55, AS 43.56, AS 43.65, AS 43.75, AS 43.77

The Film Production Credit is a transferable credit for expenditures on eligible film production activities in Alaska. Effective July 1, 2013: (1) a producer must spend at least $75,000 in qualified expenditures over a consecutive 24-month period to qualify, (2) the credit is 30 percent of eligible film production expenditures, plus an additional 20 percent credit for wages paid to Alaska residents, plus an additional six percent credit for filming in a rural area, plus an additional 2 percent credit for filming between October 1 and March 30, (3) the credits must be used within six years, (4) the tax credit applies to multiple tax programs in addition to CIT. The program is capped at a $300 million maximum budget for all projects and expires on July 1, 2023.

Minerals Exploration Incentive Credit, AS 27.30.030, AS 43.20.044

The Minerals Exploration Incentive Credit is applicable to the CIT, Mining License Tax (MLT), and

Mineral Production Royalty. It is a non-transferable credit for eligible costs of mineral or coal exploration activities and must be used within fifteen years. The credit is 100 percent of allowable exploration costs with a maximum of $20 million. For MLT, the credit is limited to the lesser of 50 percent of the MLT liability at the mining operation at which the exploration occurred or 50 percent of total MLT liability. For CIT, it is limited to the lesser of 50 percent of MLT liability at the mining operation at which the exploration occurred or 50 percent of total CIT liability. For mineral royalty, the credit is limited to 50 percent of royalty liability from the mining operation at which the exploration activity occurred.

Credits applicable to royalty

In addition to tax credits and incentives, there are several royalty related incentives in current law that are not discussed in detail in this report. 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.

Oil and gas credit and incentive history

Figure 8-3 summarizes the tax credits in current law that are applicable to the oil and gas production tax and the state CIT, and the amount of credits used in each of the past three years. Figure 8-4 shows history of total oil and gas production tax programs in Alaska from 2008 through 2014 broken down by those used by producers against their tax liability and those purchased by the state for cash. We note that there has been an increasing use of tax credits in total, especially those authorized at AS 43.55.023, over the three-year period. Figure 8-5 summarizes the oil and gas credit programs and their dates of enactment and expiration.

Figure 8-3. Alaska tax credit programs that may apply to oil and gas exploration and development.

Alaska Tax Credits Claimed[1] ($millions)			
Credit Type and Applicability[2]	Total Credits Claimed in FY ($millions)		
	2012	2013	2014 [1]
Credits Applicable to the Oil and Gas Production Tax			
Alternative Credit for Exploration (AS 43.55.025), Cook Inlet Jack-Up Rig Credit, and Frontier Basin Credit	$57	$11	$59
Carried-Forward Annual Loss Credit (AS 43.55.023(b))	Totals included in Qualified Capital Expenditure Credit		
Cook Inlet Jack-Up Rig Credit (AS 43.55.025(a)(5) and (l))	Totals included in Alternative Credit for Exploration		
Exploration Incentive Credit (AS 38.05.180(i))	$0	$0	$0
Frontier Basin Credit (AS 43.55.025(p))	Totals included in Alternative Credit for Exploration		
Per Taxable Barrel Credit (AS 43.55.024(j))	Credit program began on January 1, 2014		$492
Qualified Capital Expenditure Credit, Well Lease Expenditure Credit, and Carried-Forward Annual Loss Credit (AS 43.55.023(b))	$606	$854	$861
Small Producer / New Area Development Credit (AS 43.55.024(a) and (c))	$53	$53	$54
Transitional Investment Expenditure Credit (AS 43.55.023(i))	Cannot be reported due to taxpayer confidentiality		
Credits Applicable to the Corporate Income Tax			
Film Production Credit (AS 43.98.030)	$3	$6	$21
Gas Exploration and Development Credit (AS 43.20.043)	Cannot be reported due to taxpayer confidentiality		
Gas Storage Facility Credit (AS 43.20.046)	$0	$0	$15
In-State Gas Refinery Credit (AS 43.20.053)	Credit program began January 1, 2014		
Internal Revenue Code Credits Adopted by Reference (AS 43.20.021)	Not tracked		
LNG Storage Facility Credit (AS 43.20.047)	Program began in 2012	$0	$0
Oil and Gas Industry Service Expenditures Credit (AS 43.20.049)	Credit program began January 1, 2014		
Veteran Employment Tax Credit (AS 43.20.048)	Program began in 2013	$0	$0
Credits Applicable to Multiple Tax Programs			
Education Tax Credit (AS 21.96.070, AS 43.20.014, AS 43.55.019, AS 43.56.018, AS 43.65.018, AS 43.75.018, AS 43.77.045)	$4	$7	$3
Total All Credits	**$729**	**$940**	**$1,506**

[1]FY 2014 credit totals are estimated pending annual tax filings

[2]The Alaska DOR "Revenue Sources Book" (http://www.tax.alaska.gov/programs/sourcebook/index.aspx) can provide additional descriptions, applicability information and other details on specific credit programs.

Figure 8-4. Credits applicable to the oil and gas production tax program in Alaska, broken down by those used by producers against their tax liability and those purchased by the state for cash.[1]

	($ millions)						
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014** [1]
Statewide Credits							
Credits Used against Tax Liability	557	378	333	386	363	549	888
Credits Purchased by the State [2]	55	54	193	450	353	369	593
Total Statewide Production Tax Credits	612	432	526	836	716	918	1,481

[1] FY 2014 credit totals are estimated pending annual tax filings.

[2] Credits purchased by the State consist primarily of production tax credits purchased, but also include corporate income corporate income tax credits available for state purchase from the Oil and Gas Tax Credit Fund. These include the gas storage facility credit, LNG storage facility credit, and refinery credits.

Figure 8-5. Enactment and expiration dates applicable to the oil and gas production tax credit programs.

Credit	**Year Enacted**	**Sunset/Expiration Date**
Exploration Incentive Credit	1978	None
Qualified Capital Expenditure & Well Lease Expenditure Credit	2006 Amended 2007	None
Carried-Forward Annual Loss Credit	2006 Amended 2008	None
Small Producer/New Area Development Credit	2006	2016
Transitional Investment Expenditure Credit	2006 Amended 2008	2013
Alternative Credit for Exploration	2003 Amended 2008	2016
Cook Inlet Jack-Up Rig Credit	2010	2016
Frontier Basin Credit	2012	2016
Federal Tax Credits	1975	None
Gas Exploration and Development Credit	2003 Amended 2010	None
Gas Storage Facility Credit	2011	2015
LNG Storage Facility Credit	2012	None
Film Production Credit	2008 Amended 2012	2023
Education Credit	1987 Amended 2012	None

9. Fiscal system comparisons

This report began by presenting information comparing Alaska with a group of peers based on non-fiscal criteria that oil and gas companies may consider when deciding where to invest exploration, development and production dollars. In the previous section Alaska's fiscal regime was summarized. In this section the basic styles of worldwide fiscal regimes are outlined followed by a comparison of Alaska's fiscal regime and Alaska's peer group.

Fiscal regime styles

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

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

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

Typically there are taken to be three "headline" styles of petroleum regimes: concessions, production sharing contracts (PSCs) and service contracts (Figure 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, timing, and risks in a particular jurisdiction. The system that attracts investment most successfully is likely to be the least complex system that still properly allocates costs and benefits at the lowest risk possible.

Production sharing contracts

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

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

Service contracts

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

Concession contracts

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

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

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

Leases granted under a tax/royalty style arrangement are quite different from the old style concession agreements, even though the term “concession” may still be used (as well as “permit” or “license”). While details vary from one jurisdiction to another, they all contain significant term provisions, usually involving relinquishment of some part of the acreage at various stages such that only the immediate producing area remains held for a long time (typically the life of production). In some jurisdictions, minimum work obligations will also apply to different holding periods. Operators are generally able to report their "net" booked reserves[29], 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, definitions for several other terms are presented below.

Royalty

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

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

Rental fee (delay rental)

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

Property/ad valorem tax

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

Corporate income tax

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

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

Net tax/profit share

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

Gross/severance tax

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

Indirect sales/value-added tax

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

Participation/joint venture

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

Peer group jurisdictions

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. The information presented in Figure 9-3 and in Chapter 5 of this report will be used to compare Alaska to several other jurisdictions with which we believe the state competes for oil and gas industry investment.

Alaska is compared to other concession-based fiscal regimes largely because of the difficulty of making clear comparisons with the fundamentally very different contract-based fiscal regimes.

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

California

California (Figure 9-4) is a state with resource potential and historic production similar to Alaska. Issues regarding regulations and environmental concerns make California a reasonable addition to the peer group for Alaska. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

North Dakota

North Dakota (Figure 9-5) has historically experienced lower production volumes than Alaska; however, its production now surpasses Alaska, largely on the strength of shale oil production in the last five years. Capital and operating costs are generally assumed to be lower than Alaska. Infrastructure is well established and much more extensive than in Alaska.

Oklahoma

Oklahoma (Figure 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, largely on the strength of shale oil production. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

U.S. Gulf of Mexico Outer Continental Shelf

The Gulf of Mexico OCS (Figure 9-8) 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 BP's Macondo well blowout and spill that occurred that year. Offshore infrastructure is well-established and extensive. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska. There is no state or local CIT, property tax, severance tax, production tax or sales tax.

U.S. Beaufort and Chukchi Sea Outer Continental Shelf

The Beaufort Sea and Chukchi Sea OCS (Figure 9-9), off Alaska's northern coast, has seen very minimal historic production (from the Northstar field), but has several discovered accumulations and significant potential. There is no infrastructure in the Alaska OCS. Our assumption is that costs will be high and environmental restrictions and permitting hurdles will be greater than onshore Alaska. The U.S. OCS fiscal system has significantly lower overall government take because there is no state or local CIT, property tax, severance tax, production tax or sales tax. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska.

Alberta

Alberta, Canada (Figure 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 CIT is 26.5 percent, but this rate may be reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. Canada's federal CIT rate is 16.5 percent, lower than the 35 percent U.S. CIT. The Alberta provincial CIT rate is 10 percent.

Northwest Territories

Northwest Territories, Canada (Figure 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 Northwest Territories' provincial CIT rate is 11.5 percent.

Canada Federal Offshore Beaufort Sea

Canada's 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. Like Alaska, the Norway's North Sea basin is generally considered mature by oil and gas industry standards.

United Kingdom

The U.K. (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. Like Alaska, the U.K.'s North Sea basin is generally considered mature by oil and gas industry standards.

Excluded jurisdictions

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

Excluded states and provinces

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

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

Fiscal system exclusions

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

Geographic location exclusions

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

Production history exclusions

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

Figure 9-1. Petroleum legal arrangement classifications.

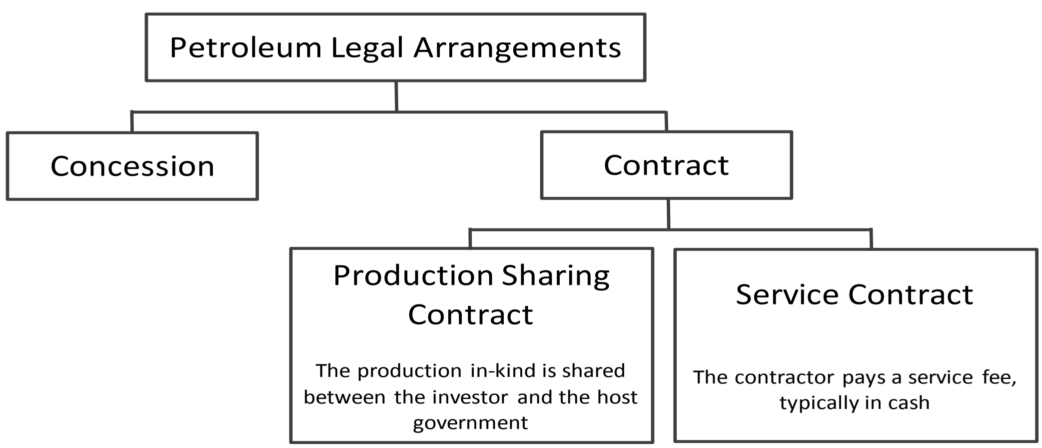

Figure 9-2. Petroleum fiscal regime peer group highlights.

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

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

Royalty:	Generally 12½ or 16⅔ percent, most production pays at 12½ percent. Higher royalty rates on some private lands do exist, but generally private rates are not lower than state rates. Natural gas royalty rate is the same as oil on state and federal lands. Most production in Alaska is on state-owned lands.
Rental Fee:	Alaska state lands: 1st year - \$1, 2nd year - \$1.50, 3rd year - \$2, 4th year - \$2.50, and 5th and subsequent years - \$3 per acre. Rental is creditable against royalties. Federal lands: \$1.50 per acre delay rental for years 1 – 5 and \$2 per acre thereafter.
Property/ad valorem tax:	The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The property tax is assessed annually and the tax rate is 20 mills. Oil and gas property that is also within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is graduated with the top tax rate of 9.4 percent levied when net incomes exceed \$90,000 for the year. The CIT for oil and gas uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operation's (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property.
Net Tax/Profit Share:	The Alaska state production tax is fundamentally different than all other federal and state jurisdictions in the U.S., in that it is a "net" tax, after most costs and expenses are subtracted from revenue. This aspect of Alaska's fiscal regime remains unchanged despite changes made to the state's oil and gas production tax that went into effect in 2014. The production tax formula consists of two primary pieces: a base tax rate of 35 percent. With the 2014 tax changes, variable credit mechanism was created, with the value of the credit changing with an inverse relationship to the value of the oil produced. A company's tax liability may be reduced by credits that are included in the production tax system. Additionally, Alaska has a 4 percent gross minimum tax that may apply in some circumstances (see Gross/Severance Tax section below). The basic tax calculation of Alaska's production tax is as follows: **Production Tax Liability = [(Value – Costs) * Tax Rate] – Credits** **Value, production from existing fields** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value **Value, new production** = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value * 80 or 70 percent **Costs** = Operating and Capital Expenditures **Tax Rate** = 35 percent **Credits, production from existing fields** = Value of \$0 to \$8 per taxable barrel of oil produced **Credits, new production** = Value of \$5 per taxable barrel of oil produced

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

Indirect Taxes: None.

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

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

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

Figure 9-4. California fiscal system highlights.

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

Figure 9-5. North Dakota fiscal system highlights.

Royalty:	North Dakota state lands: Most production pays at 16⅔ percent. Natural gas rate is same as oil. Federal lands: Most production pays at 12½ percent. Natural gas rate is same as oil. Private lands: Most production pays at 18 ¾ percent. The majority of production in North Dakota is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental Fee:	North Dakota state lands: $1 per acre (during exploration period only). Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property/ad valorem tax:	None.
CIT:	The U.S. federal CIT rate is 35 percent. The state CIT rate for oil and gas is 6.4 percent.
Net Tax/Profit Share:	None.
Gross/Severance Tax:	The overall tax is comprised of two pieces, 1. Severance Tax and 2. Oil Extraction Tax, that sum together for a total tax rate of 11½ percent, before incentives and credits. The Severance Tax is 5 percent of gross value and is effectively an irreducible minimum tax that is unaffected by any incentives or credits offered by the state. The Oil Extraction Tax starts at 6½ percent of gross value, but may be lower if production qualifies for incentives or credits offered by the state.
Indirect Taxes:	5 percent on all capital goods brought into the state.
Incentives and Credits:	North Dakota offers incentives for certain types of activities and ventures. These programs include lower Oil Extraction Tax (OET) for very-low-production volume (stripper) wells and when WTI oil price minus $2.50 falls below an inflation adjusted “Trigger” price, recently at $46.78. To encourage horizontal oil wells the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, 18 months, or $4.5 million in gross production revenue. To encourage production in the Bakken Formation, the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, or 18 months. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and tax loss carry-forward.

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

Figure 9-7. Texas fiscal system highlights.

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

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

Figure 9-9. U.S. Beaufort Sea and Chukchi Outer Continental Shelf (OCS) fiscal system highlights.

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

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

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

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

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

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

Figure 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.
CIT:	The U.K. federal CIT rate is 30 percent. Taxable income is ring-fenced for upstream oil and gas activities. Additional tax elements apply.
Net Tax/Profit Share:	Supplementary Charge is tax (32 percent from 24 March 2011 and previously 20 percent) on UK exploration and production activities that is in-addition to CIT. Taxable profits for supplementary charge purposes are calculated in the same manner as ring-fence trading profits but without any deduction for finance costs. Finance costs are defined very broadly for this purpose and include the finance element of lease rentals and any costs associated with financing transactions for accounts purposes.
Gross/Severance Tax:	None.
Indirect Taxes:	The standard rate of value added tax (VAT) in the U.K. is 20 percent, with reduced rates of 5 percent and 0 percent. The VAT is potentially chargeable on all supplies of goods and services made in the U.K. and its territorial waters.
Incentives and Credits:	The U.K. offers incentives for certain activities and ventures, including a Ring Fence Expenditure Supplement and certain research and development allowances.

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, a logical peer group is established for comparison. Alaska's peer group selection is largely tied to three elements, production and reserves, geographic location, and fiscal system type. Information is also presented on lease sales, infrastructure, permitting, and workforce availability. Other criteria may be added to this list as future discussion relates 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

The Board 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 Board is looking at several tasks that they hope to accomplish over the short- to intermediate-term.

Future efforts of the Board will require funding and DOR support to move forward in a meaningful way. One of the first steps was to ascertain who are we competing with? In this publication we have established an initial peer group, but this group should not be considered a final unalterable group. The Board will continuously review this list of peers and change it as necessary. We may also modify the criteria used to select peer group members. For example, we may have a different set of peers when considering Alaska's competitiveness with respect to exploration and development of natural gas than crude oil and liquid hydrocarbons.

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

As we review our competitiveness we need to consider the items that the State of Alaska has control of, or can influence, such as permitting, infrastructure, labor, lease costs, taxation, royalties and access to resources. We need to be able to do a grounded comparative analysis of our fiscal structure versus our peers. One of our thoughts moving ahead is to build a dashboard of critical measurements for Alaskans to easily review using principally, but not limited to items that are currently being measured by various state and federal agencies that can be compiled and provided on a single website. Our goal is to track past, current and projected future statistics and projections for a group of key diagnostic criteria that will help interested parties view specific progress or trends related to the oil and gas industry in Alaska compared to peer jurisdictions. These measures could be items like number of wells being drilled, production, resource pricing, permitting and other pertinent trending data. This will be maintained on a recurrent basis so interested parties have a baseline to current view of the industry.

The next required deliverable from the Board is a report to the Alaska State Legislature due on or before January 15, 2017. For the January 2017 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. the state's tax structure and rates on oil and gas produced south of 68 degrees North latitude;

2. a tax structure that takes into account the unique economic circumstances for each oil and gas producing area south of 68 degrees North latitude;

3. a reduction in the gross value at the point of production for oil and gas produced south of 68 degrees North latitude that is similar to the reduction in gross value at the point of production in AS 43.55.160(f) and (g); and

4. other incentives for oil and gas production south of 68 degrees North latitude.

The Board's final statutorily required deliverable is a report to the Alaska State Legislature due on or before January 31, 2021. For the January 2021 Competitiveness Report the Board is asked to provide written findings and recommendations regarding:

1. changes to the state's fiscal regime that would be conducive to increased and ongoing long-term investment in and development of the state's oil and gas resources;

2. alternative means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources; and

3. a review of the current effectiveness and future value of any provisions of the state's oil and gas tax laws that are expiring in the next five years.

Appendices

Appendix A-1. Alaska Oil and Gas Competitiveness Review Board members:

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Vice President, Oil & Gas
Carlile Transportation Systems, Inc.

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Alaska Department of Revenue

MARK MYERS
Commissioner
Alaska Department of Natural Resources

MIKE GALLAGHER
Commissioner
Alaska Oil & Gas Conservation Commission

KRISTIN RYAN
Spill Prevention and Response Director
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Alaska Oil and Gas Competitiveness Review Board web page:
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