State of Alaska Department of Revenue
Tax Division

Revenue Sources Book

FALL 2013

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Alaska Department of Revenue - Tax Division

FALL 2013

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THE STATE of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

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December 4, 2013

The Honorable Sean Parnell
Governor of Alaska
P.O. Box 110001
Juneau, Alaska 99811-0001

Dear Governor Parnell,

I am pleased to present to you the Fall 2013 Revenue Sources Book.

Briefly, the State of Alaska received a total $15.8 billion in FY 2013 from all sources. Of this total, General Fund unrestricted state revenues totaled $6.9 billion, with oil revenues accounting for approximately 92% of all unrestricted revenue. The Department of Revenue is now forecasting unrestricted revenue of $4.9 billion and $4.5 billion for FY 2014 and FY 2015, respectively. This is a significant revision to our unrestricted revenue from the previous forecast.

The single-most influential contributor to the revision is a reduced price expectation. The revenue forecast is based on an Alaska North Slope (ANS) oil price of $105.68 per barrel for FY 2014 and $105.06 per barrel for FY 2015. The forecast oil price is less than the last several years.

North Slope oil production declined 8.2% in FY 2013 to an average of 531.6 thousand barrels of oil per day. At the same time, there is a 13.6% effective increase in production in Cook Inlet since last year. The production forecast has been reduced in the next couple years to account for increased natural gas liquids (NGL) reinjection for enhanced recovery of oil, higher intensity of summer 2013 maintenance, and decreased production expectations at legacy fields. We see, however, the companies responding to the More Alaska Production Act (MAPA) and as a result spending projections on the North Slope have been increased by $10 billion over the next 10 years. At the same time, we continue to employ a methodology that accounts for uncertainty in our production forecast. Some anticipated new production from the oil industry's investment in exploration and development is included in this forecast, but most will be added as it meets our prudent thresholds of likelihood.

I am pleased with the increase in investment that we are seeing on the North Slope. However, in the short-term this is another factor that contributes to reduced revenue. Lease expenditures are a tax deductible activity that reduces taxes paid in the present, which reduces near-term total revenue. The cost of transporting oil is another expense that becomes deductible against taxes and royalty payments, reducing revenue. As production declines, the cost of transportation is spread among fewer barrels of oil causing increased transportation costs per barrel.

Given all of these changes, reforming the oil tax system from ACES to MAPA incurs a revenue reduction of approximately $250 to $300 million in FY 2014. This reduction is primarily due to the impact of closing out ACES capital credit liabilities. In FY 2015, we can report that the two tax systems generate similar revenues at the forecasted price, expenditure and production levels. This is because elimination of the ACES progressivity provision and capital credits are roughly offset by the increased 35% base rate and new per-barrel credits under MAPA.

Fundamentally, future growth in unrestricted state revenue will require higher oil prices and/or stable or increased production. Fortunately, with the More Alaska Production Act we have a tax regime that can address the one factor we can influence – increased production. We will provide a forecast update in the spring of 2014.

Sincerely,

Angela M Rodell

Angela Rodell
Commissioner

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1

Introduction

Purpose

The *Revenue Sources Book* (RSB) is intended to provide the Governor, the Alaska Legislature and Alaskans with a report of historic, current, and estimated future state revenue. This publication is prepared primarily by the Economic Research Group, a part of the Tax Division in the Department of Revenue, in accordance with AS 37.07.060 (b)(4). Forecasts of state revenue are made using econometric models developed by the Department of Revenue's Economic Research Group and other state agencies. The information in this publication is used to assist the Governor to formulate a comprehensive financial plan to present to the Alaska State Legislature. Assistance from individuals in other divisions within the department and other departments of state government is received by the Economics Research Group to ensure the most accurate and current information. The department expresses its gratitude to those state agencies and the individuals in those agencies who have provided information, assistance and analysis for this RSB.

Over the years, the RSB has become an educational tool to inform the general public of how the State's revenues are structured. The RSB also provides in-depth coverage on a topic relevant to state revenues each year. This year's chapter is entitled *Liquefied Natural Gas (LNG): Alaska's Once and Future Export?*

Changes

In an attempt to reduce duplication of information, Chapter 2 has been condensed to an executive summary that provides a broad overview of revenues and avoids delving into the specifics of the revenue sources. Specific details of each revenue source are addressed in later chapters. In addition, recent changes to specific tax structures will be identified in the chapters that concern the specific tax type. This year, the RSB will be more focused on the current and future revenues and include less historical documentation concerning each revenue source. Instead, the historic perspective will be covered in a new publication from the Tax Division entitled *Alaska State Taxes*, to be published in January 2014.

Chapter 6, on federal revenue, has been expanded to better explain the appropriation of federal funds within the State. Chapter 7, on investment revenue, has been updated with clearer graphs and tables. Because of the importance that credits have on state revenues and the economy, chapter 8 has been added this year to specifically deal with tax credits.

The text size throughout the RSB has been enlarged for reading convenience. Tables and figures are ordered by number and letter respectively and for reference purposes are now listed in the table of contents. Consistent units of measure have been applied throughout the publication, as well as a consistent style for all tables and graphs.

The RSB is available on the internet at www.tax.alaska.gov under the "Reports" tab and can be found on the list under the "Revenue Sources Book and Forecasts" hyperlink. For ease of use, in the electronic version, the table of contents is linked to the chapters.

The changes in this volume of the RSB help to improve the usability and aesthetics for readers, as well as reduce duplicative information published by the department. At the same time, the department is committed to maintaining the best traditions developed over decades of publishing the RSB.

Defining Revenue Categories

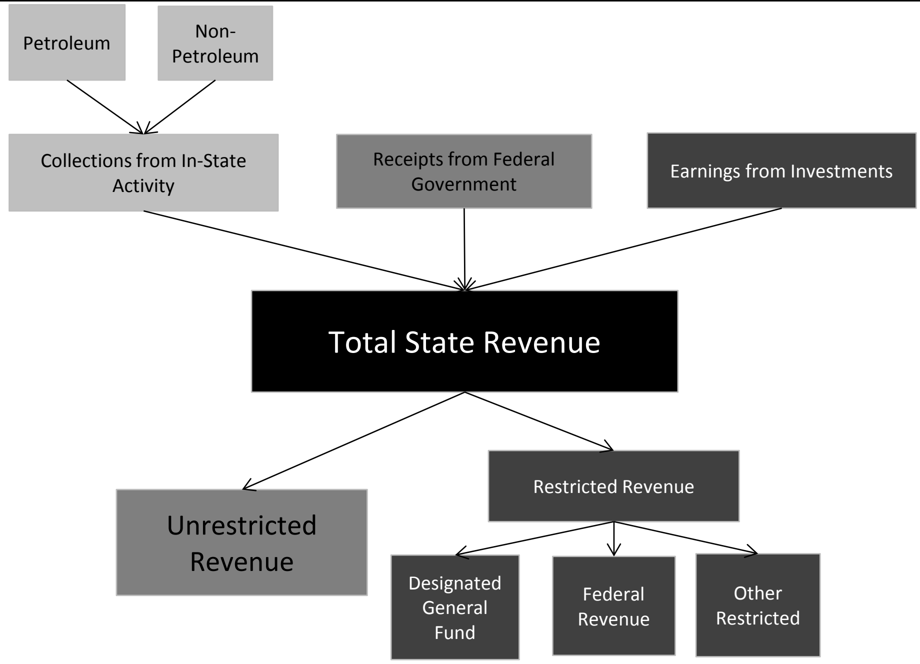
Throughout the RSB, revenue is divided into categories in two ways: based on where the revenue comes from, and based on how it can be used. There are three basic categories of revenue received by the State: 1) funds collected from In-State Activities, 2) funds received from the federal government, and, 3) interest and payments earned on assets owned by the State. Due to the overwhelming importance of revenues from oil production, In-State Activities are further divided into a) petroleum revenue and b) non-petroleum revenue. A graphic depiction of how the revenues are categorized by revenue collection type is shown in Figure 1-A.

While the revenue information in the RSB is primarily categorized by how it is collected, sometimes it is also necessary to categorize revenue based on how it can be used. Revenue can be categorized as either "unrestricted" (available to fund general state activities and capital projects) or "restricted" (required to be used for a specific purpose). Any revenue that is not restricted by the constitution, state or federal law, trust or debt restrictions or customary practice is considered "Unrestricted General Fund Revenue" or simply "unrestricted revenue."

Most legislative and public discussion centers on this category of revenue and it is the figure most commonly referenced in budget discussions.

When referring to restricted revenues, three fund categories exist, based on the types of restrictions that apply to that revenue. These categories were developed by the Division of Legislative Finance and the Office of Management and Budget in 2010 to provide additional information in the budget process. Tables that include restricted revenues will be divided in these categories and are "Designated General Fund," "Other Restricted Revenue," and "Federal Revenue." This may create confusion, but is a very useful distinction for many of the users of the RSB, especially those users involved in the budget and appropriations process.

Figure 1-A: Revenue Collection Types



Forward Looking Statements

All figures and narrative in this document that are not based on events that have already occurred, constitute "forward-looking statements." These numbers are projections based on assumptions regarding uncertain future events and the responses to those events. Such figures are, therefore, subject to uncertainties and actual results will differ, potentially materially, from those anticipated. The Department of Revenue attempts to capture these uncertainties in order to provide lawmakers and the general public with a general understanding of the scale and scope of future revenue streams. The figures provided as the official forecast take into account many possible outcomes and attempts to minimize deviations from what is likely to happen. These figures do not necessarily represent a single scenario of a future path; rather, these forecasts represent a probability weighted average of many possible outcomes.

Readers are cautioned not to place undue reliance on these forward-looking statements in making decisions. The department will update these estimates in spring 2014, as more information is received. This forecast supersedes all prior estimates or forecasts as the official forecast of the department.

2

Executive Summary

Introduction

The State of Alaska received a total $15.8 billion in FY 2013 from all sources. Of this total, General Fund unrestricted state revenues totaled $6.9 billion, with oil revenues accounting for approximately 92% of all unrestricted revenue. The department forecasts total revenue as $12.8 billion in FY 2014 and $12.3 billion in FY 2015. Figure 2-A graphically illustrates the composition of the revenue by restriction and type. As depicted in Table 2-1, the Department of Revenue is forecasting Unrestricted Revenue of $4.9 billion and $4.5 billion for FY 2014 and FY 2015, respectively. This is a significant revision to our Unrestricted Revenue from the previous forecast.

The single-most influential contributor to the revision is a reduced price expectation. The revenue forecast is based on an Alaska North Slope (ANS) oil price of $105.68 per barrel for FY 2014 and $105.06 per barrel for FY 2015.

The production forecast has been reduced in the next couple years to account for increased natural gas liquids (NGL) reinjection for enhanced recovery of oil, higher intensity of summer maintenance, and decreased production expectations at legacy fields. North Slope oil production declined 8.2% in FY 2013 to an average of 531.6 thousand barrels of oil per day. At the same time, there is a 13.6% effective increase in production in Cook Inlet since last year.

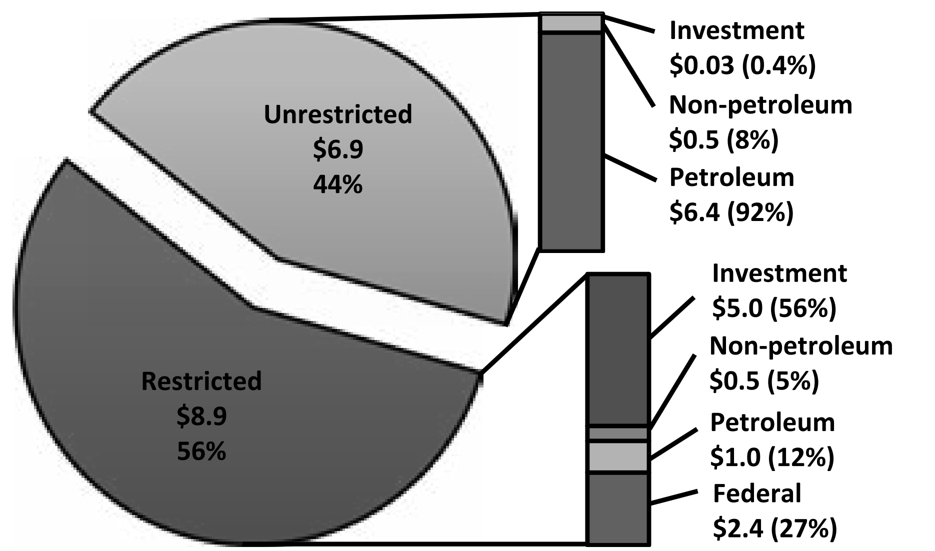


Figure 2-A: FY 2013 Total State Revenue, by restriction and type ($ billions)

As companies respond to the More Alaska Production Act (MAPA), the department has increased spending projections on the North Slope by $10 billion over the next 10 years. At the same time, we continue to employ a methodology that accounts for uncertainty in our production forecast. Some anticipated new production from the oil industry's investment in exploration and development is included in this forecast, but most will be added as it meets our prudent thresholds of likelihood.

Company spending is another factor that contributes to reduced revenue. Lease expenditures are a tax deductible activity that reduces taxes paid in the present, which reduces near-term total revenue. The cost of transporting oil is another expense that becomes deductible against taxes and royalty payments, reducing revenue. As production declines, the cost of transportation is spread among

Table 2-1: Total State Revenue, by restriction and type

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted Revenue Sources			
Unrestricted General Fund Revenue			
Petroleum Revenue	6,352.0	4,359.5	3,935.0
Non-petroleum Revenue	548.4	484.1	512.3
Investment Revenue	28.1	86.4	84.7
Federal Revenue	0.0	0.0	0.0
Unrestricted General Fund Revenue	**6,928.5**	**4,930.0**	**4,532.0**
Restricted Revenue Sources			
Designated General Fund Revenue			
Non-petroleum Revenue	299.8	329.0	327.6
Investment Revenue	40.5	40.1	30.7
Subtotal Designated General Fund Revenue	**340.3**	**369.1**	**358.3**
Other Restricted Revenue			
Petroleum Revenue	1,032.5	756.5	738.5
Non-petroleum Revenue	185.2	214.0	215.4
Investment Revenue	4,937.3	3,523.5	3,531.3
Subtotal Other Restricted Revenue	**6,155.0**	**4,494.0**	**4,485.2**
Federal Revenue			
Petroleum Revenue(1)	3.6	3.6	3.6
Federal Receipts	2,383.2	2,963.0	2,963.0
Subtotal Federal Revenue	**2,386.8**	**2,966.6**	**2,966.6**
Total Restricted Revenue	**8,882.1**	**7,829.7**	**7,810.1**
Total State Revenue	**15,810.6**	**12,759.6**	**12,342.1**

fewer barrels of oil causing increased transportation costs per barrel.

Given all of these changes, reforming the oil tax system from ACES to MAPA incurs a revenue reduction of approximately $250 to $300 million in FY 2014. This reduction is primarily due to the impact of closing out ACES capital credit liabilities. In FY 2015, the department reports that the two tax systems generate similar revenues at the forecasted price, expenditure and production levels. This is because elimination of the ACES progressivity provision and capital credits are roughly offset by the increased base rate and new per-barrel credits under MAPA.

(1) Oil revenue shown in the Federal category includes the State share of rents, royalties, and bonuses received from the National Petroleum Reserve - Alaska, as provided by federal law.

Table 2-2: Unrestricted General Fund Revenue, by type and detail

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted Petroleum Revenue			
Petroleum Taxes			
Petroleum Property Tax	99.3	99.6	97.4
Petroleum Corporate Income Tax	434.6	463.8	463.7
Oil & Gas Production Tax	4,050.3	2,099.7	1,711.1
Subtotal Petroleum Taxes	**4,584.2**	**2,663.2**	**2,272.2**
Royalties (including Bonuses, Rents, & Interest)			
Mineral Bonuses & Rents	19.0	9.4	9.4
Oil & Gas Royalties	1,748.4	1,685.9	1,652.4
Interest	0.4	1.0	1.0
Subtotal Royalties	**1,767.8**	**1,696.3**	**1,662.8**
Unrestricted Petroleum Revenue	**6,352.0**	**4,359.5**	**3,935.0**
Unrestricted Non-petroleum Revenue			
Non-petroleum Taxes			
Excise Tax			
Alcoholic Beverage	19.8	20.0	20.3
Tobacco Product – Cigarette	32.2	30.4	28.9
Tobacco Product – Other	12.6	13.7	14.1
Insurance Premium	52.4	54.4	56.4
Electric and Telephone Cooperative	0.2	0.2	0.2
Motor Fuel	41.9	41.3	40.7
Vehicle Rental	8.4	8.3	8.4
Tire Fee	1.4	1.4	1.4
Subtotal Excise Tax	**168.9**	**169.7**	**170.4**
Corporate Income Tax	**112.5**	**87.9**	**127.1**
Fisheries Tax			
Fisheries Business	19.2	22.1	22.6
Fishery Resource Landing	5.5	5.3	5.4
Subtotal Fisheries Tax	**24.7**	**27.4**	**28.0**
Other Tax			
Charitable Gaming	2.5	2.4	2.4
Estate	0.0	0.0	0.0
Large Passenger Vessel Gambling	6.0	6.0	6.0
Mining	46.7	44.8	41.9
Subtotal Other Tax	**55.2**	**53.2**	**50.3**
Subtotal Non-petroleum Taxes	**361.3**	**338.2**	**375.8**

Table 2-2: Unrestricted General Fund Revenue, by type and detail *(continued from previous page)*

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Charges for Services			
General Government	13.2	14.6	14.6
Natural Resources	2.4	7.6	7.6
Other	9.6	7.6	7.6
Subtotal Charges for Services	**25.2**	**29.8**	**29.8**
Fines & Forfeitures	**15.8**	**10.4**	**10.4**
Licenses & Permits			
Alcoholic Beverage Licenses	0.9	0.9	0.9
Motor Vehicle	38.2	40.2	40.2
Other	2.8	2.6	2.6
Subtotal Licenses & Permits	**41.9**	**43.7**	**43.7**
Rents & Royalties			
Mining Rents & Royalties	14.1	13.3	13.4
Other Non-petroleum Rents & Royalties	10.6	8.8	8.8
Subtotal Rents & Royalties	**24.7**	**22.1**	**22.2**
Miscellaneous Revenues and Transfers			
Miscellaneous	63.6	15.2	15.2
Alaska Housing Finance Corporation	9.5	0.0	0.0
Alaska Industrial Development & Export Authority	0.0	20.7	10.7
Alaska Municipal Bond Bank Authority	0.0	0.0	0.0
Alaska Student Loan Corporation	1.2	0.0	0.0
Alaska Energy Authority	0.1	0.0	0.0
Alaska Natural Gas Development Authority	0.1	0.0	0.0
Mental Health Trust	0.0	0.0	0.0
Unclaimed Property	5.0	4.0	4.5
Subtotal Transfers	**79.5**	**39.9**	**30.4**
Unrestricted Non-petroleum Revenue, except federal and investment	**548.4**	**484.1**	**512.3**
Investment Revenue			
Investments	26.7	84.9	83.2
Interest Paid by Others	1.4	1.5	1.5
Unrestricted Investment Revenue	**28.1**	**86.4**	**84.7**
Total Unrestricted Revenue	**6,928.5**	**4,930.0**	**4,532.0**

Table 2-3: Restricted Revenue, by type and category

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Designated General Fund Revenue			
Non-petroleum Revenue			
Taxes	52.3	47.9	47.1
Charges for Services	202.9	244.2	243.7
Fines and Forfeitures	17.6	9.2	9.1
Licenses and Permits	0.2	0.2	0.2
Rents and Royalties	3.6	4.6	4.6
Other	23.2	22.9	22.9
Subtotal	**299.8**	**329.0**	**327.6**
Investment Revenue			
Investments - Designated GF	2.6	2.1	2.6
Other Treasury Managed Funds	37.9	38.0	28.1
Subtotal	**40.5**	**40.1**	**30.7**
Restricted Designated General Fund Revenue	**340.3**	**369.1**	**358.3**
Other Restricted Revenue			
Oil Revenue			
Royalties to Alaska Permanent Fund & School Fund (includes Bonuses & Rents)	855.9	736.5	718.5
Tax and Royalty Settlements to CBRF	176.6	20.0	20.0
Subtotal	**1,032.5**	**756.5**	**738.5**
Non-petroleum Revenue			
Taxes	76.5	74.7	76.2
Charges for Services	40.8	70.9	70.9
Fines and Forfeitures	24.5	24.3	24.1
Licenses and Permits	29.2	29.8	29.8
Rents and Royalties	8.0	7.5	7.6
Other	6.2	6.8	6.8
Subtotal	**185.2**	**214.0**	**215.4**
Investment Revenue			
Investments - Other Restricted	5.2	4.3	5.3
Constitutional Budget Reserve Fund	618.2	618.2	458.9
Alaska Permanent Fund (GASB)[1]	4,313.9	2,901.0	3,067.1
Subtotal	**4,937.3**	**3,523.5**	**3,531.3**
Other Restricted Revenue	**6,155.0**	**4,494.0**	**4,485.2**

[1] Both realized and unrealized gains and losses are included per GASB 34 as interpreted by the Finance Division of the Department of Administration in its *Comprehensive Annual Financial Report*.

Table 2-3: Restricted Revenue, by type and category *(continued from previous page)*

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Federal Revenue			
Federal Receipts	2,383.2	2,963.0	2,963.0
Oil Revenue			
NPR-A Royalties, Rents and Bonuses	3.6	3.6	3.6
Restricted Federal Revenue	**2,386.8**	**2,966.6**	**2,966.6**
Total Restricted Revenue	**8882.1**	**7829.7**	**7810.1**

Unrestricted General Fund Revenue

Generally, Unrestricted General Fund Revenue is not restricted by the constitution, state or federal law, trust or debt restrictions, or customary practice. Table 2-2 provides an overview of the FY 2013 composition of Unrestricted General Fund Revenue as well as forecasts for FY 2014-2015.

In FY 2013, the State received $6.9 billion in revenue from unrestricted sources, $6.4 billion of which came from petroleum related activities. For FY 2014, the department is forecasting a continued decrease in Unrestricted General Fund Revenue to $4.9 billion. This projection is the result of several factors. Increased supply of oil on the global market is putting downward pressure on all oil prices, including ANS crude oil. In addition, the decline of North Slope oil production continues to erode state revenues. Furthermore, a recent increase in tax deductible company spending projections decreases the amount of tax collections in the short-term. The combination of these factors reduces the expectations for Unrestricted General Fund Revenue in the near-term compared to our previous forecast. As new near-term investments translate into increased future production volumes, it is possible that future revenue will increase relative to the current decline path. These potential increases carry some uncertainty and, therefore, do not appear fully in this forecast.

Petroleum Revenues

Petroleum revenue is projected to provide at least 88% of FY 2014 Unrestricted Revenues and 82% of forecast Unrestricted General Fund Revenue through FY 2023 as shown in Table 2-4 on page 12. These revenues come from four components – Production Tax, Royalties, Corporate Income Tax, and Petroleum Property Tax. In turn, four elements are critical to the determination of these revenue sources: price, production, lease expenditures, and transportation costs. These components are explained briefly below and in greater detail in Chapter 4. Details regarding the remaining petroleum revenue sources can also be found in Chapter 4.

Crude Oil Price

By regulation, the department uses several different reporting and assessment services to estimate the "prevailing value" for ANS oil. Because there is no spot market for ANS crude and it is not traded on an exchange, Alaska crude oil is assessed based on purchases of crude oil in the West Coast markets, where it is sold primarily to Washington State and California refiners. The average prevailing value of ANS in FY 2013 was $107.57.

In the past, ANS crude was valued against the West Texas Intermediate (WTI) benchmark. However, since the WTI benchmark has decoupled from ANS and other crude markers, assessment of ANS is now more comparable to other waterborne crude oils such as Brent. Since 2012, the department forecasts ANS crude oil price directly, rather than forecasting WTI and creating a ANS-WTI differential.

The department considered various oil price forecasts of WTI and Brent oil in deriving the fall 2013 ANS oil price forecast and relied on a panel of experts in determining the price path expectations for ANS. As such, the department projects ANS oil prices

Table 2-4: Ten-Year Forecast of Total Unrestricted General Fund Revenue

	History	Forecast ($ millions)									
Fiscal Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unrestricted Petroleum Revenue	6,352.0	4,359.5	3,935.0	4,022.6	4,382.5	4,480.8	4,486.5	4,136.2	3,802.8	3,932.7	3,380.4
Unrestricted Non-petroleum Revenue	548.4	484.1	512.3	524.1	532.5	543.4	552.1	561.4	571.7	577.3	589.8
Unrestricted Investment Revenue	28.1	86.4	84.7	62.8	65.6	80.8	96.8	112.4	128.0	143.6	159.2
Total Unrestricted Revenue	6,928.5	4,930.0	4,532.0	4,609.5	4,980.6	5,105.0	5,135.4	4,810.0	4,502.5	4,653.6	4,129.4
Percent from Oil	92%	88%	87%	87%	88%	88%	87%	86%	84%	85%	82%

will average around $106 per barrel in FY 2014 and $105 per barrel in FY 2015. In the mid-term, the department forecasts ANS to increase slightly, with a FY 2016 price of about $108 and a FY 2017 price of about $110. Details about oil price forecast methodology are provided in Chapter 4.

Crude Oil Production

In the 36th full fiscal year of North Slope production, FY 2013 averaged 531.6 thousand barrels of oil per day. The result is a year-over-year decline rate between FY 2012-FY 2013 of 8.2%, falling in the high end of the projected decline range of 4.5% to 10.6% from the fall 2012 forecast. The primary driver in the lower-than-expected volume was an increase in the reinjection of natural gas liquids (NGLs) relative to the forecast amount. This new information was accounted for in the spring 2013 forecast. Several other factors resulted in reduced performance in several fields which alter the department's outlook. Production in FY 2014 is forecast to fall to 508.2 thousand barrels of oil per day; by FY 2023, production is forecast to decline to around 312.9 thousand barrels per day, representing an average annual decline rate of about 5.1% over the next decade. Company plans are now aiming to reduce that decline rate; however, those additional volumes are not yet at a level of certainty high enough to include in this forecast.

Cook Inlet, on the other hand, in its 55th fiscal year of production, saw a third consecutive increase in its annual oil production rate. At 12.2 thousand barrels per day, a 13.6% effective increase in production rates over FY 2012, Cook Inlet is now producing more oil than its FY 2009 level. Early indications suggest that this production growth will continue next year in response to continued increases in investment.[1]

Lease Expenditures

Under Alaska's net tax system, companies are allowed to deduct certain lease expenditures from the gross value of their production before applying the tax rate. Future tax collections, therefore, are dependent not only on the oil price and the level of production, but also on the cost of that production. Costs of production may include operating expenses, such as the costs of labor or the expense to run a facility, and they may include costs to acquire production equipment or to drill a well—usually deemed to be capital expenses.

North Slope lease expenditures totaled approximately $6.1 billion in FY 2013. The department projects total North Slope spending to increase to $7.0 billion in FY 2014 and $7.8 billion in FY 2015, before tapering off thereafter. Compared to the spring 2013 revenue forecast this represents an increase of over $500 million for FY 2014 and nearly $1 billion for FY 2015. Over the next decade, the department includes about $10 billion in additional investment on the North Slope, above and beyond what was expected in spring 2013. This increased forecast reflects company plans to significantly increase spending at legacy fields, as evidenced by recent announcements of rig additions and investment in new drilling areas.

[1] Cook Inlet oil production and Alaska's Statehood started almost at the same time. Production in Cook Inlet began in 1958 and Alaska's Statehood began January 3, 1959.

However, these increased spending estimates are subject to many uncertainties, including oil prices and other economic factors.

Transportation Costs

As the volume of oil flowing through a pipeline decreases, the costs of maintaining that pipeline are spread over fewer barrels of oil. The result is that the average cost of delivery for each barrel of oil increases as production declines. Additionally, changes in marine shipping rates include changes in labor costs, capital investment, and cost of fuel. The latter two factors are directly tied to oil prices and environmental regulations. The department is now forecasting that the average cost of delivering oil from the Alaska North Slope to the West Coast will be about $10 per barrel in FY 2014 and increase to nearly $14 per barrel by FY 2023.

Non-Petroleum Revenue from In-State Activity

Other Unrestricted Revenue includes corporate income taxes from non-petroleum related businesses, excise taxes, consumption taxes, charges for services, fines, forfeitures, licenses, permits, rents, royalties, transfers, and other miscellaneous revenue. These revenues are referred to as "Non-Petroleum Revenues from In-State Activity," and do not include federal and investment revenues. Details regarding these revenue sources can be found in Chapter 5. Unrestricted Non-petroleum Revenues from In-State Activities are expected to bring around $484 million in FY 2014, representing 10% of all Unrestricted Revenues. By FY 2023, these revenues are projected to rise to about $590 million.

Unrestricted Investment Revenue

Unrestricted Investment Revenues are primarily earnings on the General Fund, as well as the Statutory Budget Reserve Fund. Unrestricted Investment Revenue is expected to be $86.4 million in FY 2014, rising to $159.2 million by FY 2023 as interest rates rebound from currently very low levels. This represents only a small portion of total investment revenue. The majority of investment revenue is restricted and discussed below.

Restricted Revenues

Restricted Revenue includes revenue restricted by the constitution, state or federal law, trust or debt restrictions, customary practice, or other restriction. Restricted Revenue reported in Table 2-3 on pages 8-9 includes money deposited into the "Restricted" component of the General Fund, with certain additions. Additions might include: (a) receipts deposited in funds other than the General Fund, and (b) receipts deposited in the General Fund, but restricted by statute or customarily appropriated for a particular purpose or program, such as sharing of fish tax revenue with municipalities. The largest sources of Restricted Revenue are royalty contributions to the Permanent Fund, receipts from federal government, and earnings from investments, as well as other restricted non-petroleum revenues. FY 2013 brought $8.9 billion in total restricted revenues to the State. The FY 2014 projection for total state restricted revenues is $7.8 billion. Details regarding these sources can be found in chapters 4, 5, 6, and 7.

Restricted Royalties

The FY 2014 projection for royalty, bonus, and rents contributions to the Permanent Fund is $724 million. This figure tracks expected changes in price, transportation costs, and production over time. By FY 2023, the department forecasts that Permanent Fund contributions will fall to $529 million, as lower oil production reduces royalty revenues.

Restricted Investment Revenue

Investment income is the earnings generated from certain assets such as the Permanent Fund, the Statutory Budget Reserve, and the Congressional Budget Reserve. FY 2013 returned $5.0 billion on total state assets of about $60 billion. The department is forecasting $3.6 billion in restricted investment revenue in FY 2014. More information about Investment Revenue can be found in Chapter 7.

Federal Revenue

All federal funds to the State are considered restricted for purposes of this forecast. Federal funds include revenues for highways, medical care, education, and other designated purposes. Over the past several years, this revenue source has contributed between $2 billion and $2.5 billion annually. The State received $2.4 billion in FY 2013 and is forecasting $3.0 billion in federal payments to the State for pre-determined uses in FY 2014. However, consistent with practice in prior years, the forecast represents the maximum possible Federal Revenue contribution, while actual revenues routinely come in below that forecast. More detail regarding Federal Revenue can be found in Chapter 6.

3

Liquefied Natural Gas: Alaska's Once and Future Export?

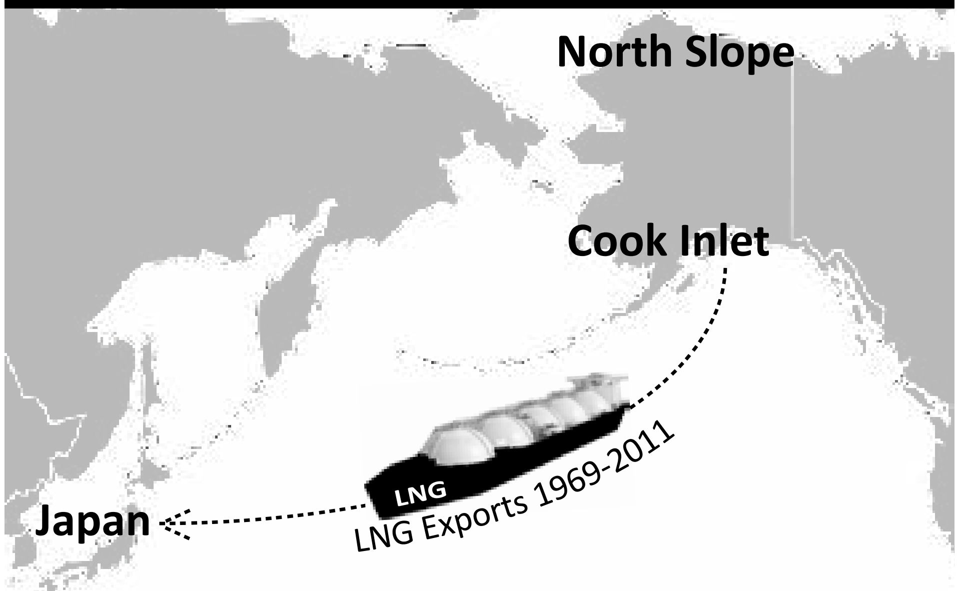
Natural gas is an abundant resource within Alaska.

Compared to oil production, natural gas production in Alaska is several orders of magnitude smaller, including the amount of tax revenue has generated for the State of Alaska. Nevertheless, natural gas production has played a significant role in Alaska's economy.

Alaska's natural gas production primarily comes from two regions: Cook Inlet and the North Slope (see Figure 3-A). The first major commercial gas discovery came in Cook Inlet in 1959, the year Alaska became a state. Natural gas was later found along with oil at Prudhoe Bay (central North Slope) in 1968.

The export of natural gas in a liquefied state to Japan was one of Alaska's first major world-class development projects. Cook Inlet natural gas has been produced for export to Japan and for in-state use for over a half-century. Overall, since 1959, Cook Inlet has produced over 7.75 trillion cubic feet of gas[(1)]; of this about 2.5 trillion cubic feet has been exported.[(2)]

Figure 3-A: Geographic Overview



Source: Background Image "Pacific Centric SVG World Map". http://commons.wikimedia.org/wiki/File:Blank_Map_Pacific_World.svg. Accessed 13 November 2013.

Figure 3-B shows natural gas exports for Cook Inlet from 1989 to 2011. Regular exports to Japan ceased by 2011.

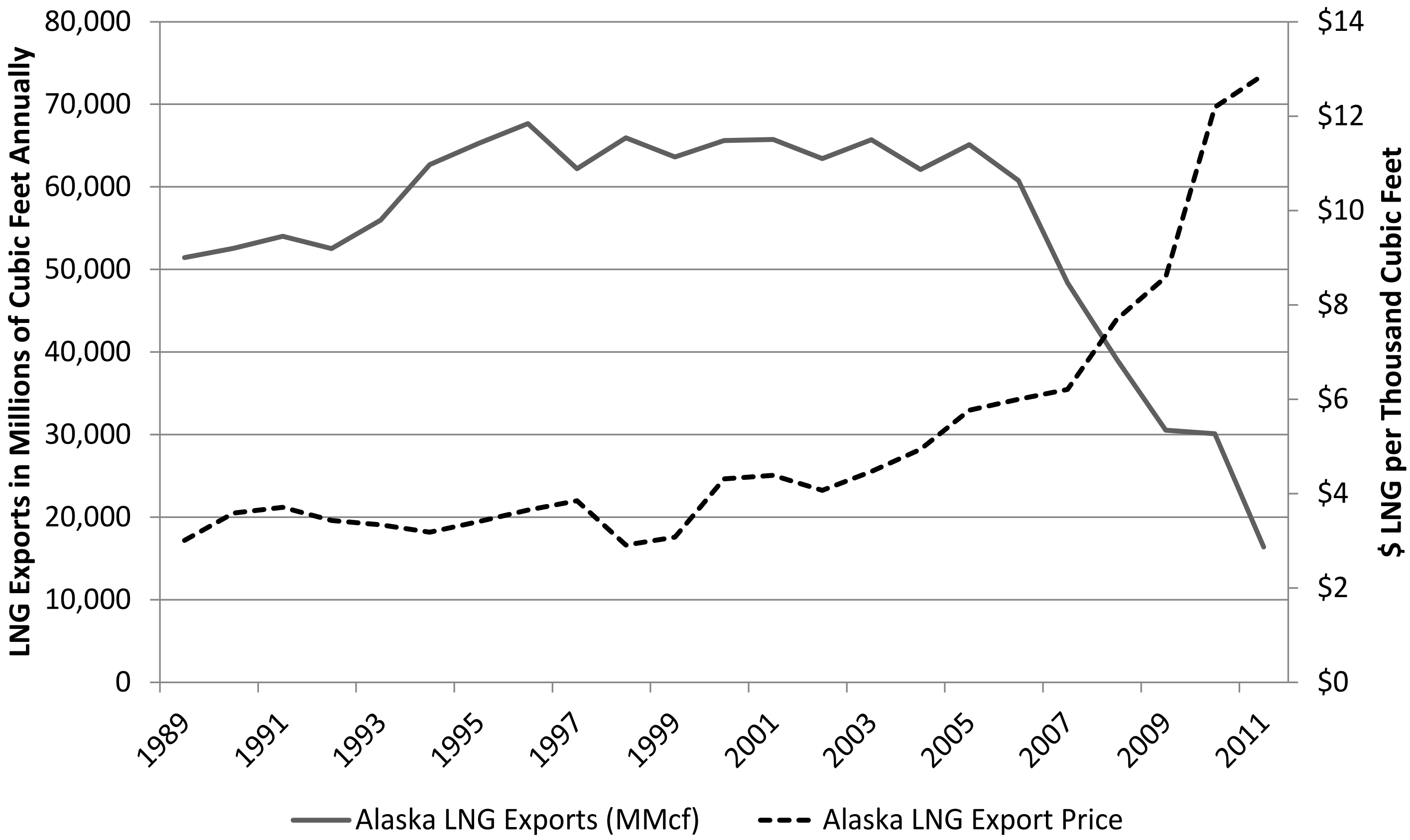
Locally, by the 1980s, natural gas became the primary fuel for generating electricity and for heating Alaska's largest city, Anchorage, and the "Railbelt" area tied into the electrical grid. Earlier, in the area of Barrow (western North Slope), the US Navy discovered natural gas as early as 1949. This field remains a source of energy for Barrow, one of the few settlements in the Arctic to be almost completely powered and heated by natural gas. The village of Nuiqsut (central North Slope) is also powered and heated by natural gas.

The export of LNG (liquefied

(1) This chapter will predominantly use the English conventions for measuring natural gas used in the United States, rather than the International System of Units (metric system).

(2) Oil and Gas Division, Alaska Department of Natural Resources

Figure 3-B: Alaska LNG Export Volumes and Price



Source: US Energy Information Agency

natural gas) was one of the major drivers of Alaska's economy and helped establish Alaska as an energy exporter. The export of LNG from Cook Inlet also set the stage in how the State would interact with the development of the North Slope – understanding that the act of exporting a resource outside of Alaska can be an engine of economic growth.

The possibility of a large-scale project that can export the immense North Slope natural gas resources to North American or global markets has been tantalizing and frustrating Alaskans for almost half a century. Economic and commercial conditions for a North Slope natural gas project have not coalesced in the last forty years. Discussion about the potential of such exports is often a major issue within Alaska, and began about the same time major oil discoveries were made on the North Slope.

Natural Gas Basics

Natural gas is a mixture of hydrocarbons, at least 70% methane (CH_4) by volume, that, at ambient temperatures, is in gaseous form. The gas can be burned to release energy in the form of heat for electricity generation and steam generators, as well as residential, commercial, and industrial heating and cooling. The heating value of natural gas within the US is defined as giving off between 950 and 1,100 British Thermal Units (BTU)[1] per standard cubic foot (scf), under standard atmospheric conditions. A barrel of oil, by comparison, gives off about as much energy as six thousand cubic feet (mcf) of natural gas. A common rule of thumb is to divide gas volumes in thousands of cubic feet by six to approximate the "barrel of oil equivalent" of gas production and consumption. The exact conversion factor varies.

(1) One BTU is the amount of energy needed to heat or cool one pound of water one degree.

Natural gas is more abundant and cleaner burning than other hydrocarbons, but is more difficult to transport and store. Like oil, natural gas can be transported over long distances in pipelines. However, unlike oil, which is liquid at ambient temperature, natural gas is difficult to ship by sea. Natural gas can be chilled to extremely cold temperatures (-259° F) to become a liquid. In its chilled state, natural gas is 600 times denser than the original gas at ambient temperatures. Liquefied natural gas can be easily transported on very large marine vessels to markets, where it is re-gasified and used as conventional natural gas. However, liquefaction is a costly process. One way to export North Slope natural gas from Alaska is to deliver gas by pipeline to a tidewater liquefaction plant, convert the gas to LNG and then ship it from a marine terminal to the destination market.

Alaska, an early global leader in LNG exports

Alaska was one of the earliest pioneers in the global trade of LNG. An LNG plant on the Kenai Peninsula, in Nikiski, Alaska, operated between 1969 and 2011 and shipped gas to Japanese electrical utilities. This LNG plant was a globally significant project, since it was the world's second-ever intercontinental LNG project, after an export project between Algeria and Italy. In addition to monetizing a world-class natural gas source at tidewater, this project created the initial destination infrastructure that allowed Japan to become a major user of LNG from global sources. For the exporter, because of US maritime laws, primarily the Jones Act, the LNG could be moved from Alaska overseas to Japan on low-cost, foreign-owned, foreign-built and foreign-operated tankers. This would not have been the case if LNG was delivered to the US, which would have required higher cost vessels and operating conditions related to the Jones Act.

For many years, Cook Inlet gas was considered relatively inexpensive, and was so plentiful relative to what was exported to Japan and what was locally used that the natural gas was also converted to a relatively low valued commodity, urea (ammonia) fertilizer, at a plant in Kenai, Alaska. The fertilizer was also exported. The plant was a major employer, with over 250 people employed, in the Kenai area from 1969 until 2007. Before it closed, it was the second largest producer of urea in the US.

Since the early 2000s, local demand for natural gas expanded with the growth of Alaska's population in the south-central area. At the same time, gas production declined, primarily because additional reserves were not developed within Cook Inlet. In 2011, according to the US Energy Information Administration, Alaska consumers used over 85 billion cubic feet of natural gas, which accounted for 63% of power generation in the State and 53% of heating fuel. See Figure 3-C for Alaska consumption trends from 2004-2011.

As natural gas prices in North America rose to all-time highs and the prices became higher relative to prices for LNG shipped to Asian markets, and since there was no regasification terminal to accept Alaska LNG on the US West Coast, the deposits in Cook Inlet were of less interest to the industry.

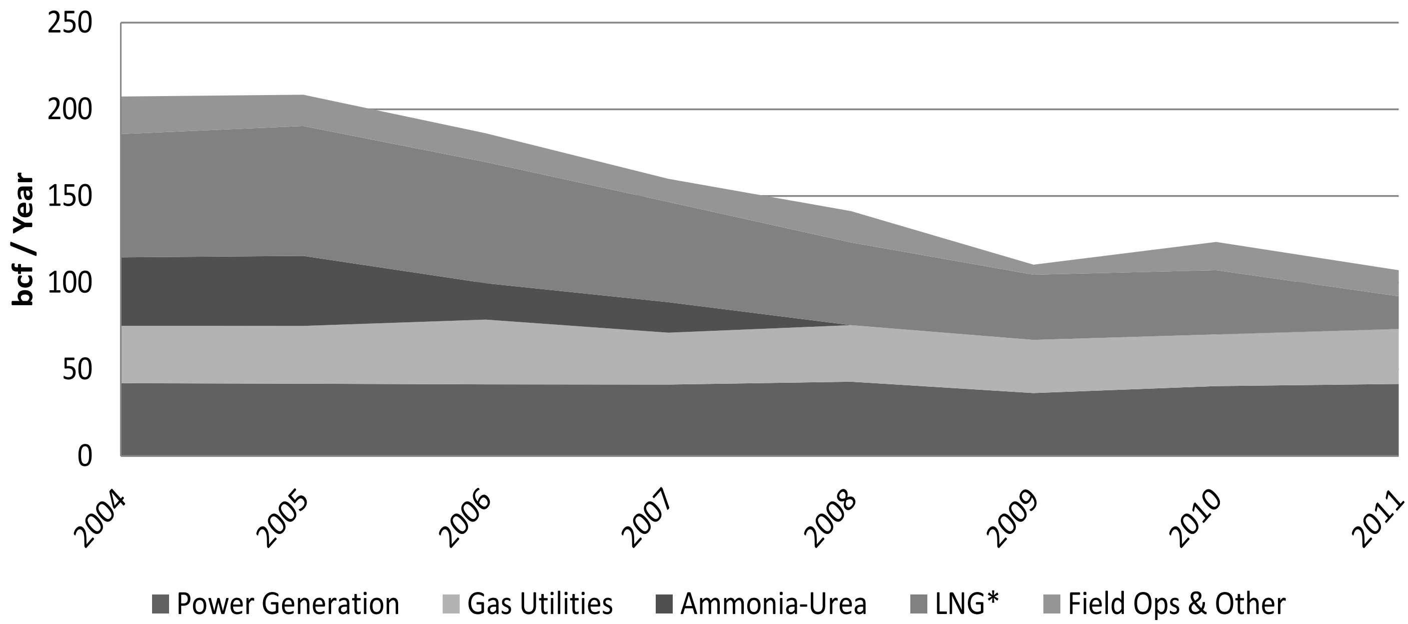
The fertilizer plant closed in 2007 and the LNG plant in 2011, as higher value use competed for diminishing gas production, and because proved gas reserves were not sufficient to meet anticipated Anchorage demand. For the same reason, lack of available gas forced the Nikiski LNG plant to close. Consistent LNG exports to Japan ceased in 2011. Figure 3-D show Cook Inlet contributions to production tax and royalty for 1991-2012.

Local Use of Natural Gas

Ensuring gas supply for Anchorage became an important issue for the Municipality of Anchorage and the State. In 2012, a gas storage facility was constructed, which allows extra gas produced in summer to be saved for use in the winter when demand out-paces production.

Several different proposals to resolve Anchorage's gas issues included bringing natural gas from the North Slope by pipeline (small or large diameter); exploring and discovering additional reserves in the Cook Inlet and/or nearby; or, even importing LNG into the Anchorage market. In the short-term, while production has declined and demand in south-central Alaska has increased, the overall rise in price as well as a fiscal policy that includes significant credits for exploration and development resulted in increased exploration. Increased exploration has, in turn, made new supply of natural gas available, and the Anchorage market now has sufficient supply through 2018, according

Figure 3-C: Cook Inlet Gas Consumption



Source: Alaska Department of Natural Resources Oil and Gas Division

to the Department of Natural Resources.

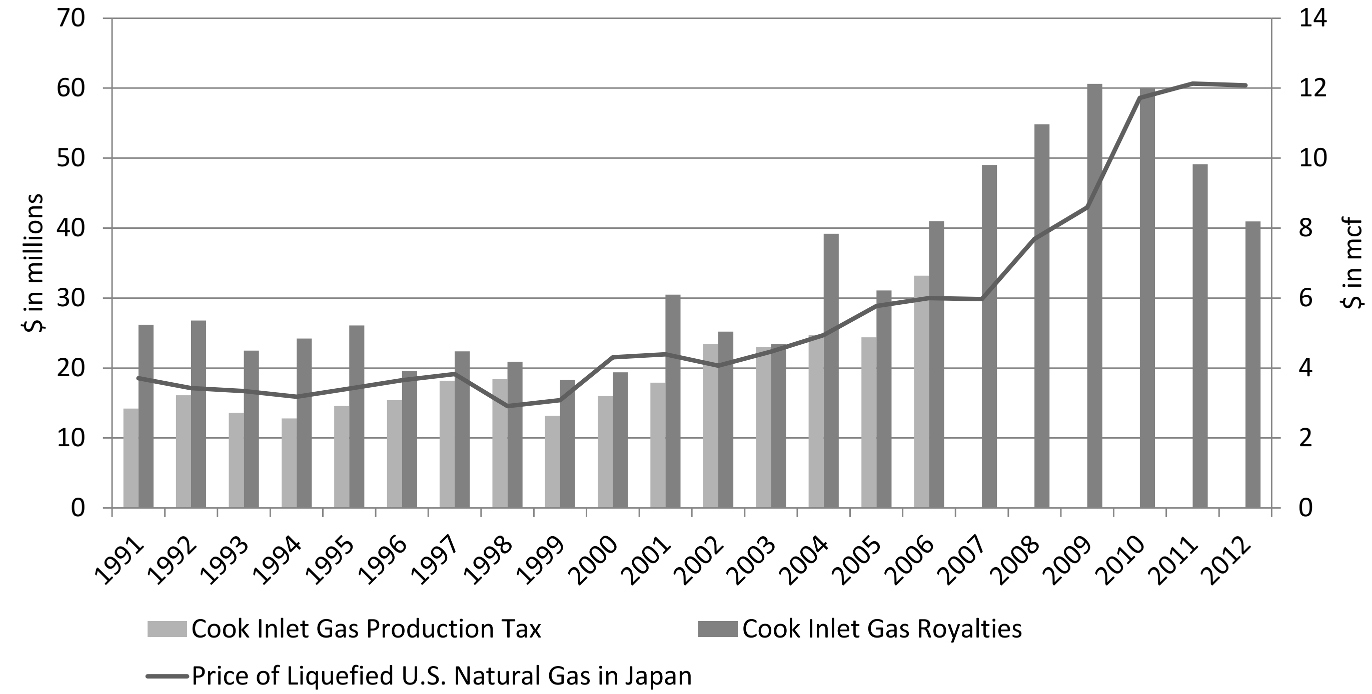
A small amount of Cook Inlet gas is trucked to Fairbanks for heat and power. Currently, 1,100 households in the Fairbanks area use natural gas. For the most part, however, Fairbanks and most outlying areas of the State do not use natural gas for electricity generation, and face significantly higher utility costs than south-central Alaska. Fairbanks faces an energy crisis because of high prices for electricity and heating. The heating issue is exacerbated by the fact that many people are heating or supplementing their ordinary heating systems with firewood, which has created a problem with air quality in the area. Current limits of the facility in Big Lake (where the Cook Inlet gas is loaded on trucks) have created demand for a new supply source from the North Slope. Access to increased supply of gas for Fairbanks could reduce the costs of both space heating and electrical generation for the Interior. Without a pipeline to supply the gas to Fairbanks, trucking gas from the North Slope has been proposed as a fast, flexible and efficient way to serve the Interior and resolve the gas supply issue for Fairbanks in the short-term. The trucking project has been discussed for several years, and may materialize in the near-future.

Expanded use for natural gas is a part of the discussion about the energy use mix within the State, especially in terms of electricity generation. Should North Slope gas be delivered to south-central Alaska or Cook Inlet production increase, at a competitive price, at sufficient volumes, new uses are proposed for natural gas within the State. For example, several mining projects have proposed using natural gas to power their operations. The developer of the Donlin Creek gold mine, a major prospect located near Bethel in Southwest Alaska, proposed constructing a 312-mile-long pipeline to the mine to generate power. Pebble Partnership proposes using natural gas in its concept plan to power mine operations. This is also coupled with the thought that such a gas supply could provide a cleaner and cheaper fuel to generate electricity for the larger region, which currently relies mainly on fuel oil. Also, any electrical energy generated in Anchorage can enter the Railbelt regional grid benefiting even the Fairbanks area population.

Past Plans for Alaska Natural Gas Export

The Prudhoe Bay oil discovery in 1968 that led to the construction of the Trans-Alaska Pipeline System (TAPS) also included an initial estimate of 23 trillion cubic feet of natural gas. Efforts to commercialize

Figure 3-D: Production Tax and Royalty Collections on Cook Inlet Natural Gas and Japan Natural Gas Price



Source: Alaska Department of Natural Resources

natural gas began soon after the completion of TAPS, and for over forty years there have been numerous proposals to move North Slope gas to markets. However, to date, Alaska does not export North Slope gas, although natural gas is used for oil recovery operations and for electricity generation on the North Slope.

The use of natural gas on the North Slope is not insignificant. Producers are prohibited by law from flaring natural gas on the North Slope unless for safety. Instead, they use it for power generation to support oil production. Since oil production began in 1977, 6 trillion cubic feet of gas has been consumed for power. Some natural gas is produced as liquids that can be shipped through the TAPS along with oil. Since the completion of the Central Gas Facility in 1986, over 600 million barrels of gas liquids have been produced. Some of the gas is turned into a “miscible injectant” that helps increase oil production. The remaining gas is re-injected into the Prudhoe Bay reservoir to maintain pressure and help increase oil production.

In 1976, Congress passed the Alaska Natural Gas Transportation Act, which provided for expedited development of a pipeline. The following year, the United States and Canadian governments approved the construction and ownership of a pipeline along a route that followed the Alaska Highway through Canada to reach Continental US customers. A competing project at the time included the El Paso Natural Gas project to export LNG to California, also called the “All-Alaska” route (a name used later by other Alaska projects that follow a similar route), to a marine terminal near the oil terminal in Valdez, Alaska. The El Paso Project was rejected under the same federal certification process that approved the Alaska Highway route. Even an “over-the-top” offshore route in the Arctic Ocean to Canada and ultimately to US East Coast markets was proposed at the time.

Deregulation of the US domestic natural gas industry led to a supply increase and a price drop for the destination markets in the Lower-48 and the Alaska Highway project never materialized. In the end, none of the projects were able to answer the ultimate question to investors and project organizers: did the margin between the delivered cost and the expected price per unit of gas result in sufficient net returns to justify the risk? In 1983, these costs needed to beat about $3.00 per thousand cubic feet of gas in real 1983 prices, while annual average wellhead prices hovered above $2.50 per thousand cubic feet. By 1986 were less than $2 per thousand cubic feet. Only the southern leg of the planned Alaska Highway route was constructed, allowing gas from the Province of Alberta to help meet Continental US demand. Natural gas wellhead prices only passed the nominal $3 per thousand cubic feet threshold in 2000.

Studies done in the 1980s revived a proposal to establish an LNG export operation for North Slope gas to Asia, but prices failed to support the commencement of such a project. Interest in a gas pipeline picked up again around the turn of the millennium due to rising prices and demand in the Continental US, primarily in using gas in electricity generation. In 1998, the Alaska Legislature passed the Alaska Stranded Gas Development Act, which allowed the State to negotiate special fiscal, tax and royalty terms, and regulatory terms with the North Slope oil producers, for an LNG project that exported "stranded gas," defined as gas that, "… is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the Department of Revenue commissioner for a particular project." The act was reauthorized in 2003 and extended to any North Slope gas pipeline project.

In 2004, Congress passed the Alaska Natural Gas Pipeline Act, which established a federal project coordinator, provided for loan guarantees, and offered tax and regulatory incentives for a pipeline project. These laws led to negotiations between the State administration and the North Slope producers that culminated in a contract in 2006 that was rejected by the State legislature. At this time, annual average nominal wellhead prices in North America exceeded $6 per thousand cubic feet.

Table 3-1: North Slope Gas Potential

Exploration Area	Mean Technically Recoverable Gas (trillion cubic feet)
Prudhoe Bay	23
Point Thompson	8
ANWR	9
Beaufort Sea OSC	32
Chukchi Sea OCS	77
Colville-Canning Area & adjacent state waters	38
NPR-A	53
Total	240

Sources: U.S. Department of Energy, August 2007; BOEM, *2011 National Assessment*. Energy Information Administration, *2009 Annual Energy Outlook*.

In 2007, the State Legislature passed the Alaska Gasline Inducement Act (AGIA), which provided for partial reimbursement for a developer's expenses, up to $500 million, in exchange for agreeing to terms including following the State's time line. TransCanada, a Canadian pipeline company, was awarded the license on the project, and ExxonMobil later agreed to work with them on the project. Meanwhile, BP and ConocoPhillips launched a competing proposal, called Denali – The Alaska Gas Pipeline. The plans in their various incarnations called for a pipeline to Canada to link into mid-American markets that were similar to the Alaska Highway proposals of the 1970s.

Falling natural gas prices in the Continental US due to the explosion of shale gas production drastically increased the North American supply within a period of a few years. In 2012, the three main North Slope oil producers, and owners of North Slope natural gas resources, joined together to propose a pipeline to a south-central Alaska LNG facility that would export gas to Asian markets, rather than a pipeline to North American markets. Work continues on this plan, and a preliminary concept was selected in early 2013. The current proposed project is reported to have an estimated cost of between $45 and $65 billion for a gas treatment plant, a 42-inch pipeline, and an LNG export facility (three trains delivering 15-18 million tons of LNG) in Nikiski, on the Kenai Peninsula.

Two other LNG proposals include a recent proposal from Japanese company Resources Energy Inc. (REI) and an older proposal, by the Alaska Gasline Port Authority (AGPA), a joint venture organized in 1999 between the Fairbanks North Star Borough, Valdez, and, at one time, the North Slope Borough. The port authority project applied for an export license, but the proposal was rejected in 2013 by the Department of Energy.

Parallel to these efforts to construct

a large-diameter pipeline is an effort to construct a smaller pipeline to transport North Slope natural gas, to serve the local needs of Alaska consumers in the Railbelt area. In 2002, Alaska voters approved a ballot measure that created the Alaska Natural Gas Development Authority (ANGDA), which was vested with the authority to act as a shipper and obtain financing for a project. In 2010, the Legislature created the Alaska Gasline Development Corporation (AGDC), as a subsidiary of the Alaska Housing Finance Corporation. AGDC was tasked with moving forward with the Alaska Stand Alone Pipeline (ASAP) project to build a line. In 2013, the Legislature made AGDC an independent corporation and folded ANGDA's operations into it. The AGDC project itself reports a cost estimate of $4.9 billion for a 36-inch pipeline to Anchorage and $2.8 billion for a gas conditioning facility on the North Slope.

Natural Gas Markets

The physical requirements needed to transport natural gas dictate the manner in which it is marketed and used. Globally, the major distinction, therefore, is between natural gas that can be delivered by pipeline overland and natural gas that is sold as LNG by sea. Countries or regions that have deposits of natural gas and have well-developed natural gas pipeline networks are able to move the gas to where it is needed. Countries or regions without natural gas or use more natural gas than they produce, must import gas either by pipeline or must import LNG to a marine terminal.

An example of the former is Germany's use of Russian natural gas that is delivered by large-diameter pipeline, and an example of the latter is Italy's import of Algerian LNG by sea. South Korea, which has little domestic gas, but has a well-developed national gas pipeline network, is able to import natural gas through three injection points and distribute it relatively efficiently throughout the country.

In contrast, Japan has a very rudimentary national pipeline network, and relies on over 20 marine terminals to accept LNG. The electrical utilities own most of the LNG import terminals and the natural gas is used to generate electricity, which is then distributed throughout the country. Rigid right-of-way laws have made the establishment of a gas pipeline network problematic.

Historically, Alaska's natural gas, produced at tidewater in Cook Inlet, was a natural candidate as an LNG export project. However, the effort to export Alaska's North Slope gas is faced with various options, including moving natural gas by pipeline to North American markets via a route to the closest major Canadian hub located in Alberta, known as the Alberta Energy Company (AECO) hub. Other options include moving the gas to a marine liquefaction plant for export to Japan or other markets in Asia, or, even to North American West Coast markets, which require the additional cost of constructing an import terminal at the destination. There have been other options considered as well. There is the previously mentioned so-called "over-the-top" option, with a pipeline going due east along the Arctic National Wildlife Refuge, into Canada. This option could also transport pick up Canadian arctic gas deposits, and delivered to markets in Northeast US. This option is typically rejected because of environmental permitting related to the federal refuge, and because the pipeline has a relatively short length within Alaska and the United States. It has been argued the project would benefit Canada disproportionately. In fact, there is an opposing state resolution (HJR 44, 2002) and a federal law (Alaska Natural Gas Pipeline Act, 2004) that prohibits the "over-the-top option." There is the option of a shorter pipeline to the Bering Sea, or taking gas directly out of the Arctic on LNG vessels, but these options have significant technical challenges.

All options require significant lead time and large capital costs, and most the construction of an overland pipeline either to Canada or to south-central Alaska. However, one option ties Alaska natural gas directly into North American markets and the extensive pipeline network, while the other, would have Alaska continue as a player in the marine LNG trade. For the export of Alaska North Slope gas, the price differentials at various times would have one option seem advantageous over the other. However, over a thirty year period, the price differential between the two destinations has been large and small, and has reversed several times.

Japan, Republic of Korea and Taiwan are the premium markets for LNG. In addition, China, India, South America, the Middle East, India and European countries represent new and growing markets for LNG. New LNG demand centers have more energy options than Japan and Korea, resulting in weaker premium LNG prices in these locations. Yet, these regions are reliant on external LNG sources.

Basins located in Russia, Qatar, Australia, and others are the main suppliers to the global LNG market. Suppliers to the LNG market are set to rapidly expand. Up to 25 countries have proposed plans to build export LNG terminals or add additional capacity over the next decade. These additional exporters have little or no current capacity. Ironically, with LNG prices at unprecedented highs, Alaska, one of the first suppliers of LNG in the world, has ceased to export LNG from Cook Inlet.

Natural Gas Prices

To get a picture of the current conditions of the global market for natural gas that are relevant to Alaska, we compare major natural gas pricing points – the US Gulf Coast Henry Hub (HH), the UK's European National Balancing Point (NBP), and the Japan-Korea Marker (JKM).

Henry Hub, in Louisiana, is the price hub that defines the market for North American pipeline gas in mid-America. Pipeline infrastructure defines natural gas markets in North America. Henry Hub natural gas prices are the most often quoted natural gas prices in North America. Natural gas pricing in North America is lucid, despite a large geographical area the infrastructure covers. Accessible infrastructure, large reserves, cutting edge production technology, stable governments, large numbers of suppliers and consumers, financial markets and other factors, have created an unparalleled distribution system in North America. US currently has some of the lowest natural gas prices in the world because of extensive infrastructure coupled with a massive amount of associated gas produced along with the relatively new "shale oil revolution" in North America. Only five years ago, this was not the case. Annual average prices were almost triple what they are today at the wellhead.

The National Balancing Point (NBP) is a virtual trading location and is a price point for British gas. Unlike Henry Hub, it is not a physical location. It includes North Sea gas transported into the UK and has both a pipeline and LNG natural gas market component. It is also the price and delivery point for the Intercontinental Exchange (ICE) for natural gas futures contracts.

The Japan-Korea Marker is Northeast Asia's pricing point that consists of an LNG import market connected to South Korea's national pipeline system, and the large number of marine terminals in Japan where the natural gas is directly converted into electricity. Japan LNG also supplies a relatively inefficient city gas market.

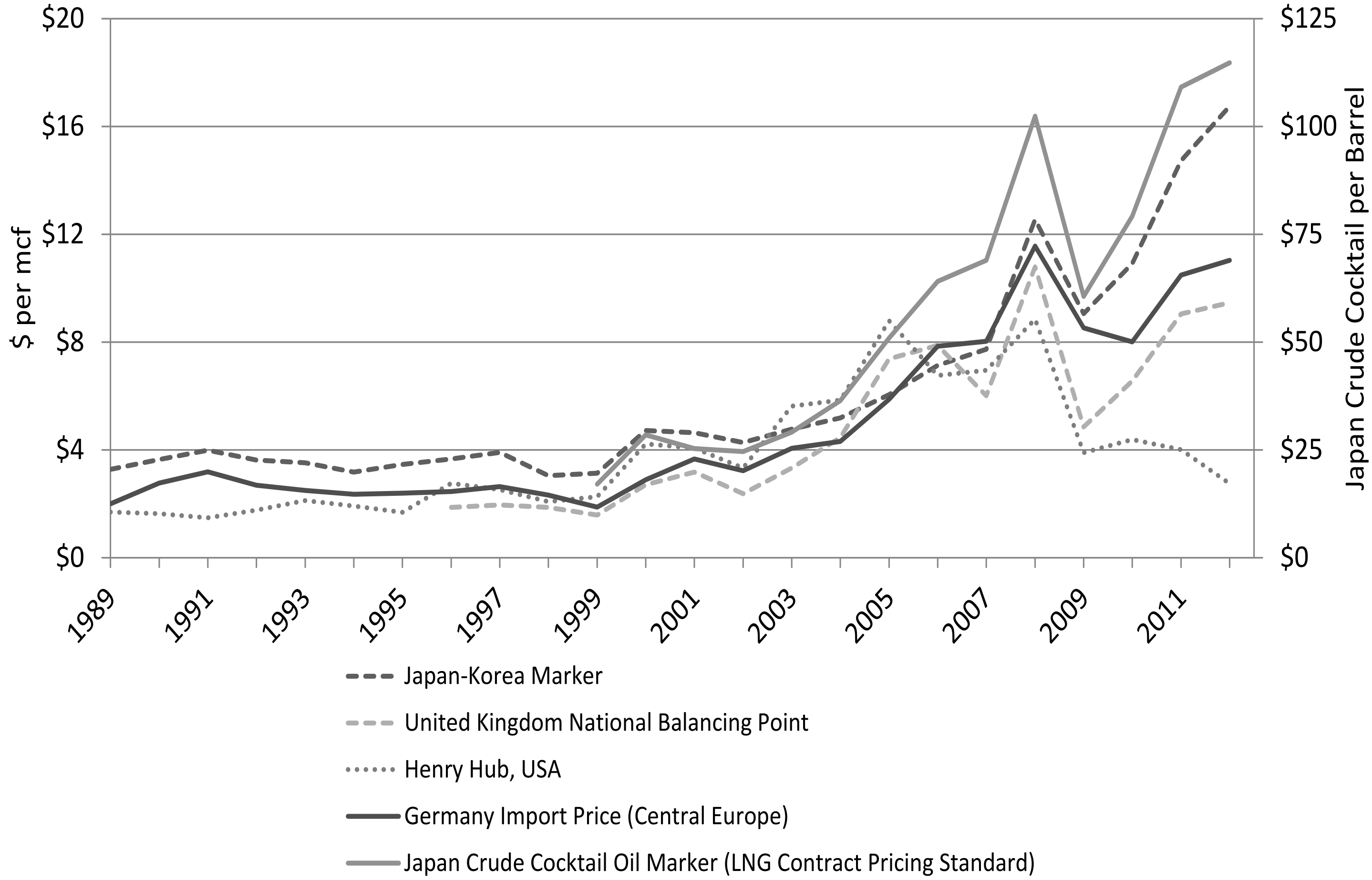
While the global gas price hubs continue to follow oil prices, Henry Hub notably does not. In general, the major price hubs have experienced significant divergence in price. Until 2007, these markets normally traded within \$2-\$3 of each other. Currently, the pipeline market and the LNG market differentials have never been greater, consistently exceeding \$10. The current divergence between Henry Hub and the Japan-Korea market differs by more than five times.

Figure 3-E illustrates the extent natural gas prices have diverged globally, including a comparison with oil price, on an equivalent thermal basis.

In the 1990s, natural gas prices in North America were relatively low and stable, and natural gas became extremely popular in electricity generation because it was a cheaper and cleaner burning fuel, relative to coal and oil. On the demand side, the US deregulation and restructuring of the natural gas industry expanded the use of natural gas in the US energy mix. On the supply side, prior to 2007, natural gas production was mainly tied to discoveries linked to oil, creating a price relationship between oil and natural gas. Oil prices started to rise in 2003 due to loss of spare capacity in the oil market, strong global growth and underinvestment by petroleum companies accustomed to a low oil price environment. Further, US supplies were constrained primarily to domestic supplies, since LNG import terminals were relatively insignificant as a source of gas supply. As demand grew and supply was constrained, the result was a sharp increase in natural gas price in US markets.

Incidentally, the 1990s coincided with proposed plans to bring Alaska LNG into the California markets. One problem was the difficulty of permitting an LNG import terminal in the Continental US. Another problem was that shipping Alaska LNG would require vessels constructed and operated under Jones Act requirements, considerably

Figure 3-E: Global Natural Gas Prices



Sources: BP's 2013 Statistical Review of World Energy, Bloomberg, and Reuters

more costly, considering delivery to higher priced Japanese LNG markets could be delivered in foreign vessels, with foreign crews.

After 2007, the oil and gas industry in North America increased investments in developing new resources of natural gas from shale. Prices in North America collapsed, further exacerbated by a lucrative market in stripping natural gas liquids (a high price commodity relative to gas), leaving behind a large supply of relatively low price natural gas. See Henry Hub prices in Figure 3-G. At the same time, in addition to Henry Hub prices diverging from other prices, the Japan-Korea Marker and National Balancing Point pricing diverged due to the way LNG contracts link to oil price markets. National Balancing Point price increases have been muted when compared to Japan-Korea Marker prices, which are heavily influenced by oil linked contracts.

Natural gas prices in Alberta have always been important to Alaska, since this would be the likely destination for any Alaska gas overland pipeline project that delivers gas to the Continental US. The differential between Louisiana and Alberta prices is the cost of transportation between natural gas coming from Alberta to Louisiana. This is a sign of a mature market with ample infrastructure.

For Alaska, price volatility (especially from the 1990s through today) has greatly affected project economics of a North American gas pipeline. In the ten years it takes to complete an Alaska project, natural gas prices could change dramatically. See Figure 3-F a geographic view of price differentials. The relatively cheap natural gas price in North America has now made it a major fuel in electricity generation. In fact, cheap natural gas burns cleaner than coal, producing 70% lower carbon emissions. This advantage has allowed natural gas to capture more

Figure 3-F: Geographic View of Price Differentials

Source: BP's 2013 Statistical Review of World Energy

of the electricity market in the US. As Figure 3-H illustrates, between 2000 and 2011 the market share of coal has decreased and natural gas market share has increased. This trend is set to continue as America's oldest electricity plants that run on coal are being retired, and are replaced by natural gas plants.

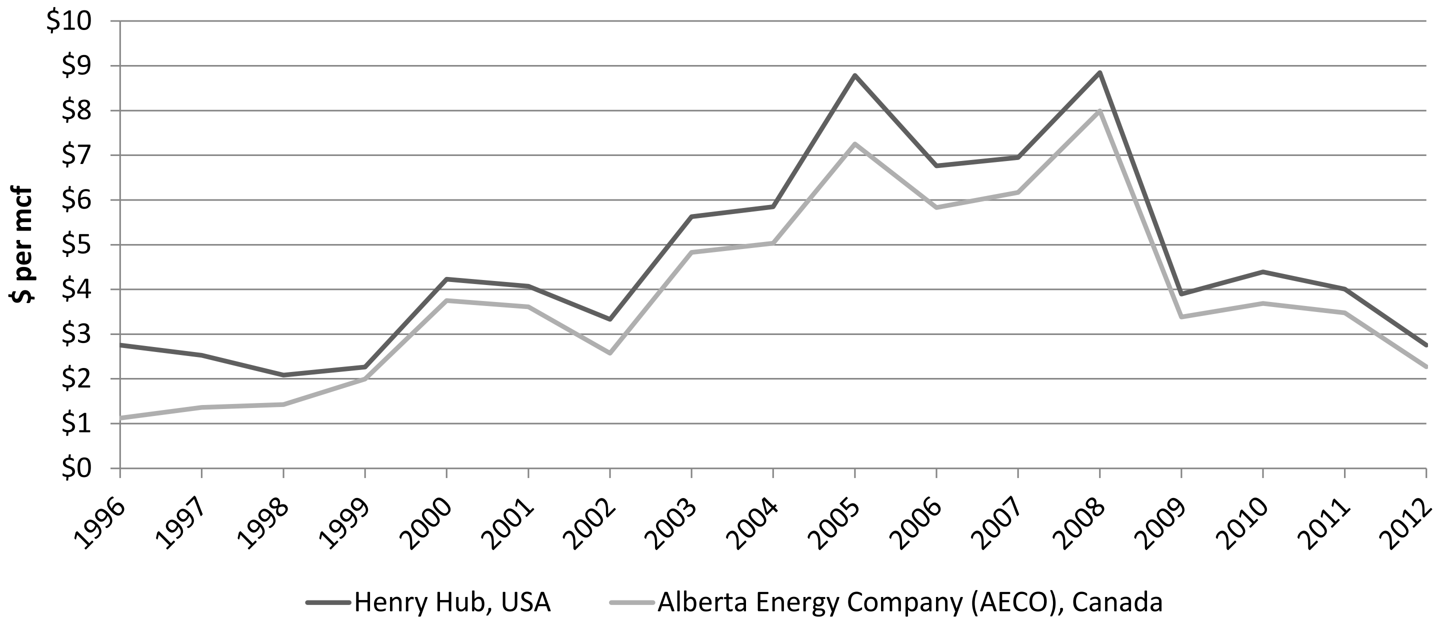
LNG Demand

Global LNG demand has grown 7.6% per year since 2000, compared to global natural gas demand growth of 2.7% over the same time period. Asia has been the single largest contributor to this rise in demand for LNG. The Fukushima reactor meltdown has anchored LNG growth in the short- to mid-term as Japan has moved away from nuclear energy for current and planned incremental electricity generation. LNG demand seems to be set to continue expanding as nations seek energy diversification and flexibility in their energy sources. There is also a growth in infrastructure within Northeast Asia and India that allows LNG use, and there is a regional concern for hydrocarbon emission and the desire to replace coal with the cleaner burning gas. Finally, there is a surge of supply as new basins are brought on line to serve the LNG demand in Asia. Europe, which has spent years developing a de-carbonization strategy, with Germany's rejection of electricity generation by nuclear energy, also a reaction to the Fukushima disaster, has not had subsequent increase of use of natural gas in electricity generation. This is primarily because Germany is one of Europe's main energy consumers and Germany's main supply of gas, by pipeline from Russia, faced the monopolistic pricing policy of Russia's state-owned gas production giant, Gazprom. Ironically, coal use in Europe has increased to compensate for the shut-in nuclear capacity.

The International Energy Agency (IEA) predicts strong global growth of natural gas usage. IEA's forecast for natural gas in 2035 is 25% of energy consumption, up from 21% in 2010. Global natural gas demand is projected to grow 1.6% per year, whereas oil growth is projected to rise at 0.8% annually over the same time frame. Estimated LNG demand in 2030 is 24,000 billion cubic feet, double 2012 demand of 12,000 billion cubic feet. LNG demand is forecast as particularly strong through 2020, with a broad range of analysts and observers projecting 5%-6% growth per year.

Currently, half of LNG market

Figure 3-G: Major North American Hub Prices



Source: BP's 2013 Statistical Review of World Energy

demand comes from Japan, Republic of Korea (South Korea) and Taiwan. New LNG demand is led by China and India. China's latest five year plan doubles the amount of LNG used from 4% when the plan came out to 8% in 2015 and 10% by 2020. In order for China to meet the goals of its "five year plan," coal consumption must decline, likely to be replaced by LNG. Currently, China's coal consumption is seven times larger than the global LNG trade. In contrast, US coal consumption for electricity generation decreased by 26% between 2007 and 2012, according to the EIA. China does have natural gas opportunities to develop, including shale gas and pipeline gas expansions, and it has pursued these opportunities aggressively. If China's natural gas demand continues to grow, pipeline and shale gas production volumes will need to be supplemented by increased LNG imports. With multiple supply options, China should be well-supplied by domestic sources, pipeline gas and LNG contracts. Figure 3-I illustrates China's projected LNG imports.

Other countries have planned new construction or to add additional capacity to import LNG. Many of these countries will be new importers. Currently, the 25 countries that import LNG have a re-gasification capacity of 28.8 trillion cubic feet per year; and, by 2020, 38.4 trillion cubic feet per year of regasification capacity could exist, an increase of 9.6 trillion cubic feet, or 33% over current capacity.

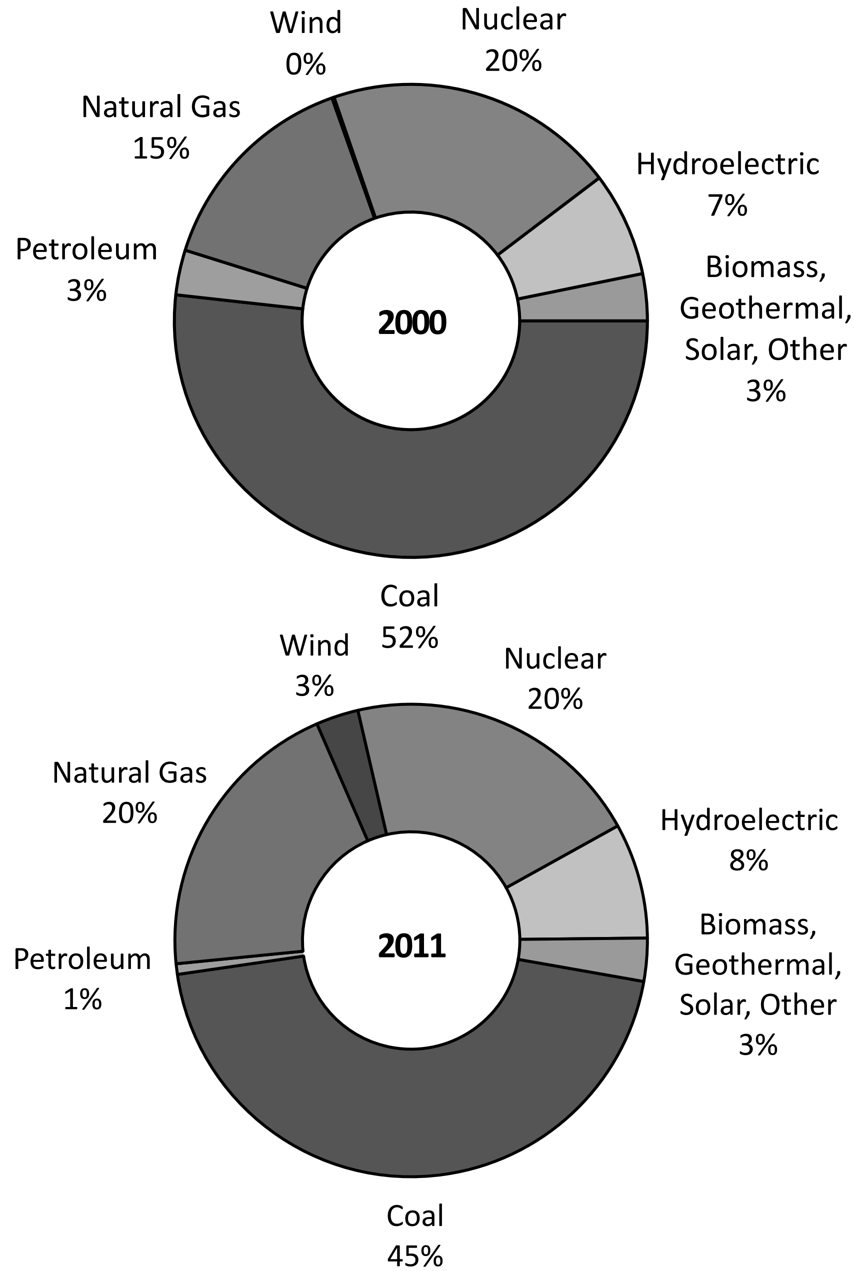
LNG Supply Risks

Uncertainty is the key term the LNG supply chain faces. Challenges exist in multiple forms on a global scale, from competition to unwieldy expensive large projects, and local to global economics. Since 2009, global economic growth has been slow to emerge. Many economies within the Organisation for Economic Co-operation and Development (OECD)[1] have yet to recover fully, with non-OECD countries growth being restricted because of this. LNG projects are handicapped with this uncertainty, even though current economic trends suggest that the global economy has stabilized and economic growth has returned.

New supplies from unconventional resources such as shale gas, coal bed methane, tight gas and methane

[1] The OECD economies are the world's industrialized economies.

Figure 3-H: U.S. Electricity Fuel Sources 2000 and 2011



Source: Energy Information Administration

hydrates could capture potential future LNG market share. These unconventional sources also exist on the North Slope of Alaska. Ten years ago, the estimated natural gas resource base worldwide was for 50 to 60 years' worth of supplies. Now the natural gas resource base is projected to have expanded to a 200 year supply. The IEA estimates there are 26,600 trillion cubic feet of technically recoverable natural gas world-wide.

LNG Supply - Capacity

Global LNG capacity has developed in stages. In addition to Alaska's Cook Inlet, early LNG exporters included Algeria, Indonesia, and Malaysia, followed more recently by Australia and Qatar. The early LNG exporters still control about 60% of the global LNG supply, with Australia and Qatar providing 20% of the market. This market structure is expected to shift dramatically by 2020. Algeria, Indonesia, and Malaysia market share will drop to about 20% on a global basis by 2020, while Australia and Qatar are expected to expand their markets share to about 50% globally.

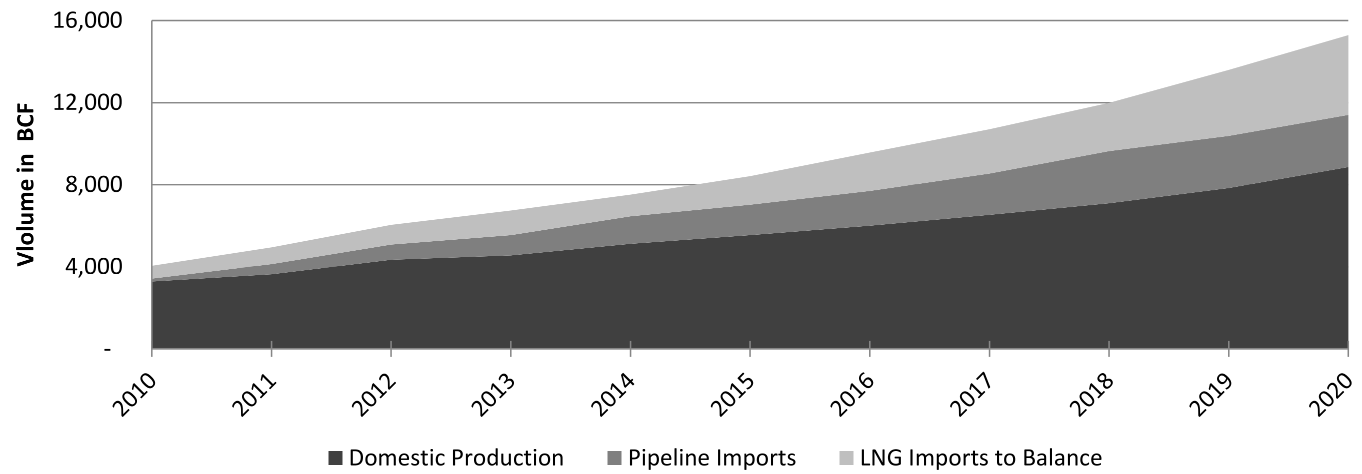
Australia in particular has a number of LNG projects under development representing a third global wave of projects. These green field projects will have the capacity to produce 2.8 trillion cubic feet annually.

LNG Supply – New Entrants

Any Alaskan LNG project must evaluate future competing LNG projects worldwide. LNG projects under construction and those projects currently supplying the LNG market are not Alaska's competitors. Those LNG projects have clients, the development costs have been partially or fully funded and risks have been resolved or negated to an acceptable level. Longer term, suppliers to the LNG market will expand as new entrants enter the market. Possible new entrants include Canada, United States, Tanzania, Mozambique, Israel, Iran, and Venezuela. Some countries like Iran and Venezuela are less likely to develop their reserves due to geopolitical events and financial constraints. Other countries like the US and Canada are in much better position to begin exports.

Future LNG projects all face unique risks. Tanzania and Mozambique proposed LNG projects have no

Figure 3-I: Chinese Natural Gas Supply Sources



Source: Ernst & Young Global LNG "Will new demand and new supply mean new pricing?" 2013

supporting infrastructure, contain security risks and are located far offshore. Canadian LNG terminals face an uphill battle due to multiple projects competing for the same market, environmental opposition, and resource constraints if multiple LNG plants are all constructed at once.

Under current conditions an Alaska project also faces significant risk, some of which would have to be mitigated to have an LNG project move forward. This may be a strategy to provide a win-win situation, where producers have an economically viable project, Alaska's economy is more diversified, and state revenues are diversified and increased.

LNG Supply – US, Canada and East Africa

The Department of Energy (DOE) must issue an export license to any US LNG export terminal according to US law. As of January 2013, there are 20 companies who have applied for an export license from DOE. Licensing for LNG exports falls into two categories, countries with whom the US has free trade agreements (FTA) and non-FTA countries. Sixteen projects have received approval to export to FTA countries and one project has non-FTA country approval. South Korea and Singapore are the only FTA countries with significant LNG demand. Japan is not an FTA country.

Nine US LNG export facilities have infrastructure already in place. These facilities were originally designed for LNG imports. They were planned just before the advent of widespread shale gas, as a way to alleviate North American supply constraints in the 2000s. These "white elephant" import facilities are being converted to export facilities. Conversion of this existing infrastructure into export facilities represents cost savings in comparison to new LNG facilities and creates revenue opportunities from otherwise money-losing infrastructure.

Cheniere's Sabine Pass LNG export terminal in the Gulf of Mexico is a converted import facility and is the only project near export production. All of its gas is under contract. Sabine Pass has export capacity of 864 billion cubic feet annually. The project has four anchor buyers and there is some gas reserved for spot sales. Contracts for buyers are structured on Henry Hub gas prices, a 15% uplift/shrinkage charge, and a fixed liquefaction charge. It is these Henry Hub structured contracts that are of great interest in the Asian markets and are of great interest to buyers looking to reduce their reliance on traditional oil-denominated contracts.

There is intense interest in exporting LNG from Western Canada. There are four projects planned, representing 2.4 trillion cubic feet of annual capacity. These projects are based on large natural gas resources located in Western Canada, supportive government policies and openness to foreign investment. These projects are expensive, costing tens of billions of dollars. Each project is a greenfield development, from the wellhead to the LNG export terminal, meaning everything has to be built from the ground up. Developers of the projects will own every aspect of the LNG project, requiring extremely large capital investments upfront. Offshore of East Africa, there have been a number of extremely large natural gas fields found in a lightly explored area. Most of the confirmed natural gas finds have occurred in Mozambique, with more recent finds in nearby Tanzania. There is an estimated 110 trillion cubic feet of natural gas in Mozambique alone. Project economics are dependent upon clustering of infrastructure to reduce costs, requiring cooperation between the ENI led consortium and the Anadarko led consortium. LNG export capacity from this area is unknown at this time since no project plan has been developed. Other considerations for the companies at this point are securing LNG export licenses, funding, clients, fiscal terms and cooperation between the different stakeholders.

LNG Economics

LNG projects are expensive, and often financing is sought for the entire LNG chain from wellhead to shipping. Suppliers of future LNG look toward clarity in pricing to justify the economics of these projects. Early LNG projects before 2003 cost less than $4 million per billion cubic feet annually. The second wave of projects cost between $10 to $25 million per billion cubic feet annually. Now projects under consideration are in the $54 million per billion cubic feet annually range according to Deutsche Bank.[1]

Analysts at Credit Suisse expect several proposed LNG export projects to be built in North America and Africa.[2] Economics of these projects compare favorably to the Australian projects being developed. The US and African projects have an estimated cost of $96 thousand per billion cubic feet per year, versus $144 thousand per billion cubic feet per year for Australian projects. Australia's economics did not look to be at such a disadvantage when the decisions were made to develop the LNG projects. Currency risk has hit Australian projects hard, as the Australian dollar has appreciated more than 60% against the US dollar since 2009, as has the shortage of specialized labor.

In order to offset these very high risk and extremely capital intensive projects, suppliers want iron clad LNG contracts linked to oil prices. Traditionally, LNG contracts were linked to oil prices, with Japan, Korea, and Taiwan willing to accept these contracts for imported LNG in order to diversify their energy sources. However, there may be less willingness to accept this standard going forward. LNG is developing a market as a separate commodity from oil and some analysts suggest that the LNG market will continue being more competitive in the future, although this view is far from universal. The LNG market views oil as becoming more scarce and higher priced and LNG becoming more plentiful making the linkage between the two undesirable, especially in the long-term. A response to this is the desire to shift from oil-indexed contracts to Henry Hub based indexing, which is now popular in Asia.

The LNG market is following a classic trajectory toward market equilibrium. Suppliers looking at developing expensive projects need high prices to justify their development. At the same time, more price sensitive buyers are unwilling to commit to expensive long term contracts. The result has been buyers signing shorter-term contracts and strict oil indexation is faltering. Again, an example of this is the preference in Asia for Henry Hub based contracts over traditional oil indexing.

Longer term market prices and oil based LNG prices should diverge from each other, as suppliers of LNG will be forced to compete on price in order to remain competitive. However, the relationship between the two will likely not collapse. In order to guarantee supply, importers of LNG will pay a higher price. The same relationship holds true in the oil market. Excess capacity exists, but there is a premium built into price to ensure adequate future supplies. The development of a more active spot market pricing for LNG would be a major next step for pricing.

A sign of a mature market is when risk based premiums for commodities weaken. Where global LNG players emerge with a portfolio of places LNG is sourced from

(1) Deutsche Bank. *Oil and Gas for Beginners Industry Update*, 25 January 2013.

(2) Credit Suisse. Global Equity Research, Global LNG Sector Update, 7 June 2012.

and this is sold to a portfolio of buyers. Major energy companies like BP and Chevron are already participants in this market development. These portfolio players will be able to sign contracts where greater flexibility will exist for a cargo's timing and delivery location. When this happens regional prices for LNG should start to converge on global price, due to arbitrage.

Financing Large Natural Gas Projects

Large project financing follows a straightforward formula. A project is identified, passes the project partners internal hurdles for investment, and project partners set up a separate entity to reduce risks to them. The newly created entity is funded with an equity contribution from each partner and debt issued by the new entity. Capital raised is used exclusively to fund the project through project completion. Cash flows from the project are the only means of repayment of debt and any excess capital is returned to the project partners, if the project is successful.

Risks

Benefits of establishing a separate entity for a large natural gas project are centered on risk management. Project risks are considerable. Risk mitigation strategies include debt default protection, clear project funding sources, separate accounting, limiting environmental liabilities, political risk, transportation risk, counter-party risk, supply risk, commodity risk, technology risk, inventory risk, taxation risk and other risks the project would encounter. These risks can be independent, dependent or interdependent on other risks the project faces.

Figure 3-J: Government Incentive Programs for Major LNG Projects

	Financial	Policy Assistance
Direct	Grants Subsidies Capital Investments Development Cost Funding Loans	Dedication of governmental natural resources Guaranteed off-take Expedited permitting Use of state property Condemnation power
Indirect	Income Tax Incentives Loan Guaranties Reduction in Fiscal Take Tax Credits Waivers of Property, Use, Sales, Franchise, and VAT taxes Use of governmental bond authority	R&D support Portfolio standards Demand incentives Fuel preference programs Consumer financial incentives Labor initiatives Building/zoning codes Interconnection planning Permitting standards

A key question becomes how projects can reduce risk exposure. One way is through the assistance of government.

Government Incentives

Large projects often require the cooperation of both industry and government. These projects can carry benefits for both industry and government. Governments can assist in making projects more attractive for financing in many different ways (as shown in Figure 3-J).

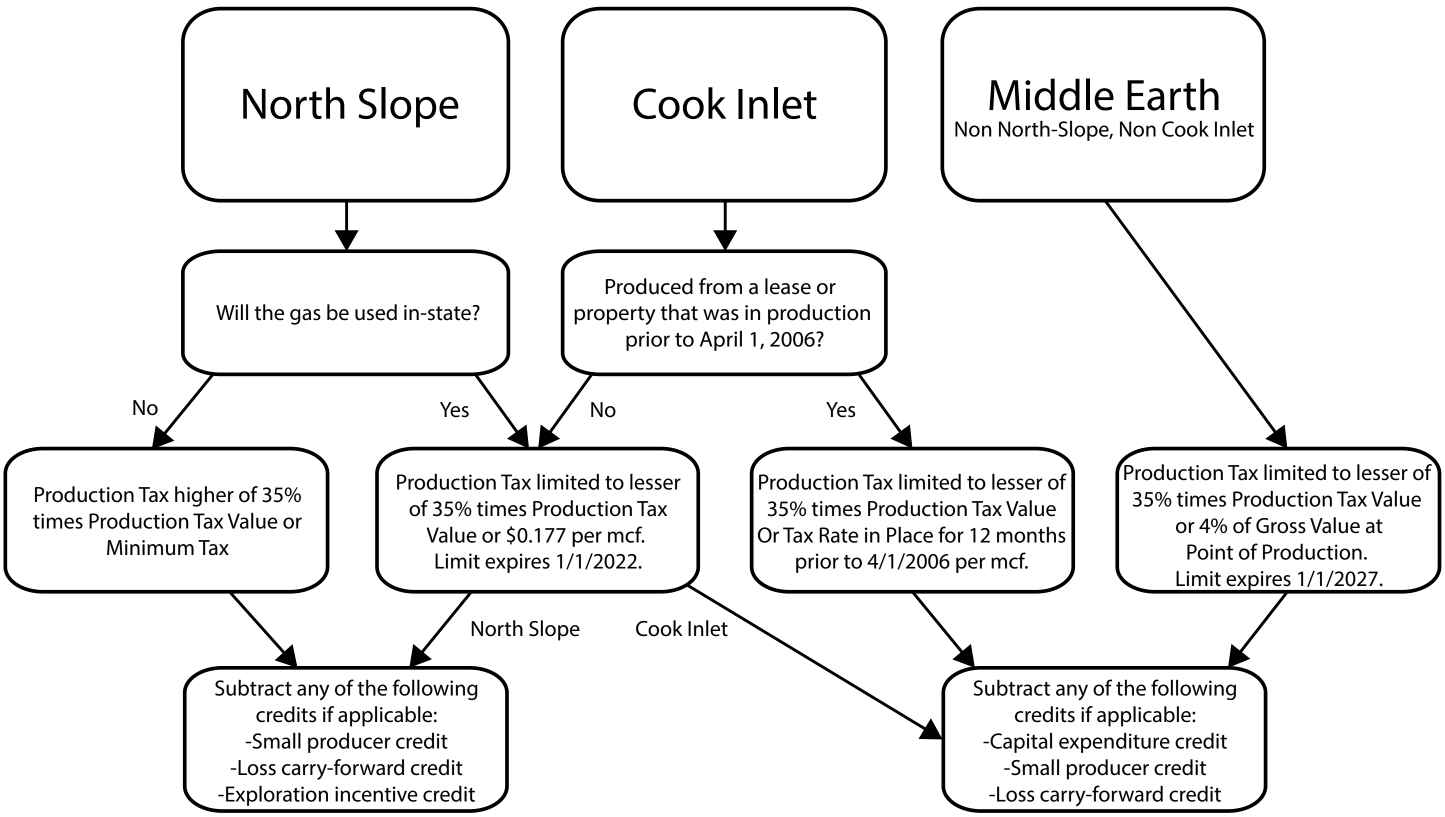
Governments have worked collaboratively on several important projects around the world. Included here is a discussion of planned projects in Russia, British Columbia, and Norway.

Russia

The Yamal Peninsula on the Arctic Ocean contains Russia's largest natural gas reserves, estimated at 1,940 billion cubic feet of natural gas. Russia's Novatek and France's Total looked to develop a green field LNG export project from the region. However, arctic conditions, high costs, long distances from customers and tax issues made the project questionable for development.

Russia is heavily dependent upon its natural resources for revenue and has substantial interests in the energy industry, including protectionist legislation and a mostly state-owned industry. Nevertheless, Russia has made the decision to cut taxes, approve LNG exporters other than Gazprom (the state-owned Russian gas company) and has provided other promises of assistance to ensure the export of Yamal gas. In 2011, the Russian government exempted LNG from the 30% minerals extraction tax. Other assistance from the Russian government will come in the form of financing of a port, an airport, gas pipelines, icebreakers,

Figure 3-K: Natural Gas Production Tax Calculation based on Production Location and Use



and dredging work. This assistance has an estimated price tag of $9 billion. Regional governments are also assisting with the development, property tax exemption, and a lower corporate income tax. These lower tax rates will expire once 8.8 trillion cubic feet of gas or 180 million barrels of condensate are extracted. Recently, foreign capital investment in the project included China National Petroleum Corporation acquisition of a 20% stake from Novatek. A final development decision is expected in 2014.

British Columbia

Lack of infrastructure hinders the development of British Columbia's large natural resource base. Oil and gas deposits are located in remote areas, with challenging geography, and require large capital investments, and high degrees of uncertainty for any project success. Hopes for an LNG export industry are based on these greenfield oil and gas projects being developed. There are currently no LNG marine export terminals, although several are planned on the Pacific Coast.

Government supported incentives for development of these greenfield projects mainly revolve around royalty credits. These credits are for roads, pipelines and LNG export terminals. It is the intention of British Columbia's government to generate more in royalties, than it spends in credits.

The framework for the credit program is based upon the original cost of the project submitted to the government before the project is started. Upon completion of the project the project can receive up to 50% of project costs as credits against royalties owed to the government. If a project cost $1 billion, the developers would be able to take up to $500 million in royalty credits.

As of June 2013, a total of $1.7 billion was made in capital investments, including 1,243 new miles of road, representing 78 new resource roads, and 1,304 miles of new pipeline.

Norway

Norway, like Alaska, is a mature petroleum production area with tremendous petroleum resources. The Snohvit gas field is currently considered as a source for LNG export. First discovered in 1984, the field took 23 years to develop. Located in the Arctic Ocean 90 miles from land, in 1,000 feet of water, the project had to confront some major obstacles and a new way of thinking about offshore development.

In order to develop the challenged Snohvit gas field, Norway reduced the tax burden on the project. Norway has a corporate income tax rate of 50% on profits generated by offshore production, plus 28% base rate paid by all corporations in the country. In order to enhance Snohvit's economics the 50% offshore tax was waived. This was done by allocating the profits from the offshore project to the onshore LNG terminal. Another important taxation issue to consider, Norway allows for a six year depreciation schedule. A six year depreciation schedule enables capital cost recovery in a shorter time period than in Alaska or at the US federal level.

Development of Snohvit required production equipment to be located on the sea floor with the gas piped onshore. Development costs totaled $10 billion, well above the projected cost estimate of $6 billion made in 2002. Snohvit has the capacity to liquefy 750 million cubic feet of natural gas per day.

State Tax and Natural Gas

In Alaska, the production tax for natural gas is calculated in the same way that the tax is calculated on oil, with regional differences. The three oil and gas producing areas are 1) North Slope, 2) Cook Inlet, and 3) the rest of Alaska (collectively known as "Middle Earth").

The production tax levied on natural gas under AS 43.55.011(e) may be limited by statute and the limit is set to a certain derived price per thousand cubic feet based. Figure 3-K is a graphic that shows how the production tax is calculated for the three regions and highlights some of the similarities and differences. The distinction on the North Slope is that the tax is calculated is based on destination, whether the gas is used in-state or leaves the State. "Gas used in state" is defined per AS 43.55.900(24) as gas "delivered for consumption as fuel in state, including as fuel consumed to generate electricity." Not all gas used in state will qualify. For example, gas used in manufacturing may not qualify. In Cook Inlet, the distinction for taxation is whether the gas is produced from a lease or property that was in production prior to April 1, 2006. Areas outside the North Slope and Cook Inlet have a maximum tax of 4% of gross value at the point of production regardless of destination, governed by AS 43.55.011(p).

For taxation purposes, natural gas volume is measured according to the average value per "barrel of oil equivalent" (BOE), a measure that equalizes the thermal value. Under the ACES tax regime, prior to January 1, 2014, including lower value gas in the same tax calculation as higher value oil reduced the progressive tax rate on oil ("progressivity"). By taxing oil and gas together, gas production reduces oil taxes even though oil operations are unaffected. This has been called the "flip the switch" problem. Under ACES, if major gas sales began, State tax revenue could have dropped significantly under certain price scenarios, including current prices. However, under the provisions of the More Alaska Production Act (MAPA), effective January 1, 2014, although oil and gas are still included in the same tax calculation, adding gas will not impact the tax rate on oil, since the legislation imposes a flat tax rate of 35%.

Conclusion

Alaska's history of exporting LNG to Japan, producing fertilizer, and utilizing natural gas for local electricity generation and heating, provides the region with a long-term familiarization with the natural gas industry, including the LNG export trade. Even the analysis and discussion of the many unfinanced and unconstructed natural gas export project plans over the years has provided Alaska experts and policy makers with a better understanding of natural gas markets.

Natural gas remains an abundant resource within Alaska. LNG is natural gas that is in a form that can be ship to distant markets by marine transport. In deciding where Alaska North Slope natural gas should be sold, given the choice to go by land in a pipeline or by sea as LNG, the discussion should revolve around the anticipated destination price minus the costs of delivering a unit of gas, over the lifetime of the project. The discussion also should revolve around the profit made at the wellhead, since this is where the current tax regime provides revenue to the State.

Natural gas markets have changed dramatically within the last five years. North American prices have fallen, while global LNG prices, especially in Asia, have risen to historic highs. The price differential between North American and Asian prices has never been greater. At this time, the price differential indicates a preference for exporting Alaska gas as LNG. However, new supply entrants are also planning to put their projects in the queue, as competing LNG projects take advantage of the current high price and supply shortfall. In some cases, the new entrants have significant government involvement and support.

The window opened by current natural gas and LNG market conditions might provide the necessary economic and commercial conditions for a North Slope natural gas project to move forward.

4

Petroleum Revenue

General Discussion

There are four sources of state revenue that come from oil and gas production (severance tax, royalties, property tax, and corporate income tax). Often referred to as a production tax, the severance tax is imposed on a producer as the resource is severed (or extracted) from the leased land. Royalties are payments to the owner of the land and represent a percentage of production. Property taxes are charged as a percentage of the value of the property and improvements on it. Finally, corporate income tax is a percentage of the profits made in an economic area to help fund the infrastructure that allows the corporation to operate.

The majority of revenues collected from oil production go to the general fund. This revenue is available for appropriation by the Legislature to support the general operation of the government and for capital improvements across the State. The rest of the revenue is put into special funds for specific purposes, rather than general spending. Currently, about 30% of royalty collections get deposited into the Permanent Fund, which is then invested in various ways by the Alaska Permanent Fund Corporation, a stand-alone corporation owned wholly by the State. Part of the earnings from these investments is paid as annual dividend checks to Alaskan residents. Another 0.5% of royalties are deposited to the Public School Trust Fund.

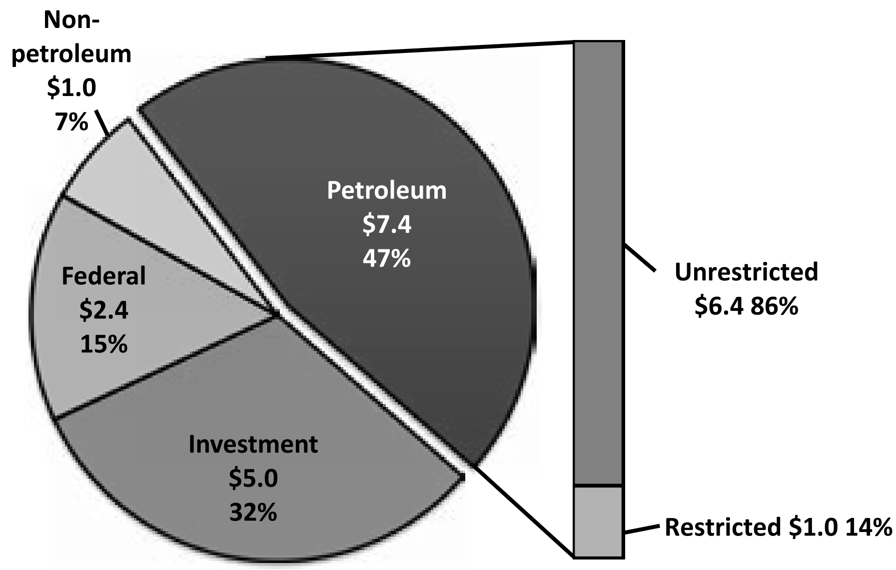


Figure 4-A: FY 2013 Oil Revenue, by restriction and type ($ billions)

Additionally, the State receives some payments from the Federal government for bonuses, rents, and royalties received by leasing lands in the National Petroleum Reserve – Alaska (NPR-A). These funds are deposited into a special NPR-A fund and are counted as "Federal Revenue."

Finally, "offshore" leases from three to six nautical miles from shore are federal leases, under which the State is entitled to 27% of the amount the federal government collects in bonuses, rents, and royalties. The authority for this revenue sharing is the federal Outer Continental Shelf Lands Act, Section 8(g), and this 3-mile band is referred to as the "8(g) zone." These funds are also counted as "Federal Revenue."

Occasionally, the State also receives settlements from tax and royalty disputes between the State and taxpayers. When these payments are received, they are deposited

Table 4-1: Total Petroleum Revenue, by restriction and type

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted Petroleum Revenue			
Petroleum Property Tax	99.3	99.6	97.4
Petroleum Corporate Income Tax	434.6	463.8	463.7
Oil & Gas Production Tax	4,050.3	2,099.7	1,711.1
Royalties (including Bonuses, Rents & Interest)	1,767.8	1,696.3	1,662.8
Unrestricted Petroleum Revenue	**6,352.0**	**4,359.5**	**3,935.0**
Increase/(Decrease) from Prior Period	(2,505.8)	(1992.5)	(424.4)
% Change from Prior Period	-28.3%	-31.4%	-9.7%
Restricted			
Other Restricted			
Royalties, Bonuses & Rents to the Alaska Permanent Fund	842.1	724.3	706.6
Royalties, Bonuses & Rents to the School Fund	13.8	12.2	11.9
Tax Settlements to CBRF	176.6	20.0	20.0
Subtotal Other Restricted	**1,032.5**	**756.5**	**738.5**
Federal			
NPR-A Royalties, Rents & Bonuses	3.6	3.6	3.6
Restricted Petroleum Revenue	**1036.1**	**760.1**	**742.1**
Increase/(Decrease) from Prior Period	9.6	(276.0)	(18.0)
% Change from Prior Period	0.9%	-26.6%	-2.4%
Total Petroleum Revenue	**7,388.1**	**5,119.5**	**4,677.1**
Increase/(Decrease) from Prior Period	(2,496.2)	(2,268.6)	(442.4)
% Change from Prior Period	-25.3%	-30.7%	-8.6%

directly into the Constitutional Budget Reserve Fund (CBRF). Table 4-1 shows the dollar value of each revenue source collected in FY 2013 and a forecast of revenues for FY 2014 and FY 2015.

Production tax represents the largest portion of unrestricted petroleum revenue, totaling 63.8% in FY 2013. Total royalty payments represent the next largest portion at 27.8% while property taxes (1.6%) and corporate income taxes (6.8%) are much smaller contributors.

Oil revenues are especially important to Alaska's revenue picture as these four sources contributed 92% of the total deposits to the unrestricted general fund, in FY 2013 in addition to deposits in restricted funds. Table 4-2 shows the ten-year forecast of revenues from these sources.

This chapter describes each of the four oil revenue sources, provides a forecast of each source, and contains a discussion on the methodology used to create these forecasts. The

Table 4-2: FY 2013 Unrestricted Petroleum Revenue and Ten-Year Forecast

($ millions)

	History	Forecast									
Fiscal Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Petroleum Property Tax	99.3	99.6	97.4	99.2	101.1	102.5	103.4	103.9	103.9	103.6	103.1
Petroleum Corporate Income Tax	434.6	463.8	463.7	460.8	465.4	456.1	441.9	424.2	400.0	382.1	361.0
Oil & Gas Production Tax	4,050.3	2,099.7	1,711.1	1,803.8	2,148.7	2,275.7	2,327.1	2,112.6	1,897.7	2,064.4	1,659.2
Royalties-Net (1)	1,767.8	1,696.3	1,662.8	1,658.8	1,667.3	1,646.5	1,614.1	1,495.5	1,401.2	1,382.6	1,257.1
Total Oil Revenue	**6,352.0**	**4,359.5**	**3,935.0**	**4,022.6**	**4,382.5**	**4,480.8**	**4,486.5**	**4,136.2**	**3,802.8**	**3,932.7**	**3,380.4**
Increase/ (Decrease) from Prior Period	(2,505.8)	(1992.5)	(424.4)	87.6	359.9	98.3	5.7	(350.3)	(333.3)	129.8	(552.3)
% Change from Prior Period	-28.3%	-31.4%	-9.7%	2.2%	8.9%	2.2%	0.1%	-7.8%	-8.1%	3.4%	-14.0%

chapter concludes with a discussion of the restricted portions of oil revenue.

Production Taxes

All oil and natural gas that is produced and sold from lands within the State of Alaska borders is subject to a severance tax as it leaves the leased land. This includes lands that are owned by the State of Alaska, the Federal government (like NPR-A), or are in private ownership, including lands owned by Native corporations. State ownership of submerged lands extends three miles from the shore. Production tax applies only to oil and gas that the producer sells, so it excludes state royalties, gas used in lease operations or flared for safety reasons, and any production that is re-injected into a reservoir.

The current tax law was passed in November 2007, known as “Alaska’s Clear and Equitable Share” (ACES). This legislation was reformed during the 2013 legislative session under Senate Bill 21 (SB 21) and was signed into law on May 21, 2013, as the “More Alaska Production Act” (MAPA). Most provisions of the new law will take effect on January 1, 2014, half way through the 2014 fiscal year. Because the method for calculating production taxes changed within the report year, a brief discussion of each follows.

ACES Tax Law

ACES is a net value severance tax; not a gross value severance tax, which is typically used elsewhere in the United States. A net value tax allows the costs of production to be deducted in the taxable value calculation. The phrase “net profits tax” is common vernacular, but is actually inaccurate in describing this tax. If it were truly a tax on net profits, it would be similar to the corporate income tax. In general, only expenses that are directly related to producing oil from the ground are tax deductible, while many other general business expenses are not. In this way, production taxes are distinctly different than corporate income taxes and are not actually tied to company profits.

Under ACES, the tax rate that is paid on oil production is 25% of the taxable value with an additional surcharge based on a company’s average net value of the oil. The surcharge is calculated on a monthly basis by subtracting the average transportation and lease expenses per taxable barrel from the prevailing value of ANS crude at its point of delivery. That per-barrel value, known as the per-barrel production tax value (PTV), is used to determine the rate of additional tax that is applied to all barrels of oil produced within the State by that company. The surcharge escalates

Figure 4-B: ACES and MAPA Tax Liability Calculation Comparison

		Under ACES	Under MAPA (no GVR)	Under MAPA (with 10% GVR eligible oil)	
Production	**Unit of Measure**			**Non-GVR Oil**	**GVR Oil**
Royalty Barrels	bbls/day	2,500	2,500	2,250	250
Non-GVR Taxable Barrels	bbls/day	17,500	17,500	15,750	
GVR Eligible Barrels	bbls/day	0	0		1,750
Average Production	bbls/day	20,000	20,000	18,000	2,000
Price					
Prevailing Value (ANS WC)	$/bbl	100.00	100.00	100.00	100.00
Marine Transportation Cost	$/bbl	3.50	3.50	3.50	3.50
TAPS Tariff	$/bbl	5.00	5.00	5.00	5.00
Feeder Pipeline Tariff	$/bbl	1.00	1.00	1.00	1.00
Wellhead Value	$/bbl	90.50	90.50	90.50	90.50
Costs					
Deductable Operating Cost	$/taxable bbl	15.00	15.00	15.00	15.00
Deductable Capital Investment	$/taxable bbl	25.00	25.00	25.00	25.00
Gross Value Reduction	$/taxable bbl	0	0	0	18.10
Net Production Tax Value	$/taxable bbl	50.50	50.50	50.50	32.40
Tax					
Production Tax Base Rate	%	25.0	35.0	35.0	35.0
Progressivity Surcharge	%	8.2	0.0	0.0	0.0
Total Tax Rate	%	33.2	35.0	35.0	35.0
Production Tax Liability	$	107,092,825	112,899,063	101,609,156	7,243,425
Credits Used Against Tax Liability	$	31,937,500	38,325,000	34,492,500	3,193,750
Net Taxes Due	$	75,155,325	74,574,063	67,116,656	4,049,675
Total Net Taxes Due	$	75,155,325	74,574,063	71,166,331	

at 0.4% per $1 of per-barrel PTV greater than $30 and less than $92.50, and then escalates at a lower rate of 0.1% per $1 until the total base tax and surcharge reaches the maximum tax rate of 75%. This escalation of the tax rate as the value of the oil increases is commonly referred to as "progressivity."

A credit system was also created to accompany the progressive tax system. Most notably, a credit for capital spending was added to help improve the economics of a project. Known as the Qualified Capital Expenditures (QCE) credit, a company is eligible to reclaim 20% of all qualifying capital costs as a credit against their production tax liability. Companies with less than 50,000 BTU equivalent barrels per day of production, and less production tax liability than credits earned, can elect to receive any remaining credits as a cash payment from the State instead.

More information on credits can be found in chapter 8, and more details about exceptions and intricacies of the ACES tax law can be found on the Department of Revenue website.

MAPA Tax Law

MAPA retains the basic framework of ACES. The primary change from ACES to MAPA is the removal of the progressive surcharge tied to the

Table 4-3: Oil Price and Transportation Forecast Assumptions

(Nominal $/bbl)

Fiscal Year	2013	2014[1]	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANS West Coast Price	107.57	105.68	105.06	107.69	110.38	115.40	121.19	122.43	123.67	133.00	131.85
ANS Marine Transportation	3.64	3.43	3.46	3.51	3.56	3.62	3.70	3.74	3.78	3.88	3.91
TAPS Tariff	5.93	6.28	6.18	5.88	5.98	6.18	6.51	6.98	7.54	8.20	8.95
Other Deductions & Adjustments[2]	0.19	0.40	0.40	0.43	0.52	0.54	0.58	0.69	0.78	0.79	0.80
ANS Wellhead Price	97.81	95.57	95.03	97.87	100.32	105.06	110.41	111.02	111.56	120.13	118.19

value of oil. The base tax rate was increased from 25% to 35% of the net value of oil and gas production. Other major factors include the replacement of credits tied to capital spending with one tied to production on the North Slope, and the creation of an incentive for the development of areas north of 68 degrees North latitude that are not currently in production. The ACES provisions are retained for production elsewhere in the State.

Under MAPA, an alternative progressivity mechanism was created in the form of a credit to maintain an overall progressive system. By tying a fixed value to each barrel of production, the effective value the State collects on that barrel increases as price increases making it a progressive system. This credit decreases as price increases until it is eliminated at wellhead values above $150 per barrel. This approach results in a slower progressivity rate than ACES and a lower maximum tax of 35% rather than 75% of the net value of oil and gas production.

As this new production credit is introduced, the credit on qualified capital expenditure (QCE) credit will be removed. The new credit will be paid directly on production rather than on spending.

The final major component of MAPA was the introduction of an incentive to bring new production areas into development. This incentive reduces the tax liability in new production areas by excluding 20% of the gross value for that production from the tax calculation. Qualifying production includes areas surrounding a currently producing area that may not be commercial to develop, as well as new oil pools that have not been discovered or developed. Oil that qualifies for this Gross Value Reduction (GVR), sometimes referred to as Gross Revenue Exclusion (GRE), receives a flat $5 per barrel credit rather than the sliding scale. A forecast of how much oil will be eligible for this incentive is included later in the production portion of this chapter. A sample tax calculation using the tax systems is shown in Figure 4-B to illustrate how the tax systems work. Note that this is a simplified example and should not be used to calculate actual tax liability.

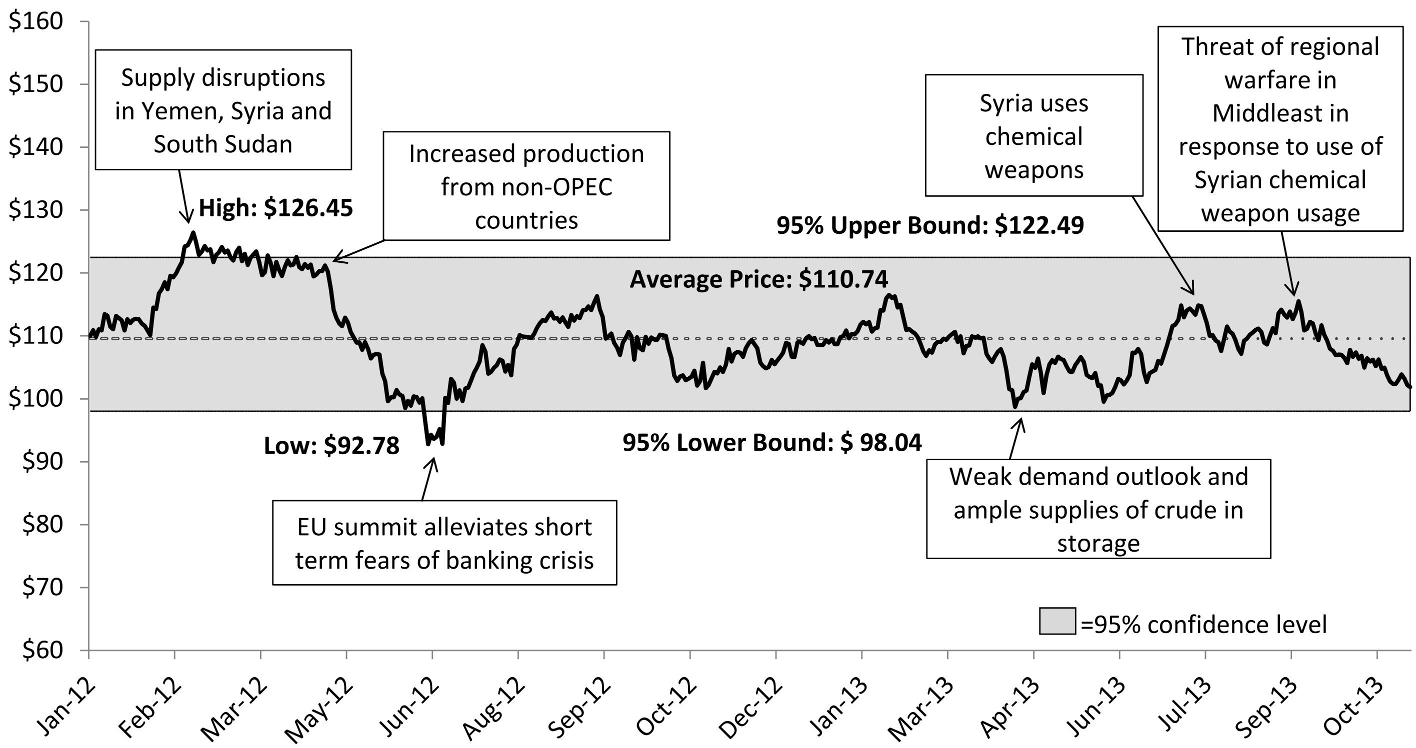
Production Tax

In order to forecast revenues from production taxes, the components of the tax calculation must be forecast. Under a net value tax system, those components are: the price of oil, the cost of transportation, the cost of production, and the volume of production. The cost of production becomes an important factor in this equation as the State effectively shares in the costs of production by making those costs tax deductible. Under ACES, due to a progressive tax rate tied to the average net value, price and costs are extremely sensitive variables, while the production volumes have an important, but lesser impact. Unfortunately, none of these variables are easy to predict and are subject to high degrees of volatility. Under MAPA, all of these

[1] FY 2014 values include four months of actual data.

[2] Includes other adjustments such as quality bank charges, feeder pipeline tariffs, location differentials and company-amended information.

Figure 4-C: Alaska North Slope Crude West Coast Price



variables are still quite important, but the flat marginal tax removes the compounding effects that price and costs once had. While the department can make reasonable approximations for how these variables will act in the future, a relatively minor deviation from the forecast of any component can still result in fairly large variations in total revenue.

What follows is a description of each component, the methodology for forecasting each component, and a forecast for the next 10 years.

Crude Oil Prices

The future price of crude oil is the most sensitive variable in the revenue forecast and it is also the most prone to uncertainty. As a price taker in the global market, Alaska cannot exert any significant pressure on the future price of oil by altering its level of production. Rather, oil prices are determined on a global basis, reflecting supply and demand.

A ten-year forecast of ANS oil prices, along with the inferred wellhead values, can be found in Table 4-3. Additionally, Appendix B includes a ten-year history and ten-year forecast of these values in nominal and real terms, and comparisons to the spring 2013 forecast.

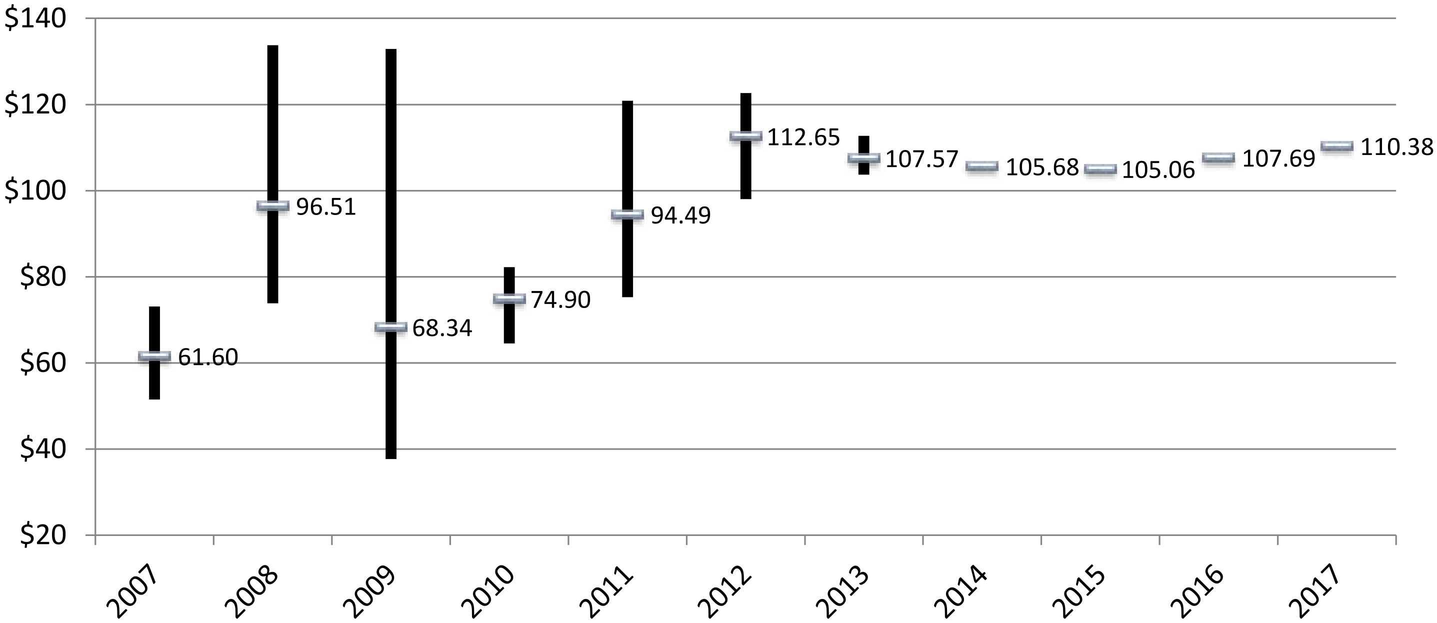
Short Term Variables that Influence Oil Prices

Several major factors contribute to the pricing of oil on the world market, including but not limited to: 1) Inventory levels, 2) Infrastructure, 3) Geopolitics, 4) Natural disasters, 5) Warfare, 6) Action by the Organization of Petroleum Exporting Countries (OPEC), 7) Macroeconomic events, 8) Financial market trends and speculation. Figure 4-C shows oil prices in recent months and associated key market events.

Each of these factors influences the price of oil and have all been encountered within the last ten-year period. Without knowledge of when and if these events will occur, it is not possible to forecast a particular path for oil prices with any certainty. Furthermore, the system is dynamic and the impact of the same event can bring about different outcomes at different times.

In the longer term, fundamental economic factors of supply and demand drive oil prices. Ultimately, predicting future price requires an understanding of demand growth and the available future supply of petroleum products.

Figure 4-D: Historical ANS West Coast FY Oil Price Bands Annual Average and Official FY 2013 Forecast



Methodology for Forecasting Prices

One of the major components in developing the official price forecast used in the RSB is a day-long price forecast session hosted by the Department of Revenue, usually held the first Tuesday of October. The forecast session uses a modified Delphi Method, a forecast method which relies on a pool of expert participants. This year, the fall 2013 oil price forecast session was held on Tuesday, October 1st with 39 participants from state government, the private sector, and academia. Each participant submitted their own price forecasts after a day of presentations by experts on oil price markets and market structure. These individual price forecasts were combined to derive the price forecasts of the session.

The participants were asked to forecast the price of Alaska North Slope (ANS) crude oil. In previous years participants were asked to forecast the West Texas Intermediate (WTI) benchmark – because it was the most widely-used US benchmark and adjustments were made with a price differential to derive the price of ANS. The move to forecast ANS price directly was started in 2012 and is the result of a change in the physical characteristics of the WTI market, which has created a price decoupling of waterborne crudes, like ANS, from those stocks bottlenecked in Cushing, Oklahoma. Furthermore, the decoupling of WTI from waterborne crudes makes comparing ANS with other forecasts of WTI problematic. Participants at the forecast session were provided with such expert price forecasts and forecast assumptions by the Energy Information Administration (EIA), the New York Mercantile Exchange (NYMEX), and other analysts for their consideration.

The forecast participants were asked to forecast ANS prices in 2013 dollars without accounting for inflation and their forecasts were submitted to the Department of Revenue at the end of the session. The median price for each time period from the post-session results was used for the department's fall 2013 forecast. These prices were converted to nominal (inflation adjusted) oil prices using the current Callan Associates, Inc. inflation assumption of 2.5%.

Price Forecast

Many factors put pressure on the future of oil prices. Currently, one of the most important drivers is increasing global supply with the advancement of horizontal drilling and hydraulic fracturing technology. This technology has unlocked billions of barrels of producible crude in North America and has the potential to unlock billions more barrels of oil around the world. These increases combine with potential increases in production from other regions including Alberta (transportation), Venezuela (lack of investment),

Table 4-4: ANS Oil & Gas Production Tax Data Summary

	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
North Slope Price and Production			
Price of ANS WC (in $/barrel)	107.57	105.68	105.06
Transit Costs & Other (in $/barrel)	9.76	10.11	10.03
ANS Wellhead (in $/barrel)	97.81	95.57	95.03
North Slope Production			
Total ANS Production (in mbbls/day)	531.6	508.2	498.4
Royalty and federal (in mbbls/day)[1]	82.7	65.7	63.8
Taxable Barrels (in mbbls/day)	448.9	442.6	434.5
North Slope Lease Expenditures[2][3]			
Total North Slope Lease Expenditures (in $ millions)			
Operating Expenditures [OPEX]	3,109.5	3,083.3	2,893.3
Capital Expenditures [CAPEX]	2,947.6	3,928.6	4,894.3
Total North Slope Expenditures	6,057.1	7,011.9	7,787.6
Deductible North Slope Lease Expenditures (in $ millions)			
Operating Expenditures [OPEX]	2,849.4	3,038.3	2,840.3
Capital Expenditures [CAPEX]	2,074.7	3,561.4	4,453.4
Deductible North Slope Expenditures	4,924.1	6,599.6	7,293.7
State Production Tax Revenue[4]			
Tax Revenue (in $ millions)	4,050.3	2,099.7	1,711.1
Production Tax Collected per Taxable Barrel	24.7	13.0	10.8
Statewide Production Tax Credits[2][5]			
Credits Used against Tax Liability (in $ millions)	469.0	1,050.0	1,000.0
Credits for Potential Purchase (in $ millions)	369.0	600.0	450.0

[1] Royalty and Federal barrels represent our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, and barrels produced from federal offshore property.

[2] Lease expenditures and credits used against tax liability for FY 2013 were prepared using unaudited company-reported estimates.

[3] Expenditure data for FY 2014 and FY 2015 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the the department. Expenditures shown here are shown in two ways: (1) total estimated expenditures including for those companies with no tax liability; and (2) estimated deductible expenditures for only those companies with a tax liability.

[4] Production tax is calculated on a company specific basis, therefore the aggregated data reported here will not generate the total tax revenue shown. For an illustration of the tax calculation, see Appendix D.

[5] Production tax credits shown include all production tax credits and all areas of the State. Assumptions for the $12 million credits for small Alaska producers are included in the table.

Brazil (offshore development), Iraq (instability), and Iran (sanctions). Together, there appears to be potential supply increases sufficient to reduce the price of oil. However, price support comes from the high cost of developing new resources. These projects require a price of around $100 per barrel, according to industry executives and industry publications, to garner initial investment. OPEC countries also need high prices to sustain social programs and have publicly stated if prices fall in a sustained fashion below $100, OPEC is likely to cut production.

Without increases in demand, prices are likely to remain fairly stable and with an increase in demand, prices may face upward pressure. The current expectation is that growth in per capita GDP in the Asian markets will increase energy demand in the mid-term. On a global scale, these increases will be greater than the decreases in energy consumption being observed in OECD countries. Therefore, global demand is likely to grow at historically normal levels and current projections of demand growth can be met with supply increases at current price levels.

Although there was consensus at the price forecasting session that the average ANS oil prices in FY 2014 will be in the range of $100 to $110, there was lack of consensus among oil price forecasts in the long term. While some experts see prices rise, there does not seem to be widespread support toward much higher prices as there is belief that new resources would become economic and fuel switching behavior would be observed. Similarly, while some experts are bearish about the future, much lower prices would curtail high cost oil production.

The department projects ANS oil prices will average around $106 per barrel in FY 2014 and $105 per barrel in FY 2015. In the mid-term, the department forecasts ANS to increase slightly, with a FY 2016 price of $108 and a FY 2017 price of $110. By 2023, prices are expected to exceed $130, mostly due to inflation.

In the future, the department plans to incorporate probability and statistical confidence in its price forecast.

Transportation Charges and Other Production Costs

Transportation costs are subtracted from the prevailing value or the sales value at point of delivery in order to estimate the value of ANS crude at the wellhead. This netback calculation is shown in Table 4-3. Components in the netback calculation include marine costs, the Trans-Alaska Pipeline System (TAPS) tariff, feeder pipeline tariffs, and quality bank adjustments.

Marine Transportation Costs

North Slope crude oil that is delivered through TAPS to Valdez is loaded on tankers and shipped to Washington, California, Hawaii and the Kenai Peninsula. Most of this crude is delivered to refineries in the Puget Sound, San Francisco and Los Angeles on a voyage that takes about two weeks.

The majority of the oil is delivered by double-hulled “Alaska Class” and “Endeavour Class” tankers. These tankers have an inner hull containing the crude oil and a surrounding outer hull for additional protection against oil spills. They range in size from 125 to 215 thousand dead-weight tons with a carrying capacity of about 800 thousand to 1.5 million barrels of oil.

For tax purposes, the company may deduct the total costs under the charter or contract for shipping oil and certain other allowable costs borne by the producer. For crude oil shipped on tankers that are owned or effectively owned by the producer of the transported oil, which is typically the case, allowable marine costs are the following: depreciation, return on investment, fuel for the vessel, wages and benefits, routine maintenance, tug and pilotage fees and dry-docking costs.

Marine costs can be broadly categorized as capital, fuel, and labor costs with each category accounting for roughly one third of the total. The marine cost model accounts for inflation in labor costs and changes in the cost of bunker fuel as it relates to the crude oil price forecast. In FY 2013, the cost of marine transportation averaged $3.64 per barrel of oil. The department is forecasting that this cost will escalate with inflation and oil prices to about $4.00 per barrel by FY 2023.

Trans Alaska Pipeline System (TAPS) Tariff

A pipeline tariff rate is a fee that an owner of a pipeline charges to ship a barrel of oil through the pipeline. Almost all oil produced in the State is shipped down TAPS. The 800 mile, 48 inch pipeline costs about a billion dollars a year to operate. Because alternatives for transporting oil are nearly nonexistent, tariff rates are regulated by the government to protect shippers from the exercise of undue market power.

Regulated pipelines charge a fee that is designed to cover operation and maintenance expenses, depreciation, income taxes, and a reasonable rate of return. Depreciation allows a pipeline owner to recover the capital investment undertaken to provide its service. The return on capital investment is compensation for the use of that capital investment. Other recoverable costs include an account for dismantling, removal and restoration, an allowance for funds used during construction, accumulated deferred income taxes, working capital, and legal fees. The department forecast does not attempt to predict the outcome of pending litigation or estimate the level and timing of protested tariffs.

Methodology

The department uses a cost-based rate-making model to forecast the cost to transport a barrel of oil on TAPS. This model mimics a cost-of-service approach, which allows the pipeline to recover the costs required to operate the pipeline in addition to a return of capital investment.

Trended original cost (TOC) methodology was established by the Federal Energy Regulatory Commission (FERC) in Opinion 154-B as the generic principles for setting just and reasonable rates for oil pipelines. A TOC tariff model with cost components and data extracted from FERC pipeline tariff filings and Form 6 filings are used to populate the model.

Cost components are summed for each year to estimate the total cost of service or the total revenue required to operate the pipeline. That number is divided by throughput to get the average cost per barrel, which makes the tariff sensitive to the production profile. Consequently, the tariff escalates when production declines, as costs are spread over fewer units.

Forecast

The weighted average tariff on TAPS is estimated to be about $6.28 per barrel in FY 2014 and forecast to increase to about $8.95 by FY 2023.

Feeder Pipeline Tariffs

Pipelines used to ship crude oil from oil fields to Pump Station No.1 of TAPS, are known as feeder pipelines. Shipping oil on these feeder pipelines requires a payment to the owner of the pipeline to cover costs and a reasonable profit. There are six feeder pipelines on the North Slope. The filed rates for CY 2013 are Kuparuk $0.29, Milne $1.19, Endicott $3.26, Badami $12.25, Alpine $0.86, and Northstar $5.47 resulting in a weighted average tariff of about $1.00 per barrel.

Methodology and Forecast

Tariff rates are forecast by estimating the cost-of-service and throughput volumes for each feeder pipeline. Each cost-of-service is divided by the respective throughput from the production forecast. Using the fall 2013 production forecast, the weighted average feeder tariff for those fields with feeder pipelines is forecast to be $1.05 in FY 2014 and increase to $2.05 in FY 2023 as production declines. For all production, including Prudhoe Bay which has no feeder pipeline, the weighted average feeder tariff is forecast to be $0.46 in FY 2014, increasing to $0.87 by FY 2023.

Lease Expenditures

Due to the deductibility of costs in the production tax equation, the department must forecast lease expenditures in addition to oil prices, production and transportation costs. Lease expenditures are defined as the upstream costs that are the directly related to exploring for, developing, or producing oil or natural gas.

Methodology for Forecasting Lease Expenditures

Since 2006, the Department of Revenue has received annual filings of tax returns under the net value production tax. Additionally, the department receives monthly information filings from oil and gas companies operating in the State that provide estimated monthly lease expenditures by property. Semi-annually, the department receives projections of lease expenditures by property for up to five years in the future. These reports are provided by the operators of the properties and have greatly enhanced the department's ability to prepare better revenue forecasts.

The department also uses several other means to forecast lease expenditures, including consulting other taxpayer-submitted information, such as plans of development. Production profiles are reviewed, as well as publicly available information on planned exploration activity, changes in activity levels at existing fields, estimated costs of bringing new fields on line and projected start-up dates.

Forecast for Lease Expenditures

In FY 2013, the unaudited lease expenditures reported by companies producing or exploring for oil and/or gas on the North Slope on monthly information forms were $3.1 billion in operating expenditures and $2.9 billion in capital expenditures. For FY 2014, the department forecasts North Slope operating expenditures to remain about $3.1 billion and capital expenditures to increase to $3.9 billion. In FY 2015, the department forecasts North Slope operating expenditures to fall slightly to $2.9 billion while capital expenditures continue increasing to $4.9 billion.

The FY 2014 and 2015 forecasts are higher in capital expenditures due to a combination of spending in new and existing ("legacy") fields. Higher spending is forecast for investment in new developments, such as Point Thomson, CD-5 (Alpine West), and Mustang, while development continues at the Oooguruk and Nikaitchuq units. Our forecasts reflect significant increases in spending at legacy fields, including recent announcements of rig additions and investment in new drilling areas. Finally, continued exploration spending by several newcomers is included, despite the speculative nature of those plans.

The total North Slope lease expenditures forecast represents an increase of over $500 million for FY 2014 and nearly $1 billion for FY 2015, compared to the spring 2013 revenue forecast. Over the next decade, the department is projecting about $10 billion in additional investment on the North Slope, above and beyond what was expected in spring 2013.

For areas outside the North Slope (including Cook Inlet), companies are also forecasting increased investment. Total lease expenditures outside the North Slope were about $640 million in FY 2013, a slight increase over FY 2012 and double the $315 million reported in FY 2011. The forecast for total lease expenditures outside the North Slope is about $900 million for FY 2014 and just over $1 billion for FY 2015.

It should be noted that these increased spending estimates are subject to many uncertainties including oil prices, and projects receiving final company approval and financing. Longer term, there is also additional upside potential for investment, especially later this decade. Several potential projects are being evaluated, but are not concrete enough to include in this forecast. For lease expenditure forecasts of FY 2016 and beyond, a risk factor has been applied to ensure consistency with the department's production forecast. For units that are not currently in production, the risk factor has been applied to the entire amount of capital and operating expenses associated with those units. For currently producing units, the risk factor has been applied only to a portion of anticipated expenses, based on the portion of production that is forecast from new oil in each year (since risk factors are only applied to that category of production). More information on the risk adjustments incorporated into the production forecast, can be found in the Crude Oil Production section of chapter 4 in the Fall 2012 RSB.

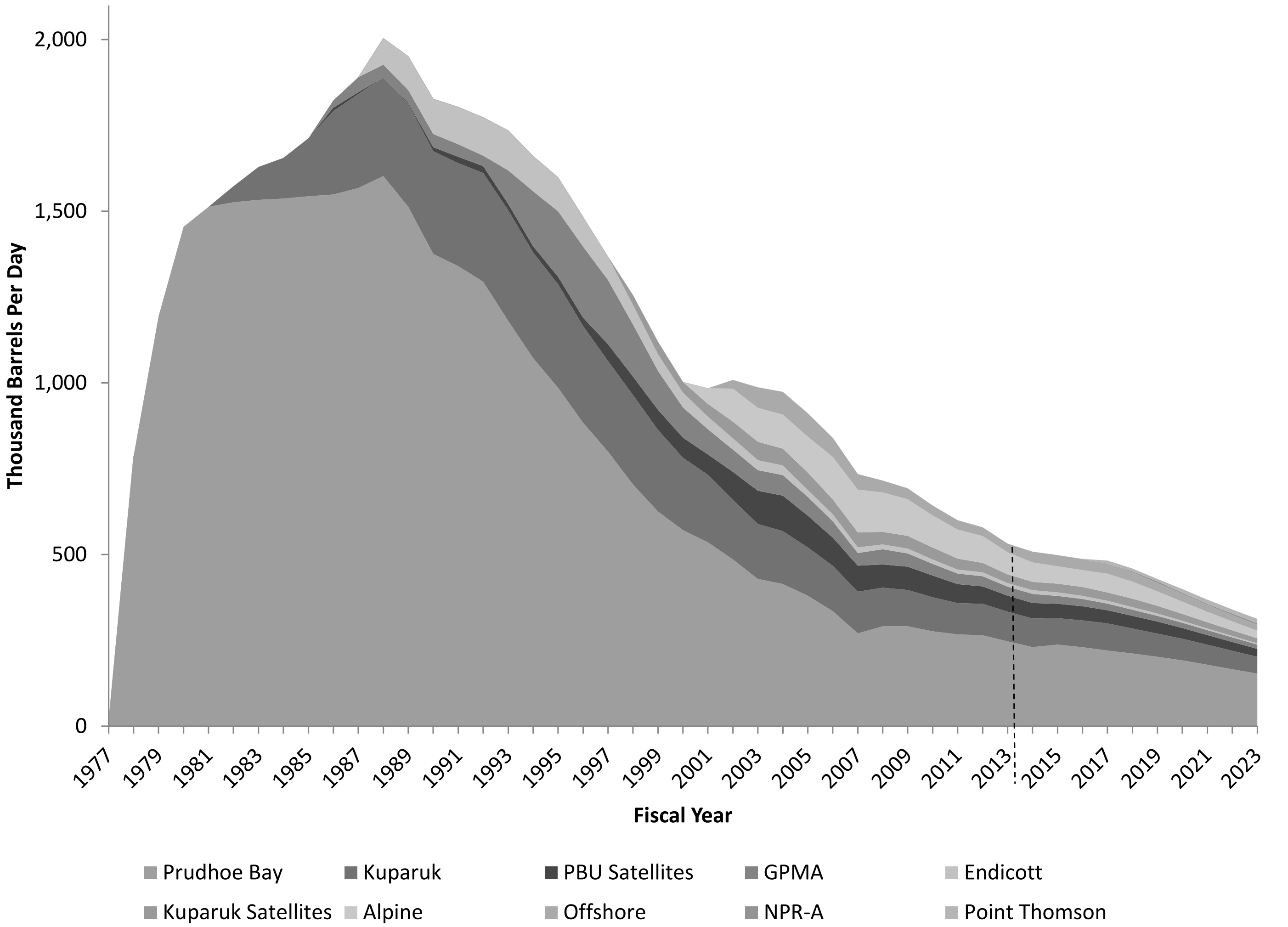
Production Volumes

The volume of oil produced in Alaska is a critical factor in calculating the amount of revenues that the State receives. Production volumes are used to calculate taxes and royalties, and are a key determinant in calculating pipeline tariff rates, which impact the wellhead value upon which both of those revenues are calculated. The production forecast also plays a role in determining the economic life of infrastructure, which is a component of some property tax assessments.

In Alaska, production from different areas within the State has different implications for petroleum revenues. Oil produced within state boundaries is subject to state taxes, but oil produced beyond three miles offshore is not. Likewise, only oil produced from lands owned by the State collects state royalties, while royalties from oil produced on Federal lands is shared with the State. Finally, as mentioned previously, a zone, exists between 3-6 miles offshore where the Federal government shares 27% of the royalties it collects with the State. The production volume being forecast is best described as the mean expected volume flowing through the Trans-Alaska Pipeline System, which includes volumes from each of the above areas.

As with any forward looking statements, the future is inherently difficult to predict. For this reason, the values expressed here are not intended to be predictions of the future; rather they are probability weighted values of many possible future outcomes. Therefore, it should be noted that these values attempt to minimize the error in the forecast rather than attempt to make judgments on exactly what the future will hold. The department began moving toward probability based forecasting last year and details

Figure 4-E: Alaska North Slope Production



surrounding that change can be found in the Fall 2012 RSB.

Consistent with the process used last year, the fall 2013 forecast consists of two components – oil from wells currently in production ("currently producing") and oil from potential new developments ("new oil"). Production from wells drilled since the last forecast are now included as "currently producing," whereas those projects were counted as "new oil" last year. This distinction may make it difficult to compare forecasts between publications, except the total values.

Methodology

To assist with production forecasting, the Department of Revenue contracts an outside petroleum engineering consultant to evaluate Alaska production on a well-by-well basis. This consultant and in-house experts meet with oil producing companies in the State to discuss the intricacies of each operator's area of operation. As a result of these meetings, the consultant is able to advise the department on expected future operations, maintenance plans, general risks, concerns, and uncertainties regarding future operations. The consultant provides an expert assessment, based on engineering principles, as to the technical potential production level for each oil pool over time. The department then applies appropriate considerations for economic limits and uncertainty.

An illustration of the necessity for a risking method is evident in the later years of the fall 2013 forecast. In the fall 2012 forecast, a substantial project was included. This year, that project has been shifted into the future to account for delays and difficulties in equipment, logistics, and permitting.

Table 4-5: ANS Oil Production Forecast

	(bbls/day)									
Fiscal Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Currently Producing	488,436	437,683	396,605	359,016	328,567	301,593	278,379	257,622	238,924	222,454
Decline Rate of Currently Producing	-8%	-10%	-9%	-10%	-9%	-8%	-8%	-8%	-7%	-7%
Risk Adjusted New Oil	19,770	60,705	91,039	123,703	130,920	127,498	121,231	111,200	101,215	90,446
Risk Adjusted Total Forecast	508,207	498,388	487,644	482,719	459,487	429,091	399,610	368,822	340,138	312,900
Anticipated Net Rate of Decline	-4%	-2%	-2%	-1%	-5%	-7%	-7%	-8%	-8%	-8%
New Oil Share of Total Production	4%	12%	19%	26%	28%	30%	30%	30%	30%	29%
GVR Eligible	36,428	37,649	37,858	47,550	45,907	41,723	39,944	37,627	36,026	34,896
% GVR Eligible	7%	8%	8%	10%	10%	10%	10%	10%	11%	11%

Without risking, this delay would have caused a 20,000 barrel per day reduction in FY 2019-2021 volumes. However, by accounting for this possibility, nearly all of this impact is absorbed and the necessity to reduce the forecast of future revenues is avoided. The consistency in the risking method also creates a converse situation for new project announcements. Although these projects are anticipated by the department, the full volumes from them do not enter revenue projections, but rather are added incrementally as they become more certain.

Currently Producing

To assess the future production profile of wells that are already in production, the department's consultant utilizes data from the Alaska Oil and Gas Conservation Commission to develop a time series data set. This data, provided by the producers, includes information on reservoir characteristics, oil flow rates, gas/oil ratios, and water cuts. By assessing these data with decline curve analysis, an expectation for future production is determined for each producing well. Planned downtime is factored in for known work-overs and stimulation work and anticipated responses are incorporated into future production. These production profiles are then aggregated into oil pools, resulting in an aggregate expected decline rate based on well specific data.

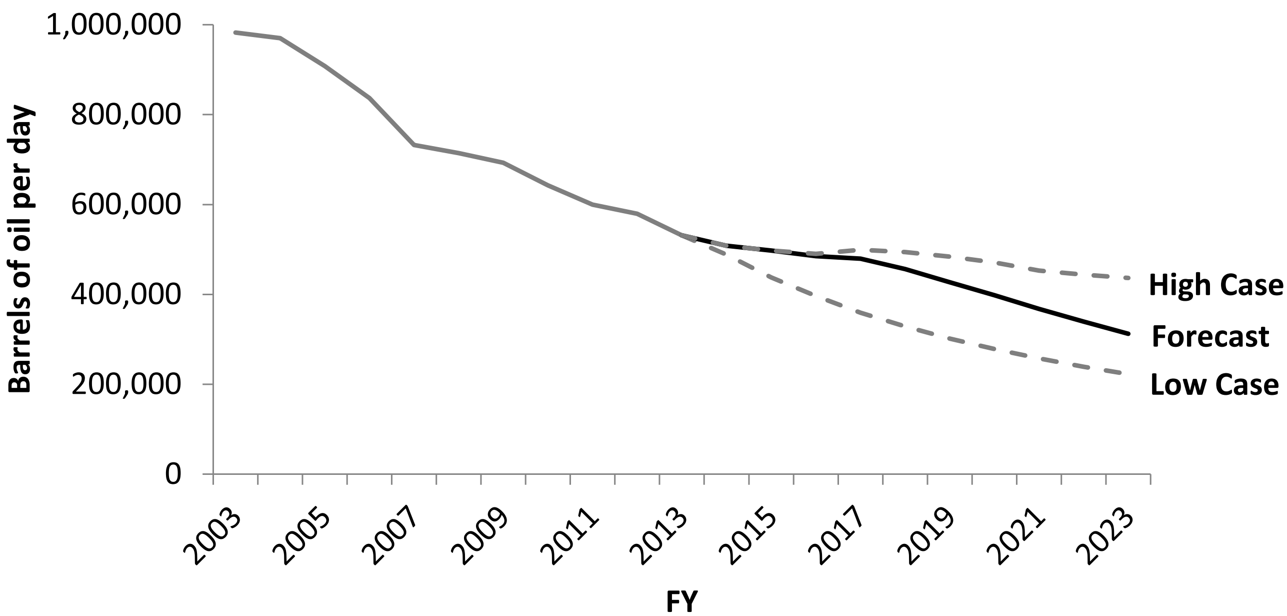
The currently producing component is the least speculative category of this forecast. As the cost associated with producing from these wells is simply the continued operating costs, the currently producing layer of the forecast is nearly analogous to assuming no future capital investment. For this reason, this layer is also employed as the "low case" forecast.

New Oil

All oil in the forecast that is not produced from existing wells is considered to be "new oil" for the purpose of this forecast. This should not be confused with oil that is eligible for a Gross Value Reduction (GVR) under the new tax law. New oil includes production from infill drilling within existing units, incremental oil from enhance oil recovery methods, increases in flow rates via de-bottlenecking facilities, and the development of new areas that are not currently in production. This layer consists of projects considered "under development" as well as "under evaluation." More information regarding these terms is available in previous publications.

Because all oil in this category requires some level of capital employment and the use of equipment, there is potential for each of these projects to be delayed or abandoned. The actual performance of each project is also uncertain as no production data exists. Therefore, some consideration must be given to the associated risk and accounted for, or else the forecast is prone to be optimistic. In the best case scenario, all projects

Figure 4-F: ANS Oil Production Forecast



would come in on-time, on-budget, and on-target. This unlikely scenario is used as the "high case" forecast. The official forecast accounts for and adjusts for those uncertainties in the final production forecast.

Performance

In the 36th full fiscal year of North Slope production, FY 2013 averaged 531,639 barrels of oil per day. The result is a year over year decline rate between FY 2012-2013 of 8.2%, falling in the high end of the projected decline range of 4.5% to 10.6% from the fall 2012 forecast. The primary driver in the below expected volume was an increase in re-injection of natural gas liquids (NGLs) relative to the forecast amount. This new information was accounted for in the spring update last March. Several other factors resulted in reduced performance in several fields which alter the department's outlook as well.

Cook Inlet on the other hand, in its 55th fiscal year of production since statehood, saw its third consecutive annual increase in production. At 12,154 barrels per day, a 13.6% effective increase in production over FY 2012, Cook Inlet is now producing more oil than its FY 2009 level. Early indications suggest that this production growth will continue next year thanks to continued increases in investment.

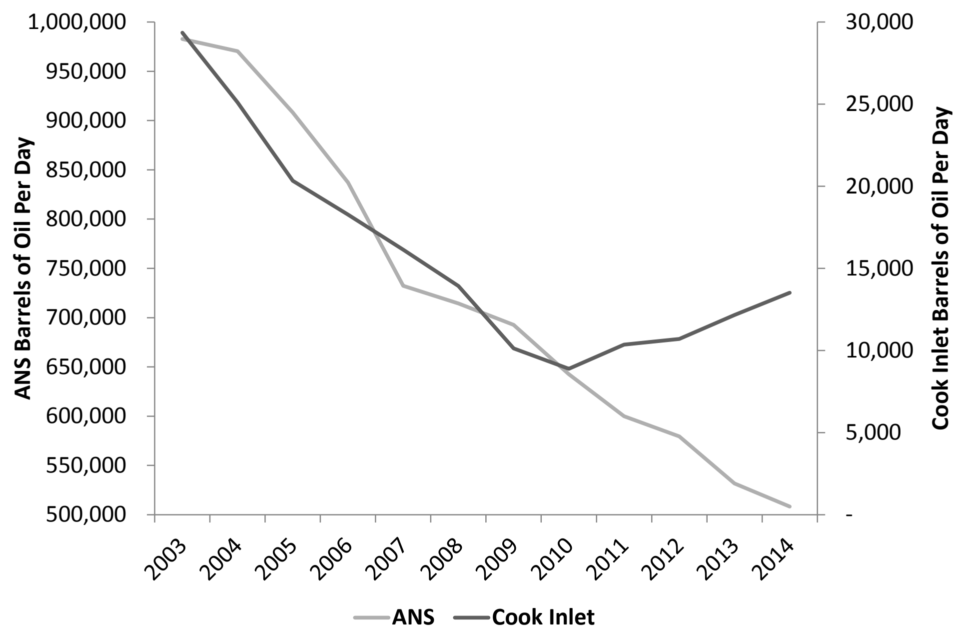
Forecast

In all, an increase in investment and future new production is being anticipated by the department. However, the full impacts of these increases are not fully appreciated when simply looking at the change in production forecasts. This is due to many factors, including adjusting for uncertainty and updating expectations of reservoir performance given another year of production data. It is likely that future forecasts will increase further as uncertainty around fiscal terms are alleviated and companies complete a budget cycle under the new terms.

The forecast of FY 2014 production has been reduced relative to last year's forecast. There are four key components responsible for this adjustment. First, an increase in NGL re-injection is now being forecast relative to last fall. This adjustment was made in the spring forecast and represents a downward revision of almost 12,000 barrels per day. Second, with actual data for the first quarter of FY 2014 now available, it is evident that the summer maintenance cycle was more extensive than last year's forecast anticipated. This results in a reduction of roughly 8,000 barrels per day in the production forecast. Third, the well performance and enhanced recovery response expectations in Prudhoe Bay and Alpine have been slightly reduced on the average well basis. When aggregated, the result is a net downward revision of about 6,000 and 7,000 barrels per day, respectively. Finally, increased drilling is expected from other areas, which result in a net increase of about 3,000 barrels per day. Combined, the result is a downward revision of FY 2014 production to an estimate of 508 thousand barrels per day. FY 2015 and FY 2016 tell an analogous story -- a reduction in well performance is evident in all three major production areas (PBU, KRU and CRU).

The upside is that increased investment and accelerated drilling plans are evident in the midterm. This increased activity acts to offset some of the decreases in performance in the forecast, resulting in minor positive net changes. This occurs in spite of these new production volumes being adjusted for risk and uncertainty.

Figure 4-G: Alaska North Slope and Cook Inlet Production 2003-2014



Cook Inlet Forecast

Cook Inlet has participated in the resurgence of investment and production that the rest of the country has enjoyed over the last few years. FY 2013 resulted in the third consecutive year of oil production increases and FY 2014 looks to continue the upward trend. The department is forecasting oil production to exceed 13,500 barrels per day this fiscal year, a 52% increase over FY 2010 production, all from already developed fields. The ability to improve the recovery of these aging fields gives great hope to the remaining potential on the North Slope as well.

While the official forecast for Cook Inlet does show a decline after next year, the ability for companies to continue increasing production from developed fields does exist. In addition, companies are conducting exploration activities and may provide even greater incremental production in the future. In accordance with the department's prudent and responsible forecasting methodology, these potential increases have not entered the forecast at this point. As companies continue to explore, develop, and invest, future forecasts will incorporate these activities.

Not in Forecast

Likewise, a great deal of future potential exists on the North Slope. Billions of barrels of oil exist in legacy fields that cannot be extracted with current technology. Billions more exist in heavy, shale and viscous oil formations already being evaluated and tested. Billions more recoverable barrels exist in areas near infrastructure that have not been developed. And billions more exist in areas further away that will require a great deal of capital to access and face large regulatory burdens.

In spite of the tremendous accomplishment of bringing nearly 17 billion barrels of oil to market to date, Alaska remains one of the greatest resource potential regions in the world. However, these resources will require a great deal of commitment and capital from world class oil production companies to avoid this potential from being stranded in the ground. Because the actual recovery of these resources is very uncertain, both in absolute terms and in timing, it is not prudent for the State to project revenues based on these possibilities. Therefore, the department does not incorporate these projects into its forecasts until the resources have been discovered, evaluated, tested, planned and financed by a company. Without well data and a development plan, all of these prospects remain classified as potential resources and are outside the forecast production.

Production Tax Forecast

In the end, the forecasts of the components that determine production taxes are not the aim of the department. Instead, the department is forecasting the total revenues that stem from the components. In FY 2013, the State received $4.1 billion in production tax revenue. The forecast receipts in FY 2014 are $2.1 billion. This reduction in forecast revenue relative to the spring 2013 forecast of $1.5 billion is mostly explained by changes in four components. The reduced forecast price ($500 million), the increasing deductible forecast cost ($300 million), the reduced near-term forecast production expectations ($250 million), and the change in tax systems, including a forecast change in credits ($250-300 million). By FY 2023, production tax revenues are expected to be $1.7 billion unless new production comes online or oil prices increase relative to the forecast. The forecast revenue from Cook Inlet production is negligible due to the tax incentives currently in place.

Royalties

A royalty interest is an ownership of future production and is a typical feature in oil and gas contracts with a landowner. These royalty interests are made as part of a contract prior to the actual development of a project and allow the company to shift some of the risk on to the landholder. When a company bids on a lease, they pay an up-front bonus payment, agree to an annual rental payment, and typically offer a royalty interest in any discoveries that may be found. Thus, the bonus is a guaranteed payment to the State as the owner, while the royalty is a contingent amount, only paid if there is success in production.

In Alaska, the State retains ownership of all subsurface minerals on state lands and requires a minimum royalty rate of 1/8 (12.5%) of any production, although there are exceptions that can be made for economically challenged projects. In other U.S. oil producing areas, private citizens usually own these subsurface rights and the royalty is paid directly to the landowner, rather than the government. Occasionally, a company may enter into a net profits sharing lease (NPSL) which bases the royalty payment on net profits rather than gross value of the oil. These profit sharing leases can reach as high as 75% of company profits after their development costs are recovered. Most leases in Alaska are 1/8 (12.5%) or 1/6 (16.67%) royalty.

Alaska has the option of allowing the company to sell the royalty oil on its behalf (known as "royalty in-value" or "RIV"), or to sell the royalty oil itself (known as "royalty in-kind" or "RIK"). The State currently holds a contract to sell some royalty oil, which was renewed this year, with Flint Hills Resources (an oil refinery) in North Pole, Alaska. The contract is for up to 30,000 barrels of oil per day for 5 years. The State now holds a second contract with Tesoro Alaska's Kenai refinery. The State is obligated to negotiate a higher value from taking royalty in-kind than it would receive in-value.

The actual price received for RIV oil is a derived price based on the value of oil sold on the West Coast and adjusted by a formula defined by DNR regulation. Basically, the value is calculated in this way to ensure that the State receives the same value for its oil that the oil company does. In order to avoid collecting value on the costs of transporting oil, all costs of shipping the oil on pipelines and tankers are subtracted from this value in order to determine the actual value of only the oil (called the "wellhead value"). This value may be slightly different between calculating royalty values and taxable values due to differences in statutes and regulations between the Department of Revenue and the Department of Natural Resources.

For more information about royalties, visit the Department of Natural Resources, Division of Oil and Gas website:
http://dog.dnr.alaska.gov/

Royalty Forecast

The department forecasts that $1.7 billion in unrestricted royalty revenues will be collected by the Department of Natural Resources in FY 2014. Current projections show a FY 2023 collection of $1.3 billion.

Property Tax

Property subject to state oil and gas property tax includes property used in the exploration, production, and pipeline transportation of unrefined oil and gas. Each year, the Department of Revenue determines the assessed value for taxable petroleum property as of the assessment date of January 1st. The State then levies a tax on its assessments at a rate of 20 mills (2%) of the assessed value. When petroleum property is located within a municipality, the municipality may also levy a tax on the department's assessments at the same rate it taxes all other property within its jurisdiction. The tax paid to a municipality on petroleum property assessments act as a credit towards payment to the State on those same assessments.

Petroleum Property Tax Revenue

The forecast of state revenues from petroleum property tax starts with the assessed value for each class of property. Assumptions are made regarding new capital investment and typical depreciation curves are applied. The State rate of 20 mills is applied to the forecast values and the estimated payments made to municipalities are subtracted to estimate net receipts to the State.

Property Tax Forecast

In FY 2013, the State collected about $99 million in property tax revenue. The department is projecting state revenue from petroleum property tax to be about $100 million in FY 2014, increasing to about $103 million in FY 2023.

Table 4-6: FY 2013 Distribution of Petroleum Property Tax(1)

Municipality	Gross Tax	($ millions) Local Share	State Share
Anchorage	7.0	5.5	1.1
Fairbanks	19.0	13.0	3.8
Kenai	19.8	9.7	10.1
North Slope	375.7	347.5	26.3
Other Municipalities(2)	0.4	0.2	0.2
Unorganized	97.5	-	58.9
Valdez	53.5	53.5	-
Total Petroleum Property Tax	**573.0**	**429.3**	**100.4**

Corporate Income Tax

An oil and gas corporation's Alaska income tax liability depends on the relative size of its Alaska and worldwide activities and the corporation's total worldwide net earnings. The corporation's Alaska taxable income is derived by apportioning its worldwide income to Alaska based on the average of three factors as they pertain to the corporation's Alaska operations: (1) tariffs and sales, (2) oil and gas production and (3) property. The Alaska State Legislature changed corporate tax rates effective for tax years beginning on or after August 26, 2013. The tax rates are graduated according to the schedule in Table 5-3.

Methodology

Corporate income tax revenues are perhaps the most volatile of all the tax revenue sources for the State of Alaska. Using the most relevant collections information for this estimate is very important. For the FY 2014 forecast, the most recent collections information is used in a statistical model to select the most likely revenue amount from a range of possible outcomes. For FY 2015, our forecast represents the average corporate income tax revenue from FY 2008-2013.

Corporate Income Tax Forecast

FY 2013 receipts totaled $435 million. The department is forecasting that FY 2014 receipts will rise to around $464 million. Collections are projected to trend toward $361 million by FY 2023 as Alaskan apportionment factors decrease.

Oil Revenue Summary

In all, the department is forecasting that oil revenues will continue to be the most significant source of revenue to the State in the foreseeable future. Current projections are that total unrestricted revenues from all sources directly tied to oil production will reach $4.4 billion in FY 2014. This revenue stream is expected to trend downward with production and is very sensitive to price changes. Current projections show total unrestricted oil revenues trending toward $3.4 billion by FY 2023.

Restricted Revenues

As mentioned earlier, some oil revenue is not available to the Legislature for general spending and is instead deposited into special accounts for special purposes. More detail about these funds and their balances is available in chapter 9.

Restricted Royalties

The majority of oil revenue that is restricted comes from royalties. At least 25% of royalty collections are required to be deposited into the Permanent Fund by the Alaska State Constitution. Some properties pay

(1) Tax amounts shown here represent the total certified tax roll for the 2013 tax year, due June 30, 2013. These amounts may not exactly match cash revenue received in the fiscal year as presented elsewhere in this book.

(2) Includes Matanuska-Susitna Borough, Cordova, Northwest Arctic Borough and Whittier.

50%. The weighted average of these contributions works out so that about 30% of all royalty collections get deposited into the Permanent Fund principle account.

Additionally, 0.5% of royalty collections get deposited into the Public School Trust Fund and added to the principal of that account (Principal Fund). Some of the earnings from that principal are then moved to an Income Fund which supports the State public school program. The current balance of the Principal Fund of the Public School Trust Fund is about $500 million.

NPR-A Fund

The State is entitled to 50% of the bonuses, rents and royalties that the Federal government receives from the leasing of lands in the National Petroleum Reserve – Alaska (NPR-A). This relates to federal legislation that provides certain states with a bonus, rents, and royalty share of federal revenues from mineral development on federal lands. These revenues are deposited into the NPR-A Special Revenue Fund and are restricted for specific uses. These funds can be appropriated to municipalities in the form of grants to compensate for any impacts resulting from the development on those lands. Revenue that is not appropriated is treated like other royalty revenue (at least 25% is deposited into the Permanent Fund, and 0.5% to the Public Schools Trust Fund), with the remaining revenue available for appropriation to either the Power Cost Equalization Fund, Rural Electric Capitalization Fund, or the General Fund. For purposes of categorization, these funds are considered "Federal Revenues." In FY 2013 these payments amounted to about $3.6 million, but have exceeded $20 million during years with high interest lease sales.

Hazardous Release Surcharge

Finally, up to $0.05 per barrel of taxable oil is collected and deposited into the Oil and Hazardous Substance Release Prevention and Response Fund (or simply the "Response Fund"). This fund was created in 1986 under Alaska Statute 46.08 and is intended to be a source of funds that can be drawn upon in the event of the release of a hazardous substance for the abatement of damages from them. The fund is separated into two accounts – a response account and a prevention account. As the names imply, the response fund is designed to respond to a spill or discharge, while the prevention account is intended to support the Department of Environmental Conservation in spill prevention and preparedness planning activities. The prevention account can also be used to respond to substance released that are not declared a disaster by the governor or can be used to support other response and prevention programs if appropriated by the Legislature.

The surcharge paid to the response account is $0.01 per taxable barrel of oil produced in the State. However, the surcharge is suspended when the account has a balance of $50 million. In November of 2006, the fund was accessed to assist with pipeline spills on the North Slope. The surcharge was reimposed in 2007 and has been suspended and reimposed since. The balance of the fund as of September 30, 2013 was $47.8 million.

Following a 2006 amendment, the prevention account now receives a surcharge of $0.04 per taxable barrel of oil produced within the State (increased from $0.03). All interest payments, penalties, settlements and fines from both accounts are deposited into the prevention account and are available for appropriation to eligible programs. This account does not have a limit.

5

Non-petroleum Revenue

Introduction

Revenue collections from In-State Activities other than petroleum include non-petroleum taxes, charges for services, fines and forfeitures, licenses and permits, rents and royalties and miscellaneous and transfer revenue sources such as dividends from public entities. These sources are categorized as "Non-petroleum Revenue, except federal and investment," sometimes shortened to "Non-petroleum Revenue." Federal and investment revenue are discussed in chapters 6 and 7, respectively. These revenue sources are each subcategorized into Unrestricted, Designated General Fund and Other Restricted Revenue in Table 5-1. The amounts of each revenue type are reflected in Table 5-2 and Tables 5-4 through 5-8 in this chapter.

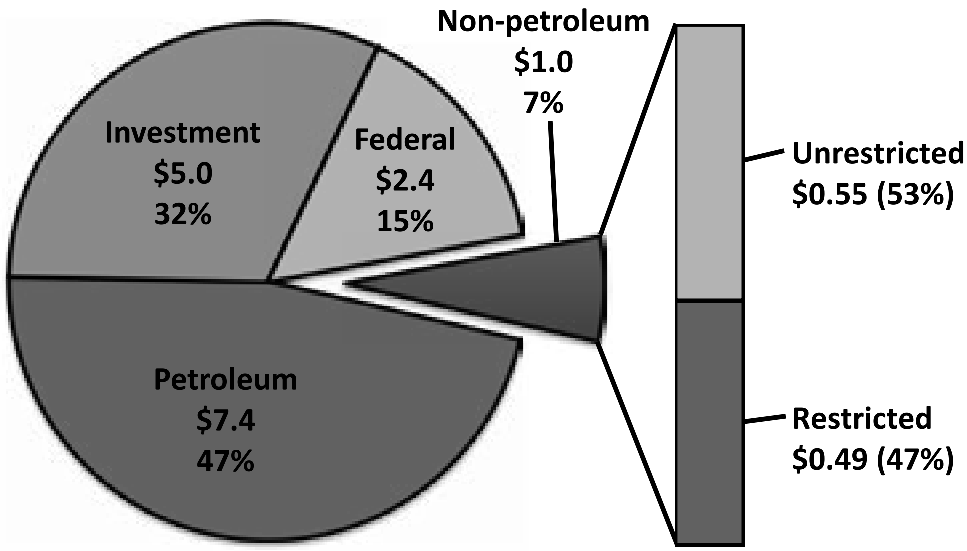


Figure 5-A: FY 2013 Non-petroleum Revenue, by restriction and type ($ billions)

This chapter provides history on non-oil revenue sources for FY 2013 and forecasts revenue for FY 2014 and FY 2015. The chapter also includes descriptions of each revenue source and explains the methodology used for the forecasts. The Department of Revenue's *Alaska State Taxes* contains more comprehensive historical information about each tax type, and the Department of Administration's *Comprehensive Annual Financial Report* contains more detail about many non-tax revenue sources.

Taxes

Charitable Gaming

Under Alaska law, municipalities and qualified nonprofit organizations may conduct specific charitable gaming activities allowed by law. The purpose of such activities is to derive public benefit in the form of money for charities and revenue for the State. The department collects permit and license fees, a 1% net proceeds fee and a 3% pull-tab tax.

Commercial Passenger Vessel Taxes

Alaska voters approved an initiative to impose new taxes and fees on commercial passenger vessels in 2006, which the Legislature modified in 2010. Following are descriptions of the various commercial passenger vessel taxes and fees in current law. The Ocean Ranger Fee is described under "Charges for Service" below.

• The Commercial Passenger Vessel Tax (CPVT) is a tax of $34.50 on each passenger aboard a commercial passenger vessel with 250 or more

Table 5-1: Non-petroleum Revenue, by restriction and category

	History	Forecast	
($ millions)	FY 2013	FY 2014	FY 2015
Unrestricted Non-petroleum Revenue			
Taxes	361.3	338.2	375.8
Charges for Services	25.2	29.8	29.8
Fines & Forfeitures	15.8	10.4	10.4
Licenses & Permits	41.9	43.7	43.7
Rents & Royalties	24.7	22.1	22.2
Other	79.5	39.9	30.4
Unrestricted Non-petroleum Revenue	**548.4**	**484.1**	**512.3**
Restricted			
Designated General Fund			
Taxes	52.3	47.9	47.1
Charges for Services	202.9	244.2	243.7
Fines & Forfeitures	17.6	9.2	9.1
Licenses & Permits	0.2	0.2	0.2
Rents & Royalties	3.6	4.6	4.6
Other	23.2	22.9	22.9
Subtotal	**299.8**	**329.0**	**327.6**
Other Restricted			
Taxes	76.5	74.7	76.2
Charges for Services	40.8	70.9	70.9
Fines & Forfeitures	24.5	24.3	24.1
Licenses & Permits	29.2	29.8	29.8
Rents & Royalties	8.0	7.5	7.6
Other	6.2	6.8	6.8
Subtotal	**185.2**	**214.0**	**215.4**
Total Restricted	**485.0**	**543.0**	**543.0**
Total Non-petroleum Revenue	**1,033.4**	**1,027.1**	**1,055.3**

Table 5-2: Non-petroleum Tax Revenue, by restriction and detail

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
Corporate Income Tax (non-petroleum)	**112.5**	**87.9**	**127.1**
Excise Tax			
Alcoholic Beverage	19.8	20.0	20.3
Tobacco Products – Cigarettes	32.2	30.4	28.9
Tobacco Products – Other (General Fund)	12.6	13.7	14.1
Electric & Telephone Cooperative	0.2	0.2	0.2
Insurance Premium	52.4	54.4	56.4
Motor Fuel Tax	41.9	41.3	40.7
Tire Fee	1.4	1.4	1.4
Vehicle Rental	8.4	8.3	8.4
Subtotal	**168.9**	**169.7**	**170.4**
Fish Tax			
Fisheries Business	19.2	22.1	22.6
Fishery Resource Landing	5.5	5.3	5.4
Subtotal	**24.7**	**27.4**	**28.0**
Other Tax			
Charitable Gaming	2.5	2.4	2.4
Estate	0.0	0.0	0.0
Large Passenger Vessel Gambling	6.0	6.0	6.0
Mining License	46.7	44.8	41.9
Subtotal	**55.2**	**53.2**	**50.3**
Unrestricted Non-petroleum Tax Revenue	**361.3**	**338.2**	**375.8**

berths. Revenue is deposited into a subfund of the General Fund, the Commercial Vessel Passenger Tax Account. Five dollars of the tax can be appropriated to each of the first seven ports of call. If a commercial passenger vessel visits a port that levies a tax similar to the CPVT, and that tax was in place before December 17, 2007, the local tax imposed is allowed as a credit against the State tax. Only Juneau and Ketchikan had qualifying levies in place at that time (Juneau's fee is $8 per passenger and Ketchikan's is $7). CPVT can only be collected if a cruise ship spends more than 72 consecutive hours in Alaskan waters. All funds received from the CPVT must be spent on port facilities, harbor infrastructure, and other services provided to commercial passenger vessels and the passengers on board those vessels. The entire passenger fee is considered restricted revenue.

• The Large Passenger Vessel Gambling Tax is a tax of 33% on the adjusted gross income from gaming or gambling activities aboard large passenger vessels in the State. Revenue goes to the General Fund and is considered unrestricted.

• The Alaska corporate income tax now applies to large commercial passenger vessels, and the revenue is

Table 5-2: Non-petroleum Tax Revenue, by restriction and detail (*continued from previous page*)

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Restricted			
Designated General Fund			
Alcoholic Beverage (alcohol & drug treatment)	19.8	20.0	20.3
Insurance Premium/Other[(1)]	7.8	5.5	5.5
Tobacco – Cigarettes (school fund)	21.6	20.3	19.3
Tobacco – Cigarettes (tobacco use cessation)	3.1	2.1	2.0
Subtotal	**52.3**	**47.9**	**47.1**
Other Restricted			
Cost Recovery Fisheries Assessment	1.3	1.2	1.5
Cruise Ship Passenger Fee (State Share)	2.8	5.0	5.0
Cruise Ship Passenger Fee (Municipal Share)	14.4	11.2	11.2
Dive Fishery Management Assessment (designated management areas)	0.8	0.8	0.8
Electric and Telephone Cooperative (Municipal Share)	4.1	4.1	4.1
Fisheries Business (Municipal Share)	25.1	25.4	25.9
Fishery Resource Landing (Municipal Share)	7.8	6.7	6.9
Motor Fuel Tax-Aviation (Municipal Share)	0.2	0.2	0.2
Salmon Enhancement (Aquaculture Association Share)	8.5	8.6	8.8
Seafood Development (qualifying regional associations)	1.8	1.7	1.8
Seafood Marketing Assessment (seafood marketing programs)	9.6	9.8	10.0
Settlements to CBRF (non-petroleum taxes)	0.1	0.0	0.0
Subtotal	**76.5**	**74.7**	**76.2**
Restricted Non-petroleum Tax Revenue	**128.8**	**122.6**	**123.3**
Total Non-petroleum Tax Revenue	**490.1**	**460.8**	**499.1**

included in the forecast of corporate income taxes.

• There are penalties for false reporting, violating environmental regulations and failing to make proper disclosures on promotions and shore side activity sales. Revenue from these provisions is included in the Fines and Forfeitures section.

About one million passengers visited the State in large passenger vessels in FY 2013, and expectations are similar for FY 2014 and FY 2015.

Corporate Income Tax[(2)]

Alaska levies the corporate income tax on corporations doing business in the State. Beginning on or after August 26, 2013, corporate tax rates are graduated according to the schedule in Table 5-3.

[(1)] In addition to the worker's compensation insurance premiums for the Insurance Premium Tax, this amount also includes services fees from employers who are self-insured.

[(2)] Excluding petroleum-related corporations that must report using AS 43.20.144.

S-Corporations and LLCs that file federally as partnerships are generally exempt from corporate income tax. A corporation computes their tax liability based on the federal taxable income of its water's edge combined report, with Alaska adjustments. Corporations other than oil and gas corporations apportion their income to Alaska by using a three-factor apportionment based on sales, property and payroll. Alaska taxable income is determined by applying the apportionment factor to the corporation's modified federal taxable income.

Using relevant collections information for this estimate is very important. For the FY 2014 forecast, the most recent collections information is used in a statistical model to select the most likely revenue amount from a range of possible outcomes. For FY 2015, our forecast represents the average corporate income tax revenue from FY 2008-2013.

Estate Tax

Estate tax is levied on the transfer of an estate upon death. The Alaska estate tax is tied to the federal tax, with the amount of the State tax equaling the maximum state credit allowed on the estate's federal return. All revenue derived from estate taxes is deposited in the General Fund.

In 2005, federal law eliminated the State tax credit and replaced it with a deduction. This change was made permanent in 2012, rendering Alaska's estate tax obsolete. Future Revenue Sources Books will no longer include the Estate Tax unless changes are made to relevant Alaska or federal statutes.

Table 5-3: Corporate Income Tax Rate Schedule[(1)]

Taxable Income	Marginal Tax Rate
$0-$25,000	0.0%
$25,000-$49,000	2.0%
$49000-$74,000	3.0%
$74,000-$99,000	4.0%
$99,000-$124,000	5.0%
$124,000-$148,000	6.0%
$148,000-$173,000	7.0%
$173,000-$198,000	8.0%
$198,000-$222,000	9.0%
$222,000+	9.4%

Fisheries Business Tax

The fisheries business tax is levied on businesses that process fisheries resources in Alaska or export fisheries resources from Alaska. Although the tax is usually levied on the act of processing, the tax is often referred to as a "raw fish tax" because it is based on the value of the raw fishery resource. Tax rates vary from 1% to 5%, depending on whether a fishery resource is classified as "established" or "developing," and whether it was processed by a shore-based or floating processor. Revenue from the tax is deposited in the General Fund. Fifty percent of the revenue (before credits) is shared with qualified municipalities and is treated as Other Restricted Revenue.

Fisheries business tax revenue retained by the State is reduced by an estimate of tax credits, including Salmon Product Development credits, which apply only to the State portion of the tax. Forecasts of fisheries business tax revenue are based on estimated taxable values of the major fisheries in the State and historical effective tax rates. The Department of Revenue expects Fisheries Business Tax revenue to rebound slightly in FY 2014 then remain relatively constant in FY 2015, as strong salmon returns are balanced by lower prices for groundfish.

Fishery Resource Landing Tax

The fishery resource landing tax is based on the unprocessed statewide average price of the resource and is levied on fishery resources processed outside of Alaska and first landed in Alaska. The tax is collected primarily from factory trawlers and floating processors that process fishery resources outside the State's three mile limit and bring their products into Alaska for shipment. The tax rates vary from 1% to 3%, based on whether the resource is classified as "established" or "developing." All revenue derived from the tax is deposited in the General Fund. Fifty percent of the revenue (before credits) is shared with qualified municipalities, and is treated as Other Restricted State Revenue.

Fisheries resource landing tax revenue retained by the State is reduced by a forecast of tax credits which apply only to the State's share of the tax. The Department of Revenue forecasts fisheries resource landing tax revenue based on estimated taxable values of the major fisheries in the State and historical effective tax rates. The Department expects fisheries resource landing tax revenue to fall slightly in FY 2014 due to lower prices for groundfish,

(1) Effective for tax years beginning on or after August 26, 2013.

which account for over 90% of landing tax revenue.

Insurance Premium Tax

Insurance companies in Alaska pay an insurance premium tax instead of corporate income tax, sales or other excise taxes. The tax is levied as a percentage of the total insurance premiums for policies in the State of Alaska. Revenue is deposited into the General Fund, and for most types of insurance, the tax is treated as Unrestricted Revenue. Insurance premium taxes on worker's compensation insurance are deposited into a subfund of the General Fund, the Workers Safety and Compensation Fund, and are reflected as restricted in this forecast. The restricted component also includes service fees paid into the Workers Safety and Compensation Fund by employers who are uninsured or self-insured.

The forecast of insurance premium tax revenue are estimates provided by the Department of Commerce, Community and Economic Development's Division of Insurance, which administers the insurance premium tax, and the Department of Labor and Workforce Development's Workers Compensation Division, which collects worker's compensation service fees.

Mining License Tax

The Mining License Tax (MLT) ranges from 0% to 7% on the net income of most mining operations in the State. New mining operations are exempt from the MLT for a period of 3.5 years after production begins. Sand and gravel operations are exempt from the MLT tax.

This forecast uses a bottom-up approach to estimate tax payments for each of the major mines in the State based on expected minerals prices and production. MLT revenue increased from $40.7 million in FY 2012 to $46.7 million in FY 2013. Gold and zinc play the largest role in the MLT, as the largest mines in the State rely heavily on those two metals. For FY 2014 and FY 2015, the department forecasts modest decreases in the MLT primarily due to lower gold prices.

Motor Fuel Tax

The motor fuel tax is imposed on all motor fuel sold, transferred or used within Alaska. Per gallon rates are $0.08 for highway use, $0.05 for marine fuel, $0.047 for aviation gasoline, $0.032 for jet fuel, and $0.08 or $0.02 for gasohol, depending on the season, location and EPA mandate. Motor fuel taxes are collected primarily from wholesalers and distributors licensed as qualified dealers. Various uses of fuel are exempt from tax, including fuel used for heating or flights to or from a foreign country. All revenue derived from motor fuel taxes is deposited in the General Fund. Sixty percent of the revenue attributable to aviation fuel sales at municipal airports is shared with the respective municipalities and is treated as Other Restricted Revenue.

The forecast of motor fuel tax revenue shows slight declines in FY 2014 and FY 2015, based on the Energy Information Agency projections for declines in total U.S. motor fuel consumption.

Tire Fee

The tire fee has two components. The first component is a tax of $2.50 on all new tires sold in Alaska for motor vehicles intended for highway use. The second component is an additional $5 fee per tire on all new tires with heavy studs sold in Alaska, and a $5 fee per tire on the installation of heavy studs on a previously un-studded tire.

Forecasted revenue from the tire fee is based on the expected number of vehicle registrations in the State.

Seafood Assessments and Taxes

The Department of Revenue administers five different programs that collect funds through seafood assessments and taxes. The rates for these assessments and taxes are determined by a vote of the appropriate association within the seafood industry, by members of the Alaska Seafood Marketing Institute, or by the Department of Revenue. The five programs are:

• The seafood marketing assessment, which applies to all seafood products made or first landed in Alaska and all unprocessed products exported from Alaska. It is currently a 0.5% assessment and supports the operations of the Alaska Seafood Marketing Institute.

• The dive fishery management assessment is levied on the value of fishery resources taken using dive gear in a designated management area. The current assessment rate is 5% for sea cucumbers and 7% for geoducks and sea urchins. Dive fishery taxes are based on the value of the fishery in the prior fiscal year.

• The regional seafood development tax, which is levied on the value of fishery resources in a designated management area. The current tax rate is 1% and covers drift and set gillnet

Table 5-4: Revenue from Charges for Services, by restriction and detail

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
General Government	13.2	14.6	14.6
Natural Resources	2.4	7.6	7.6
Other	9.6	7.6	7.6
Unrestricted Revenue from Charges for Services	**25.2**	**29.8**	**29.8**
Restricted			
Designated General Fund			
DCCED Business Licenses	9.4	9.4	9.4
Environmental Compliance Fees	1.0	0.9	0.9
General Government - GF Subfunds	7.0	6.7	6.7
Marine Highway Receipts	52.3	54.4	53.9
Natural Resources	0.2	0.3	0.3
Ocean Ranger Fees	3.9	3.7	3.7
Oil and Gas Conservation	5.5	6.5	6.5
RCA Receipts	9.2	10.8	10.8
Receipt Supported Services	113.5	150.7	150.7
Timber Sale Receipts	0.9	0.8	0.8
Subtotal	**202.9**	**244.2**	**243.7**
Other Restricted			
General Government - Special Funds	0.5	0.3	0.3
Statutorily Designated	40.3	70.6	70.6
Subtotal	**40.8**	**70.9**	**70.9**
Restricted Revenue from Charges for Services	**243.7**	**315.1**	**314.6**
Total Revenue from Charges for Services	**268.9**	**344.9**	**344.4**

operations in Prince William Sound, as well as drift gillnet operations in Bristol Bay. Seafood development tax revenue is based on the estimated taxable value of seafood processed in Alaska.

• The salmon enhancement tax, which is levied on salmon sold or exported from designated aquaculture regions. The rate varies from 2-3% by location.

• The cost recovery fisheries assessment, a program authorized in 2006 that allows hatcheries to establish a common property fishery and recoup costs through an assessment on fishery resources taken in the terminal harvest area. This program was first used starting in 2012 for the Hidden Falls hatchery in Southeast Alaska.

Revenue received under these assessments is deposited in the General Fund. Funds treated as Other Restricted Revenue in this forecast are set aside for appropriation for the benefit of the seafood industry, either in marketing or in management and development of the industry.

The estimated taxable value of Alaska's salmon fishery and historical effective tax rates are used to forecast salmon enhancement tax revenue. Seafood assessment taxes are forecasted using the department's estimates of fisheries values developed for the fisheries business and landing taxes.

Vehicle Rental Tax

Vehicle rental tax is a 10% tax on most passenger vehicle rentals of 90 days or less, and a 3% tax on rentals of recreational vehicles for 90 days or less. Beginning in May 2013, motorcycles are exempt from the tax.

Revenue from the vehicle rental tax is expected to remain constant.

Charges for Services

The charges for services category includes fees and other program charges for state services. Revenues reported in this category do not include all charges for state services. This category only includes those services that do not fit into other categories in this report.

Most of these receipts are considered Restricted Revenue because they are returned to the program where they were generated. The only Unrestricted Revenue listed in this category come from charges that do not have program receipt designations, or are not otherwise segregated and appropriated back to a program. Many of the charges for services are small amounts that the department has grouped into the broad categories "General Government," "Natural Resources" and "Other." Estimates for these categories are based on fiscal year-to-date collections and historical averages. The largest categories of charges for services are listed separately and are discussed below.

Marine Highway Fund

The Alaska Marine Highway Fund is a subfund of the General Fund and receives revenue from state ferry system operations. Because revenue is customarily appropriated for Alaska Marine Highway operations, it is considered Restricted Revenue for this forecast. Revenue projections are based upon revenue expectations provided by the Alaska Marine Highway Division within the Alaska Department of Transportation.

Environmental Compliance Fund

Commercial passenger vessel fees paid into the Environmental Compliance Fund come from two sources: Ocean Ranger fees, and environmental compliance fees. All fees paid into the fund are considered restricted for purposes of this forecast and are based on estimated cruise ship passenger levels. The Ocean Ranger fee is levied on each voyage in Alaska by commercial passenger vessels with 250 or more berths at a rate of $4 per berth. The fee is levied to support the Ocean Ranger program, which provides for independent observers of engineering, sanitation and health practices aboard the vessels. This fee was imposed as part of a broader cruise-ship related initiative passed by voters in August 2006.

Environmental compliance fees are levied on commercial passenger vessels with over 50 berths. Fees range from $75 to $3,750 per vessel based on the number of berths, and funds are used to support environmental compliance programs.

Program Receipts

Under AS 37.05.142 – 37.05.146, receipts from authorized state programs are accounted for separately and appropriated to administer and implement laws related to the program, or cover costs associated with collecting the receipts. Some programs with program receipt authority are not included in the department's Charges for Services category because they are reported elsewhere in this forecast or because they do not generate revenue available for general appropriation.

Expected revenue from program receipts are based on discussions with the Governor's Office of Management and Budget and analysis of the most recent budget expectations for these categories.

Program receipts listed in this section are:

• Receipt supported services, which include state services such as Pioneers homes and occupational licensing that are funded by program receipts.

• Statutorily designated program receipts, which include money received from sources other than the State or federal government and restricted by the terms of a gift, grant, bequest or contract.

• Regulatory Commission of Alaska (RCA) receipts, which are regulatory cost charges and user fees levied on utilities and pipelines to fund costs of regulation.

• Timber sale receipts, which are used to fund the timber disposal program of the Department of Natural Resources.

• Oil and Gas Conservation Commission receipts, which are fees and charges for regulation of oil and

Table 5-5: Revenue from Fines & Forfeitures, by restriction and detail

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
Fines and Forfeitures	15.8	10.4	10.4
Unrestricted Revenue from Fines & Forfeitures	**15.8**	**10.4**	**10.4**
Restricted			
Designated General Fund			
Tobacco Settlement (Tobacco Use Education & Cessation Fund)	6.0	6.0	5.9
Other - GF Subfunds	11.6	3.2	3.2
Subtotal	**17.6**	**9.2**	**9.1**
Other Restricted			
Tobacco Settlement (Northern Tobacco Securitization Corporation)	24.0	23.9	23.7
Other - Special Revenue Funds	0.5	0.4	0.4
Subtotal	**24.5**	**24.3**	**24.1**
Restricted Revenue from Fines & Forfeitures	**42.1**	**33.5**	**33.2**
Total Revenue from Fines and Forfeitures	**57.9**	**43.9**	**43.6**

gas wells and pipelines.

• Business license fees collected by the Department of Commerce, Community and Economic Development.

Fines and Forfeitures

Fines and forfeitures include civil and criminal fines and forfeitures and money received by the State from the settlement of civil lawsuits. The largest single source of receipts under this category is the multi-state tobacco settlement often referred to as the Master Settlement Agreement. Other sources are forecast based on fiscal year-to-date collections and historical averages.

Tobacco Settlement

The tobacco Master Settlement Agreement was signed by 46 states, including Alaska, in November 1998 and dictates annual payments to each of the States. Eighty percent of the settlement revenue is earmarked for the Northern Tobacco Securitization Corporation for payments on bonds that were sold based on the future revenue stream. The revenue for these bonds is considered other Restricted Revenue. The remaining 20% of the revenue is deposited into the Tobacco Use Education and Cessation Fund, a subfund of the General Fund. Tobacco Use Education and Cessation Fund revenue is considered Designated General Fund Revenue.

Tobacco settlement payments are based on a complex formula that takes into account several factors including declines in cigarette consumption, inflation and certain adjustments for litigation expenses and market share losses related to the settlement.

Licenses and Permits

Licenses and permits represent revenue derived from charges for participating in activities regulated by the State. The majority of the receipts under this category are from motor vehicle registration and fishing and hunting license fees. Several other small license and permit fees are summarized in the Other Fees category. Alcoholic beverage license fees are forecast separately.

Alcoholic Beverage Licenses

Alcoholic beverage licenses are

Table 5-6: Revenue from Licenses & Permits, by restriction and detail

	History	Forecast	
	($ millions)		
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
Alcoholic Beverage Licenses	0.9	0.9	0.9
Motor Vehicles	38.2	40.2	40.2
Other Fees	2.8	2.6	2.6
Unrestricted Revenue from Licenses & Permits	**41.9**	**43.7**	**43.7**
Restricted			
Designated General Fund			
Other Fees - GF Subfunds	0.2	0.2	0.2
Other Restricted			
Alcoholic Beverage License Share	0.9	0.9	0.9
Hunting and Fishing Fees (Fish & Game Fund)	24.8	24.9	24.9
Other Fees - Special Revenue Funds	3.5	4.0	4.0
Subtotal	**29.2**	**29.8**	**29.8**
Restricted Revenue from Licenses & Permits	**29.4**	**30.0**	**30.0**
Total Revenue from Licenses & Permits	**71.3**	**73.7**	**73.7**

required to manufacture or sell alcoholic beverages in Alaska. Licenses are issued by the Alcoholic Beverage Control Board and revenue is deposited into the General Fund. All of the revenue from biennial license fees collected within municipalities, excluding annual wholesale fees and biennial wholesale license fees, is shared with the municipalities and treated as other Restricted Revenue for purposes of this forecast. The department expects little change in revenue because the issuance of alcoholic beverage licenses is limited based on population, and population growth is relatively steady.

Hunting and Fishing License Fees

Hunting and fishing licenses are issued by the Alaska Department of Fish and Game for participation in various hunting, fishing, and related activities. The majority of this revenue is appropriated to a special revenue fund called the Fish and Game Fund and are classified as Other Restricted Revenue. Money in the fund can only be spent for fish and game management purposes. Revenue forecasts from hunting and fishing license fees are provided by the Alaska Department of Fish and Game.

Motor Vehicle Registration Fees

Motor vehicle registration fees are collected by the Division of Motor Vehicles within the Department of Administration. Most fees are considered unrestricted license and permit revenue; however, some registration fees are considered restricted receipt supported services and are reflected in the Charges for Services section. Historical and forecast revenue from motor vehicle registration fees is based on data provided by the Division of Motor Vehicles.

Rents and Royalties

Rents and royalties from sources other than oil and gas fall into two categories: mining rents and royalties, and other non-petroleum rents and royalties. All rents and royalties from oil and gas are reported in the Oil Revenue section.

Table 5-7: Revenue from Rents & Royalties, by restriction and detail

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
Mining Rents and Royalties	14.1	13.3	13.4
Other Non-Petroleum Rents and Royalties	10.6	8.8	8.8
Unrestricted Revenue from Rents & Royalties	**24.7**	**22.1**	**22.2**
Restricted			
Designated General Fund			
Other Non-Petroleum Rents & Royalties	3.6	4.6	4.6
Other Restricted			
Mining Rents & Royalties	8.0	7.5	7.6
Restricted Revenue from Rents & Royalties	**11.6**	**12.1**	**12.2**
Total Revenue from Rents & Royalties	**36.3**	**34.2**	**34.4**

Mining Rents and Royalties

As with oil and gas production, the State earns revenue from other mineral production that occurs on state lands leased for exploration and development. As the landowner, the State earns revenue from leases as: (1) up-front bonuses, (2) annual rent charges, and (3) as a retained royalty interest in minerals production.

Revenue received from mining rents and royalties is deposited as follows: between 25% and 50% into the Permanent Fund, 0.5% into the School Fund, and the remainder into the General Fund. The Permanent Fund and School Fund portions are treated as Other Restricted Revenue.

Future revenue from mining rents and royalties are based on analyst forecasts of future minerals prices and mine-specific forecasts for large mines on state land.

Other Non-Petroleum Rents and Royalties

The State receives revenue from the leasing, rental, and sale of state land. While all of this revenue is deposited into the General Fund, some is deposited into sub-funds of the General Fund and is treated as Designated General Fund Revenue for purposes of this forecast. This category includes revenue from leasing, rental, and sale of state land that do not fall into the oil and gas or mining royalty categories. Other non-petroleum rents and royalties are based on analysis of fiscal year-to-date and historical collections.

Miscellaneous and Transfer Revenues

This category includes unclaimed property transfers, transfers to the State from component organizations, and miscellaneous revenue.

Projections of miscellaneous revenue, which include contributions to the State and other revenue, are based on analysis of fiscal year-to-date and historical collections. Unclaimed property and transfers from component organizations are discussed below.

Unclaimed Property

Alaska's unclaimed property statutes require businesses and corporations to report unclaimed intangible property to the State. Property is reportable if an owner cannot be located, the owner has not cashed a property check, or an account has not had any owner-initiated activity for at least three years. Unclaimed property may include checking accounts, customer deposits and over-payments, gift certificates, unpaid wages, and security related accounts. The State holds the property in trust until the owner or his or her legal heir claims

Table 5-8: Miscellaneous & Transfer Revenues, by restriction and detail

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted Miscellaneous & Transfer Revenues			
Miscellaneous	63.6	15.2	15.2
Alaska Housing Finance Corporation	9.5	0.0	0.0
Alaska Industrial Development & Export Authority	0.0	20.7	10.7
Alaska Municipal Bond Bank Authority	0.0	0.0	0.0
Alaska Student Loan Corporation	1.2	0.0	0.0
Alaska Energy Authority	0.1	0.0	0.0
Alaska Natural Gas Development Authority	0.1	0.0	0.0
Mental Health Trust	0.0	0.0	0.0
Unclaimed Property	5.0	4.0	4.5
Unrestricted Miscellaneous & Transfer Revenues	**79.5**	**39.9**	**30.4**
Restricted			
Designated General Fund			
Miscellaneous - GF Subfunds(1)	23.2	22.9	22.9
Other Restricted			
Miscellaneous - Special Revenue Funds(1)	6.2	6.8	6.8
Restricted Miscellaneous & Transfer Revenues	**29.4**	**29.7**	**29.7**
Total Miscellaneous & Transfer Revenues	**108.9**	**69.6**	**60.1**

it. Each year the unclaimed property trust account is evaluated and the excess of the working trust balance is transferred to the General Fund.

Transfers from Component Organizations

Each year, the State receives money in the form of transfers from component organizations, such as the Alaska Housing Finance Corporation and the Alaska Industrial Development & Export Authority, frequently in the form of dividends. Component organizations are covered in more detail in chapter 10, State Entities. Some component organizations do not make transfers to the State and, as a result, not all component organizations are listed here.

Actual transfers for FY 2013 are reflected in draft tables from the Comprehensive Annual Financial Report. Forecasts for FY 2014 and FY 2015 transfers are based on discussions with the Governor's Office of Management and Budget, and analysis of the most recent budget expectations for these categories.

Transfers from component organizations presented under this category may differ from those presented in the State Entities section for two reasons: (1) amounts in this section account differently for funds paid over time for multi-year capital projects, and (2) amounts in this section include funds that are transferred to the State and then appropriated to the component unit for operations.

(1) Revenue shown under account codes for "other" or "contributions" in the Alaska State Accounting System for General Fund subfunds and special revenue subfunds.

6

Federal Revenue

General Discussion

The federal government continues to play a significant role in Alaska's economy. In FY 2013, the State of Alaska was authorized for $2.8 billion in federal funds, however, only $2.4 billion were received, constituting roughly 15% of total state revenues. This federal funding is generally restricted to specific uses such as road improvements, Medicaid payments, and aid to schools. Potential changes to federal law, differing federal and state fiscal years, and varying numbers of eligible Alaskans in certain programs make forecasting federal revenue difficult.

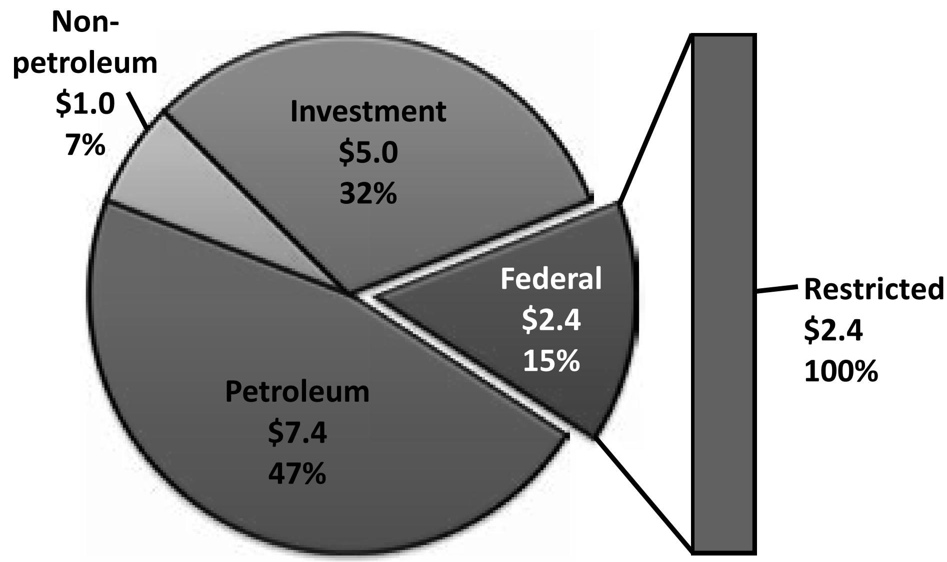


Figure 6-A: FY 2013 Federal Revenue, by restriction ($ billions)

Forecast

Estimates of FY 2014 and FY 2015 receipts come from the Office of Management and Budget and are based on state agency projections of potential federal revenue. Table 6-1 provides the FY 2013 actual and FY 2014-2015 forecasts.

During FY 2014, the State is authorized to receive nearly $3.0 billion in federal receipts. It is important to note that the Legislature authorizes state agencies to receive and spend the maximum that federally funded programs might receive, while collectively the actual appropriation amounts are historically 20-30% less. In addition, some of the funding granted for multi-year capital projects is received and spent in years following the year in which the money is procured. All federal funds, whether spent in the operating or capital budget, are limited in how they may be used and, therefore, are shown as restricted revenue.

State-Matching

Most federal funding requires state-matching. The State match for federal spending in FY 2013 and the enacted FY 2014 budgeted amount are included in Table 6-2. Overall, in FY 2013, Alaska spent $642.3 million and received $2.4 billion to fund specific programs. This means Alaska received roughly $3.71 in federal funds for each dollar it spent in matching state funds.

Distribution of Restricted Revenue

Roughly 70% of federal receipts were authorized to the operating budget and the remaining 30% was authorized to capital projects. Medicaid received much of the federal funds authorized in the operating budget, reflected through

Table 6-1: Federal Revenue, by restriction

	($ millions)		
	History	Forecast	
Unrestricted General Fund	**FY 2013**	**FY 2014**	**FY 2015**
Federal Receipts	0.0	0.0	0.0
Restricted (Federal)			
Federal Receipts Authorization(1)	2,383.2	2,963.0	2,963.0
Total Federal Revenue	**2,383.2**	**2,963.0**	**2,963.0**

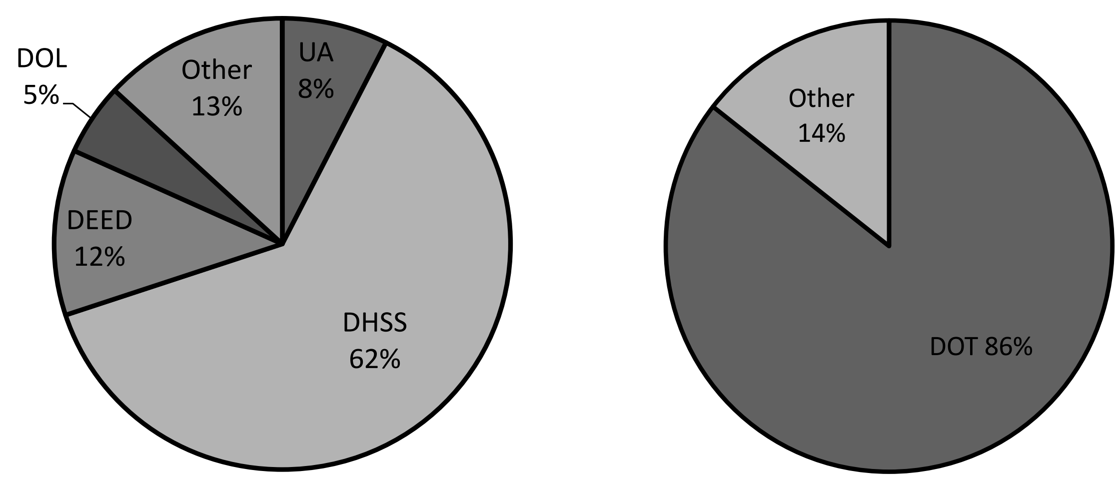
Sources: Historical figures provided by the Division of Finance and projected revenue by the Office of Management and Budget.

Table 6-2: Budgeted State Funds Matching Requirement

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Operating Budget	568.0	572.8	572.8
Capital Budget	74.7	67.8	67.8
Total Matching Requirement	**642.7**	**640.6**	**640.6**

the Department of Health and Social Services. The Department of Education and University of Alaska together received 20% of the authorized federal funds in the operating budget. In the capital budget, the Department of Transportation received about 86%. Figure 6-B illustrates the distribution of federal funds allocated across state agencies.

Figure 6-B: FY 2013 Federal Revenue Allocation; Operating (left) and Capital (right), by Recipient Agency



(1) This amount includes federal receipts other than Alaska's share of NPR-A oil royalties, which are presented in Chapter 2.

7

Investment Revenue

Investment Forecast

The investment revenue for FY 2013 came to approximately $5.0 billion, with nearly all of it classified as restricted revenue as shown in Figure 7-A. The majority (86%) of revenues from investment are from the Alaska Permanent Fund. Table 7-1 shows that FY 2014-2015 forecast lower returns in investment for the Alaska Permanent Fund than FY 2013. Unrestricted Investment Revenue is expected to increase in FY 2014-2015 over three-fold.

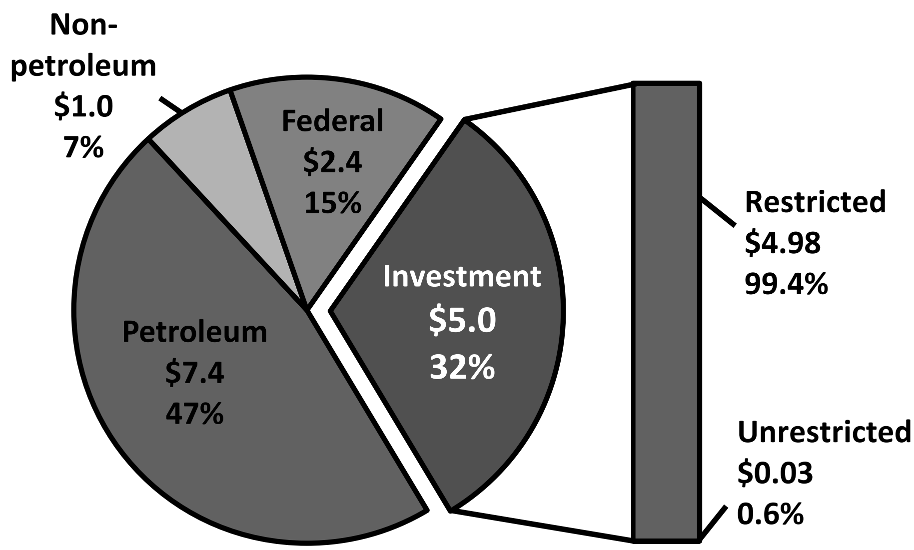


Figure 7-A: FY 2013 Investment Revenue ($ billions)

To forecast investment revenue for the current fiscal year, the department combines actual performance through September 30, 2013, with a projection for the remainder of the year. Forecasts and capital market median returns are based on information in the Five- to Ten-Year capital market returns estimated by the State's investment consultant, Callan Associates, Inc.

Table 7-4 shows a summary of Callan Associates, Inc. long-term capital market projections, as well as the benchmark against which performance for a specific asset class is measured in the State portfolios. "Projected Returns" is the estimated return. The numbers in the "Projected Risk" column represent a statistical measure called standard deviation, which is the most commonly used measure of risk in the investment world. The standard deviation is a measure of the dispersion of data around its mean. The analyst can use the standard deviation to provide a range of possible outcomes at any desired level of confidence. With a bell-curve (normal) distribution, approximately 68% of the observed outcomes are expected to be one standard deviation from the mean. A greater level of confidence (say 95%) would require a broader range (two standard deviations). For example, Callan estimates an average annual return for the Domestic Fixed Income asset class of 2.50% and a projected risk for that asset class of 3.75%. That means Callan is forecasting, with a normal distribution, the annual return for the Domestic Fixed Income asset class will fall between -1.25% and 6.25%, (one standard deviation). A prediction at 95% confidence would run from -5.00% to 10.00% (plus or minus two standard deviations from the mean), and is too broad a range to be useful. The probability that a particular asset class or portfolio will have a negative return over a given period of time reflects the downside risk of the asset class or portfolio.

Table 7-1: Total Investment Revenue[1], by restriction and detail

	($ millions)		
	History	Forecast	
	FY 2013	**FY 2014**	**FY 2015**
Unrestricted			
Investments[2]	26.7	84.9	83.2
Interest Paid by Others	1.4	1.5	1.5
Unrestricted Investment Revenue	**28.1**	**86.4**	**84.7**
Restricted			
Designated General Fund Revenue			
Investments - Designated GF[3]	2.6	2.1	2.6
Other Treasury Managed Funds	37.9	38.0	28.1
Subtotal Designated General Fund	**40.5**	**40.1**	**30.7**
Other Restricted			
Investments - Other Restricted	5.2	4.3	5.3
Constitutional Budget Reserve Fund	618.2	618.2	458.9
Alaska Permanent Fund	4,313.9	2,901.0	3,067.5
Subtotal Other Restricted Revenue	**4,937.3**	**3,523.5**	**3,531.3**
Restricted Investment Revenue	**4,977.8**	**3,563.6**	**3,562.0**
Total Investment Revenue	**5,005.9**	**3,650.0**	**3,646.7**

Unrestricted Investment Revenue

Unrestricted Investment Revenue is earned on the General Fund and other non-segregated investments, and the Statutory Budget Reserve Fund. The Statutory Budget Reserve Fund was segregated from the General Fund and given its own asset allocation on July 1, 2013. When forecasting earnings on the Statutory Budget Reserve Fund, this projection rolls into the total unrestricted investment revenue associated with the General Fund. These funds are managed by the Treasury Division of the Department of Revenue. Interest Paid by Others is interest received by the State other than on its investments. Oil and gas royalty interest, production tax interest, and corporate income tax interest are included in the Oil Revenue section of this forecast.

Restricted Investment Revenue

Restricted Investment Revenue consists of earnings from governmental funds, the Constitutional Budget Reserve Fund (CBRF - Main and Subaccount), other Treasury Division managed governmental funds, and the Alaska Permanent Fund.

The application of Callan's five- to ten-year capital market estimates to

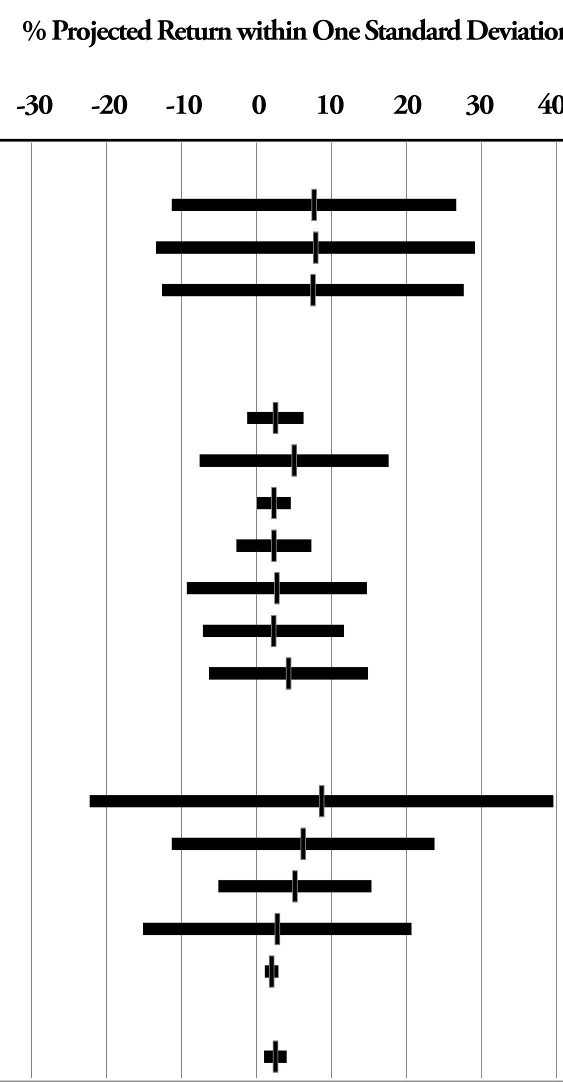
[1] Governmental Accounting Standards Board (GASB) principles require the recognition of changes in the value of investments as income or losses at the end of each trading day, whether the investment is actually sold or not.

[2] Includes projected SBR unrestricted investment revenue.

[3] Includes subfunds of the General Fund.

Table 7-2: 2013 Summary of Callan Associates, Inc. Long-term Capital Market Projections, as of November 8, 2013

Asset Class	Benchmark for Asset Class	Projected Return: Ten-Year Geometric*	Projected Risk: Standard Deviation
Equities			
Broad Domestic Equity	Russell 3000 Index	7.65%	18.95%
Global ex-US Equity	MSCI ACWI ex-U.S.	7.85%	21.25%
International Equity	MSCI EAFE	7.50%	20.10%
Fixed Income			
Domestic Fixed	Barclays Aggregate	2.50%	3.75%
High Yield	Barclays High Yield	5.00%	12.60%
Government 1-3	Barclays Gov't 1-3 Year	2.30%	2.25%
TIPS	Barclays TIPS	2.30%	5.00%
Long Duration	Barclays Long Gov't / Credit	2.70%	12.00%
Non-U.S. Fixed	Citi Non-U.S. Gov't	2.25%	9.40%
Emerging Market Debt	JPM EMBI Global Div.	4.25%	10.60%
Other			
Private Equity	VE Post Venture Cap	8.65%	30.90%
Real Estate	Callan Real Estate	6.20%	17.50%
Hedge Funds	Callan Hedge FoF	5.10%	10.20%
Commodities	DJ-UBS Commodity	2.75%	17.90%
Cash Equivalents	90-Day T-Bill	2.00%	0.90%
Inflation	CPI-U	2.50%	1.50%



*Geometric returns are derived from arithmetic returns and the associated risk (standard deviation)

Table 7-3: General Fund and Statutory Budget Reserve Fund Revenues

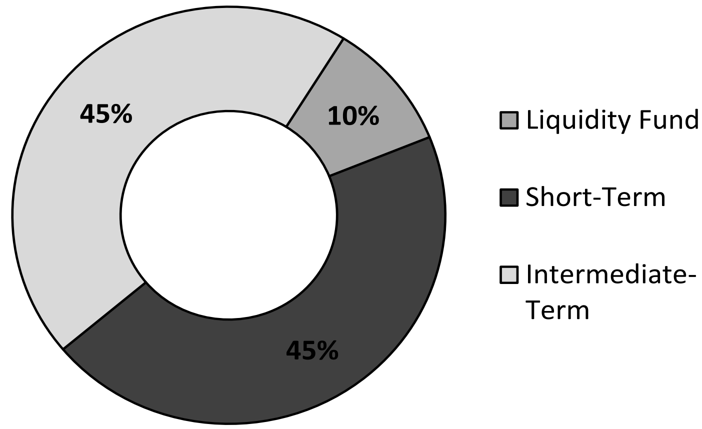
	($ millions)		
	Actual	Projected	
	FY 2013	**FY 2014**	**FY 2015**
Investment Revenue Unrestricted	26.7	84.9	83.2
Investment Revenue Restricted - Designated GF[1]	2.6	2.1	2.6
Investment Revenue Restricted - Other Restricted	5.2	4.3	5.3
Total	34.5	91.3	91.1

(1) Includes subfunds of the General Fund.

Table 7-4: General Fund; Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Short-term Fixed Income Pool	45%	3-Month U.S. Treasury Bill
Liquidity Fund	10%	3-Month U.S. Treasury Bill
Intermediate-Term Fixed Income Pool	45%	Barclays 1-3 Year Gov't Bond Index
Bank Bonds	0%	Allocation up to 1%
T-Bills, T-Notes, T-Bonds or Fed. Agency Debentures	0%	Allocation up to 2%
Investment Balance: September 30, 2013	5,282.0	$ million
Long-term Expected Rate of Return	2.14%	Callan's returns
Probability of Negative Return Over 1 Year	4.76%	

Figure 7-B: General Fund, non-segregated investments Moderate Risk: Short to Intermediate Horizon

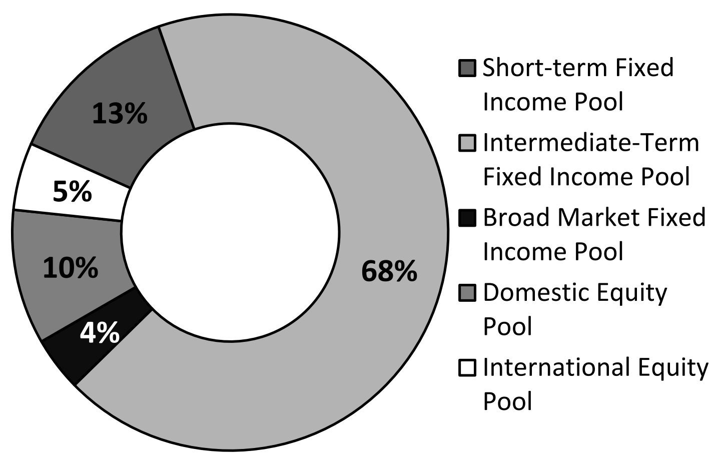


*Short-term: 3-month U.S. T-Bill;
Intermediate Term: Barclays 1-3 Year Gov't Bond Index

Table 7-5: Statutory Budget Reserve Fund[1]; Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Short-term Fixed Income Pool	13%	3-Month U.S. Treasury Bill
Intermediate-Term Fixed Income Pool	68%	Barclays 1-3 Year Gov't Bond Index
Broad Market Fixed Income Pool	4%	Barclays US Aggregate
Domestic Equity Pool	10%	Russell 3000
International Equity Pool	5%	MSCI EAFE
Investment Balance: September 30, 2013	5,514.5	$ million
Expected Rate of Return	2.90%	Callan's returns
Probability of Negative Return Over 1 Year	15.30%	

Figure 7-C: Statutory Budget Reserve Fund Moderate Risk: Short to Intermediate Horizon



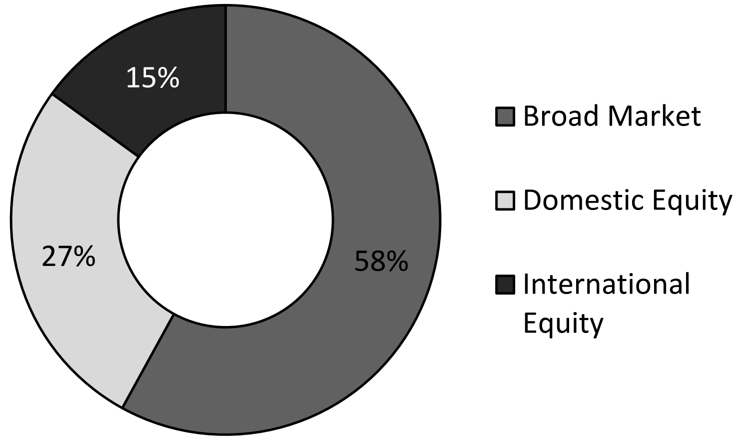
*Short-term: 3-month U.S. T-Bill; Intermediate Term: Barclays 1-3 Year Gov't Bond Index; Broad Market: Barclays U.S. Aggregate; Domestic Equity: Russell 3000 Stock Index; International Equity: MSCI EAFE

[1] Statutory Budget Reserve Fund was segregated from the General Fund and given its own asset allocation July 1, 2013.

Table 7-6: Public School Trust; Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Broad Market Fixed Income Pool	58%	Barclays US Aggregate
Domestic Equity Pool	27%	Russell 3000 Index
International Equity Pool	15%	MSCI EAFE
Short-term Fixed Income Pool	0%	Allocation up to 2%
Public School Fund Balance: September 30, 2013[1]	531.6	$ million
Long-term Expected Rate of Return	5.15%	Callan's returns
Probability of Negative Return Over 1 Year	25.73%	

Figure 7-D: Public School Trust Fund Moderate Risk: Long-term Investment Horizon

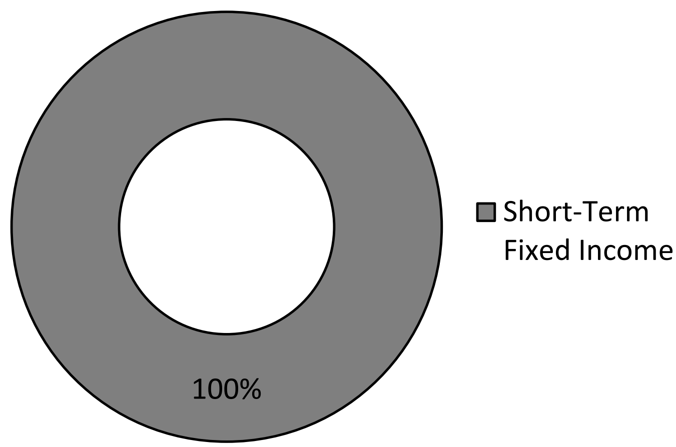


*Broad Market: Barclays U.S. Aggregate;
Intermediate Term: Barclays 1-3 Year Gov't Bond Index;
Domestic Equity: Russell 3000 Stock Index

the Permanent Fund Corporation's current asset allocation results in a 6.7% median expected total return. These estimates result in forecasted earnings of $2.9 billion for FY 2014 and $3.1 billion for FY 2015. Actual net income returns for FY 2013 was $4.3 billion, $1.6 billion above the fall 2013 forecast, and $1.2 billion higher than the projection for FY 2014. This highlights the effect that unanticipated market fluctuations have on the earnings of the fund.

The Constitutional Budget Reserve Fund returned $0.6 billion in FY 2013 and is expected to return $0.6 billion in FY 2014 and $0.5 billion in FY 2015.

Figure 7-E: Public School Trust Fund Low Risk: Short-term Investment Horizon



*Short-term: 3-month U.S. T-Bill

Table 7-7: Public School Fund Revenue

	$ millions		
	Actual	Projected	
Restricted - Designated General Fund	**FY 2013**	**FY 2014**	**FY 2015**
Public School Trust Total Investment Income	37.9	38.0	28.1
Public School Trust Income Distributed[2]	13.6	10.0	10.0

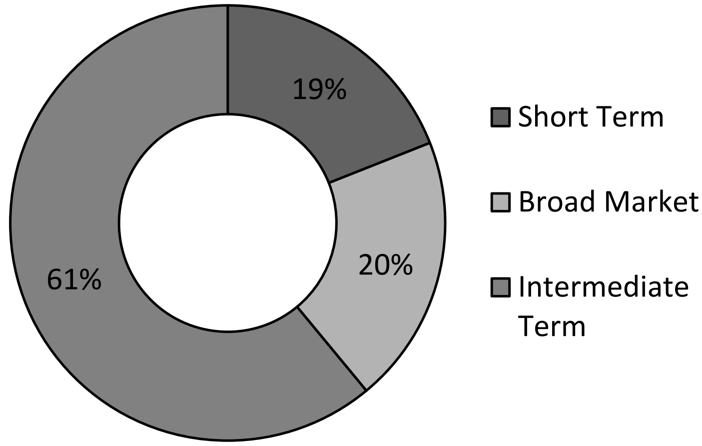
[1] Includes the balance of the Public School Trust Fund Principal and Income Account.

[2] Public School Trust Fund Income Distributed reflects the EED Actual and Projected Appropriations.

Table 7-8: Constitutional Budget Reserve Fund; Main Account Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Short-term Fixed Income Pool	19%	3-Month U.S. Treasury Bill
Intermediate-Term Fixed Income Pool	61%	Barclays 1-3 Year Government Bond Index
Broad Market Fixed Income Pool	20%	Barclays US Aggregate
Bank Bonds	0%	Allocation up to 2%
Regular Account Balance: September 30, 2013	5,832.9	$ million
Long-term Expected Rate of Return	2.30%	Callan's returns
Probability of Negative Return Over 1 Year	13.23%	

Figure 7-F: Main Constitutional Budget Reserve Fund Moderate Risk: Intermediate Investment Horizon

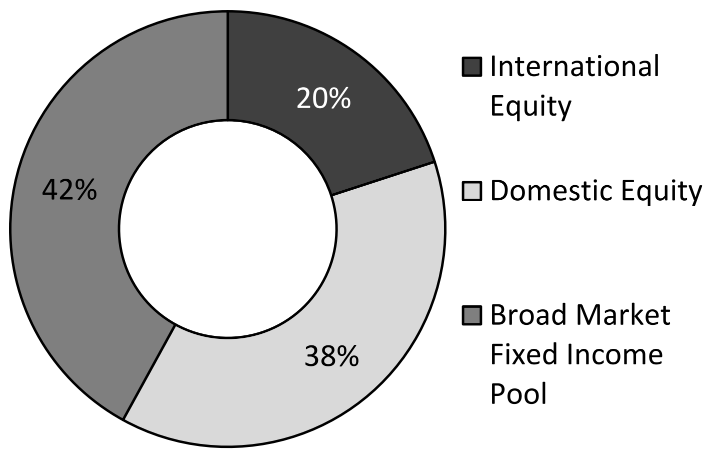


*Short-term: 3-month U.S. T-Bill; Intermediate Term: Barclays 1-3 Year Gov't Bond Index; Broad Market: Barclays U.S. Aggregate

Table 7-9: Constitutional Budget Reserve Fund; Special Subaccount Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Broad Market Fixed Income Pool	42%	Barclays US Aggregate
Domestic Equity Pool	38%	Russell 3000 Index
International Equity Pool	20%	MSCI EAFE Index
Short-term Fixed Income Pool	0%	Allocation up to 2%
Special Subaccount Balance: September 30, 2013	6,085.3	$ million
Long-term Expected Rate of Return	5.98%	Callan's returns
Probability of Negative Return Over 1 Year	28.94%	

Figure 7-G: Constitutional Budget Reserve Subaccount High Risk: Moderately Long Investment Horizon



*Broad Market: Barclays U.S. Aggregate; Domestic Equity: Russell 3000 Stock Index; International Equity: MSCI EAFE

Table 7-10: Constitutional Budget Reserve Fund Revenue

	$ millions		
	Actual	Projected	
Restricted - Other Restricted	**FY 2013**	**FY 2014**	**FY 2015**
Regular Account	8.2	54.9	67.7
Special Subaccount	610.0	563.3	391.2
Total	618.2	618.2	458.9

Table 7-11: Constitutional Budget Reserve Fund; Cash Flows ($ millions)

	($ millions)		
	Actual	Projected	
	FY 2013	**FY 2014**	**FY 2015**
Beginning Cash Balance CBRF	10,642.3	11,564.3	12,248.9
Beginning Main Account Balance	5,452.0	5,764.0	5,885.3
Earnings on Main Account Balance(1)	8.2	54.9	67.7
Petroleum Tax, Royalty Settlements(2)(3)	303.8	66.4	20.0
(Loan to GF)/Repayment to CBRF	0.0	0.0	0.0
Draw from/to GF	0.0	0.0	0.0
Ending Main Account Balance	5,764.0	5,885.3	5,973.0
Beginning Special Subaccount Balance	5,190.3	5,800.3	6,363.6
Earnings on Special Subaccount Balance(1)	610.0	563.3	391.2
Transfer to Subaccount from Main Acct	0.0	0.0	0.0
Ending Special Subaccount Balance	5,800.3	6,363.6	6,754.8
Total CBRF Balance	**11,564.3**	**12,248.9**	**12,727.8**

Table 7-12: CBRF Depletion Date(4)

Annual State Budget	**Fiscal Model of Oil Revenue & CBRF Performance at Selected Prices ($ per barrel starting FY 2015)(5)**						**Fall 2013 Oil Price Forecast(6)**
(% change starting FY 2016)	**$70**	**$80**	**$90**	**$100**	**$110**	**$120**	
-4%	Sep-2020	Jun-2021	Jun-2023	Jun-2024	Jun-2024	Jun-2024	Jun-2024
-2%	Dec-2019	Aug-2020	Nov-2021	Jun-2024	Jun-2024	Jun-2024	Jun-2024
0%	Jul-2019	Jan-2020	Dec-2020	Feb-2023	Jun-2024	Jun-2024	Jun-2024
2%	Mar-2019	Aug-2019	May-2020	Jan-2022	Dec-2023	Jun-2024	Jun-2024
4%	Jan-2019	Apr-2019	Dec-2019	Mar-2021	Oct-2022	Jun-2024	Feb-2024
6%	Oct-2018	Jan-2019	Aug-2019	Sep-2020	Nov-2021	Apr-2023	Nov-2022

(1) The long-term earnings estimate for the main account is 2.30% and the long-term earnings estimate for the special subaccount is 5.98%. These projections are based on 2013 Callan's capital market assumptions and Department of Revenue, Treasury Division's asset allocation.

(2) Settlement estimates are provided by the Department of Revenue and Department of Law, net of annual Federal Minerals Management Service payments.

(3) The petroleum tax, royalty settlements number on this sheet is shown on a cash basis. Please note the State accounting system numbers presented elsewhere in this book include accruals and therefore may differ from the numbers presented here.

(4) Based on the current forecast and the assumption that in the occurrence of a budget deficit, the SBRF would be the first fund to be drawn down, and upon depletion, would be followed with draws upon the CBRF. Current balance of the SBRF is approximately $5.5 Billion.

(5) Matrix allows reader to select specific fiscal year price (from FY 2014-beyond), with anticipated percent change in budget to determine CBRF exhaustion date. Fall 2013 forecasted production volumes are used. A date of Jun-2025 indicates that the CBRF does not run-out before that date.

(6) See Appendix B-1b for Fall 2013 oil price forecast used in base scenario.

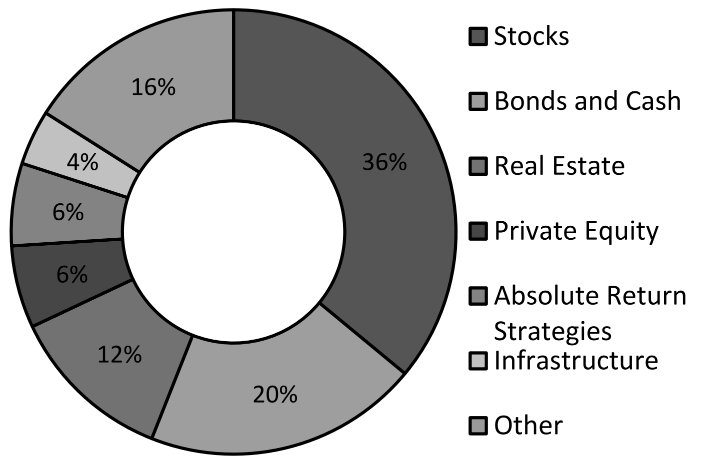
Table 7-13: Alaska Permanent Fund Revenue

	$ millions		
	Actual	Projected	
Restricted - Other Restricted	**FY 2013**	**FY 2014**	**FY 2015**
Annual Unrealized Gain/Loss	1,356.3	922.5	692.4
Annual Realized Earnings/Loss	2,957.6	1,978.5	2,374.7
Reported Earnings	4,313.9	2,901.0	3,067.1

Table 7-14: Alaska Permanent Fund; Special Subaccount Asset Allocation and Summary

Treasury Pool	Target Percent Allocation	Performance Benchmark
Stocks	36%	Multiple Strategies
Bonds and Cash	20%	Multiple Strategies
Real Estate	12%	Multiple Strategies
Private Equity	6%	Multiple Strategies
Absolute Return Strategies	6%	Multiple Strategies
Infrastructure	4%	Multiple Strategies
Other	16%	Multiple Strategies
Special Subaccount Balance: June 30, 2013	44,853.3	$ million
Long-term Expected Rate of Return	6.70%	Callan's returns
Probability of Negative Return Over 1 Year	29.0%	

Figure 7-H: Alaska Permanent Fund Target Asset Allocation



Expected Lifetime of the CBRF

As approved by voters in 1990, all receipts from oil and gas tax and royalty settlements are deposited into the Constitutional Budget Reserve Fund (CBRF). As of September 30, 2013, since the CBRF's inception, the State has deposited about $7.6 billion into the fund and generated another $4.3 billion in investment earnings. A cumulative total of approximately $8.8 billion has been borrowed from the CBRF to balance the budget during prior fiscal years, but has been fully repaid to the CBRF. The current net asset value in the CBRF, as of September 30, 2013, is about $11.9 billion. Since the increase in oil prices beginning in 2003, no significant CBRF withdrawals have been necessary to balance the State's budget. However, the State may have to depend on the CBRF in the future should state revenue decline and spending remain at current levels. Table 7-12 is a matrix that estimates the time period in which the CBRF would be depleted, depending on the price of oil and percent change in the budget. The far right scenario is based on the price forecast for fall 2013. In the event of a budget deficit, the SBRF would be the first fund to be drawn down, and upon depletion, would be followed with draws upon the Constitutional Budget Reserve Fund. As of September 30, 2013, the SBRF had a net asset value of approximately $5.5 billion. Table 7-12 shows that, given the current oil price and production forecast and an assumption of 4% budget decreases from FY 2015 levels, the CBRF would not be depleted before 2024. However, projecting an oil price of $70 at the current production forecast, and an assumption of 6% budget increases, the CBRF could be depleted as early as 2018.

8

Credits

Introduction

Alaska's tax code provides for a wide variety of credits. Credits are applied to tax liabilities and generally reduce the tax revenue paid to the State. Because the State never receives this revenue, these credits are not directly included in revenue and spending numbers. This chapter provides an overview of the various credits, how they are earned, their limitations, and their total annual value. Other types of tax exemptions and exclusions are not tracked, and are therefore not included in this chapter.

Many tax credits can be applied only in the tax year in which the credit is earned, but some can be carried forward into future years. In some cases, credits are recognized by a tax program when they are applied to an annual or quarterly tax return. These tax credits can be difficult to forecast, as very little may be known about the spending patterns of taxpayers. There are several credit programs that are exceptions, however, and have an approval process prior to the issuance of the credit. One such program is the film tax credit, which has an extensive approval process prior to issuing credits. Other programs include tax credits applicable to the oil and gas production tax, for which lease expenditures, and the resulting credits, are built into revenue forecasts.

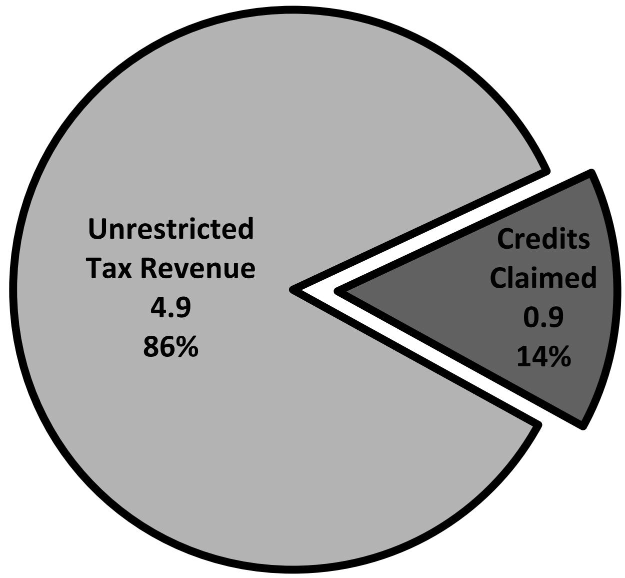


Figure 8-A: FY 2013 Credits Claimed and Unrestricted Tax Revenue ($ billions)

Oil and Gas Tax Credit Fund

The Oil and Gas Tax Credit Fund, established under AS 43.55.028, was created for the State to purchase certain oil and gas tax credit certificates. Money in this fund is appropriated annually by the Legislature for state purchase of certain transferrable oil and gas tax credit certificates. Credits available for state purchase include the transferrable credits under AS 43.55.023 and AS 43.55.025. Non-transferrable credits are not available for state purchase, and state purchase is only available for companies with fewer than 50,000 British Thermal Unit (BTU) equivalent barrels per day of production. This fund allows companies undertaking exploration and development activity to monetize the full value of their tax credits when they do not have an offsetting tax liability.

Credits Applicable to the Oil and Gas Production Tax

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%

Table 8-1: FY 2011-2013 Tax Credits Claimed

	Total Credits Claimed in ($ millions)		
	History		
	FY 2011	**FY 2012**	**FY 2013**[1]
Credits Applicable to the Oil and Gas Production Tax			
Alternative Credit for Exploration, Cook Inlet Jack-Up Rig Credit, and Frontier Basin Credit	19	57	8
Exploration Incentive Credit	0	0	0
Taxable Per-Barrel Credit	Credit program begins on January 1, 2014		
Qualified Capital Expenditure Credit, Well Lease Expenditure Credit, and Carried-Forward Annual Loss Credit	765	606	772
Small Producer / New Area Development Credit	52	53	58
Transitional Investment Expenditure Credit	Cannot be reported due to taxpayer confidentiality		
Credits Applicable to the Corporate Income Tax			
Film Production Credit	<1	3	6
Gas Exploration and Development Credit	Cannot be reported due to taxpayer confidentiality		
Gas Storage Facility Credit[2]	-	0	0
Internal Revenue Code Credits Adopted by Reference	Not tracked		
LNG Storage Facility Credit[3]	-	0	0
Oil and Gas Industry Service Expenditures Credit	Credit program begins on January 1, 2014		
Veteran Employment Tax Credit, AS 43.20.048[4]	-	-	0
Credits Applicable to Multiple Tax Programs			
Education Tax Credit	3	4	7
Minerals Exploration Incentive Credit	<1	6	6
Credits Applicable to Fisheries Taxes			
Scholarship Contributions Credit	<1	<1	<1
Salmon Product Development Credit	2	<1	2
Community Development Quota Credit	<1	<1	<1
Other Taxes Credit	Not tracked		
Total All Reportable Tax Credits	**845**	**732**	**861**

[1] FY 2013 credit totals are estimated pending annual tax filings.

[2][3][4] Credit program began in 2011, 2012, 2013, respectively

Table 8-2: History of Production Tax Credits 2007-2013

	($ millions)						
Fiscal Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**[1]
Statewide Credits							
Credits Used against Tax Liability	557	378	333	412	386	363	469
Credits Purchased by the State	55	54	193	250	450	353	369
Total Statewide Production Tax Credits	**612**	**432**	**526**	**662**	**836**	**716**	**838**

for seismic costs outside an existing unit, 30% for drilling costs greater than 25 miles from an existing unit, 30% for pre-approved new targets greater than 3 miles from an existing well, and 40% for pre-approved new targets greater than 3 miles from a well and greater than 25 miles from an existing unit. The 3-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% for seismic costs outside an existing unit, 30% for drilling costs greater than 10 miles from an existing unit, 30% for pre-approved new targets, and 40% for drilling costs that are 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% of the carried-forward annual loss. Beginning January 1, 2014, the credit for carried-forward annual losses incurred on the North Slope increases to 45% 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% 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 in to Cook Inlet. It is only for expenses incurred in drilling wells that test pre-tertiary; all three wells must be drilled by unaffiliated parties using the same rig. The credit is 100% of costs for the first well up to $25 million, 90% of costs for the second well up to $22.5 million, and 80% of costs for the third well up to $20 million. If the exploration well is brought into production, the operator repays 50% 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 Commissioner of the Department of Natural Resources. Credit may be granted for up to 50% of the cost of drilling or seismic work, not to exceed 50% 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 43.55.011(p), also called the "Frontier Basin." The credit is for the lesser of 80% of qualified exploration drilling expenses or $25 million; or for seismic projects, credit is for lesser of 75% of qualified seismic

[1] FY 2013 credit totals are estimated pending annual tax filings.

Table 8-3: Fall 2013 Ten-Year Forecast for Production Tax Credits

	($ millions)									
Fiscal Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Statewide Credits										
Credits Used against Tax Liability	1050	1000	980	800	770	530	490	450	310	390
Credits Purchased by the State	600	450	425	300	300	300	300	300	300	300
Total Statewide Production Tax Credits	**1650**	**1450**	**1405**	**1100**	**1070**	**830**	**790**	**750**	**610**	**690**

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 $5 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 sliding scale with $10 increments. The sliding scale credit is a dollar-per-taxable-barrel credit ranging from zero dollars per barrel at per-barrel gross value at point of production (GVPP) values greater than $150 to $8 per barrel at per-barrel GVPP values less than $80. The sliding scale credit may not reduce the producer's 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 (l)

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 AS 43.20.043. The credit is 20% of eligible expenditures anywhere in the State, or 40% for qualified well lease expenditures for areas other than the North Slope. The qualified capital expenditure credit will no longer be 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 credit 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(i)

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 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% of qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10% of the capital expenditures incurred between March 31, 2006 and January 1, 2008.

Credits Applicable to Corporate Income Tax

Education Credit

See "Credits Applicable to Multiple Tax Programs."

Gas Exploration and Development Credit, AS 43.20.043

The Gas Exploration and Development Credit is a non-transferable credit for qualified expenditures for the exploration and development of non-North Slope natural gas reserves. The credit is 25% of qualified expenditures for investment after January 1, 2010; investments in existing units qualify. The credit is capped at 75% 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% of costs incurred to establish the facility.

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% of the amount of the credit determined for federal income tax purposes which is attributable to Alaska.

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 lesser of $15 million or 50% of costs incurred to establish the facility. It applies to facilities with a minimum storage capacity of 25,000 gallons of LNG, and that are public utilities regulated by the Regulatory Commission of Alaska. 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% 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 corporate income tax 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.

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 corporate income taxpayers 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 Fisheries Taxes

Community Development Quota Credit, AS 43.77.040

The Community Development Quota Credit is a non-transferable credit for contributions to an Alaska nonprofit corporation that is dedicated to fisheries industry-related expenditures. The credit is available only for fishery resources harvested under a community development quota (CDQ). The credit is 100%

of contribution amount up to a maximum of 45.45% of tax liability on fishery resources harvested under a CDQ.

Education Credit

See "Credits Applicable to Multiple Tax Programs."

Other Taxes Credit, AS 43.77.030

The Other Taxes Credit is a non-transferable credit for taxes paid to another jurisdiction on fishery resources landed in Alaska. The credit is 100% of taxes paid with a maximum of 100% of the Alaska tax liability on the fishery resources.

Salmon Product Development Credit, AS 43.75.035

The Salmon Product Development Credit is a non-transferable credit for eligible capital expenditures to expand value-added processing of Alaska salmon, including ice-making machines. The credit is 50% of qualified investments up to 50% of tax liability incurred for processing salmon during the tax year. The credit may be carried forward for three years, but the authorizing statute is scheduled to sunset on December 31, 2015.

Scholarship Contributions Credit, AS 43.75.032, AS 43.77.035

The Scholarship Contributions Credit is applicable to both the Fisheries Business Tax and the Fishery Resource Landing Tax. It is a non-transferable credit for contributions to the A.W. "Winn" Brindle memorial education loan account. The credit is 100% of the contribution amount, up to a maximum of 5% of tax liability.

Credits Applicable to Multiple Tax Programs

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 applicable to the Corporate Income Tax, 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 non-transferable 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% of annual contributions up to $100,000, 100% of the next $200,000, and 50% of annual contributions beyond $300,000. 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% of eligible film production expenditures, plus an additional 20% credit for wages paid to Alaska residents, plus an additional 6% credit for filming in a rural area, plus an additional 2% credit for filming between October 1 and March 30; 3) the credits must be used within six years; 4) the tax credit applies to Corporate Income Tax, 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. 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 Corporate Income Tax, Mining License Tax, 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% of allowable exploration costs with a maximum of $20 million. For the mining license tax (MLT), the credit is limited to the lesser of 50% of the MLT liability at the mining operation at which the exploration occurred or 50% of total MLT liability. For the corporate income tax, it is limited to the lesser of 50% of the MLT liability at the mining operation at which the exploration occurred or 50% or total CIT liability. For mineral royalties, the credit is limited to 50% of royalty liability from the mining operation at which the exploration activity occurred.

9

State Endowment Funds

General Discussion

This section compares important attributes of five endowment funds. The University of Alaska endowment is included in this comparison because it is one of Alaska's public endowment funds that uses the annual distribution calculation method typical of the vast majority of endowments in the United States and Canada.[(1)]

The fiduciary for each of these endowment funds has the responsibility for establishing an asset-allocation policy for the fund. Tables 9-1 and on the next page compares the asset-allocation policies for these endowments.

Under the standards adopted by the Governmental Accounting Standards Board (GASB), public funds calculate and report their income by recognizing changes in the value of securities as income, or losses, as they occur at the end of each trading day. They do this regardless of whether the securities are actually sold, and the income, or losses, are taken or realized. All five of these endowments report annual income on this basis. However, three of them use other measures of annual income for determining their distributions. These include the Alaska Permanent Fund and the Mental Health Trust Fund, both administered by the Alaska Permanent Fund Corporation, and the Public School Trust.

In determining the amount of income available for distribution each year for the two funds managed by the Alaska Permanent Fund Corporation, gains or losses on individual investments are not recognized until the investment is sold. For calculating distributable income for the Public School Trust, only interest earned and dividends received are treated as income. Gains and losses in the value of individual investments are never recognized as income. By law, those gains and losses remain with the principal of the fund.

Alaska Permanent Fund

The annual distribution for the Permanent Fund Dividend follows the formula in AS 37.13.140-.145, which specifies that 10.5% of the past five years' total realized income shall be paid out as dividends, but also sets the limitation that the annual distribution may never exceed 50% of the balance in the fund's Realized Earning Account (REA). The 50% limitation has never been triggered.

An annual appropriation is needed to "inflation proof" the principal of the Permanent Fund (but not the accumulated earnings) pursuant to AS 37.13.145. The legislative appropriation requires a transfer from the Realized Earnings Account to the fund's principal an amount equal to the calculated U.S. Consumer Price Index's effect on the value of the principal, comprised of oil and gas royalty contributions and legislative appropriations. The Alaska Permanent Fund Corporation's Trustees have proposed a constitutional amendment that would inflation- proof the entire fund—the principal and accumulated earnings—by limiting the annual distribution of earnings to 5% of a five-year moving average of the market value of the fund.

[(1)]In 2009, the Board of Trustees for the Alaska Permanent Fund Corporation elected to move to a new asset allocation grouping based on risk and return profiles. The Alaska Permanent Fund and Mental Health Trust funds are broken out above using both the traditional asset allocation and the new risk-based asset allocation. For more information please see the Alaska Permanent Fund Corporation Website: http://www.apfc.org/home/Content/investments/assetAllocation2009.cfm

Table 9-1: State Endowment Funds' Target Asset Allocation- Traditional Grouping

	(%)							
	Cash	U.S. Bonds	International Bonds	U.S. Equities	International Equities	Global Equities	Real Estate	Alternative Investments
Public School Trust	0	58	0	27	15	0	0	0
Power Cost Equalization	0	25	0	49	26	0	0	0
University of Alaska Endowment	0	15	0	0	0	50	0	35

Table 9-2: State Endowment Funds' Target Percent Asset Allocation- Risk/Return Grouping

	(%)				
	Cash	Interest Rate Class	Company Exposure	Real Assets	Special Opportunities
Alaska Permanent Fund	2	6	55	19	18
Mental Health Trust	2	6	55	19	18

Mental Health Trust

Current statute requires net income earned on the cash principal of the fund to be calculated by the Alaska Permanent Fund Corporation in the same manner used to determine the net income of the Alaska Permanent Fund. Accumulated undistributed earnings in one year are available for distribution in subsequent years. Aside from the statutory limits on income distribution, the Mental Health Trust Board has established an asset management policy that limits actual distributions in any given year to 4.25% of the four year moving average of total fund ending net assets plus certain adjustments including interest earned on the budget reserve account, and income earned on land assets as well as lapsing appropriations back to the fund.

The asset management policy adopted by the Board of Trustees currently limits distributions of accumulated earnings on the fund to a percentage of total net assets that is periodically reviewed for sufficiency. To the extent retained investment earnings exceed distributions, total fund balance grows accordingly. The authority also has adopted a policy transferring funds from the reserve account to principal whenever the reserve account exceeds four times the annual distribution.

Public School Trust

The annual distribution of the Public School Trust Fund is a percentage of the Trust's principal market value so long as that amount does not exceed the interest and dividend earnings available in the earnings account.

The asset-allocation policy is such that, when combined with the requirement that the fund's capital gains and losses remain part of the principal, the retained capital gains are adequate to inflation proof the fund.

Power Cost Equalization (PCE) Endowment

The annual distribution is 7% of the fund's market value. For the initial transition years, state statute specifies that the fund shall use the market value on February 1 for the subsequent fiscal year's distribution. Thereafter, the fund is to distribute each year 7% of the monthly average market value for a specified 36-month period.

The statutory requirement for distributing 7% allows for all or almost all anticipated earnings to be allocated.

University of Alaska Endowment

The annual distribution is 4.5% of a five-year moving average of the market value of the fund.

The University's distribution policy of 4.5% of the moving five-year average of the fund's market value should allow for retained earnings to inflation proof the fund.

10

Public Entities and University of Alaska

Overview

The State has established the following public corporations and entities to carry out certain public policies:

- Alaska Aerospace Corporation (AAC)
- Alaska Energy Authority (AEA)
- Alaska Gasline Development Corporation (AGDC)
- Alaska Housing Finance Corporation (AHFC)
- Alaska Industrial Development and Export Authority (AIDEA)
- Alaska Mental Health Trust Authority (AMHTA)
- Alaska Municipal Bond Bank Authority (AMBBA)
- Alaska Natural Gas Development Authority (ANGDA)
- Alaska Railroad Corporation (ARC)
- Alaska Seafood Marketing Institute (ASMI)
- Alaska Student Loan Corporation (ASLC)
- University of Alaska (UA)

These twelve entities are components of state government presented in the State's Comprehensive Annual Financial Report. Information in this section is provided by these entities. The Alaska Housing Finance Corporation, Alaska Industrial Development and Export Authority, Alaska Student Loan Corporation and Alaska Municipal Bond Bank Authority pay, or may elect to pay, some portion of their income as an annual "dividend" to the State. This chapter summarizes the missions, financing and dividends of these corporations and other public entities.

Missions, Financing and Dividends

Alaska Aerospace Corporation (AAC)

AAC operates and maintains a commercial spaceport in Kodiak, Alaska and provides commercial rocket vehicle launch support services. It promotes space-related business, research, education, and economic growth in the State of Alaska.

The State has supported AAC through funding for capital and operating expenses. In FY 2013, the State contributed $4.6 million to maintain operations. AAC does not pay a dividend or return capital to the State.

Alaska Energy Authority (AEA)

AEA provides loans to utilities, communities, and individuals to pay for the purchase or upgrade of equipment, and for bulk fuel purchases. Additionally, the agency administers the Power Cost Equalization program, subsidizing rural electric costs with the Power Cost Equalization Endowment. AEA also receives federal and state money to provide technical advice and assistance in energy planning, emergency response management, energy infrastructure construction and conservation in rural Alaska. AEA owns, and operates and maintains (under contractual agreements) state-owned power projects, such as the Bradley Lake Hydroelectric Project and the Alaska Intertie.

The AEA was established in 1976 to finance and operate power projects. This corporation has also administered rural energy programs at various times, including the present. As a result of legislatively mandated reorganizations, capital has moved into and out of the corporation.

AEA does not pay a dividend or return capital to the State on a regular basis.

Table 10-1: Public Entities - FY 2013 Financial Facts[1]

	($ millions)				
	Total Assets	Assets Less Liabilities Book Value	FY 2012 Operating Budget	FY 2013 Operating Budget	Total Positions [2]
Alaska Aerospace Corporation	86.8	80.1	29.0	10.5	50
Alaska Energy Authority [3]	1352.2	1181.1	48.4	50.1	See AIDEA
Alaska Gasline Development Corporation	21.7	17.2	17.5	16.5	7
Alaska Housing Finance Corporation	3981	1526	88.5	90.3	355
Alaska Industrial Development and Export Authority	1402.5	1161.3	12.3	14.1	97
Alaska Mental Health Trust Authority	571.5	527.4	3.0	2.9	16
Alaska Municipal Bond Bank Authority	881.4	57.4	0.5	0.7	1
Alaska Railroad Corporation [4]	989.9	255.7	136.0	134.6	658
Alaska Seafood Marketing Institute	N/A	N/A	19.8	29.5	19
Alaska Student Loan Corporation [5]	541	218.6	12.9	12.9	93
University of Alaska	1803.3	1487.9	891.1	925.8	4949

Alaska Gasline Development Corporation (AGDC)

The Alaska Gasline Development Corporation was created in 2010 and is now a public corporation of the State in the Department of Commerce, Community and Economic Development but with a separate and independent legal existence. AGDC's mission or purpose is to advance the planning, constructing, financing and operations of in-state natural gas pipeline projects or other transportation systems to deliver natural gas and other non-oil hydrocarbon products available to Fairbanks, the Southcentral region, and other communities in the State at the lowest rates possible.

The In-State Natural Gas Pipeline Fund was established in the AGDC and consists of money appropriated to it (AS 31.25.010). The State Legislature appropriated $355 million to the In-State Natural Gas Pipeline Fund for FY 2014. Effective June 30, 2013, AGDC's FY 2012 and FY 2013 unexpended and unobligated appropriation balance of $16.5 million was re-appropriated to the In-State Natural Gas Pipeline Fund.

Alaska Housing Finance Corporation (AHFC)

Using proceeds from the sale of bonds backed by its corporate assets, AHFC purchases home mortgages from Alaska banks. Income from payments on these mortgages repays bond holders and adds to the corporation's income, thereby enabling the corporation to pay an annual dividend and/or return of capital to the State in some years. In addition to ensuring that Alaskans, especially Alaskans of low and moderate income and those in remote and underdeveloped areas of the State, have adequate housing at reasonable cost, the corporation

(1) ANGDA is excluded because it did not have a budget in FY 2013.

(2) Permanent Full Time (PFT), Permanent Part Time (PPT) and Temporary (TMP) are included in total positions.

(3) The AIDEA provides staff for the activities of the AEA. A significant portion of AIDEA's 97-member staff is engaged in AEA programs.

(4) The ARC reports financial data on a calendar year basis. Assets and book value shown in this table are from audited December 31, 2012, financial statements. The operating budget figure shown here is for CY 2012.

(5) The ASLC contracts with the Alaska Commission on Postsecondary Education (ACPE) to service its loan portfolio and provide staff support. Budget and positions reported are those of ACPE's funded by ASLC.

Table 10-2: Public Entities - FY 2013 Revenue and Dividends[1]

	($ millions)				
	Revenue	Expenditures	Net Income	Dividend	State Contribution
Alaska Aerospace Corporation	8.6	13.3	(4.2)	0.0	8.0
Alaska Energy Authority	215.9	181.9	110.5	0.0	76.5
Alaska Gasline Development Corporation	32.8	16.5	16.3	0.0	32.8
Alaska Housing Finance Corporation	315.3	343.9	(28.6)	27.3	0.0
Alaska Industrial Development and Export Authority	57.9	31.2	85.5	20.4	79.3
Alaska Mental Health Trust Authority	63.9	24.0	39.9	0.0	0.0
Alaska Municipal Bond Bank Authority	33.9	36.1	(3.4)	0.0	0.0
Alaska Railroad Corporation	185.9	175.5	10.4	0.0	0.0
Alaska Seafood Marketing Institute	20.9	19.9	1.0	0.0	16.7
Alaska Student Loan Corporation	30.1	29.9	0.2	0.0	0.0
University of Alaska	823.4	803.7	19.7	0.0	371.1[2]

administers federally- and state-funded multi-residential, senior and low-income housing, residential energy, and home weatherization programs. In recent years, the Legislature has authorized AHFC to finance the construction of schools, University of Alaska housing, and other capital projects identified by the Legislature. AHFC also managed the Alaska Gasline Development Corporation as a subsidiary until 2013, when it was made an independent entity. The Legislature appropriated $739.9 million in cash and $292.5 million in mortgages held by the General Fund to the corporation between 1976 and 1984. The payments on those mortgages and additional mortgages purchased with the cash have helped build the corporation's asset base and allow it to return some capital to the State each year. In 1993, AHFC received an additional $27.7 million in cash and $9.3 million in equity when the Legislature merged the Alaska State Housing Authority with this corporation.

In 2003, the Twenty-Third Legislature enacted SCS HB 256 (the "2003" Act), which added language to the Alaska Statutes to modify and incorporate a transfer plan between AHFC and the State. As approved and signed into law by the Governor and modified by the Twenty-Fourth Legislature in 2006 with SB 236, the 2003 Act calls for annual transfers that do not exceed the lesser of 75% of adjusted change in net assets for the fiscal year two years prior to the current fiscal year or $103 million less debt service on certain State Capital Project Bonds, less any legislative appropriation of AHFC's unrestricted, unencumbered funds other than appropriations of its operating budget. Since 1991, AHFC has paid nearly $2 billion in dividends to the State.

Alaska Industrial Development and Export Authority (AIDEA)

AIDEA provides various means of financing and investment to advance economic growth in Alaska. By lending money, guaranteeing loans, issuing revenue bonds, or becoming an owner, AIDEA makes financing available for industrial, export, and other business enterprises in Alaska. The corporation generates income from interest on its loans, investments, leases, and operations of its properties.

Between 1981 and 1991, the State of Alaska transferred various loan portfolios worth $297.1 million and $69.2 million in cash to this corporation. Since then, it has sustained itself without further state assistance while also paying dividends to the State in most years.

[1] ANGDA is excluded because it did not have a budget in FY 2013.

[2] Does not include On-Behalf payments made by State of Alaska for pension.

By statute, AIDEA must make available to the State each year not less than 25% and not more than 50% of its audited "net income" (as defined in statute) for the "base year." The "base year" is the fiscal year ending two years prior to the end of the fiscal year in which the dividend payment is made to the State of Alaska. In no case may the dividend exceed the base year unrestricted audited "net income." The actual transfer of the dividend requires a legislative appropriation that may be line item vetoed by the Governor. Since 1997, AIDEA has paid over $345 million in dividends to the State treasury.

Alaska Mental Health Trust Authority (AMHTA)

The Alaska Mental Health Trust Authority is a public corporation of the State within the Department of Revenue and carries out the State's obligations under the Mental Health Enabling Act of 1956, namely to ensure an integrated comprehensive mental health program. The Mental Health Enabling Act established the Alaska Mental Health Trust as a perpetual trust and capitalized it with one million acres of land that was to be managed to generate income for mental health services in Alaska. During the course of class action litigation, the Alaska Supreme Court concluded the State breached its fiduciary duty while managing Trust land. A 1994 settlement created the Alaska Mental Health Trust Authority and established a seven-member board of Trustees to oversee it. The settlement recapitalized the Mental Health Trust with $200 million and one million acres of land consisting of original Trust land as well as replacement lands.

Under the terms of the settlement and state statute, the Alaska Permanent Fund Corporation manages the cash principal. The Department of Natural Resources manages the land assets and a portfolio of directly owned real estate investments. The Trust Authority operates similar to a private foundation to administer, protect and enhance the Mental Health Trust. The Trust Authority provides leadership in advocacy, planning, implementing and funding Alaska's comprehensive integrated mental health program and coordinates with state agencies on programs and services to help improve the lives of Trust beneficiaries.

Alaska Municipal Bond Bank Authority (AMBBA)

The Bond Bank loans money to Alaska municipalities for capital improvement projects. The bank's larger capital base, its reserve funds and its credit rating enable it to sell bonds at lower interest rates than the municipalities could obtain on their own. The Bond Bank earns interest on the money it holds in reserve and returns a dividend to the State in most years. Between 1976 and 1986, the Legislature appropriated $18 million to AMBBA to be used for backing bond issues. In addition, the Legislature gave AMBBA $2.5 million in 1981 to fund a direct loan by a municipality. The municipality repaid the loan and the Bond Bank retained the appropriation. In 2012 the Legislature appropriated $13 million to the Bond Bank to forgive loans from the general fund issued to back bond issues. By statute, the Bond Bank annually returns earnings or income of its reserve fund, in excess of expenses, to the State. Since its inception, it has transferred $27.8 million to the State's general fund.

Alaska Natural Gas Development Authority (ANGDA)

The authority was established by a voter initiative in 2002 with the purpose of bringing Alaska natural gas to Alaskan consumers. In 2013, the corporation's operations were folded into AGDC. Previously, it had broad authority to develop a natural gas pipeline. It received yearly funding from the State, but also had the authority to issue bonds. The State did not contribute financially to ANGDA's operations in FY 2013.

Alaska Railroad Corporation (ARC)

The corporation operates freight and passenger rail services between Seward and Fairbanks, including a spur line to Whittier. In addition, the corporation generates revenues from real estate it owns.

The State bought the railroad from the federal government in 1985. The purchase price of $22.7 million was recorded as the State's capitalization. The corporation does not pay a cash dividend to the General Fund.

Alaska Seafood Marketing Institute (ASMI)

The institute is a marketing organization with the mission of increasing the economic value of Alaska seafood. It conducts advertising campaigns and public relations for the seafood industry. It also works directly with foodservice distributors, retailers and restaurants to build the Alaska Seafood brand. ASMI is a public-private partnership and receives funding from the State of Alaska, the federal government and private industry.

The State levies a 0.5% assessment on fisheries to support ASMI's operations, the Seafood Marketing Assessment. In addition, ASMI received $4.3 million in federal funding and $7.7 million of General Funds.

Alaska Student Loan Corporation (ASLC)

The Alaska Student Loan Corporation issues debt and recycles education loan payments to finance education loans. Education loan payments satisfy debt obligations and provide funding for operations. Alaska statutes authorize the board of directors to return capital to the State based on net income. Alaska statutes also authorize the corporation to issue bonds for the purpose of financing projects of the State. Those bonds in aggregate may not exceed $280 million. The corporation issued $163 million in bonds, the proceeds of which have been appropriated to fund capital projects of the State. In FY 1988, the State transferred $260 million of existing student loans to this corporation. Additional appropriations of cash between FY 1988 and FY 1992 totaled $46.7 million.

This corporation, at the discretion of its board of directors, may make available to the State a return of contributed capital or dividend for any base year in which the net income of the corporation is $2 million or more. A base year is defined as the year two years before the payment year. If the board authorizes a payment, it must be between 10% and 35% of net income for the base year (AS 14.42.295). The corporation may also issue bonds in an aggregate amount not to exceed $280 million, for the purpose of financing projects of the State as those projects (AS 14.42.220). Investment earnings on proceeds of bonds issued in 2004 under this statute are also used to finance projects of the State.

University of Alaska (University)

The University of Alaska is a constitutionally-created corporation of the State of Alaska which is authorized to hold title to real and personal property and to issue debt in its own name. The University is the only public institution of higher learning in Alaska. It is a statewide system that consists of three universities located in Anchorage, Fairbanks, and Juneau, with each having extended satellite colleges and sites throughout Alaska. The system's administrative offices are located on the Fairbanks campus. The University is governed by an eleven-member Board of Regents, which is appointed by the governor.

The University of Alaska System is supported by the State of Alaska general fund appropriations, student tuition and fees, and grant and contract revenue from a diverse group of federal agencies, the State of Alaska and private sponsors, including the University of Alaska Foundation.

Appendices

Glossary

Constitutional Budget Reserve Fund (CBRF)

Created by voters in 1990, the Constitutional Budget Reserve Fund receives proceeds from settlements of oil, gas, and mining tax and royalty disputes. The Legislature may, with a three-quarters majority vote in each chamber, withdraw money from the fund.

Designated General Fund Revenue

General Fund revenue that is designated for a specific purpose, typically using a General Fund subaccount. The Legislature can at any time remove the restrictions on this category of revenue as they are solely imposed by either Alaska statute or customary practice. At times, this category of revenue may be included in legislative and public debate over the budget.

Federal Revenue

When the federal government gives money to states, it typically restricts how that money can be used. For example, highway and airport construction funds, Medicaid, and education funding cannot be used for other purposes. In addition to restricting how the money is spent, the federal government often requires states to put up matching funds to qualify for the federal funding.

General Fund Revenue

General Fund Revenue has different meanings in different contexts. In the State's official financial reports, General Fund Revenue is used to designate the sum of General Fund Unrestricted Revenue, General Fund sub-account revenue, program receipts and other funds spent through the General Fund. In budget reports, General Fund Revenue is split into revenue with no specific purpose, and revenue with a specific purpose. These categories are called Unrestricted General Fund Revenue and Designated General Fund Revenue, respectively.

Other Restricted State Revenue

Non-federal revenue that is not deposited to the General Fund or a subaccount of the General Fund. This revenue is restricted by the constitution, state or federal law, trust or debt restrictions, or by customary practice.

Permanent Fund GASB (or Market) Income

Under standards adopted by the Governmental Accounting Standards Board, the Permanent Fund's income—and that of any other government fund—is the difference between the purchase price of the investments and their market value at a given point in time, plus any dividends, interest or rent earned on those investments. Under GASB standards, the Permanent Fund does not have to sell the investment to count the gain or loss as it changes value. It is called "marking to market," that is, measuring the value of the fund's investments by the current market price. This can produce a much different picture than Permanent Fund statutory income, which does not reflect fluctuating investment values until the assets are sold.

Permanent Fund Statutory Income

The annual Permanent Fund dividend is based on statutory income. This is the sum of realized gains and losses of all Permanent Fund investment transactions during the year, plus interest, dividends and rents earned by the fund. The Legislature may appropriate the earnings for any purpose it chooses. The historical practice has been to use realized income primarily for dividends and inflation-proofing, and then either leave the excess in the Realized Earnings Account, or transfer it to the principal of the Permanent Fund.

Restricted Program Receipts

This revenue is earmarked in state statute or by contract for specific purposes and is usually appropriated back to the program that generated the revenue. Examples include University of Alaska tuition payments, marine highway receipts, payments to various revolving loan funds, and public corporation receipts. Some of this revenue is actually dedicated as a consequence of provisions of the Alaska Constitution. The remainder, while statutorily earmarked, may be appropriated to purposes other than those reflected in statute if the Legislature so chooses. These earmarked funds are categorized as designated general funds.

Restricted Revenue

Restricted revenue represents revenue that is restricted by the constitution, state or federal law, trust or debt restrictions, or by customary practice. The Legislature can at any time remove restrictions that are solely imposed by either Alaska statute or customary practice. Program receipts, revenue allocated to sub-accounts of the General Fund, and General Fund Revenue customarily shared with other entities are all considered Restricted Revenue for the purposes of this report. In this report, the department presents three categories of Restricted Revenue: Designated General Fund Revenue, Other Restricted State Revenue, and Federal Revenue.

Unrestricted General Fund Revenue

Revenue not restricted by the constitution, state or federal law, trust or debt restrictions, or customary practice. This revenue is deposited into the State's unrestricted General Fund and most legislative and public debate over the budget each year centers on this category of revenue. In deriving the department's Unrestricted Revenue figure from total General Fund Revenue, the department has excluded General Fund subaccount revenue, as well as customarily Restricted Revenue such as shared taxes and pass-through revenue for qualified fisheries associations. The department has also added certain revenue such as transfers to the State treasury from the Unclaimed Property Trust and dividends from component units.

Abbreviations

bbl - Barrel of Oil

$/bbl - Dollars per Barrel of Oil

bbl/day - Barrels of Oil per Day

bcf - billion cubic feet

BTU - British Thermal Units

Mbbls - Thousands of Barrels of Oil

Mcf - Thousand Cubic Feet

$ m - Millions of Dollars

scf - Standard Cubic Foot

Acronyms

ACES - Alaska's Clear and Equitable Share

AGIA - Alaska Gasline Inducement Act

ANS - Alaska North Slope

GRE - Gross Revenue Exclusion

GVR - Gross Value Reduction

LNG - Liquified Natural Gas

MAPA - More Alaska Production Act

TAPS - Trans-Alaska Pipeline System

Table A-1: Unrestricted General Fund Revenue Matrices, with Price Sensitivity FY 2014-2016[1]

FY 2014 At forecasted production of 508.2 thousand bbls/day		FY 2015 At forecasted production of 498.4 thousand bbls/day		FY 2016 At forecasted production of 487.6 thousand bbls/day	
ANS $/barrel[2]	GF Unrestricted Revenue	ANS $/barrel	GF Unrestricted Revenue	ANS $/barrel	GF Unrestricted Revenue
$50	$2,350	$50	$1,860	$50	$1,820
$60	$2,620	$60	$2,130	$60	$2,090
$70	$2,880	$70	$2,410	$70	$2,350
$80	$3,170	$80	$2,690	$80	$2,620
$90	$3,530	$90	$3,240	$90	$3,160
$100	$4,370	$100	$4,150	$100	$4,040
$105.68	$4,930	$105.06	$4,532	$107.69	$4,610
$110	$5,380	$110	$4,900	$110	$4,930
$120	$6,360	$120	$5,820	$120	$5,830
$130	$7,470	$130	$6,730	$130	$6,720
$140	$8,450	$140	$7,650	$140	$7,460
$150	$9,420	$150	$8,560	$150	$8,360

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

(2) ANS $/barrel values are fiscal year averages that incorporate actual prices for the first 4 months of FY 2014. Because oil prices were in the $100-$110 range in the first 4 months, it can take a different price for the remainder of the year to bring the fiscal year average to levels in the table. For example, a fiscal year price of $80 per barrel would require 8 months of oil prices around $65 per barrel.

Figure A-A: Unrestricted General Fund Revenue, with Price Sensitivity

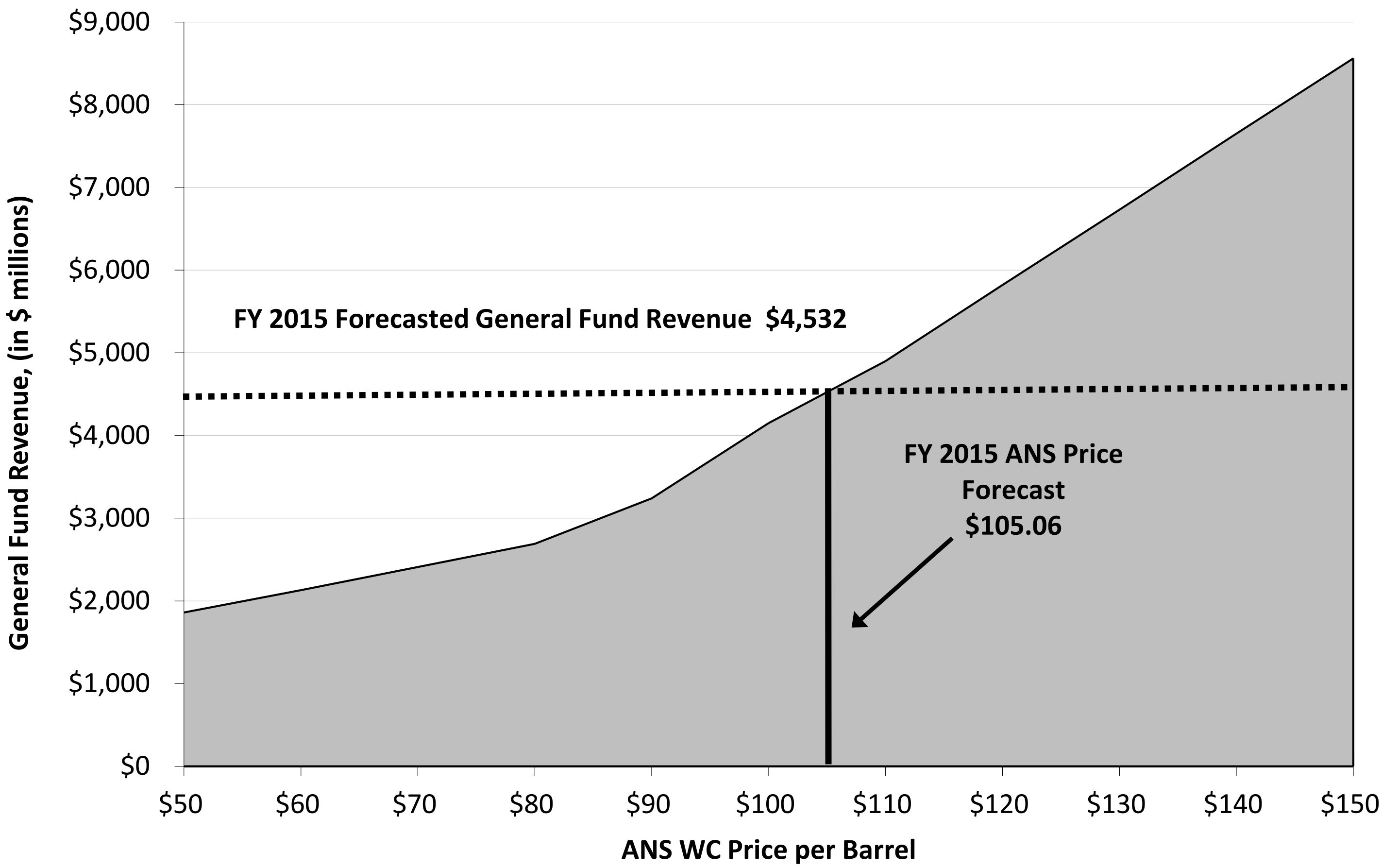


Table A-2: History of Unrestricted General Fund Revenue(1), by type

($ millions)

Fiscal Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Tax Revenue										
Petroleum Property Tax	**47.3**	**42.5**	**54.5**	**65.6**	**81.5**	**111.2**	**118.8**	**110.6**	**111.2**	**99.3**
Excise Tax										
Alcoholic Beverages	16.4	17.3	17.6	17.1	20.0	19.5	19.5	19.4	19.4	19.8
Tobacco Products	16.0	25.1	35.4	43.8	44.9	46.6	45.1	46.5	45.6	44.8
Insurance Premium	43.7	45.9	44.3	46.5	47.1	45.5	50.4	49.6	54.8	52.4
Electric and Telephone Cooperative	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.2	0.2
Motor Fuel Tax	41.2	39.4	42.0	39.2	41.8	10.1	28.8	39.5	40.9	41.9
Vehicle Rental tax	2.7	7.5	7.7	8.0	8.5	8.0	7.3	8.3	8.5	8.4
Tire Fee	0.8	1.6	1.6	1.5	1.5	1.5	1.4	1.5	1.4	1.4
Total	**121.0**	**137.0**	**148.8**	**156.3**	**164.0**	**131.3**	**152.6**	**164.9**	**170.8**	**168.9**
Income Tax										
General Corporate	39.6	61.8	138.0	176.9	182.7	120.9	81.9	157.7	98.5	112.5
Petroleum Corporate	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1	568.8	434.6
Total	**338.4**	**585.8**	**799.1**	**771.3**	**788.5**	**613.1**	**528.0**	**699.8**	**667.3**	**547.1**
Oil and Gas Production Tax										
Oil and Gas Production Tax	642.7	854.9	1,191.7	2,198.3	6,810.9	3,100.9	2,860.7	4,543.2	6,136.7	4,042.5
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Hazardous Release	9.2	8.3	7.8	10.1	11.7	11.1	10.3	9.7	9.4	7.8
Total	**651.9**	**863.2**	**1,199.5**	**2,208.4**	**6,822.6**	**3,112.0**	**2,871.0**	**4,552.9**	**6,146.1**	**4,050.3**
Fisheries Tax										
Fisheries Business Tax	14.9	10.7	15.4	17.1	14.7	19.3	14.0	20.1	26.4	19.2
Fishery Landing	2.5	3.9	4.7	5.3	7.9	4.7	8.3	2.7	6.3	5.5
Total	**17.4**	**14.6**	**20.1**	**22.4**	**22.6**	**24.0**	**22.3**	**22.8**	**32.7**	**24.7**
Other Tax										
Estate	2.3	1.5	0.6	0.1	0.0	0.2	0.0	0.0	0.0	0.0
Mining	3.2	10.3	18.6	79.1	54.4	15.5	29.7	49.0	40.7	46.7
Charitable Gaming	2.4	2.5	2.4	2.5	2.7	2.8	2.6	2.5	2.6	2.5
Large Passenger Vessel Gambling	0.0	0.0	0.0	0.0	0.0	0.0	6.3	5.8	5.2	6.0
Total	**7.9**	**14.3**	**21.6**	**81.7**	**57.1**	**18.5**	**38.6**	**57.3**	**48.5**	**55.2**
Total Unrestricted General Fund Tax Revenue	**1,183.9**	**1,657.4**	**2,243.6**	**3,305.7**	**7,936.3**	**4,010.1**	**3,731.3**	**5,608.3**	**7,176.6**	**4,945.5**

Table A-2: History of Unrestricted General Fund Revenue[1], by type *(continued)*

($ millions)

Fiscal Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Non-Tax Revenue										
Licenses and Permits	**41.8**	**42.7**	**41.0**	**42.0**	**38.9**	**35.5**	**39.5**	**42.8**	**42.3**	**41.9**
Intergovernmental Receipts										
Federal Shared Revenue	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Charges for Services	**11.1**	**17.9**	**21.8**	**28.5**	**29.3**	**19.3**	**17.1**	**18.5**	**29.2**	**25.2**
Fines and Forefeitures	**16.0**	**9.4**	**8.5**	**7.8**	**8.9**	**10.5**	**10.4**	**7.0**	**10.9**	**15.8**
Rents and Royalties										
Oil and Gas Royalties-Net	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3	2,022.8	1,748.4
Oil and Gas Bonuses, Rents, Interest[2]	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0	8.9	19.4
Other [3]	7.8	9.3	8.8	11.8	14.6	15.6	13.2	17.6	20.4	24.7
Total	**1,063.9**	**1,429.2**	**1,792.9**	**1,624.8**	**2,460.7**	**1,481.2**	**1,490.2**	**1,860.9**	**2,052.1**	**1,792.5**
Investment Earnings	**9.7**	**24.7**	**53.3**	**140.1**	**227.9**	**247.6**	**184.0**	**96.3**	**107.8**	**28.1**
Miscellaneous Revenue[4]	**19.2**	**7.5**	**39.3**	**9.7**	**26.2**	**27.0**	**40.8**	**39.1**	**66.3**	**79.5**
Total Unrestricted General Fund Non-Tax Revenue	**1,161.7**	**1,531.4**	**1,956.8**	**1,852.9**	**2,791.9**	**1,821.1**	**1,782.0**	**2,064.6**	**2,308.6**	**1,983.0**
Total Unrestricted General Fund Revenue	**2,345.6**	**3,188.8**	**4,200.4**	**5,158.6**	**10,728.2**	**5,831.2**	**5,513.3**	**7,672.9**	**9,485.2**	**6,928.5**

[1] Unrestricted General Fund Revenue includes those revenue that are not restricted by statute or custom, as reported elsewhere in this publication. A summary of historical Unrestricted General Fund Revenue can be found on the Tax Division's web site at: www.tax.alaska.gov/sourcesbook/GeneralFundUnrestrictedRevenueHistory.pdf

[2] This category is primarily composed of petroleum revenue.

[3] Includes non-petroleum rents and royalites.

[4] Starting in FY 2010, dividends and payments from state-owned corporations are included in unrestricted miscellaneous revenue.

Table A-3a: Petroleum Revenue History[1]

FY	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
					($ millions)					
Unrestricted Petroleum Revenue										
Petroleum Property Tax	47.3	42.5	54.5	65.6	81.5	111.2	118.8	110.6	111.2	99.3
Petroleum Corporate Income Tax	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1	568.8	434.6
Oil and Gas Production Tax	642.7	854.9	1,191.7	2,198.3	6,810.9	3,100.9	2,860.7	4,543.2	6,136.7	4,042.5
Oil and Gas Hazardous Release	9.2	8.3	7.8	10.1	11.7	11.1	10.3	9.7	9.4	7.8
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Royalties-Net[2]	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3	2,022.8	1,748.4
Bonuses, Rents & Interest-Net[2][3]	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0	8.9	19.4
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unrestricted Petroleum Revenue	**2,054.1**	**2,849.6**	**3,699.2**	**4,481.4**	**9,956.0**	**5,181.0**	**4,912.9**	**7,048.9**	**8,857.8**	**6,352.0**
Cumulative Unrestricted Petroleum Revenue[4]	55,260	58,110	61,809	66,291	76,247	81,428	86,340	93,389	102,247	108,599
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	2.5	31.6	4.5	12.8	5.2	14.8	21.3	3.0	4.8	3.6
Royalties to AK Permanent Fund	354.7	476.9	599.5	535.0	834.0	659.8	696.1	857.3	904.9	842.1
Royalties to Public School Fund	7.1	9.6	12.0	10.6	16.5	11.0	11.1	13.6	14.7	13.8
CBRF Deposits	8.4	27.4	43.7	101.9	476.4	202.6	552.7	167.3	102.1	176.6
Restricted Petroleum Revenue	**372.7**	**545.5**	**659.7**	**660.3**	**1,332.1**	**888.2**	**1,281.2**	**1,041.2**	**1,026.5**	**1,036.1**
Total Petroleum Revenue	**2,426.8**	**3,395.1**	**4,358.9**	**5,141.7**	**11,288.1**	**6,069.2**	**6,194.1**	**8,090.1**	**9,884.3**	**7,388.1**

[1] Historical Unrestricted General Fund petroleum revenue can be found on the Tax Division's website at: http://www.tax.alaska.gov/sourcesbook/PetroleumRevenueHistory.pdf. The table on the Tax website includes historical Reserve Tax (FY 1976-1977 and Petroleum Special Settlements (FY 1986-1995).

[2] Royalties, bonuses, rents and interest rate are net of Permanent Fund Contribution and (CBRF) deposits.

[3] This category is primarily composed of petroleum revenue.

[4] The cumulative Unrestricted General Fund petroleum revenue is based on revenue beginning in FY 1959.

Table A-3b: Petroleum Revenue Forecast

($ millions)

FY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unrestricted Petroleum Revenue										
Petroleum Property Tax	99.6	97.4	99.2	101.1	102.5	103.4	103.9	103.9	103.6	103.1
Petroleum Corporate Income Tax	463.8	463.7	460.8	465.4	456.1	441.9	424.2	400.0	382.1	361.0
Oil and Gas Production Tax	2,091.6	1,703.2	1,796.0	2,141.0	2,268.3	2,320.3	2,106.3	1,891.8	2,059.0	1,654.2
Oil and Gas Hazardous Release	8.1	8.0	7.8	7.7	7.4	6.9	6.4	5.9	5.4	5.0
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Royalties-Net(1)	1,685.9	1,652.4	1,648.4	1,656.9	1,636.1	1,603.7	1,485.1	1,390.8	1,372.2	1,246.7
Bonuses, Rents & Interest-Net(1)(2)	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unrestricted Petroleum Revenue	**4,359.5**	**3,935.0**	**4,022.6**	**4,382.5**	**4,480.8**	**4,486.5**	**4,136.2**	**3,802.8**	**3,932.7**	**3,380.4**
Cumulative Unrestricted Petroleum Revenue(3)	112,959	116,894	120,917	125,299	129,780	134,266	138,403	142,205	146,138	149,519
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Royalties to AK Permanent Fund	724.3	706.6	703.2	707.3	703.1	688.7	632.1	584.3	582.9	528.9
Royalties to Public School Fund	12.2	11.9	11.9	11.9	11.8	11.6	10.7	10.0	9.9	9.0
CBRF Deposits	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Restricted Petroleum Revenue	**760.1**	**742.1**	**738.6**	**742.8**	**738.5**	**723.8**	**666.3**	**617.9**	**616.3**	**561.5**
Total Petroleum Revenue	**5,119.5**	**4,677.1**	**4,761.3**	**5,125.3**	**5,219.3**	**5,210.3**	**4,802.5**	**4,420.7**	**4,549.0**	**3,941.8**

(1) Royalties, bonuses, rents and interest rate are net of Permanent Fund Contribution and (CBRF) deposits.

(2) This category is primarily composed of petroleum revenue.

(3) The cumulative Unrestricted General Fund petroleum revenue is based on revenue beginning in FY 1959.

Table A-4a: Unrestricted General Revenue History

FY	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
					($ millions)					
Total Unrestricted Petroleum Revenue	2,054.1	2,849.6	3,699.2	4,481.4	9,956.0	5,181.0	4,912.9	7,048.9	8,857.8	6,352.0
General Fund Unrestricted Non-petroleum Revenue	291.5	339.2	501.2	677.2	772.2	650.2	600.4	624.0	627.4	576.5
Total Unrestricted General Fund Revenue	**2,345.6**	**3,188.8**	**4,200.4**	**5,158.6**	**10,728.2**	**5,831.2**	**5,513.3**	**7,672.9**	**9,485.2**	**6,928.5**
Total Unrestricted General Fund Revenue from Petroleum	88%	89%	88%	87%	93%	89%	89%	92%	93%	92%

Table A-4b: Unrestricted General Revenue Forecast

($ millions)

FY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total Unrestricted Petroleum Revenue	4,359.5	3,935.0	4,022.6	4,382.5	4,480.8	4,486.5	4,136.2	3,802.8	3,932.7	3,380.4
General Fund Unrestricted Non-petroleum Revenue	570.5	597.0	586.9	598.1	624.2	648.9	673.8	699.7	720.9	749.0
Total Unrestricted General Fund Revenue	**4,930.0**	**4,532.0**	**4,609.5**	**4,980.6**	**5,105.0**	**5,135.4**	**4,810.0**	**4,502.5**	**4,653.6**	**4,129.4**
Total Unrestricted General Fund Revenue from Petroleum	88%	87%	87%	88%	88%	87%	86%	84%	85%	82%

Table A-4c: FY 2013 Unrestricted General Revenue, Oil Price and Production Forecast

	History	Forecast									
Fiscal Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ANS WC Oil price ($/barrel)	107.57	105.68	105.06	107.69	110.38	115.40	121.19	122.43	123.67	133.00	131.85
ANS Production (thousand barrels per day)	531.6	508.2	498.4	487.6	482.7	459.5	429.1	399.6	368.8	340.1	312.9
GF Unrestricted Petroleum Revenue ($ million)	6,352.0	4,359.5	3,935.0	4,022.6	4,382.5	4,480.8	4,486.5	4,136.2	3,802.8	3,932.7	3,380.4
GF Unrestricted Non-petroleum Revenue ($ million)	576.5	570.5	597.0	586.9	598.1	624.2	648.9	673.8	699.7	720.9	749.0
Total General Fund Unrestricted Revenue ($ million)	6,928.5	4,930.0	4,532.0	4,609.5	4,980.6	5,105.0	5,135.4	4,810.0	4,502.5	4,653.6	4,129.4

Table B-1a: Nominal Netback Costs History

($/bbl)

FY	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ANS West Coast Spot	**32.36**	**44.85**	**62.12**	**61.60**	**96.51**	**68.34**	**74.90**	**94.49**	**112.65**	**107.57**
Netback Costs										
Marine Costs	1.69	1.79	1.65	1.62	1.93	2.05	2.21	2.44	3.24	3.64
TAPS Tariff	3.16	3.33	3.55	4.37	5.08	4.59	3.81	4.02	5.06	5.93
Feeder Tariff	0.28	0.27	0.30	0.45	0.31	0.31	0.31	0.29	0.31	0.35
Quality Bank	-0.24	-0.38	-0.24	-0.86	-1.26	-0.52	-0.41	-0.54	-0.68	-0.67
Other	0.00	-0.29	0.17	-0.18	-0.01	-0.05	0.09	0.46	0.44	0.51
Sum of Netback Costs	**4.89**	**4.72**	**5.43**	**5.40**	**6.05**	**6.38**	**6.01**	**6.67**	**8.37**	**9.76**
ANS Wellhead Weighted Average All Destinations	**27.47**	**40.13**	**56.69**	**56.20**	**90.46**	**61.96**	**68.89**	**87.82**	**104.28**	**97.81**

Source: Data maintained by Alaska Department of Revenue, Tax Division, Economic Research Section. The department attempts to use a consistent methodology when reporting data. However, data sources and formats have changed over time making consistent comparison of data potentially difficult.

Table B-1b: Nominal Netback Costs Forecast

	($/bbl)									
FY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ANS West Coast Spot	**105.68**	**105.06**	**107.69**	**110.38**	**115.40**	**121.19**	**122.43**	**123.67**	**133.00**	**131.85**
Netback Costs										
Marine Costs	3.43	3.46	3.51	3.56	3.62	3.70	3.74	3.78	3.88	3.91
TAPS Tariff	6.28	6.18	5.88	5.98	6.18	6.51	6.98	7.54	8.20	8.95
Feeder Tariff	0.46	0.46	0.49	0.58	0.60	0.65	0.76	0.85	0.87	0.87
Quality Bank	-0.46	-0.46	-0.46	-0.47	-0.49	-0.52	-0.53	-0.53	-0.57	-0.57
Other	0.40	0.39	0.40	0.41	0.43	0.45	0.46	0.46	0.50	0.49
Sum of Netback Costs	10.11	10.03	9.82	10.06	10.34	10.78	11.41	12.11	12.87	13.66
ANS Wellhead Weighted Average All Destinations	95.57	95.03	97.87	100.32	105.06	110.41	111.02	111.56	120.13	118.19

Table B-2: Price Difference from Spring 2013 Forecast

FY	2013	2014	2015	2016	2017 ($/bbl)	2018	2019	2020	2021	2022
Spring 2013 Forecast										
ANS West Coast	109.21	109.61	111.67	114.88	116.22	117.16	118.29	119.74	121.42	123.34
Sum of Netback Costs	9.56	8.87	9.03	9.42	9.75	9.95	10.24	10.67	11.08	11.44
ANS Wellhead Wtd Average All Destinations	99.66	100.74	102.63	105.46	106.47	107.22	108.06	109.06	110.34	111.91
Fall 2013 Forecast										
ANS West Coast	107.57	105.68	105.06	107.69	110.38	115.40	121.19	122.43	123.67	133.00
Sum of Netback Costs	9.76	10.11	10.03	9.82	10.06	10.34	10.78	11.41	12.11	12.87
ANS Wellhead Wtd Average All Destinations	97.81	95.57	95.03	97.87	100.32	105.06	110.41	111.02	111.56	120.13
Absolute change from prior forecast										
ANS West Coast	-1.64	-3.93	-6.61	-7.19	-5.84	-1.76	2.90	2.69	2.25	9.66
Sum of Netback Costs	0.20	1.24	1.00	0.40	0.31	0.39	0.54	0.74	1.03	1.43
ANS Wellhead Wtd Average All Destinations	-1.85	-5.17	-7.60	-7.59	-6.15	-2.16	2.35	1.96	1.22	8.22
Percent change from prior forecast										
ANS West Coast	-1.5%	-3.6%	-5.9%	-6.3%	-5.0%	-1.5%	2.5%	2.2%	1.9%	7.8%
Sum of Netback Costs	2.1%	14.0%	11.1%	4.2%	3.2%	3.9%	5.3%	6.9%	9.3%	12.5%
ANS Wellhead Wtd Average All Destinations	-1.8%	-5.1%	-7.4%	-7.2%	-5.8%	-2.0%	2.2%	1.8%	1.1%	7.4%

Table C-1: Production Differences from Spring 2013 Forecast

	(mbbls/day)									
FY	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Spring 2013 Forecast										
Alaska North Slope	538.3	526.6	512.8	499.7	476.9	443.3	422.4	399.4	372.3	344.5
Non-North Slope	10.4	9.6	8.9	8.3	7.7	7.2	6.7	6.3	5.9	5.6
Total	**548.7**	**536.2**	**521.7**	**508.0**	**484.6**	**450.5**	**429.1**	**405.7**	**378.2**	**350.1**
Fall 2013 Forecast										
Alaska North Slope	531.6	508.2	498.4	487.6	482.7	459.5	429.1	399.6	368.8	340.1
Non-North Slope	12.2	13.5	11.6	10.4	9.5	8.8	8.1	7.6	7.1	6.6
Total	**543.8**	**521.7**	**510.0**	**498.1**	**492.2**	**468.3**	**437.2**	**407.2**	**375.9**	**346.8**
Volume change from prior forecast										
Alaska North Slope	(6.7)	(18.4)	(14.4)	(12.1)	5.8	16.2	6.7	0.2	(3.5)	(4.4)
Non-North Slope	1.8	3.9	2.7	2.1	1.8	1.6	1.4	1.3	1.2	1.0
Total	**(4.9)**	**(14.5)**	**(11.7)**	**(9.9)**	**7.6**	**17.8**	**8.1**	**1.5**	**(2.3)**	**(3.3)**
Percent change from prior forecast										
Alaska North Slope	-1.2%	-3.5%	-2.8%	-2.4%	1.2%	3.7%	1.6%	0.1%	-0.9%	-1.3%
Non-North Slope	17.3%	40.8%	30.1%	25.7%	23.8%	21.8%	21.3%	20.2%	19.8%	18.1%
Total	**-0.9%**	**-2.7%**	**-2.2%**	**-2.0%**	**1.6%**	**3.9%**	**1.9%**	**0.4%**	**-0.6%**	**-1.0%**

Table C-2a: Annual Historical Daily Averaged Crude Oil Production

	(mbbls/day)									
FY	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Prudhoe Bay[(1)(2)]	414.4	380.2	335.4	270.8	291.1	291.4	276.7	267.6	265.2	247.4
PBU Satellites[(1)(3)]	103.3	92.4	82.1	75.7	67.5	67.9	63.1	55.4	50.7	46.5
GPMA[(4)]	59.9	54.6	47.5	36.9	44.3	38.5	34.0	30.8	29.7	26.3
Kuparuk	154.0	140.8	132.0	121.4	112.6	105.6	99.2	91.0	91.6	86.4
Kuparuk Satellites[(5)]	48.9	51.0	43.3	43.8	36.5	37.0	35.0	31.9	27.5	25.3
Endicott[(6)]	28.1	20.0	20.5	16.4	14.1	14.2	12.7	11.7	11.3	10.4
Alpine[(7)]	99.0	104.6	123.4	124.4	114.9	106.7	93.5	84.6	78.2	64.5
Offshore[(8)]	66.1	67.7	55.4	44.9	34.4	31.5	28.4	27.0	25.2	24.8
NPR-A[(9)]	-	-	-	-	-	-	-	-	-	-
Point Thomson[(9)]	-	-	-	-	-	-	-	-	-	-
Total Alaska North Slope	**973.8**	**911.3**	**839.7**	**734.2**	**715.4**	**692.8**	**642.6**	**599.9**	**579.4**	**531.6**
Cook Inlet	**25.1**	**20.3**	**18.3**	**16.1**	**13.9**	**10.1**	**8.9**	**10.4**	**10.7**	**12.2**
Total Alaska	**998.9**	**931.6**	**858.0**	**750.4**	**729.4**	**702.9**	**651.5**	**610.3**	**590.1**	**543.8**

(1) Milne Point Unit production is now being reported with PBU Satellites instead of with PBU volume. Historical volumes will, therefore, not match the Fall 2011 RSB.

(2) Includes NGLs from Central Gas Facility shipped to TAPS.

(3) Aurora, Borealis, Midnight Sun, Orion, Polaris, Milne Point, Sag River, Schrader Bluff, Ugnu

(4) Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk

(5) Meltwater, NEWS, Tabasco, Tarn, West Sak

(6) Endicott, Minke, Sag Delta, Eider, Badami

(7) Alpine, Fiord, Nanuq, Qannik, Mustang (after 2016)

(8) Northstar, Oooguruk, Nikaitchuq, Liberty (delayed)

(9) Not in production

* Totals may show slight differences from other sources due to rounding and aggregation differences

Table C-2b: Annual Forecasts of Daily Averaged Crude Oil Production

(mmbls/day)

FY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Prudhoe Bay	230.6	237.9	230.3	220.7	212.1	202.4	192.0	179.3	166.1	153.5
PBU Satellites(1)	45.1	41.9	41.3	38.2	36.8	35.0	31.1	28.0	25.5	23.1
GPMA(2)	26.5	22.8	21.1	19.4	17.8	16.5	15.4	14.3	13.4	12.5
Kuparuk	83.3	77.0	78.1	79.0	72.7	67.5	62.9	58.4	53.9	48.8
Kuparuk Satellites(3)	24.1	25.3	25.8	24.1	24.6	22.4	20.0	18.1	16.3	14.5
Endicott(4)	11.0	10.4	9.2	8.3	7.6	7.0	5.8	5.0	4.3	3.8
Alpine(5)	56.8	50.6	49.1	54.7	49.7	41.9	35.8	30.4	26.0	22.4
Offshore(6)	30.8	32.4	31.2	29.6	27.5	24.8	22.4	20.4	18.7	17.2
NPR-A	-	-	-	-	2.6	4.2	3.3	2.5	4.4	4.4
Point Thomson	-	-	1.6	8.7	8.0	7.4	10.8	12.5	11.8	12.7
Total Alaska North Slope	**508.2**	**498.4**	**487.6**	**482.7**	**459.5**	**429.1**	**399.6**	**368.8**	**340.1**	**312.9**
Cook Inlet	**13.5**	**11.6**	**10.4**	**9.5**	**8.8**	**8.1**	**7.6**	**7.1**	**6.6**	**6.2**
Total Alaska	**521.7**	**510.0**	**498.1**	**492.2**	**468.3**	**437.2**	**407.2**	**375.9**	**346.8**	**319.1**

(1) Aurora, Borealis, Midnight Sun, Orion, Polaris, Milne Point, Sag River, Schrader Bluff, Ugnu

(2) Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk

(3) Meltwater, NEWS, Tabasco, Tarn, West Sak

(4) Endicott, Minke, Sag Delta, Eider, Badami

(5) Alpine, Fiord, Nanuq, Qannik, Mustang (after 2016)

(6) Northstar, Oooguruk, Nikaitchuq, Liberty (delayed)

Table D-1a: History of Lease Expenditures 2007-2013

($ millions)

Fiscal Year	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Total North Slope Lease Expenditures							
Operating Expenditures	2,081.0	2,027.0	2,085.0	2270.0	2614.0	3,001.2	3109.5
Capital Expenditures	1,578.0	1,953.0	2,212.0	2389.0	2317.0	2,383.4	2947.6
Total North Slope Lease Expenditures	**3,659.0**	**3,980.0**	**4,297.0**	**4,659.0**	**4,931.0**	**5,384.6**	**6,057.1**
Total Non-North Slope Lease Expenditures (includes Cook Inlet)							
Operating Expenditures	222.9	278.6	201.3	164.5	190.9	244.5	259.1
Capital Expenditures	134.4	247.4	340.6	167.9	123.3	349.6	382.4
Total Non-North Slope Lease Expenditures	**357.3**	**526.0**	**541.9**	**332.4**	**314.2**	**594.1**	**641.5**
Total Statewide Lease Expenditures							
Operating Expenditures	2,303.9	2,305.6	2,286.3	2,434.5	2,804.9	3,245.7	3,368.6
Capital Expenditures	1,712.4	2,200.4	2,552.6	2,556.9	2,440.3	2,733.0	3,330.0
Total Statewide Lease Expenditures	**4,016.3**	**4,506.0**	**4,838.9**	**4,991.4**	**5,245.2**	**5,978.7**	**6,698.6**

Table D-1b: FY 2013 Ten-Year Forecast of Lease Expeditures

($ millions)

Fiscal Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total North Slope Lease Expenditures										
Operating Expenditures	3,083.3	2,893.3	2,926.6	2,930.9	3,084.8	2,866.6	2,787.9	2,682.0	2,616.2	2,572.2
Capital Expenditures	3,928.6	4,894.3	4,617.3	3,747.5	3,294.0	3,666.2	3,663.8	3,520.6	3,369.9	3,018.7
Total North Slope Lease Expenditures	**7,011.9**	**7,787.6**	**7,543.9**	**6,678.4**	**6,378.9**	**6532.8**	**6451.7**	**6,202.7**	**5986.1**	**5,590.9**
Total Non-North Slope Lease Expenditures (includes Cook Inlet)										
Operating Expenditures	294.9	339.2	352.3	353.9	346.5	338.4	330.3	322.4	313.2	304.0
Capital Expenditures	598.5	677.9	660.3	610.0	568.7	518.3	483.2	458.2	445.3	432.1
Total Non-North Slope Lease Expenditures	**893.4**	**1,017.1**	**1,012.6**	**963.9**	**915.2**	**856.7**	**813.5**	**780.6**	**758.5**	**736.1**
Total Statewide Lease Expenditures										
Operating Expenditures	3,378.2	3,232.5	3,278.9	3,284.8	3,431.3	3,205.1	3,118.2	3,004.4	2,929.4	2,876.2
Capital Expenditures	4527.2	5,572.1	5,277.6	4,357.5	3,862.7	4,184.5	4,147.0	3,978.9	3,815.1	3,450.8
Total Statewide Lease Expenditures	**7,905.4**	**8,804.6**	**8,556.5**	**7,642.3**	**7,294.1**	**7,389.6**	**7,265.2**	**6,983.3**	**6,744.6**	**6,327.0**

Table E-1a: Income Statement FY 2013 Production Tax Estimate using Income Statement Format

This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication.

	Price	Barrels (Thousands)	Value ($ millions)
Avg ANS Oil Price ($/bbl) & Daily Production	$107.57	531.6	$57.2
Annual Production			
Total		194,034	$20,872.2
Royalty, Federal and other barrels(1)		-30,177	($3,246.2)
Taxable barrels from companies with tax liability(2)		163,857	$17,626.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$3.64		
TAPS Tariff	-$5.93		
Other	-$0.19		
Total Transportation Costs	-$9.76	163,857	($1,599.2)
Deductible Lease Expenditures(3)			
Deductible Operating Expenditures	-$17.39		($2,849.4)
Deductible Capital Expenditures	-$12.66		($2,074.7)
Total Lease Expenditures	-$30.05	163,857	($4,924.1)
Production Tax			
Production Tax Value (PTV)			$11,102.7
Base Tax (25%*PTV)			$2,775.7
Production Tax Value per barrel	$67.76		
Progressive Tax = (15.1% * PTV)			$1,676.9
Total Tax before credits			**$4,452.6**
North Slope Credits applied against tax liability			**($430.0)**
Estimated Total Tax after credits(4)			**$4,022.6**

(1) Royalty, Federal and other barrels represents the department's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies that are not expected to have a tax liability.

(2) This number does not represent all taxable barrels, only those produced by companies that are expected to have a tax liability.

(3) Deductible Lease Expenditures represents the department's best estimate of lease expenditures that are applicable to companies that are likely to produce a tax liability for the year. The per-barrel expenditures reflect expenditures per taxable barrel and do not reflect expenditures per all barrels produced.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Table E-1b Income Statement FY 2014 Production Tax Estimate using Income Statement Format

This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication.

	Price	Barrels (Thousands)	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production	$105.68	508.2	$53.7
Annual Production			
Total		185,495	$19,603.9
Royalty, Federal and other barrels[(1)]		-23,964	($2,532.6)
Taxable barrels from companies with tax liability[(2)]		161,531	$17,071.2
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$3.43		
TAPS Tariff	-$6.28		
Other	-$0.40		
Total Transportation Costs	-$10.11	161,531	($1,633.3)
Deductible Lease Expenditures[(3)]			
Deductible Operating Expenditures	-$18.81		($3,038.3)
Deductible Capital Expenditures	-$22.05		($3,561.4)
Total Lease Expenditures	-$40.86	161,531	($6,599.6)
Production Tax Value (PTV)			
Base Tax (25%*PTV for ACES, 35%*PTV for MAPA)			$8,838.3
Production Tax Value per barrel			$2,651.5
Progressive Tax under ACES = (9.9% * PTV)	$54.72		
Total Tax before credits			$436.9
Total Tax before credits			**$3,088.4**
North Slope Credits applied against tax liability			**($1,010.0)**
Estimated Total Tax after credits[(4)]			**$2,078.4**

(1) Royalty, Federal and other barrels represents the department's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies that are not expected to have a tax liability.

(2) This number does not represent all taxable barrels, only those produced by companies that are expected to have a tax liability.

(3) Deductible Lease Expenditures represents the department's best estimate of lease expenditures that are applicable to companies that are likely to produce a tax liability for the year. The per-barrel expenditures reflect expenditures per taxable barrel and do not reflect expenditures per all barrels produced.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Table E-1c: Income Statement FY 2015 Production Tax Estimate using Income Statement Format

This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication.

	Price	Barrels (Thousands)	Value ($ millions)
Avg ANS Oil Price ($/bbl) & Daily Production	$105.06	498.4	$52.4
Annual Production			
Total		181,912	$19,111.6
Royalty, Federal and other barrels[(1)]		-23,301	($2,448.0)
Taxable barrels from companies with tax liability[(2)]		158,611	$16,663.6
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$3.46		
TAPS Tariff	-$6.18		
Other	-$0.40		
Total Transportation Costs	-$10.03	158,611	($1,591.0)
Deductible Lease Expenditures[(3)]			
Deductible Operating Expenditures	-$17.91		($2,840.3)
Deductible Capital Expenditures	-$28.08		($4,453.4)
Total Lease Expenditures	-$45.99	158,611	($7,293.7)
Production Tax			
Gross Value Reduction			($63.8)
Production Tax Value (PTV)			$7,715.2
Base Tax (35%*PTV)			$2,700.3
Total Tax before credits			**$2,700.3**
North Slope Credits applied against tax liability			**($960.0)**
Estimated Total Tax after credits[(4)]			**$1,740.3**

[(1)] Royalty, Federal and other barrels represents the department's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies that are not expected to have a tax liability.

[(2)] This number does not represent all taxable barrels, only those produced by companies that are expected to have a tax liability.

[(3)] Deductible Lease Expenditures represents the department's best estimate of lease expenditures that are applicable to companies that are likely to produce a tax liability for the year. The per-barrel expenditures reflect expenditures per taxable barrel and do not reflect expenditures per all barrels produced.

[(4)] Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Revenue Sources Book

Alaska Department of Revenue - Tax Division

FALL 2013

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