# Chapter Six: Oil and Gas Exploration, Development, Production, and Transportation

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# Chapter Six: Oil and Gas Exploration, Development, Production, and Transportation

## A. Geology

### 1. Tectonic Setting

The Cook Inlet basin occupies the forearc setting between the Aleutian-Alaska Range magmatic arc on the west and the Chugach terrane accretionary prism on the east. The basin-fill succession is floored by Permian and Triassic volcanic agglomerate and limestone, the oldest units of the Peninsular terrane, exposed only locally on the northeastern Alaska Peninsula at Puale Bay. Lower Jurassic through Upper Cretaceous volcanic and sedimentary Peninsular terrane rocks are known from outcrop and wells to be widespread beneath Cook Inlet, providing a stratigraphic record of its early, dominantly marine stage of basin evolution. Paleocene and younger formations of the entirely nonmarine Kenai Group overlie the Mesozoic succession with a significant angular unconformity that records compressional uplift above sea level, erosion, and a gap in deposition during latest Cretaceous to Paleocene time. Strata of the lower Kenai Group are present locally in the Southwest Cook Inlet exploration license area north of Chinitna Bay and are present in the shallow section of some offshore wells outside the license area in Lower Cook Inlet, but Tertiary units are entirely absent on the Iniskin Peninsula.

### 2. Mesozoic History and Rock Units

The Alaska-Aleutian Range batholith, dominantly diorite, quartz monzonite, and granodiorite (Detterman and Hartsock 1966), form the deep roots of the magmatic arc on the west side of Cook Inlet. Together, Middle Jurassic plutons and the overlying Lower Jurassic volcanic edifice that they intrude constitute much of the Talkeetna arc (Nokleberg et al.1994), a volcanic oceanic island arc within the Peninsular terrane, believed to have formed above a northward-dipping subduction zone before the Peninsular terrane accreted to the southern Alaska margin in mid-Cretaceous time. The Lower Jurassic Talkeetna Formation, mainly submarine volcanic flows and breccias, reaches a total thickness on the order of 2,600-2,750 m on the west side of Cook Inlet (Magoon and Claypool 1981; Detterman and Hartsock 1966) and at least 5,270 m east of Cook Inlet near Seldovia (Bradley et al.1999).

By mid-Jurassic time, parts of the Talkeetna Formation were subject to erosion at or above sea level, generating large volumes of volcanic-rich clastic sediment that were re-deposited in the nearby shallow marine forearc setting to form the siltstones, fossiliferous graywacke sandstones, and conglomerates of the Middle to Upper Jurassic Tuxedni and Chinitna Groups. These units reach a combined thickness of up to 1,150 m on the west side of lower Cook Inlet (Detterman and Hartsock 1966). Geochemical evidence identifies Tuxedni Group siltstones and shales as the source rock for commercial oil produced from Tertiary reservoirs in upper Cook Inlet (Magoon and Claypool 1981; Magoon and Anders 1992; Magoon 1994a, 1994b; Stanley et al. 2011; Stanley, Herriott, et al. 2013).

Deposition of the Upper Jurassic Naknek Formation marked a significant change in sediment composition, from volcanic-rich graywackes of the underlying Tuxedni and Chinitna Groups to plutonic-rich arkosic sandstones, siltstone, and conglomerate (e.g., Detterman and Hartsock 1966). This indicates erosional unroofing of the intrusive roots of the magmatic arc on the basin's western margin in response to uplift on the Bruin Bay fault system while the marine forearc basin continued accumulating sediment during Late Jurassic time. Syntectonic deposition is further reflected by eastward thinning and grain size decrease, particularly in the lower Naknek. Reported thicknesses of the Naknek Formation range from a minimum of 1,663 m in the Lower Cook Inlet COST No. 1 well (Magoon 1986) to more than 2,185 m elsewhere in Cook Inlet (Magoon and Claypool 1981).

The Cretaceous stratigraphic record is incomplete in the Cook Inlet region, with significant time represented only by unconformities. Within the onshore parts of the Southwest Cook Inlet exploration license area, Cretaceous strata are entirely absent, due to non-deposition or erosion, or both. Outside the license area at the offshore Lower Cook Inlet COST No. 1 well, the Lower Cretaceous Herendeen Formation unconformably overlies the Naknek Formation with a gap in deposition of nearly 20 million years (Magoon and Claypool 1981). The Herendeen comprises fossiliferous sandstone and sandy limestone totaling approximately 570 m thick (Magoon 1986). The Lower to Upper Cretaceous Matanuska Formation and the Upper Cretaceous Kaguyak Formation overlie the Herendeen Formation unconformably with a gap in the stratigraphic record that varies from approximately 25 to 55 million years in different areas of the basin. These units are in part laterally equivalent to each other, and reach reported thicknesses of 744 to 2,600 m, respectively (Magoon 1986; Magoon and Claypool 1981). They are dominated by deep water turbidites, but the Matanuska is punctuated by internal unconformities, and both locally include or are partially time-equivalent to shelfal, shallow marine and non-marine facies (Nokleberg et al. 1994; Lepain et al. 2012; Wartes et al. 2013). The Cretaceous unconformities in Cook Inlet attest to tectonic instability of the forearc setting, though the uplift and subsidence mechanisms that created them are not well understood.

## 3. Cenozoic History and Rock Units

As noted above, Mesozoic and Cenozoic strata in Cook Inlet are separated by a regional angular unconformity corresponding to uplift that elevated the basin above sea level, creating nonmarine conditions that persisted throughout Tertiary time. Calderwood and Fackler (1972) assigned most Tertiary strata in the basin to the redefined Kenai Group, made up of five formations, in stratigraphic order, the West Foreland Formation, Hemlock Conglomerate, Tyonek Formation, Beluga Formation, and Sterling Formation. They estimated the maximum thickness of Tertiary strata in excess of 7.9 km based on drilling data; seismic mapping by Shellenbaum and others (2012) places the basal Tertiary unconformity at a depth of greater than 7.6 km in the area north of East Foreland, the basin's deepest part. The Kenai Group thins dramatically toward the south in the Cook Inlet offshore, due in large part to uplift and erosion on the Seldovia Arch, a major structural high that trends nearly east-west across the basin between the southernmost Kenai Peninsula and Augustine Island. Tertiary strata also thin from offshore to onshore, again largely due to uplift and erosion, although depositional thinning also plays a role. The result is that Kenai Group strata are absent entirely from the onshore parts of the exploration license area south of Chinitna Bay and probably too thin to host significant hydrocarbon accumulations where they are present locally in Lake Clark National Park onshore north of Chinitna Bay.

## 4. Structure

The structural framework of Cook Inlet is dominated by transpression (Haeussler et al. 2000), faulting and folding combining strike-slip and compressional movements. The Bruin Bay and Lake Clark – Castle Mountain fault systems are steeply-dipping structures with a significant component of up-to-northwest vertical displacement bounding the basin on the west and north. Most of the major fault systems in central and southern Alaska have a right-lateral sense of horizontal displacement, but there is some evidence for left lateral movement on the Bruin Bay fault (Detterman and Hartsock 1966; Detterman and Reed 1980; Decker et al. 2008). The transpressional regime has created en echelon folds, anticlines and synclines arrayed in overlapping steps. Anticlinal geometries vary widely throughout Cook Inlet, from long, narrow highs with steeply dipping limbs, to broad, elliptical closures with gently dipping limbs (Haeussler et al. 2000). Offset of anticlines by cross faults is common, creating separated compartments with oil and gas trapping potential. Major folds within the Southwest Cook Inlet exploration license area include a narrow, dominantly south-plunging, internally faulted anticline with moderate to very steeply dipping limbs (Fitz Creek anticline) and a broader, south-plunging, slightly asymmetric syncline with more moderately dipping limbs (Tonnie syncline). The Bruin Bay fault system transects the license area, northeast-southwest across the neck of the Iniskin Peninsula; interpretations vary as to whether it is best viewed as a discrete fault zone or as overlapping en echelon strands (Detterman and Hartsock 1966; Hartsock 1954).

# B. Exploration History

## 1. Oil Seeps and Initial Prospecting

Natural seepages of oil at the surface have been known on the Iniskin Peninsula since at least 1853, and were reportedly first sampled in 1882 (Martin 1905; Detterman and Hartsock 1966), leading to the staking of oil prospecting claims in 1892 and 1896. Detterman and Hartsock (1966) mapped live oil seeps in three areas: Well Creek, one-half mile north of the head of Oil Bay near the south end of the peninsula; Brown Creek, two miles north of the head of Dry Bay on the southeast side of the peninsula; and Fitz Creek, in the interior of the peninsula. All of these seeps are located along mapped faults, which are presumed to be more favorable as flow conduits than the relatively low permeability Jurassic sandstones found in the area (Detterman and Hartsock 1966).

The earliest petroleum exploration wells in Cook Inlet were drilled by the Alaska Petroleum Company, beginning in 1902 on a claim staked in 1896 near Oil Bay and the Well Creek oil seep(s). Drilling of the first well was concluded in 1903, and although no official records are known, it is reported to have reached a total depth of 305 m, with continuous gas encountered below 58 m, as well as “considerable” oil flow at 213 m. Upon further drilling, strong water influx shut off the flow of oil, though the gas flow continued even after drilling was concluded (Martin 1905). The company drilled a second well about a quarter of a mile northwest of the first in 1903, encountering oil shows while drilling in badly caving shale (presumably faulted or fractured) at a depth of 98 m. This well was abandoned at a total depth of 137 m, unable to produce oil due to the collapsing shale (Martin 1905). A third well, located 76 m south of the previous well, reached a total depth of 274 m, encountering oil and gas in three thin sandstones at approximately 236 m, as well as gas shows at various other depths, some sufficient to blow the water out of the hole to a height of 6 m (Martin 1905). The fourth and final well drilled by Alaska Petroleum Company was located on top of a low hill approximately 260 m north of the second hole. There is no information available regarding the depth drilled or shows encountered in this well.

A well drilled by the Alaska Oil Company in 1902 near the seep on Brown Creek north of Dry Bay reached a total depth of just 98 m, abandoned without oil shows when drilling tools were lost in the hole. A second attempt nearby in 1903 apparently met with even less success, and was abandoned at shallow depth after a mishap with the equipment (Martin 1905). Subsurface exploration shut down in 1903, and no additional wells have been drilled at either Oil Bay or Dry Bay since this initial prospecting phase.

Initially, oil and gas activities were subject to mining claims under the General Mining Act of 1872. Federal lands were closed off to mineral entry in 1910. The Mineral Leasing Act of 1920 authorized leasing of public lands for developing deposits of coal, petroleum, natural gas, and other hydrocarbons. In 1959, following Alaska statehood and the creation of state natural resource agencies, oil companies bought exploration leases from the state.

## 2. Iniskin Bay Association No. 1 Well

Between 1903 and 1934, exploration activity in the license area was limited to geologic field studies by USGS geologists (Moffit 1922a; 1922b; 1927), which described the potential structural trap now known as the Fitz Creek anticline. The Iniskin Bay Association (IBA) obtained exploration rights on 51,000 acres on the anticline near the Fitz Creek oil seep, built a road into the interior of the Iniskin Peninsula up the Fitz Creek drainage from Chinitna Bay, and began drilling the Iniskin Bay phase Association No. 1 well in late 1936 (Detterman and Hartsock 1966). Working over four summer seasons, drilling was suspended in 1939 at a total depth of 2.7 km after penetrating Middle Jurassic sedimentary rocks, apparently only the lower formations of the Tuxedni Group. It encountered trace oil and gas shows at a depth of 1.5 km upon penetrating the nearly vertical Fitz Creek fault zone that cores the tight anticline. The well penetrated high-pressure gas in thick sandstones between 1.5 and 2 km, and a thin oil-bearing sandstone at 2.1 km just before the end of the 1938 drilling season. When the well was reentered in May 1939, the crew recovered 12 barrels of high gravity oil before drilling the deepest section of the hole, comprising mostly hard dark gray to black shales with occasional thin sandstones characterized by strong oil and gas shows accompanied by strong salt water influx. When the well was abandoned in 1939, it was flowing 240 barrels of water per day with minor oil and gas. Oil sampled from the well in 1946 yielded a highly favorable analysis of 47.6 degree API gravity (Detterman and Hartsock 1966).

## 3. Beal No. 1 and Zappa No. 1 Wells

Oil and gas exploration in the license area came to a halt during World War II, and resumed under a new group of investors called Iniskin Unit Operators formed by IBA president Russell Havenstrite in 1953. Preparations for drilling began the same year, and the group drilled the Beal No. 1 well between August 1954 and October 1955 (Detterman and Hartsock 1966). The well is located 213 m east of the Fitz Creek fault in the downthrown block, approximately one mile southeast of the structurally highest point on the Fitz Creek anticline, where structural closure cannot be demonstrated. Beal No. 1 encountered sedimentary strata of the lower Tuxedni Group before entering Lower Jurassic Talkeetna Formation volcanic and volcaniclastic rocks at 2.8 km, and penetrated to a total depth of 2.97 km (Detterman and Hartsock 1966). Gas shows were noted in sandstones of the lower Gaikema Formation between 748 and 788 m and in a thin Red Glacier Formation sandstone at 1.15 km. Core samples taken near a zone of steep dips and fractures just below 1.95 km yielded oil shows with good cut fluorescence. Further oil shows appeared below 2.35 km and the well yielded 14 barrels of oil-rich fluid at 2.38 km. The operator reentered Beal No. 1 in 1956 and 1957, perforating selected intervals and recovering a small but unspecified quantity of oil and gas; casing head pressures were used to obtain a computed gas flow rate of 4,000 cubic feet per day. The operator transferred the lease to Alaska Consolidated Oil Company in 1958, but further efforts to achieve commercial flow rates, including hydraulic fracture stimulation, were unsuccessful.

Alaska Consolidated Oil Co. drilled one additional well in 1958-1959. The Antonio Zappa No. 1 is located some 732 m west of the Beal No. 1, immediately west of the Fitz Creek fault in the upthrown block near the structural crest of the Fitz Creek anticline. The well bottomed at 3.42 km total measured depth, having encountered numerous minor to fair oil shows beginning at a depth of approximately 213 m and becoming abundant below 1.83 km. Nearly all oil indications were restricted to the surfaces of faults, fractures, and associated calcite vein fills, well described from cuttings samples and the 30 cores attempted in the well (AOGCC 2014). Drilling records identify the top of the Talkeetna Formation volcanics at a depth of 2.97 km, nearly 183 m deeper than in the nearby Beal No. 1 (despite the fact that the well was spudded in the upthrown block), suggesting that the well may have penetrated the fault and passed into the downthrown block (Detterman and Hartsock 1966). The presence of oil shows in fractured volcaniclastic strata nearly 457 m below the top of the Lower

Jurassic Talkeetna Formation at the bottom of the well strongly suggests oil migration into the Fitz Creek anticline from Middle Jurassic Tuxedni Group source rocks deeper in the basin offshore to the east. Figure 6.1 depicts the location and type of oil and gas wells that have been drilled in the license area.

## 4. Recent Activity and Interest

The most recent exploration activity in the license area has been two-dimensional seismic acquisition conducted mostly onshore during summer 2013. At the time of this writing, little additional public data was available regarding the project.

One application was received in April 2013 indicating interest in oil and gas exploration in the area. Following DNR's issuing of a Notice of Intent to Evaluate Oil and Gas Exploration License Proposal a competing proposal was received leading to a potential competitive bidding situation to obtain the exploration license.

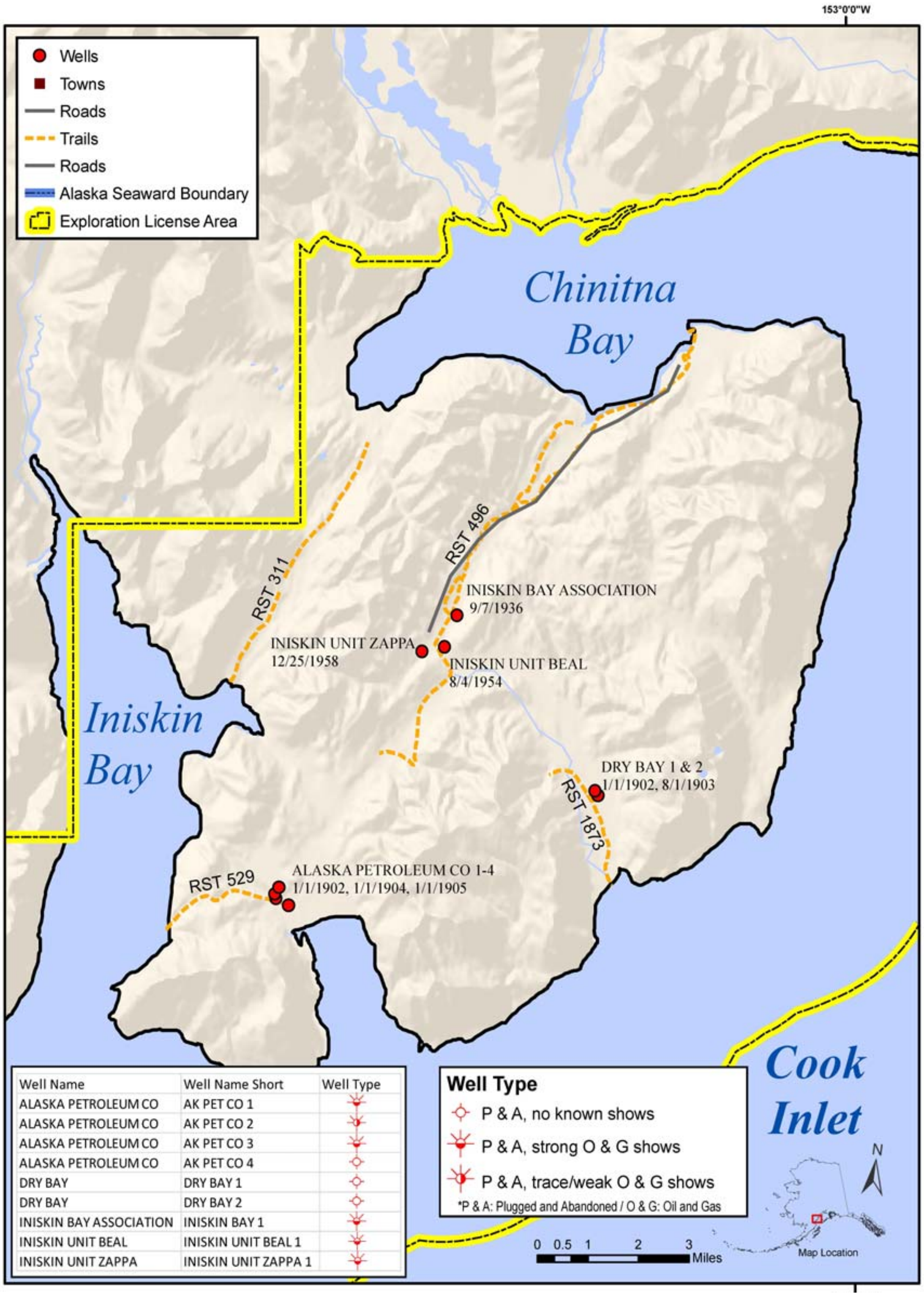


**Figure 6.1. Oil and gas wells in the license area**

# C. Oil and Gas Potential

The several proven and potential petroleum systems of Cook Inlet provide important insights into the oil and gas resource potential of the license area. Commercial production in Cook Inlet comes from two main plays: 1) biogenic natural gas, sourced from Tertiary coals and reservoired in sandstones of the middle and upper Kenai Group (upper Tyonek, Beluga, and Sterling Formations), and 2) thermogenic oil with minor associated gas, sourced from the Middle Jurassic Tuxedni Group and reservoired in sandstones of the lower and middle Kenai Group (West Foreland, Hemlock, and lower Tyonek Formations).

Contiguous to the license area in the waters of Cook Inlet is the federal Bureau of Ocean and Energy Management (BOEM) Outer Continental Shelf (OCS) oil and gas leasing area. The offshore acreage that can be offered in a federal oil and gas lease sale is reported to be approximately 5.36 million acres. The BOEM special interest oil and gas lease sale is tentatively scheduled in Cook Inlet for 2016, pending additional resource and environmental information (BOEM 2013). There are no current active federal oil and gas leases in the direct vicinity of the license area.

## 1. Biogenic Gas

Biogenically sourced methane in Cook Inlet originated from the bacterial decay of Tertiary Kenai Group coals and carbonaceous mudstones during the early stages of burial in the relatively shallow subsurface, where bacteria flourish at temperatures less than approximately 80°C. As pressure increased with deeper burial, the bacterial methane dissolved in pore waters and adsorbed onto the carbon-rich micro-fabric of the coals, where it was effectively trapped until late Tertiary to Quaternary tectonics uplifted much of the basin. This uplift lowered the confining pressure on the coals, causing the gas to bubble out of solution to form a free gas phase, and allowing the cleats (coal fractures) to open and serve as conduits for gas to flow. At that point, the gas migrated by buoyancy out of the coals and into nearby sandstones, forming dry gas accumulations in numerous structural traps.

## 2. Thermogenic Oil and Gas

Geochemical “fingerprinting” techniques have been applied to both oil samples and rock samples from the license area, and clearly demonstrate that the commercial oil accumulations were sourced from the Tuxedni Group. Even so, there are remarkably few published analyses characterizing the Tuxedni Group in terms of organic richness and kerogen type, the key attributes of source rock type and quality. Four thermally immature samples from the Soldotna 33-33 well exhibit only marginal or fair oil source quality, averaging 1.7% TOC represented by mixed Type II/III kerogens. Three thermally mature samples from the Beal 1 well on the Iniskin Peninsula and 19 overmature outcrop samples from the Red Glacier area north of Chinitna Bay yield lower TOC values and low levels of remaining pyrolyzable hydrocarbon, consistent with partially to completely spent source (Magoon and Claypool 1981; Magoon and Anders 1992; Magoon 1994a; Stanley, Herriott, et al. 2013; LePain et al. 2014).

## 3. Resource Potential

Together, Cook Inlet’s Tertiary-reservoired oil and gas plays are assessed by the USGS (Stanley et al. 2011) as having mean undiscovered, technically recoverable resources of 394 million barrels of oil plus natural gas liquids and 12.2 trillion cubic feet of natural gas. However, Tertiary Kenai Group strata are absent over nearly all of the license area. Where strata of the Kenai Group are locally present onshore north of Chinitna Bay, they are devoid of structural trapping potential, of limited stratigraphic thickness, and within Lake Clark National Park, all of which makes them unattractive as petroleum targets.

The greatest prospectivity in the license area is thus for Jurassic-sourced thermogenic oil and gas in Jurassic sandstones of the Tuxedni Group, Chinitna Group, and the Naknek Formation. Natural oil seepages and the small quantities of oil and gas recovered in wells drilled on the Iniskin Peninsula provide clear evidence that hydrocarbons have been generated and migrated into onshore portions of the license area. These occurrences are believed to be controlled by the network of faults and natural fractures (Detterman and Hartsock 1966). The chief uncertainty is whether the chemically and mechanically unstable, igneous-rich Jurassic sandstones have retained sufficient porosity and permeability to host economically viable reservoirs; it is unknown at present whether oil and gas is present in the rock matrix or only in the fractures. A secondary risk is that the integrity of anticlinal structural traps in the license area may have been compromised by faulting, causing leakage of potentially trapped hydrocarbons.

Throughout the Cook Inlet basin, Stanley and others (2011) estimate the Mesozoic sandstones to have mean undiscovered, technically recoverable resources of 241 million barrels of oil and more than 1.5 trillion cubic feet of gas in conventional, buoyancy-driven accumulations, plus about 0.6 trillion cubic feet of gas in unconventional, continuous (tight) accumulations where the Middle Jurassic Tuxedni Group source rocks are modeled to be at gas-window thermal maturity below about 6 km depth in the deepest part of the basin near East Foreland. Although there is proof of oil in the license area, the 2011 study includes no estimates of potential in-place volumes or the likelihood that oil can be commercially recovered (Stanley et al. 2011).

# D. Phases of Oil and Gas Resource Development

License and lease-related activities may proceed in phases: disposal (licensing and leasing), exploration, development and production, and transportation. Subsurface storage may be an additional phase. Only exploration may occur under an exploration license. Various activities may occur at each of these phases, depending on the specifics of a project, and although each subsequent phase’s activities may depend on the initiation or completion of the preceding phase, phases may overlap in time and may occur simultaneously.

Until discoveries are made, the level of associated activities and their specific effects may be unknown. Generally, the process for evaluating a prospect is lengthy. It may involve shallow geophysical surveys, core hole test wells, pilot projects, water disposal plans, field development, and gas transportation.

## 1. Disposal Phase

The exploration license will grant the licensee the exclusive right to explore for oil and gas within the license area (AS 38.05.132). The license will have a term of four years. There is a non-refundable fee of $1 per acre.

The exploration license is conditioned on a specific work commitment over the 5 year term of the license. The licensee must complete at least 25% of that commitment by the fourth anniversary of the license, and must post a bond and annually renew it. Allowable expenditures for the work commitment are cash expenses such as labor costs, equipment, materials, supplies, and contractors, with the goal of gathering exploration data or drilling one or more exploration wells.

## 2. Exploration Phase

Exploration activities may include the following: examination of the surface geology, geophysical surveys, performing environmental assessments, and drilling one or more exploratory wells. Surface analysis includes the study of surface topography or the natural surface features of the area, near-surface structures revealed by examining and mapping exposed rock layers, and geographic features such as hills, mountains, and valleys.

### a. Geophysical Exploration

Geophysical surveys help reveal the characteristics of the subsurface geology. Seismic surveys are the most common type of geophysical exploration. To gather seismic data, an energy source is emitted into the subsurface and reflected energy waves are recorded by vibration-sensitive receivers called geophones. Impulses are recorded, processed on high-speed computers, and displayed in the form of a seismic reflection profile. Different densities of rock layers beneath the surface result in a unique seismic profile that can be analyzed by geophysicists to determine subsurface structures and petroleum potential. Both two-dimensional (2D) and three-dimensional (3D) data are gathered from seismic surveys.

### b. Exploratory Well Drilling

Exploratory drilling may occur under a license and under a lease. It often occurs after seismic surveys are conducted and the interpretation of the seismic data incorporated with all available geologic data indicates gas prospects. Exploration drilling is the only way to learn whether a prospect contains commercial quantities of oil and gas, and helps determine whether to proceed to the development phase.

Drilling operations collect well logs, core samples, cuttings, and a variety of other data. A well log is a record of one or more physical measurements as a function of depth in a borehole and is achieved by lowering measuring instruments into the well bore and taking measurements at various depths. Well logs can also be recorded while drilling. Cores may be cut at various intervals so that geologists and engineers can examine the sequences of rock that are being drilled. Rock fragments (drill cuttings) are produced during the drilling of the borehole. Drilling fluids (muds) are used to circulate the cuttings out of the hole. During drilling operations, the cuttings are separated from the drilling muds and disposed of. The muds may be re-circulated or disposed.

The drill site is selected to provide access to the prospect and is located to minimize the surface area that may have to be cleared. Sometimes temporary roads must be built to the area. If oil or gas is discovered at the exploratory well, it is likely that the gravel pad used for the exploratory well will also be used for development and production operations. Gravel pads are semi-permanent structures and can be rehabilitated following field depletion.

If the exploratory well is successful, the operator may drill additional wells to delineate the extent of the discovery and gather more information about the field. The licensee needs to know the quantity of gas, and the quality of the rocks or coal in which it is found, to determine whether to proceed to convert to a lease, and whether to proceed with further exploration and/or development.

## 3. Development and Production Phase

Development and production are interrelated and may overlap in time; therefore, this section discusses them together.

### a. Conversion to Leases

If the licensee meets the work commitment, it may request conversion of the license to leases of up to 5,760 acres each. The leases are subject to a production royalty of 12.5% and an annual rental of $3 per acre until the state’s royalty income exceeds rental income. A lease is for a maximum period of 10 years and is automatically extended if, and for so long as, oil or gas is produced in paying quantities from the lease or the lease is committed to a unit.

If the license is converted to leases, further exploration may occur, with either or both geophysical exploration or drilling one or more wells.

## b. Development

Development and production phases begin after exploration has been completed and tests show that a discovery is economically viable. During the development phase, operators evaluate the results of exploratory drilling and develop plans to bring the discovery into production. Production operations bring well fluids to the surface and prepare them for transport to the processing plant or refinery. The fluids undergo operations to purify, measure, test, and transport. Pumping, storage, handling, and processing are typical production processes (Van Dyke 1997).

After designing the facilities and obtaining the necessary permits, the operator constructs permanent structures that will last the life of the field and drills production wells. New facilities may have to be designed and added for enhanced recovery operations as production proceeds. After exploration wells have been drilled, a process called extended reach drilling (ERD) may be used during production. ERD can be used for both onshore and offshore reservoirs. ERD is already being used in Prudhoe Bay, Alaska to access offshore reservoirs using drilling rigs from land (New Developments in Upstream Oil and Gas Technologies 2011). ERD may not only reduce wellsite footprint and minimize environmental effects, but may also improve reservoir drainage at the least cost (Schlumberger 2013). A single production pad and several directionally drilled wells can develop larger subsurface areas, as compared to drilling multiple vertical wells to reach the same subsurface areas.

## c. Production

Production facilities on the well site may include oil and gas processing facilities to remove some of the water produced with the petroleum, water and sewage treatment equipment, power generators, a drilling rig, and support buildings and housing for workers. Support facilities may include a production facility to receive and treat or transport the oil and gas to markets, refineries, or for shipment to other processing facilities in the lower 48 states and elsewhere. Other support facilities may include a supply base and a transportation system for cement, mud, water, food, and other necessary items.

Production operations for natural gas generally follow these steps:

- Natural gas flows through a high-pressure separator system where any liquids (water, condensate, etc.) are removed. Produced oil goes through a separator to remove the natural gas from the oil.
- Gas is compressed if necessary.
- Gas is dehydrated to lower its water content.
- Impurities are removed, if necessary.
- Gas is then metered, i.e. the amount of gas produced is measured.
- Gas is transported to a facility where it passes through a water precipitator to remove any liquid.
- Gas may be conditioned or treated prior to transportation. An example is the conversion of gas to liquefied natural gas.

Production operations steps for oil are:

- Produced crude oil goes through a separator to remove water and gas from the oil stream.
- Oil moves to a processing facility via a pipeline.
- Gas removed from the oil may be used to power production facilities or compressed and reinjected to keep the pressure up in the producing formation to assist in oil production.

## 4. Oil and Gas Storage Phase

Under AS 38.05.180(u), the Commissioner of DNR may authorize the subsurface storage of oil or gas to avoid waste or to promote conservation of natural resources. In Alaska, depleted reservoirs with established well control data are preferred storage zones. Subsurface storage must comply with all applicable local, state, and federal statutes and regulations, and with any terms imposed in the authorization or in any subsequent plan of operation approvals, or in the Alaska Oil and Gas Conservation Commission (AOGCC) Storage Injection Order.

A subsurface storage authorization allows the storage of gas and associated substances in the portions of the gas storage formation, subject to the terms and applicable statutes and regulations, including mitigation measures incorporated by reference into the authorization. It does not matter whether the gas is produced from state land, so long as storage occurs in land leased or subject to lease under AS 38.05.180. A gas lease on which storage is authorized shall be extended at least for the period of storage and so long thereafter as oil or gas not previously produced is produced in paying quantities. The feasibility of subsurface storage depends on favorable geological and engineering properties of the storage reservoir, including its size and its gas cushion (or base gas requirements). It also depends on access to transportation, pipeline infrastructure, existing production infrastructure, gas production sources, and delivery points.

DNR may amend a subsurface storage authorization if stored gas migrates from the gas storage formation to other formations or if stored gas expands beyond the limits of the authorized area. DO&G must be notified of any anticipated changes in the project resulting in alteration of conditions that were originally approved and further approval must be obtained before those changes are implemented.

The availability of subsurface storage horizons and gas storage facilities affect the technologies and preferred routes of transportation used for natural gas distribution.

Facilities for gas storage may be integral components of the natural gas transportation system. Cryogenic tanks are used to store liquefied natural gas. Gas condensate is stored between production and shipping in condensate storage tanks. Distances to market and the need to allocate supply at prescribed times of demand may justify the construction and operation of storage facilities along the distribution system route.

## 5. Transportation

Transportation is also a phase of oil and gas resource development. See the next section for further discussion.

# E. Likely Methods of Transportation

AS 38.05.035(g)(1)(B)(iii) requires the director to consider and discuss the method or methods most likely to be used to transport oil or gas from an area, and the advantages, disadvantages, and relative risks of each. Transportation of oil or gas from the area would probably involve the construction of a pipeline transmission system.

Strategies used to transport potential oil and gas resources depend on many factors, most of which are unique to an individual discovery. The location and nature of oil and gas deposits determine the type and extent of facilities necessary to develop and transport the resource. DNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed. Modern oil and gas transportation systems may consist of pipelines, marine terminals with offshore loading platforms, trucks, and tank vessels. The location and nature of oil or gas deposits determine the type and extent of facilities needed to develop and transport the resource. Due to the limited road system in the license area, the most likely method of transportation will include pipelines, marine terminals and tanker vessels.

If the license is eventually converted to leases, no oil or gas will be transported from the area until the lessee has obtained the necessary permits and authorizations from federal, state, and local governments. The state has broad authority to withhold, restrict, and condition its approval of transportation facilities. In addition, the federal and local governments may have jurisdiction over various aspects of any transportation alternative.

The mode of transport from a discovery will be an important factor in determining whether future discoveries can be economically produced – the more expensive a given transportation option is, the larger a discovery will have to be for economic viability.

## 1. Pipelines

One method of transporting oil is by pipeline. Pipelines may be onshore or offshore. Onshore pipelines may be buried or unburied. Buried pipelines, over which the ground is normally reseeded, are advantageous because they do not pose an obstacle to wildlife or result in scenic degradation. However, buried pipelines are more expensive to install and to maintain than unburied pipelines. This is especially true in regards to inspection, repair and maintenance (SPCO 2011). Spills may result from pipeline leaks in either buried or unburied pipelines, and leak detection systems play a primary role in reducing discharges of oil from either system. Elevated pipelines offer more ways to monitor the pipeline such as ground inspection, visual air inspections, ground-based infrared (IR) and airborne forward-looking infrared (FLIR) surveys. In-Line Inspection (ILI) can be used for both aboveground and belowground crossings, but is the only practical method for belowground installations. Mitigation measures in this finding are designed to mitigate potential releases from a pipeline. Pipelines must be buried where conditions allow and must be designed and constructed to assure integrity against climatic and geophysical hazards (SPCO 2011).

Offshore pipelines usually do not hinder water circulation and minimally affect fish and wildlife habitat. Weighted pipelines are used in areas where tidal currents are exceptionally strong. Marine arctic pipelines are usually trenched and buried (C-CORE 2008). This technique is advantageous because it may offer a way to avoid creating a navigational hazard, being damaged by ship anchors, by sea ice, or trapping fishing nets. In deeper water, weighted pipelines may be disadvantageous because they may become silted-in or self-buried. A disadvantage of sub-sea pipelines is that they are expensive to build and maintain. They can be difficult to monitor for leaks, defects, and corrosion problems, however significant advances have been made in recent years.

Sophisticated monitoring methods now available can overcome many disadvantages of subsea pipelines. Some of these include:

- volumetric flow measurement;
- pressure monitoring;
- pressure measurement with computational analysis;
- external oil detection;
- remote sensing;
- geophysical sensing techniques;
- pressure or proof testing;
- pipe integrity checking (i.e., smart pigging);
- visual inspection; and
- through-ice borehole sampling.

Many of these methods are considered to be proven technology while others are still under development (C-CORE 2008).

## 2. Marine Terminals

If oil or gas must be transported across marine waters by tanker, a marine terminal is necessary. Crude oil terminal facilities generally store quantities of oil equivalent to several large tanker loads. Therefore, a disadvantage of transporting oil or gas by tanker is the possibility for a very large spill at these facilities. A strong earthquake or other natural disaster could damage the facilities and initiate a large spill. The risk of explosion or sabotage at the facilities also exists. Accidental ballast discharge or loading or unloading accidents could also cause a spill. However, environmental risks can be minimized through improved design, construction, operating techniques and spill prevention measures.

The fixed location of loading facilities at marine terminals improves spill response and contingency planning. With constant staffing, leaks are easier to detect than with some pipelines. For example, the Valdez Marine Terminal is staffed 24 hours a day and its oil response crews are trained to conduct land and water response operations. Even though a spill from a tanker is the responsibility of the tanker owner, Alyeska Pipeline Service Company provides initial response. Spill prevention measures include (APSC 2011):

- training;
- extensive inspection programs;
- monitoring of transfer operations;
- facility security programs;
- use of proper valves and overfill alarms;
- secondary and tertiary containment systems around the tanks; and
- drug and alcohol testing of personnel.

## 3. Tank Vessels

Deep water ports are required for tanker operations; it is therefore anticipated that any future tanker operations associated with the license area would be located on the northeast side of the Iniskin Peninsula. A disadvantage for tankers is the potential for a large oil spill, although in recent years spills from pipelines outnumber those from tankers (Etkin 2009). Data also indicate that tanker spillage continues to decline despite an overall increase in oil trading (ITOPF 2012; Anderson et al. 2012).

Tankers are also used to transport natural gas. Liquefied natural gas (LNG) is methane that has been cooled to an extremely cold temperature (-260° F), where it becomes liquid. At standard atmospheric conditions, methane is a vapor. LNG is stored and transported exclusively at cryogenic temperatures, so it is maintained in a liquid state, facilitating storage and transportation. LNG should not be confused with NGL (Natural Gas liquid) or LPG (liquefied petroleum gas), which are transported at near ambient temperature.

## 4. Summary

The mode of transportation from a discovery will be an important factor in determining whether or not a discovery can be economically produced. The more expensive a given transportation option, the larger a discovery will have to be for economic viability. Oil and gas produced from the license area would likely be transported by a system of gathering lines, processing facilities, marine terminal, and tankers. If resources are discovered and developed, more detailed transportation options, such as exact routes, locations, and size of facilities, would need to be evaluated.

# F. Regulating Pipelines

Jurisdictional authority over pipelines depends on many factors such as design, pipe diameter, product transported, whether it meets state or federal designation (e.g., transmission line, gathering line, or distribution line), and other attributes as specified in regulations. Generally, the design, maintenance, and preservation of transmission pipelines transporting gas are under the authority and jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and specific regulations for natural gas (49 CFR 192). Both regulations prescribe the minimum requirements that all operators must follow to ensure the safety of their pipelines and piping systems. The regulations not only set requirements, but also provide guidance on preventive and mitigation measures, establish time frames for upgrades and repairs, and incorporate other relevant information such as standards incorporated by reference developed by various industry consensus organizations.

Both state and federal agencies have oversight of pipelines in Alaska. State agencies include the Petroleum Systems Integrity Office (PSIO) and DO&G within DNR; the State Pipeline Coordinator's Office; and DEC. Federal agencies include the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation.

# G. Oil Spill Risk, Prevention, and Response

## 1. Risk

DEC administers and enforces laws and regulations related to oil spill prevention and cleanup contingency plans. To ensure that a contingency plan is not required for a well, DEC requires AOGCC to make a determination that the exploration wells will not penetrate a formation capable of flowing oil to the ground surface (AS 46.04.050; AS 31.05.030(l)). If that determination cannot be made, the licensee is required to have an approved oil discharge prevention and contingency plan (C-Plan) and determination of financial responsibility prior to commencing operations.

Whenever hazardous substances are handled, there is a risk of a spill. Consequently, measures are imposed to mitigate the possibility of a spill.

## 2. Prevention

A well blowout can take place when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud, are not effective. The result is that oil, gas or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers, which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by AOGCC (AS 46.04.030). Blowout preventers greatly reduce the risk of a release. If a release occurs, however, the released gas will dissipate unless it is ignited by a spark. Ignition could result in a violent explosion. Released oil would likely precipitate in the vicinity of the well head.

Each well has a blowout prevention program developed before the well is drilled. Operators review bottom-hole pressure data from existing wells in the area and seismic data to learn what pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance.

Effective monitoring of pipelines is crucial and the technology for monitoring is continually improving. To ensure the efficient and safe operation of pipelines, operators are required to routinely inspect pipelines for corrosion and defects. This is done through the use of robotic devices known as "pigs" which are propelled down pipelines to evaluate the interior of the pipe. Pigs can test pipe thickness, roundness, check for signs of corrosion, detect minute leaks, and any other defect along the interior of the pipeline that may either impede the flow of oil or gas, or pose a potential safety risk for the operation of the pipeline. Pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems. The Trans-Alaska Pipeline

System operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures.

If pipelines are used in the development of the license area, operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would perform regular maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors, and continuing regular visual inspections.

An integrity management plan is a documented and systematic approach to ensure the long-term integrity of an asset and a process for assessing and mitigating risks in an effort to reduce the likelihood and consequences of incidents. Basic requirements for an integrity management plan include:

- Periodic integrity assessment of pipelines that could affect high consequence areas. Integrity assessments are performed by in-line inspection (also referred to as “smart pigging”), hydrostatic pressure testing, or direct assessment. Through these assessment methods, potentially injurious pipeline defects that could eventually weaken the pipe, or even cause it to fail, are identified early and can be repaired. This significantly improves the pipe’s integrity.
- Development and implementation of a set of safety management and analytical processes collectively referred to as an integrity management program. The purpose of the program is to assure pipeline operators have systematic, rigorous, and documented processes in place to protect high consequence areas.

## 3. Response

Response plans in relation to the sale area are included in the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases (Unified Plan) and the Cook Inlet Subarea Contingency Plan (DEC 2010a, 2010b).

A Unified Command structure of the Incident Command System (ICS) is the basis for government response and organization in the State of Alaska. The Unified Command brings together the Federal On-Scene Coordinator (FOSC), the State On-Scene Coordinator (SOSC), and the Responsible Party’s Incident Commander into one governing unit. If an immediate threat still exists to the health and safety of the local populace the Local On-Scene Coordinator (LOSC) will also be brought in (DEC 2010a, 2010b).

Response objectives include (DEC 2010a, 2010b):

- ensure safety of responders and the public;
- stop the source of the spill;
- deploy equipment to contain and recover the spilled product;
- protect sensitive areas (environmental, cultural, and human use);
- track the extent of the spill and identify impacted areas;
- cleanup contaminated areas and properly dispose of wastes;
- notify and update the public; and
- provide avenues for community involvement where appropriate.

Federal response action priorities/strategies general guidelines include (DEC 2010a, 2010b):

- safety of life;
- safety of vessel, facility and cargo;
- control sources of discharge;
- limit spread of pollution; and
- mitigate effects of pollution.

DEC, Division of Spill Prevention and Response is responsible for ensuring facilities prevent spills and take proper response actions when spills occur. One of their programs is the Prevention and Emergency Response Program (PERP). Its mission statement is as follows (DEC 2011):

> Protect public safety, public health and the environment by preventing and mitigating the effects of oil and hazardous substance releases and ensuring their cleanup through government planning and rapid response.

Because of statutory requirements, the State of Alaska implemented the following Response Objectives (DEC 2010a, 2010b, 2011):

- safety—ensure the safety of all persons involved in a response or exposed to the immediate effects of the incident;
- public health—ensure the protection of public health from the direct or indirect effects of contaminated drinking water, air or food;
- environment—ensure the protection of the environment, including natural and cultural resources, from the direct or indirect effects of contamination;
- cleanup—ensure adequate containment, control, cleanup and disposal by the responsible party, or take over the response when cleanup is judged inadequate;
- restoration—ensure the assessment of damages from contamination and the restoration of property, natural resources and the environment; and
- cost recovery—ensure the recovery of costs and penalties for reimbursement to the Oil and Hazardous Substance Release Prevention and Response Fund for use in Future emergency response actions.

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