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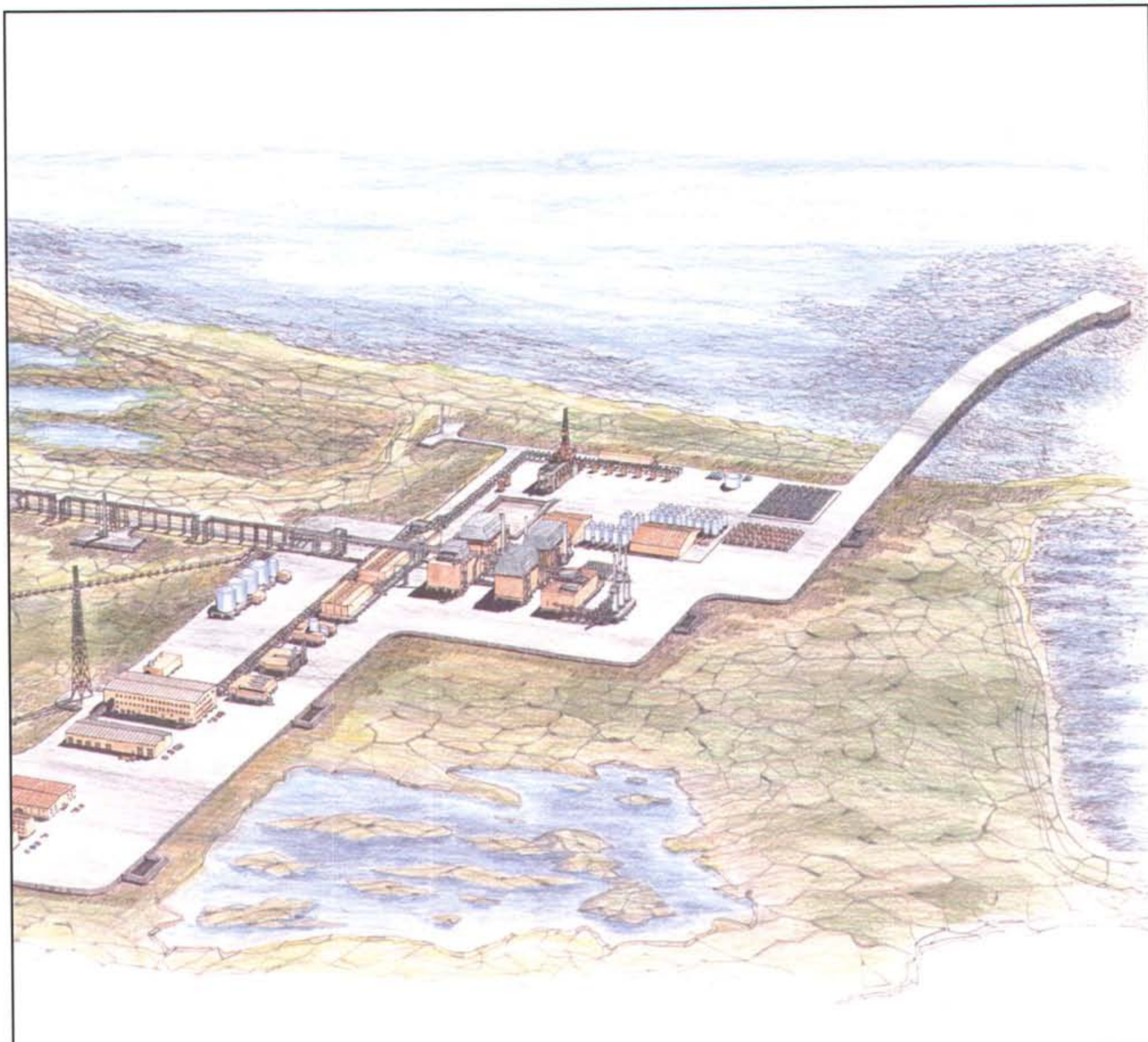
ExxonMobil

Point Thomson Gas Cycling Project

Decision Support Document for Year-Round Drilling



ExxonMobil Development Company
P.O. Box 4876
Houston, Texas 77210-4876

ExxonMobil
Development

March 19, 2003

Mr. Bill Hutmacher
Manager, Industry Preparedness Program
Alaska Department of Environmental Conservation
555 Cordova Street
Anchorage, Alaska 99501-2617

Re: Point Thomson Unit Gas Cycling Project Year-Round Drilling Plan

Dear Mr. Hutmacher:

ExxonMobil is pleased to submit the enclosed "Decision Support Document for Year-Round Drilling" for our proposed Point Thomson Gas Cycling Project. This document represents contributions from several subject matter experts, and it reflects the results of our numerous meetings with the Alaska Department of Environmental Conservation, the Alaska Oil and Gas Conservation Commission, and other agencies.

Based on our experience drilling wells in high pressure reservoirs around the world and the enclosed assessment, ExxonMobil believes it can safely drill the Point Thomson wells year-round. It is ExxonMobil's contention that seasonal drilling restrictions at the Point Thomson project offer no net environmental benefit. In the coming weeks, ExxonMobil plans to submit an Oil Discharge Prevention and Contingency Plan for the Point Thomson Gas Cycling Project that is based on year-round drilling. ExxonMobil will continue the project planning on that basis, unless it hears otherwise from you. If you have any questions or require additional copies, please don't hesitate to contact Mike Barker at 907 564-3691.

Sincerely,

for R. F. Buckley
Project Manager

Enclosure

cc: Jim Baumgartner, ADEC
Gary Evans, ADEC
Ed Meggert, ADEC
Lydia Miner, ADEC
Leslie Pearson, ADEC
Dick LeFebvre, ADNR
Leon Lynch, ADNR

cc: continued

cc: continued

Bruce Webb, ADNR
Jack Winters, ADFG
Bob Crandall, AOGCC
Jack Hartz, AOGCC
Carl Lautenberger, EPA
Ted Rockwell, EPA
Jeff Walker, MMS
Larry Peltz, NMFS
Martha Falk, NSB
Tom Lohman, NSB
Rex Okakok, NSB
Terry Carpenter, USACOE
Richard Hannan, USFWS
Jim Zelenak, USFWS
Brad Hahn, ACS
Lee Majors, ACS
Gar Carothers, CH2M HILL
Kathy Fontaine, CH2M HILL

Point Thomson Gas Cycling Project

Decision Support Document for Year-Round Drilling

March, 2003

ExxonMobil

ExxonMobil Development Company
P.O. Box 196601
Anchorage, Alaska 99519-6601

PROPOSED POINT THOMSON GAS CYCLING PROJECT: Decision Support Document for Year-Round Drilling

Published by:

ExxonMobil Development Company
P.O. Box 196601
Anchorage, Alaska 99519-6601

EXECUTIVE SUMMARY

ExxonMobil Development Company (ExxonMobil) has prepared this document in support of the year-round drilling program at its proposed Point Thomson Gas Cycling Project. As currently planned, this project involves the drilling of 13 gas production wells and eight gas injection wells on three pads adjacent to the Beaufort Sea coast approximately 50 miles east of Prudhoe Bay. The project will deliver gas condensate to the Trans Alaska Pipeline System for transport to market.

Year-round drilling is critical to this project both for its economic viability and for environmental protection. The benefits include:

- **Safe and efficient drilling operations:** Allows for drilling the first wells into the Thomson Sand reservoir during winter, and permits drilling the shortest-reach wells before the more-challenging long-reach wells.
- **Reduced risk of a blowout:** Year-round drilling reduces the risk of a blowout because each well can be drilled to completion before moving to the next well. This minimizes the operations required to suspend and reenter wells and to shutdown and restart the rig — operations that have a higher risk of well-control issues and human error.
- **Significant environmental benefits:** Year-round drilling also minimizes the number of pad-to-pad rig moves, allows necessary moves to be made in winter, and minimizes transfers of fuel, equipment, and mud supplies. The Class I disposal well will be drilled first, providing for efficient disposal of drilling wastes. Air emissions from rig operations are minimized because of the early use of clean-burning natural gas to replace diesel for rig fuel and the elimination of air emissions from standby rigs.
- **Accelerated revenues to the State of Alaska:** Year-round drilling offers the quickest path to first production and maximizes throughput to the sales pipeline at least 8 months earlier.
- **Economic viability:** Keeps project cost acceptable by eliminating costly rig standby charges and permits a single demobilization of drilling equipment. Drilling costs comprise nearly half the cost for the project.

ExxonMobil believes that it can safely drill the Point Thomson production and injection wells year-round and should not be subject to seasonal drilling restrictions. This position is based on the company's extensive experience drilling wells in similar high-pressure gas reservoirs around the world and on the following factors:

- **Detailed knowledge of the subsurface geology:** Data are available from 19 exploration wells in the Point Thomson area;
- **A conservative drilling program:** The drilling program incorporates numerous prevention measures and engineering safeguards, many of which exceed regulatory requirements;

- **Lack of lasting environmental impact from a condensate release:** Condensate is relatively non-persistent in the environment, is readily combustible, and burns efficiently with very little smoke; and
- **Streamlined well ignition procedures:** To minimize the volume of gas condensate to be cleaned up from an unlikely blowout, ExxonMobil procedures support voluntary ignition, within 2 hours, if a blowout is releasing significant quantities of liquid and other means of immediate well control appear ineffective.

The Alaska Department of Environmental Conservation (ADEC) has sometimes imposed seasonal drilling restrictions to reduce the risk and magnitude of a potential spill during periods of broken ice in the Beaufort Sea. ExxonMobil's Point Thomson drilling program has been designed to reduce the *risk* of a blowout, and the *magnitude* of any spill resulting from a blowout would be minimized through well ignition. The on-site Drilling Supervisor has authority to voluntarily ignite a well in the event of a blowout, regardless of the time of year and based on predefined criteria. Because combustion of gas condensate is extremely efficient, voluntary well ignition will not significantly impact air quality.

ORGANIZATION OF DOCUMENT

This document is organized in five major sections that cover the following:

- Background on the Point Thomson project and on seasonal drilling restrictions.
- History of exploration drilling at Point Thomson and summary of reservoir information on the Thomson Sand.
- The Point Thomson drilling program, including drilling mud, well casing, drilling procedures, and training.
- Results of modeling studies to characterize the behavior of condensate released in a blowout and to quantify the combustion efficiency and air quality impact of a burning condensate blowout.
- Preauthorized blowout ignition criteria.

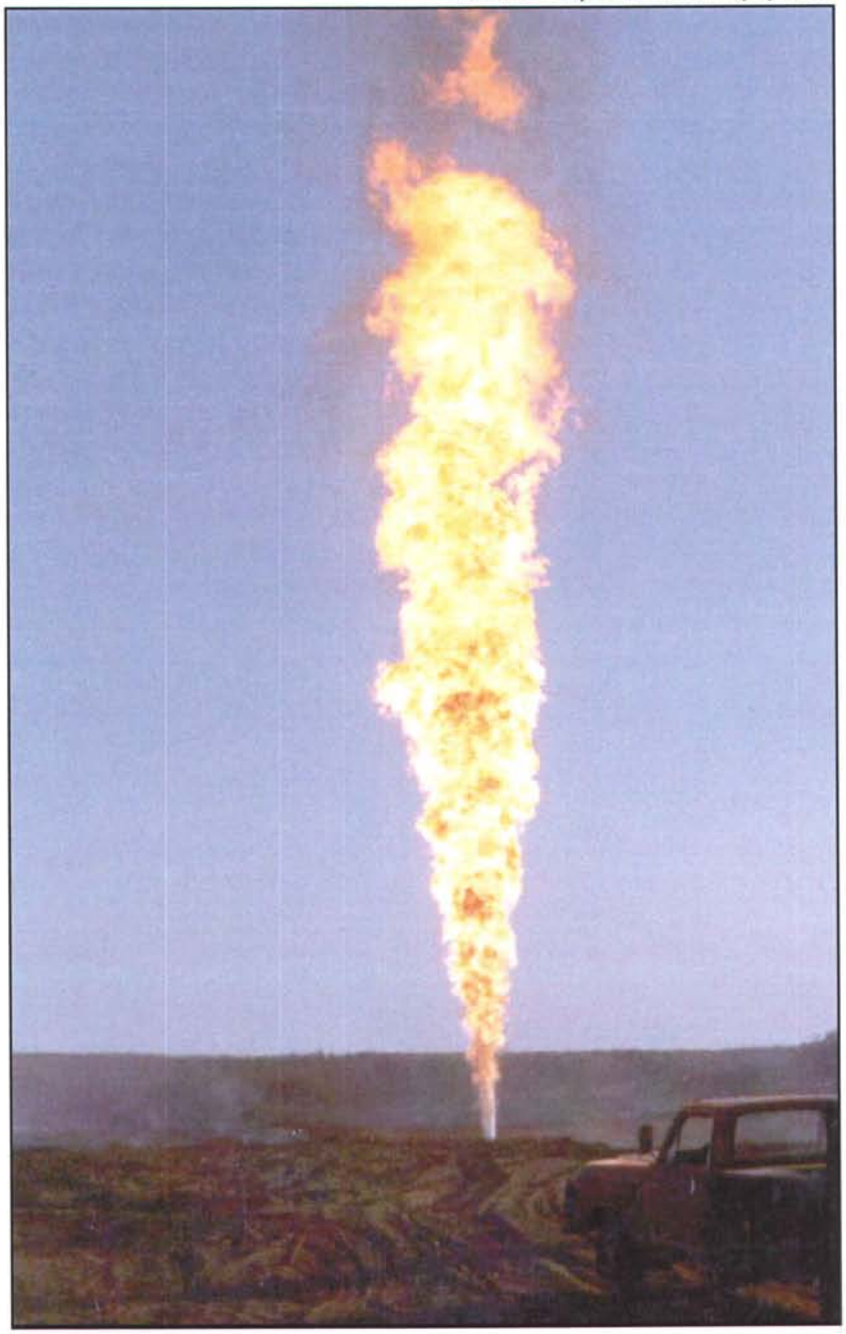
This document also contains an appendix that provides a detailed history of seasonal drilling restrictions in Alaska, followed by a list of literature cited in the document. The following discussion summarizes the key points presented in this decision support document for year-round drilling.

BACKGROUND

Project Summary

ExxonMobil's proposed Point Thomson Gas Cycling Project includes plans to produce gas from the Thomson Sand, extract the liquid hydrocarbon (condensate) contained in the gas stream, and return the dry gas to the reservoir. The condensate will be transported to the Trans Alaska Pipeline System for shipment to market. The Thomson Sand reservoir is a high-pressure gas reservoir discovered in 1977 and delineated with a total of 14 out of 19 exploration wells drilled in the area. The reservoir is estimated to contain more than 8 trillion cubic feet of gas and over 400 million barrels of recoverable condensate.

Photo courtesy Mike Miller, Safety Boss



Photograph of the Burning Lodgepole Blowout in Alberta

This photo shows burning gas and condensate from the Lodgepole blowout near Lodgepole, Alberta, Canada, in 1982. The well was estimated to be releasing upwards of 150 million standard cubic feet/day of gas and 20,000 barrels/day of condensate. Note that there is virtually no smoke plume and that the fire begins some distance above the wellhead. See Section 4.3.1 for a detailed discussion of the blowout.

Unlike oil, gas condensate typically exists as a vapor at initial reservoir conditions, but partially condenses to a lightweight liquid hydrocarbon when produced along with the gas. Point Thomson gas condensate is lighter and less persistent than typical North Slope crude oil. While over 70 percent of the Point Thomson condensate consists of hydrocarbons similar to or lighter than kerosene, the total hydrocarbon stream is relatively dry gas (approximately 60 barrels of condensate per million standard cubic feet of gas).

State of Alaska Requirements

Seasonal drilling restrictions were first applied to production drilling in the late 1990s when production operations moved farther offshore. Since the 1979 Alaskan Beaufort Sea oil and gas lease sale, such restrictions have been applied to some exploration drilling. Regulators have been concerned about protecting the migrating whales that are important for Native subsistence hunting on the North Slope and about the ability of the industry to clean up oil spills during the brief periods of broken ice in the Beaufort Sea. After a series of industry demonstrations in 1983, the state allowed exploration drilling during broken ice under certain conditions based on the demonstrated industry ability to ignite and burn spilled oil on water and on burning a blowout at the wellhead.

In 1990, the Alaska State Legislature amended the state's oil pollution law to require that contingency plan holders show that they can meet a "response planning standard" (RPS), which involves containing, controlling, and removing the largest realistic spill from the waters of the state within 72 hours. The law requires that the holder of an oil discharge prevention and contingency plan have available:

> "sufficient oil discharge containment, storage, transfer, and cleanup equipment, personnel, and resources to meet the following response planning standards… For a discharge from an exploration or production facility or a pipeline, *the plan holder shall plan to be able to contain or control, and clean up the realistic maximum oil discharge in 72 hours*" [AS 46.04.030(k), emphasis added].

Based on the amended state oil pollution law, ADEC issued revised spill contingency planning regulations in 1991 (18 AAC 75). The ADEC regulations require operators to plan for the use of mechanical equipment and techniques for responding to an RPS spill under normal conditions. Operators must further define the environmental conditions — e.g., fog, wind, ice, etc. — that would prevent the planned response from cleaning up the RPS volume in 72 hours using mechanical equipment. ADEC has the discretion to impose additional prevention measures on a facility or operation to *reduce the risk or magnitude* of an oil discharge when such conditions are reached. The presence of broken ice in the nearshore Beaufort Sea is one such condition.

Since 1999, several production facilities near or in the Beaufort Sea have operated under a drilling restriction that forbids drilling into a major hydrocarbon reservoir from June until at least 18 inches of solid ice are present in the fall. The operators accepted this condition in recognition of the inability to meet a mechanical response planning standard during broken ice. In 2002, ADEC allowed nearshore year-round drilling in the Prudhoe Bay gas cap, which contains condensate. This program is very similar to the drilling plans for Point Thomson. The decision was based on the fact that black oil would not be encountered in the wells.

SUMMARY OF KEY ISSUES

Knowledge of Subsurface Geology

Nineteen exploration wells have been drilled in and near the Point Thomson Unit, and eight three-dimensional seismic surveys have been conducted in the unit. The data from these wells and surveys provide a detailed picture of the conditions that will be encountered during drilling of production and injection wells. Typically, only two or three wells are drilled into a reservoir before development; Point Thomson has had 14 penetrations of the reservoir out of a total of 19 exploration wells drilled in the area. The detailed data from all of these wells — coupled with technical analysis and computer modeling — give ExxonMobil the ability to design the development-well drilling program with a high degree of confidence.

State-of-the-Art Drilling Program

The Thomson Sand reservoir is unique on the North Slope in that reservoir pressure exceeds 10,000 pounds per square inch (psi), compared to the lower pressures typically encountered in other North Slope production areas. ExxonMobil has extensive experience drilling and producing high-pressure reservoirs around the world with bottom-hole pressures ranging from 12,000 to over 18,000 psi. ExxonMobil has applied stringent design standards to these and all other wells. The drilling program at Point Thomson will be based on this experience and will meet, and in many cases exceed, all regulatory standards.

Special emphasis will be placed on well design, procedures, communication, and training to ensure the wells can be safely drilled, completed, produced, and maintained. A minimum of two safety barriers will be in place at all times. For example, during drilling, the drilling mud will act as one barrier and the blowout prevention equipment will act as another. If a barrier is compromised, work will be stopped and the barrier restored before proceeding with the work. The purpose of this philosophy is to prevent a single-point failure from escalating into a loss of well control.

The framework ExxonMobil uses to manage safety, health, and environmental issues is called the Operations Integrity Management System (OIMS). OIMS requires ExxonMobil to conduct business in a manner that is compatible with the environmental and economic needs of the communities in which we operate and that protects the safety and health of our employees, those involved in our operations, our customers, and the public. OIMS drilling requirements provide numerous detailed and explicit guidelines for planning and implementing safe drilling operations. This framework requires us in our design standards to meet or exceed regulatory requirements and incorporate responsible requirements where regulations do not exist. For Point Thomson, equipment and procedures to be used in the drilling program meet or exceed the requirements of the Alaska Oil and Gas Conservation Commission (AOGCC). These include the drilling fluid program, blowout prevention equipment, real-time logging and pressure-while-drilling measurement, the casing and cementing program, the Pressure Hunt Team and tools, and training.

ExxonMobil is confident the Point Thomson well program can handle conditions experienced during drilling for the following reasons:

- **Extensive geological information:** Numerous historical penetrations and well tests establish *pore pressure* and *fracture gradients*, which are key geological variables in designing conservative drilling fluid and well casing programs. Also, the top of abnormal pressure and top of the Thomson Sand reservoir can be identified from the seismic data.

- **Use of overbalanced drilling:** Adequate formation integrity is present to allow *overbalanced* drilling while drilling into and through the Thomson Sand — i.e., the weight of the drilling mud will be greater than the pore pressure in the formation.
- **Real-time monitoring:** ExxonMobil will employ on every well the latest *logging while drilling* (LWD) equipment and a computerized mudlogging system to help engineers quantify pressure and identify formation lithology and fluids as drilling progresses. This equipment will give ExxonMobil engineers significant additional information beyond what is typically obtained during drilling of normally pressured formations on the North Slope. ExxonMobil's team of drilling engineers and geologists (Pressure Hunt Team) will predict the pore pressure and fracture gradient before drilling and use real-time monitoring of wellbore conditions to identify pressure while each well is being drilled, thereby minimizing the probability of a hydrocarbon influx.
- **Blowout prevention and training:** The Point Thomson drilling program will include the use of blowout preventers and monitoring techniques that exceed regulatory requirements. As an added safety measure, a surface-controlled subsurface safety valve (SCSSV) will be in each tubing string in the completed well to automatically shut in the well if necessary. Specific training and drills will focus on early detection of kicks and practices for high-pressure drilling.
- **Assurance of well tubular integrity:** ExxonMobil will test and qualify tubing and casing connections for seal integrity. Metal-to-metal seals, which are superior to the customary elastomeric seals, will be used in the wellhead for maximum seal integrity.
- **On-site mud system:** A complete mud plant and storage facility will be constructed to support drilling operations. This plant will augment the rig systems for both mud mixing and storage during any period when mud requirements are critical. Due to the remote nature of Point Thomson, high-pressure fluid-pumping equipment must reside in the field, and redundant units will be available for immediate use if a well-control incident occurs.

Blowout Modeling

Geological and well-testing information was used to characterize the components of the Point Thomson condensate when it reaches the surface. This characterization formed the basis for the fate and behavior modeling studies of a potential blowout that releases condensate to the environment.

ExxonMobil has undertaken studies to model the flow of hydrocarbons that would occur in a highly unlikely blowout situation, the dispersion of the ensuing plume and deposition of liquid condensate from the plume, and the fate of the liquid that could reach the Beaufort Sea. ExxonMobil used Titan Research and Technology's SCIPUFF model to predict the liquid deposition from the plume, Applied Science Associates' OILMAP model to map the spill trajectory on water, and the SCREEN3 model to determine the air quality impact of a burning condensate blowout. Both the SCIPUFF and SCREEN3 models are approved by the U.S. Environmental Protection Agency.

Based on the modeling studies, an unignited well blowout at Point Thomson could release large quantities of gas and condensate due to the prolific nature of the Point Thomson reservoir. Past experience and modeling show that an *ignited* blowout would significantly reduce land and water impact while not having a significant impact on air quality, based on National Ambient Air Quality Standards. Condensate blowouts documented in the technical literature show that combustion efficiencies are extremely high and that unburned condensate will likely evaporate or disperse.

Voluntary Ignition of Blowout

Because of the large volume of liquid condensate that could fall to water and/or land from an unignited blowout, ExxonMobil procedures support voluntary ignition, within 2 hours, if a blowout is releasing significant quantities of liquid. ExxonMobil's decision to ignite a blowout at Point Thomson within 2 hours or less revolves around two important considerations:

- The safety of all personnel on-site, including both spill response and well-control personnel, is the primary consideration in view of the extreme danger of an unintentional explosion from high volumes of gas and the subsequent combustion of pooled liquid hydrocarbons in the work area, and
- The extensive areas of light condensate accumulation that would result from an unignited gas-condensate blowout plume would not be amenable to containment and/or removal.

Both modeling results and documented case histories show that the effectiveness of voluntary ignition is independent of season — in other words, voluntary ignition effectively prevents a large portion of the condensate discharge from reaching the land and water. During a significant gas condensate blowout, ExxonMobil's well-control contractor will not attempt to access the well with pooled hydrocarbons present in the work area because the pooled liquid could ignite and limit escape by personnel. Ignition of the plume will eliminate pooling and assure access and safety. As a result, based on pre-established criteria, the ExxonMobil on-site Drilling Supervisor will ignite a gas condensate blowout as soon as personnel safety has been assured.

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SECTION 1
INTRODUCTION

1.1 PURPOSE OF THIS DOCUMENT

ExxonMobil Development Company (ExxonMobil) has prepared this document to support the case for year-round drilling at its proposed Point Thomson Gas Cycling Project (Figure 1-1). ExxonMobil's Point Thomson drilling program includes significant prevention measures that minimize the risk of a blowout. Furthermore, ExxonMobil has authorized the on-site Drilling Supervisor to ignite a blowout for environmental protection using straightforward criteria, thus minimizing the amount of liquid that can reach the waters and lands of the state. Another factor in support of year-round drilling is the volatility and non-persistent nature of the condensate at Point Thomson as compared to typical North Slope crude oils.

This document presents technical detail on the geology of the Point Thomson area; on the proposed drilling program, both in terms of well design and drilling procedures; and on the characteristics of the gas condensate and its behavior in the environment. ExxonMobil's drilling program is supported by extensive data on the geological characteristics of the Point Thomson field and on sophisticated modeling and interpretation of the results from 19 exploration wells drilled in the area in the last 30 years.

PHOTO 1-1
Broken-Ice Conditions near Flaxman Island in the Point Thomson Area

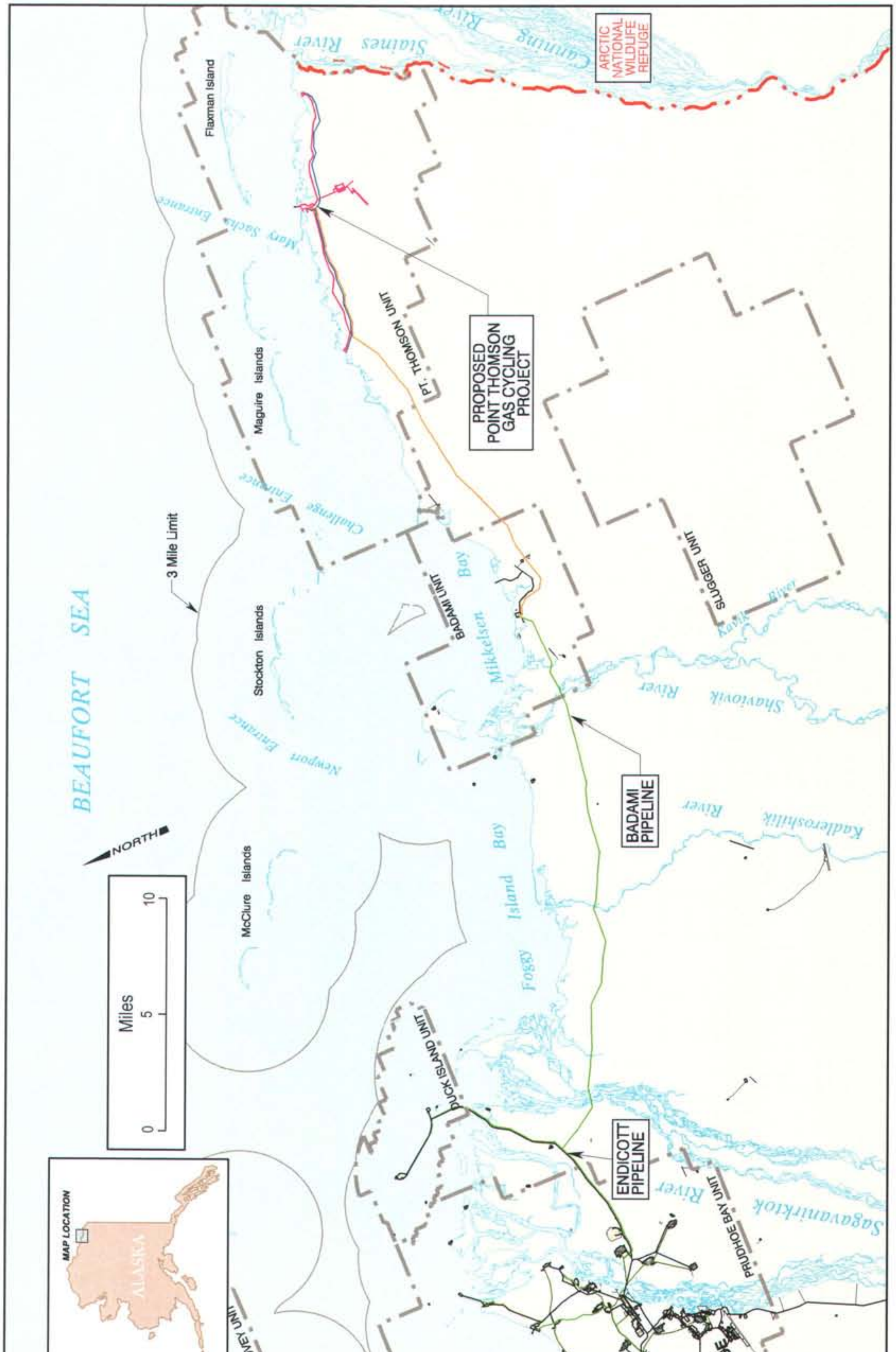


FIGURE 1-1
Project Location Map (Based on February 2003 Project Description)

1.2 BACKGROUND

Spill response planning for the coastline and waters of Alaska's Beaufort Sea requires consideration of methods for dealing with periods of broken ice that limit the effectiveness of conventional oil skimmers and containment boom. Broken ice can introduce unsafe conditions that make it difficult for spill response vessels to access oil on the water among ice pieces, and unstable ice conditions can prevent access by response workers. Ice pieces and slush formed at freezing temperatures can quickly clog skimmer intakes. These operational limitations would not prevent a mechanical response that recovers oil from the water's surface, but they could result in an extended operation. A response during fall freeze-up could last into the winter as oiled ice is removed, and a response during spring breakup could continue into the open-water season.

For the nearshore Alaskan Beaufort Sea, broken-ice conditions usually begin in June when the decaying ice becomes unsafe for personnel and equipment. In the Prudhoe Bay region, freeze-up normally begins in the first half of October, and six to eight weeks typically pass before the ice in nearshore waters is stable enough to work on (D.F. Dickins et al., 2000). During the spring, the period of reduced accessibility for mechanical recovery equipment occurs from two events — one when the rivers overflood the landfast ice and the other between breakup and the occurrence of first open water. In the nearshore region, river overflood normally occurs in late May, the onset of breakup ranges from early June to early July, and the start of open water (less than 10 percent ice) ranges from late June to late July. The total period of limited accessibility in any particular area is approximately two to three weeks in spring and fall (D.F. Dickins et al., 2000).

An important response tool during broken-ice conditions is in-situ burning on water and within broken ice. Oil that cannot be readily accessed by mechanical equipment can be ignited from the air and can be successfully burned — but with varying degrees of completeness depending on a number of factors. Furthermore, it is sometimes better not to respond immediately. For example, in the case of a spill into ice that is forming in the fall, it may be better to allow the ice to freeze and encapsulate the oil for later removal by a variety of techniques.

Response planners for oil facilities either offshore or on the shore of the Alaskan Beaufort Sea formulate contingency plans to deal with the conditions described above according to the Alaska Department of Environmental Conservation (ADEC) regulations contained in 18 AAC 75. These regulations require that contingency plans present scenarios that demonstrate how a certain amount of oil spilled to water would be contained and recovered mechanically (with booms and skimmers) within 72 hours under normal conditions. That volume of oil is referred to as the *response planning standard* (RPS) volume for the facility. In the case of oil production drilling operations, the RPS volume is defined as the amount of oil that could be released from a well blowout. For example, if the most prolific well at a production facility can conceivably blow out at a rate of 5,500 barrels per day, then the RPS volume for that facility is 16,500 barrels (three days' flow). The facility's contingency plan must then present a response plan to contain and recover 16,500 barrels of oil within 72 hours of the start of the spill — if all of that oil would fall to water.

Clearly, response planners are challenged when faced with a blowout in broken ice. As mentioned above, a mechanical response to such a release could stretch over months, and it is difficult, if not impossible, to prepare a planning scenario whereby the full RPS volume is contained and recovered in 72 hours by mechanical methods alone. ADEC regulations restrict planning scenarios to mechanical response techniques; options such as in-situ burning of oil on the water are considered alternative measures when environmental conditions restrict the use of mechanical techniques to meet the RPS.

ADEC's regulations require that contingency plans identify environmental conditions that render a planned mechanical response ineffective. These conditions are termed *realistic maximum response operating limitations* (RMROL):

> "In designing a spill response, severe weather and environmental limitations that might be reasonably expected to occur during a discharge event must be identified. The plan must use realistic efficiency rates for the specified response methods to account for the reduction of control or removal rates under those severe weather or other environmental limitations that might reasonably be expected to occur. *The department will, in its discretion, require the plan holder to take specific temporary prevention measures until environmental conditions improve to reduce the risk or magnitude of an oil discharge during periods when planned spill response methods are rendered ineffective by environmental limitations"* [18 AAC 75.445(f), emphasis added].

Beginning in 1998, ADEC invoked the RMROL clause to impose restrictions on the operation of oil production facilities on the shore of the Beaufort Sea. Because responders were unable to show complete mechanical recovery of the RPS volume for a blowout in 72 hours, the contingency plans have included an additional prevention method designed to remove the possibility of a blowout during broken-ice conditions. The plan holders agreed that drilling into a major hydrocarbon zone would not take place from June 1 of each year until there were 18 inches of ice cover for one-half mile in all directions during fall freeze-up. Similar criteria and requirements were applied to exploration well drilling in the National Petroleum Reserve-Alaska (NPR-A).

This prevention measure is known as a *seasonal drilling restriction.* In one form or another, seasonal drilling restrictions have existed in Alaska since the 1979 lease sale, when the exploration leases granted for offshore drilling in the Beaufort Sea contained such a restriction because of the belief at the time that the oil industry did not have the capability to clean up an oil spill in broken ice. The primary purpose of this restriction was to ensure that a major oil spill did not occur during spring and fall subsistence whale hunting by Alaska Natives. The appendix contains a detailed history of seasonal drilling restrictions in Alaska.

1.3 SUMMARY PROJECT DESCRIPTION

The proposed Point Thomson Gas Cycling Project (Figure 1-2) includes plans to produce gas condensate from the Thomson Sand and deliver that condensate to the Trans Alaska Pipeline System for shipment to market. Point Thomson is located on the North Slope of Alaska immediately west of the Staines River and approximately 50 miles east of Prudhoe Bay. The Thomson Sand reservoir is a high-pressure gas reservoir discovered in 1977 and estimated to contain more than 8 trillion cubic feet of gas and over 400 million barrels of recoverable condensate. (Condensate is a lightweight hydrocarbon liquid that condenses from the produced gas.)

ExxonMobil Corporation, operator of the Point Thomson Unit on its behalf and on behalf of the major working interest owners BP Exploration (Alaska) Inc., ChevronTexaco, and ConocoPhillips, plans to reach a final development decision based on project economics and the ability to secure reasonable permits from various federal, state, and local agencies with jurisdiction over the pro-

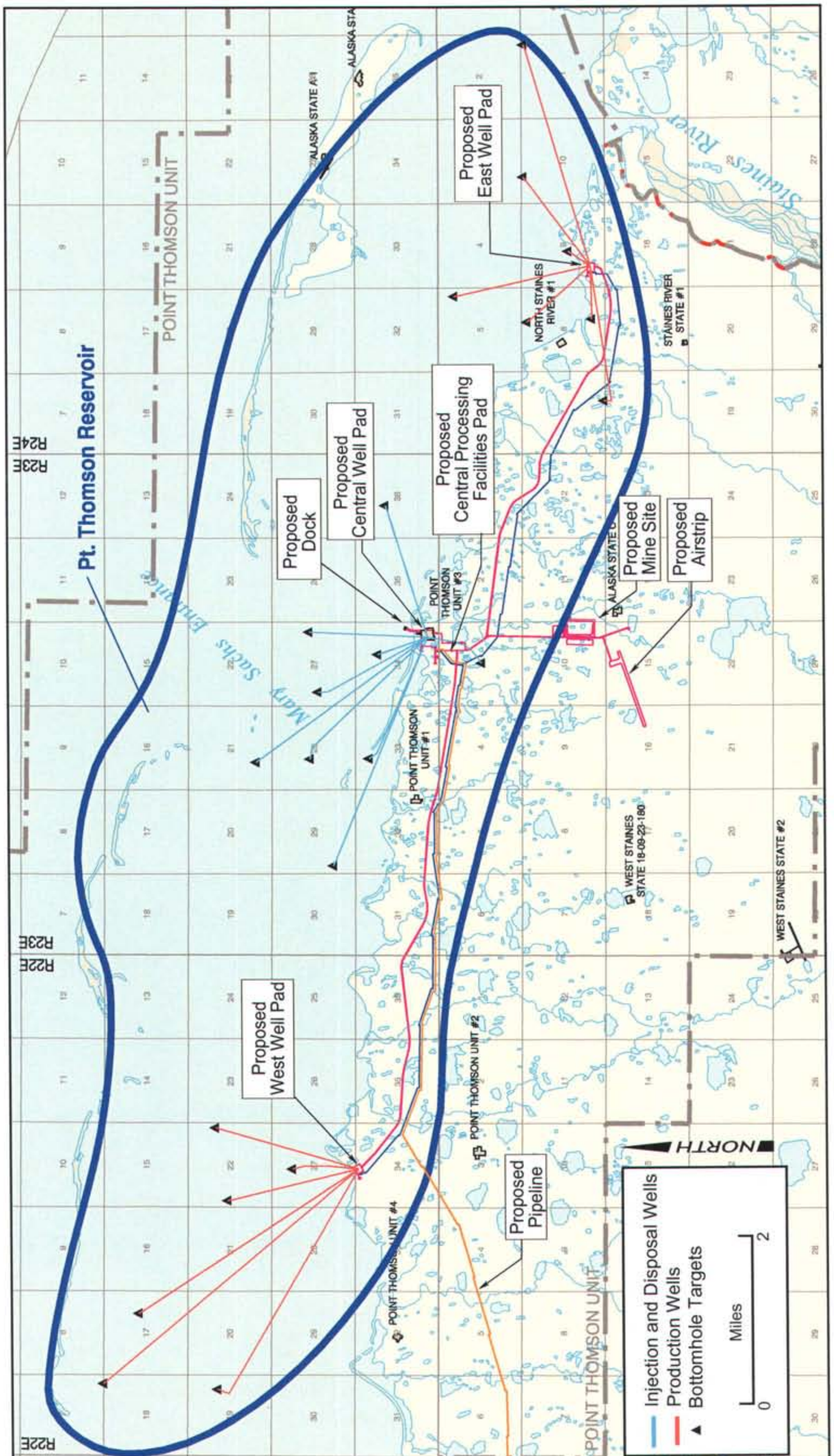


FIGURE 1-2
Point Thomson Development
(Based on February 2003 Project Description)

posed project. The field is expected to produce from 13 wells drilled from two onshore pads — one on the east side of the reservoir and one on the west side. A pipeline gathering system will collect production from the well pads and deliver it to the Central Processing Facility. The production stream will be composed of gas, water, and hydrocarbon liquids (condensate). These components will be separated at the Central Processing Facility. Dry gas will be injected back into the reservoir at the Central Well Pad, except for a small amount of the gas used to fuel the facility. Produced water will be injected into one or more disposal wells at the Central Well Pad. Figure 1-3 shows a detailed rendering of the Central Well Pad/Processing Facility based on the February 2003 project description published by ExxonMobil. Figures 1-4 and 1-5 show artist's conceptions of the West Well Pad and East Well Pad, respectively; these figures are based on a project description published by ExxonMobil in September 2002 and are still relatively accurate.

The separated condensate will be stabilized at the Central Processing Facility to meet pipeline specifications. A new 22-mile pipeline will transport the condensate to the existing Badami sales oil pipeline, with ultimate delivery to the Trans Alaska Pipeline System at Pump Station No. 1.

1.3.1 Drilling

As currently envisioned, the reservoir will be developed by drilling and completing 13 production wells: six at the West Well Pad and seven at the East Well Pad. In addition, eight gas injection wells and one Class I waste disposal well will be drilled and completed from the Central Well Pad. All wells will require directional drilling to reach the bottom-hole locations (Figure 1-2). Special em-

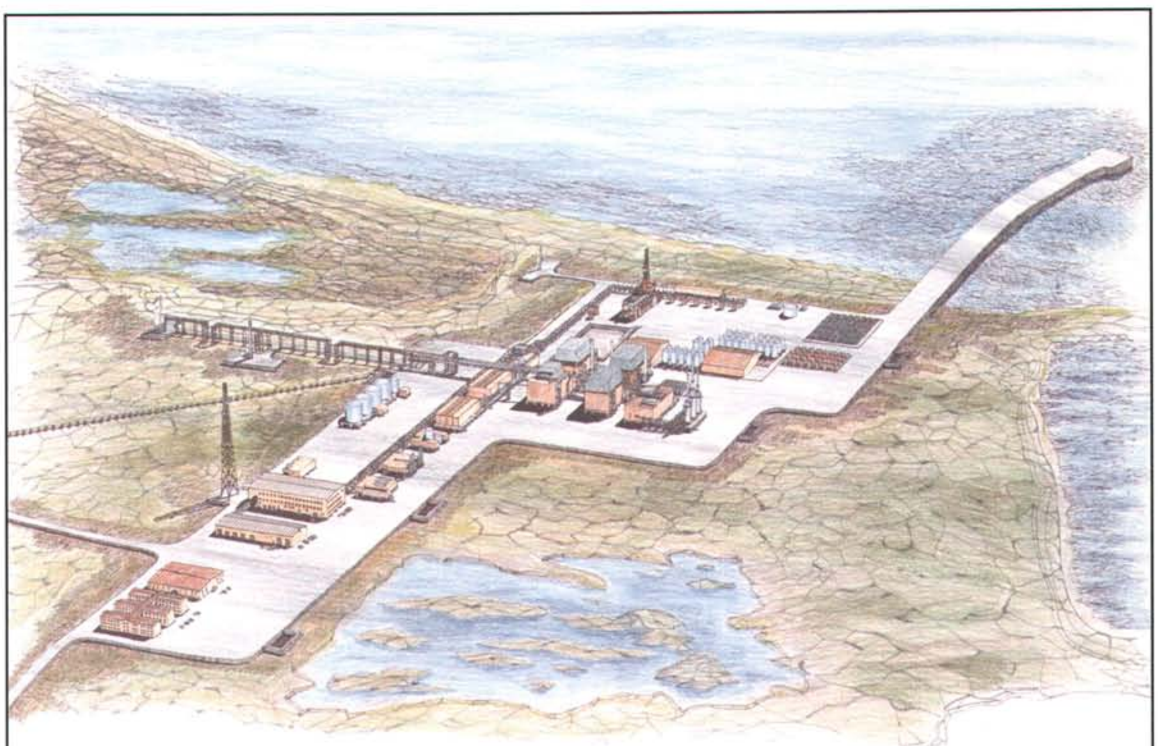


FIGURE 1-3
Detailed Rendering of Central Well Pad and Central Processing Facility Pad
(Based on February 2003 Project Description)

FIGURE 1-4
Artist's Conception of West Well Pad (Based on September 2002 Project Description)

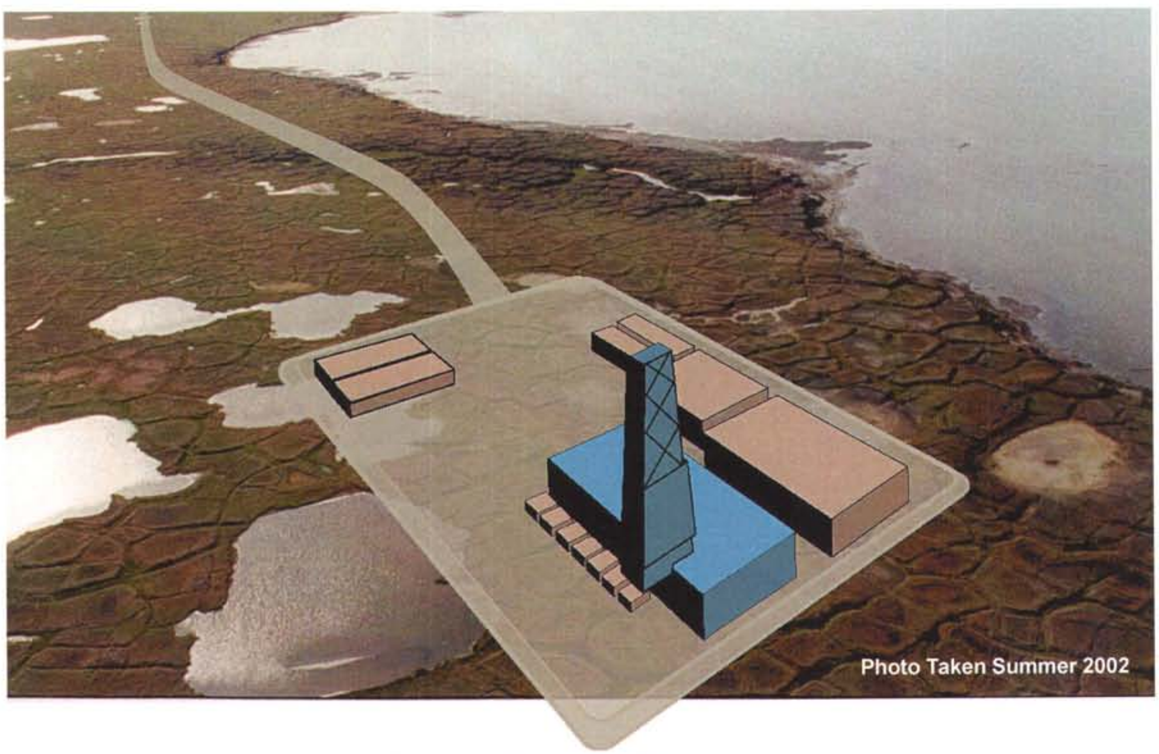


FIGURE 1-5
Artist's Conception of East Well Pad (Based on September 2002 Project Description)

phasis will be placed on well design, procedures, communication, and training to ensure that the wells can be safely drilled, used, and maintained.

1.3.2 Project Facilities

Process facilities will consist of east and west production well pads, production gathering lines, the Central Processing Facility, and the Central Well Pad and associated injection lines. When production begins, facilities will include production manifolds, well metering and control facilities, electrical buildings, methanol tanks and injection systems, and gathering-line pig launchers.

Production fluids from both the East and West Well Pads will be piped from the well manifolds to the gathering lines and then to the Central Processing Facility. The lines will be placed on vertical support members sized to maintain a minimum height above the tundra. Pressure monitoring is planned as the primary means of leak detection for gathering lines, which will also be visually monitored.

The Central Processing Facility Pad, which will use an existing gravel pad, will be the largest of the gravel pads and will house the main gas processing modules. Facilities at the pad will support remote operations and include temporary and permanent camps; office, warehouse and shop space; normal and emergency power-generating equipment; fuel, water, and chemical storage; and treatment systems for potable and waste water. An airstrip will be built south of the Central Processing Facility, and a dock will be constructed adjacent to the Central Well Pad.

The Central Well Pad will be adjacent to and directly north of the Central Processing Facility Pad and will be built on an existing Point Thomson Unit exploration-well gravel pad. During early construction, the Central Well Pad will be used primarily for drilling operations. It will contain the Class I disposal well, the grind-and-inject facility for drilling wastes, drilling equipment and supplies, a mud plant, an electrical building, an early-fuel-gas treating facility, and storage areas for drilling activities. High-pressure gas piping will transport the gas from the Central Processing Facility Pad to the eight injection wells at the Central Well Pad.

1.3.3 Export Pipeline System

The Point Thomson Export Pipeline will be built in winter and operated as a common carrier system according to proven North Slope design and construction criteria. The export system will consist of a carbon steel pipeline about 22 miles long to transport condensate from the Central Processing Facility to the existing Badami pipeline. The pipeline will have a leak detection system based on best available technology that is sensitive to a leak of no more than 1 percent of the daily flow. Pig launchers and receivers will be included. The pipeline will be supported on vertical support members providing separation between the bottom of pipe and the tundra surface. The entire pipeline right-of-way will cross land owned by the State of Alaska.

SECTION 2
POINT THOMSON RESERVOIR GEOLOGY

Knowledge of the reservoir geology is essential to designing the Point Thomson drilling program and its well control features. Drilling engineers base the design of well casings and the drilling fluid program on knowledge of the geologic formations to be drilled through. Geologists have a number of tools available to help them understand these underground formations. These tools include remote-sensing technologies such as seismic surveys and well logs from exploration wells, as well as direct measurements in the form of reservoir flow tests and core samples from exploration wells. Using these tools, the geologists apply sophisticated computer-modeling techniques to prepare detailed cross-sectional drawings of the rock strata the well must penetrate, along with specific characteristics of those strata to help the drilling engineer understand the nature of the rock, the pressures to be expected, and other characteristics of the rock.

The Point Thomson area is somewhat unique among oil and gas prospects in that an unusually large amount of data is available as development plans are being made. Detailed seismic surveys have been run across the entire area and numerous exploration wells have been drilled and tested in the area over the past 30 years. This geological information gives ExxonMobil confidence in its interpretation of the nature of the rock formations in the Point Thomson Unit. The high-quality geological information in turn gives ExxonMobil confidence that the drilling program for Point Thomson is effective and conservative.

2.1 HISTORY OF EXPLORATION IN THE AREA

The Point Thomson Field is a major hydrocarbon accumulation that was discovered in 1975. The primary reservoir, the Thomson Sand, is a large, overpressured gas-condensate reservoir located approximately 12,750 feet below sea level (the term *overpressured* is applied to reservoirs that have pressures higher than water gradients). A total of 19 exploration wells have been drilled in and around the field, and numerous seismic surveys have been acquired to further delineate this extensive resource. Since only two or three exploration wells are typically drilled before a field is developed, an unusually large amount of geological information is available for Point Thomson. The field is about 50 miles east of Prudhoe Bay.

In 1977, the Point Thomson Unit was formed, and the State of Alaska designated ExxonMobil (formerly Exxon Company U.S.A.) as the Unit operator. Throughout the 1980s and 1990s, ExxonMobil and other Point Thomson Unit owners continued to delineate the Thomson Sand and shallower Brookian accumulations within the Unit while conducting feasibility studies for development. In April 2000, interests among the major Point Thomson Unit owners were realigned for all horizons. Currently, the Point Thomson Unit covers approximately 117,000 acres.

The Point Thomson Unit #1 well discovered the Thomson Sand in 1977. Including this discovery well, 14 exploration wells have penetrated the Thomson Sand reservoir. The Alaska State G-2 well drilled in 1983 was the last well designed to target the Thomson Sand. In the 1990s, the Sourdough and Red Dog exploration programs targeted the shallower Brookian (Lower Tertiary) sandstones and did not penetrate the Thomson Sand.

Several different types of processing have been applied to the seismic surveys that cover the Point Thomson area. Several Brookian accumulations have been identified and their areal extent mapped and documented. Within the Brookian section, 11 well tests were conducted, and six of these wells flowed oil. The results from these tests have shown that the Brookian is a poor-quality reservoir with relatively low productivity and limited extent. With the available reservoir-quality information obtained from the wells and the size of the reservoirs mapped from the seismic data, these prospects have been deemed to be uneconomic to develop.

Any individual sand over 25 feet thick exhibits a seismic response and can be detected. The location and thickness of the Brookian sands are important factors in safely drilling the Point Thomson wells. Unlike the Thomson reservoir, which contains condensate, the Brookian sands, if hydrocarbon-bearing, contain oil. The Point Thomson drilling program will avoid these isolated, low-flow deposits, but should a Brookian sand be encountered in an area where the sands are not seismically detectable — i.e., less than 25 feet thick — ExxonMobil has designed drilling procedures to safely handle these intervals. Furthermore, the geophysical interpretation conducted for the Brookian produced adequate results to be used in preliminary well-screening efforts, but further work will be done during the well planning stage to predict in detail the lithology and fluid content of each borehole. As the well trajectories are being finalized for well permitting, ExxonMobil will work closely with the Alaska Oil and Gas Conservation Commission (AOGCC) to ensure that the seismically detectable Brookian sands are avoided where possible.

Detailed modeling has demonstrated that in the unlikely event of a well control situation while drilling through the Brookian section, the well could be quickly controlled due to the low flow rates. This information on the Brookian has been provided to AOGCC for review. The same modeling techniques have also been applied to the Thomson Sand reservoir, which is of a higher quality than the Brookian. The details of this Thomson Sand-related modeling and the associated remedial actions are discussed in Section 4.

The value of the numerous exploration wells in the area is that they provide detailed data on the conditions encountered while the wells were being drilled. Data from seismic surveys of the area and from well logging and tests help ExxonMobil geologists and reservoir engineers create detailed three-dimensional models of the underground conditions the Point Thomson development wells will encounter. Using this information, ExxonMobil drilling engineers can design a drilling program tailored specifically to these conditions.

2.2 THOMSON SAND GEOLOGY

2.2.1 Seismic Surveys

Typically, the first geological data available comes from seismic surveys, which give geologists a regional view of the types and locations of various formations and is frequently the basis for exploratory drilling. Seismic surveys operate on the same principle scientists use to study earthquakes. As shock, or seismic, waves move through the earth, a boundary between two rock types can change the direction of the waves. In addition, the density of the rock affects the speed of the waves. A man-made vibration on the surface creates seismic waves that travel through the ground and are reflected back to the surface at different times by changes in rock layers. Based on the time it takes the waves to return to the surface, a continuous readout can be made of the rock layers and formations along a "seismic line" on the surface. A series of parallel seismic lines provides views of slices of the earth's crust that can be used to build a three-dimensional image of the crust under a given land area. The number and spacing of seismic lines determine the resolution of the survey.

In the Point Thomson area, a total of eight seismic surveys have been conducted, as shown on Figure 2-1. Some of these data have been electronically reprocessed to improve the imaging of the Thomson Sand. Figure 2-2 provides a sample of the data obtained from a seismic line. This image shows how geologists can interpret the location of rock layers, in this case the top and base of the Thomson Sand, as well as the location of faults.

2.2.2 Well Logs, Cores, and Flow Tests

Geologists use the data from seismic surveys to decide where to drill wells, which provide physical information on the underground formations. The more wells in a region, the more complete the geological picture of the subsurface. By boring a hole into the earth, geologists can verify the picture of an area's geology obtained by seismic methods. As an exploration well is being drilled, paleontologists, geochemists, and sedimentologists study the drill cuttings. The driller records a log of such information as the kind of rock encountered at various depths, the time to drill through each layer, and the nature of any fluids encountered. Exploration wells in essence provide ground-truthing for the data interpreted from seismic surveys. Since the wells provide discrete sampling points, seismic survey data fill in the gaps between the wells and help geologists extrapolate how the rock layers lie between the wells. The data available from exploration wells in the Point Thomson area come from well logs, core samples, and reservoir flow tests.

As a well is being drilled, it is "logged." Well logging is a key tool for identifying the type and quality of rocks penetrated, including sand and shale sequences, and indicates the presence or absence of hydrocarbons. Most logging occurs before casing is placed in the portion of the well to be logged; this is called *open-hole logging*. These well logs are created by lowering sensors (*sondes*) into the hole. The logs can be used to accurately map the rock layers with as much detail as can be obtained from a surface outcrop and help determine the type and amount of hydrocarbons in a given formation and the ability of these hydrocarbons to flow.

The primary type of well log is the *electrical resistivity log*, which measures the resistance of the rock layers to electrical current. This resistance varies with the type of rock; for instance, clays have a low resistance, while sands with hydrocarbons have a high resistance. Other types of logs include *gamma ray logs*, which measure natural radioactivity to distinguish shale from sand, and *porosity logs,* which measure the void fraction of the bulk rock volume which contains the formation fluids.

At Point Thomson, open-hole logs were run on 13 of the exploration wells. Figure 2-3 (foldout) shows a sequence of logs from eight of these wells, as well as the location of all 19 wells. In this figure, the wells logs have been arranged side-by-side, and the colored bands drawn between the logs connect the same rock layers in each well. By convention, well logs for each well are displayed in a certain order. From left to right, the graphic for each well displays the gamma ray log, depth, location of conventional core recovered, resistivity log, porosity log, and the zone flow-tested.

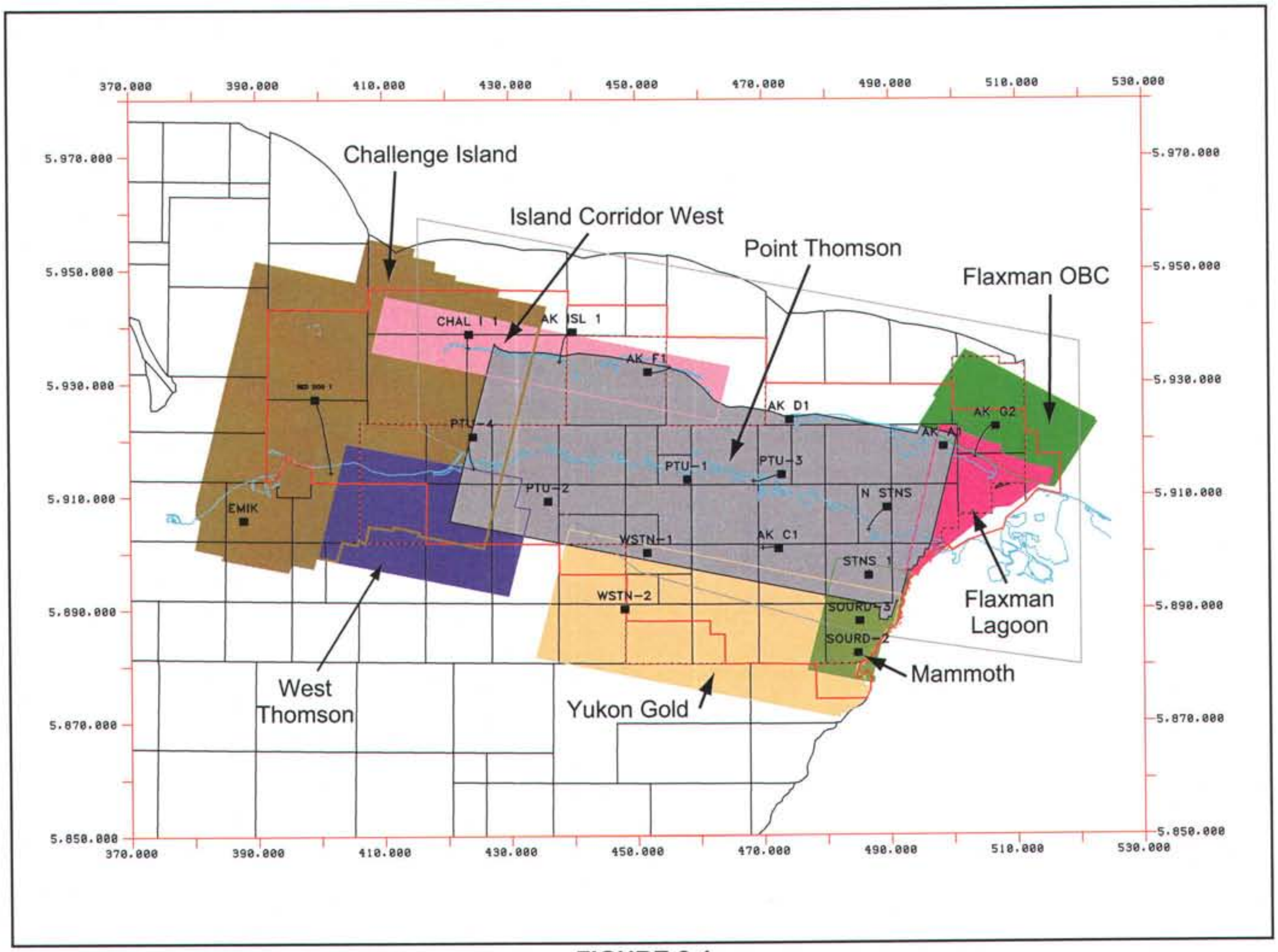


FIGURE 2-1
3D Seismic Surveys in the Point Thomson Unit

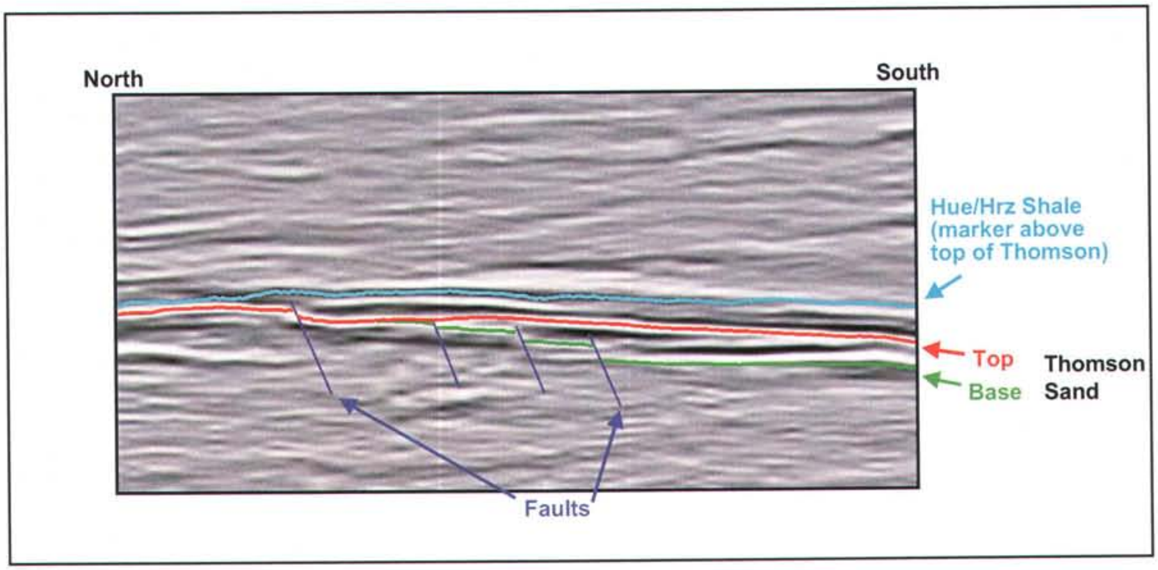
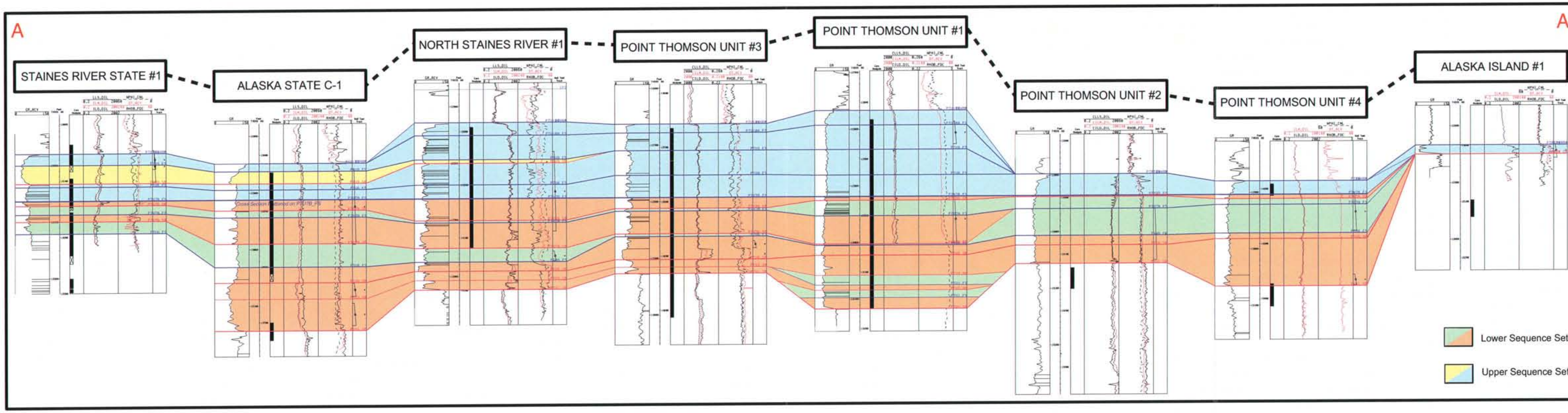
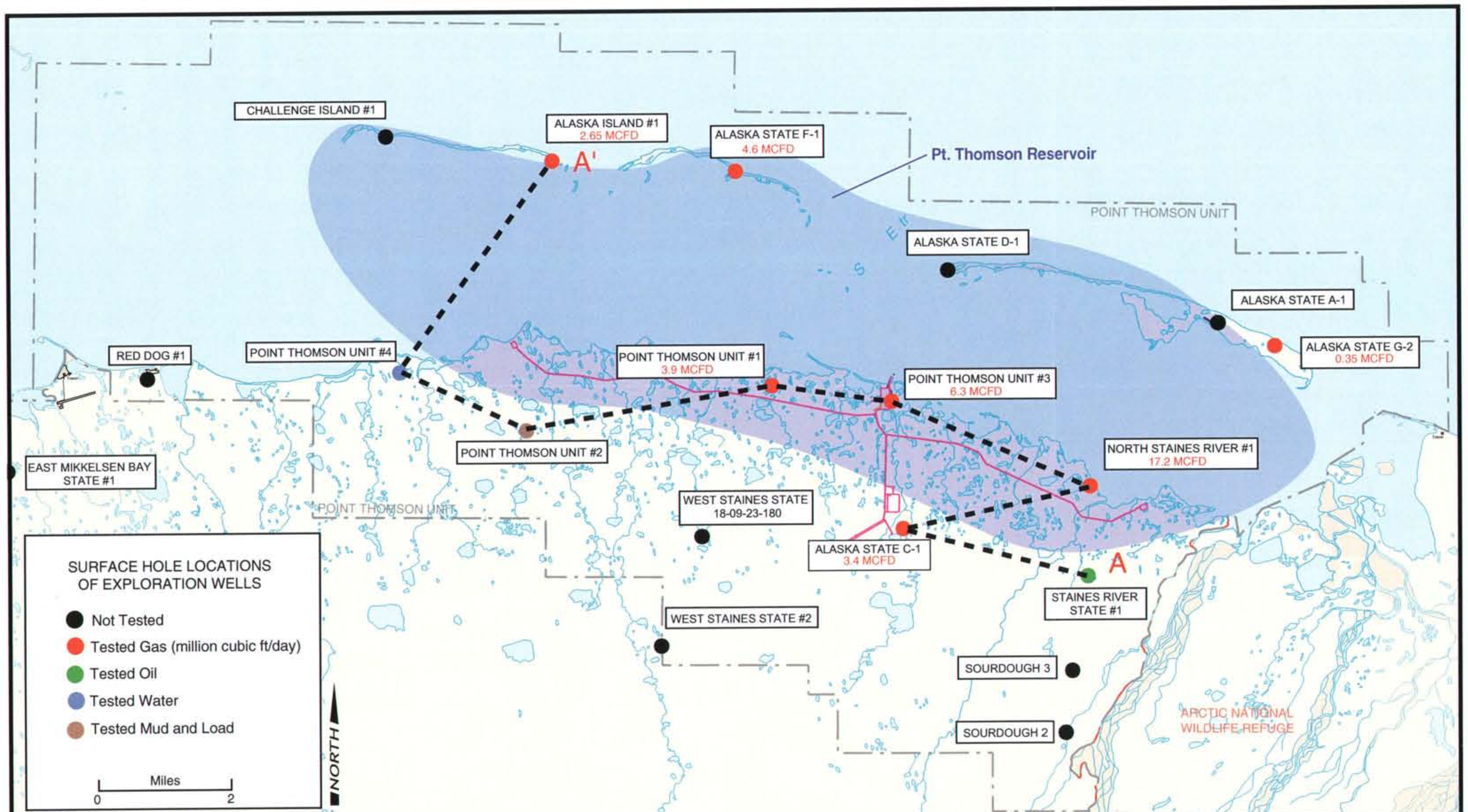


FIGURE 2-2
Close-up of Seismic Line from 1989 Point Thomson 3D Survey





The map at left shows the Point Thomson Unit, with the surface locations of the 19 exploration wells drilled in the area. The wells are color-coded to show the flow test that was conducted in the Thomson Sand. For the eight wells in the Unit that flow-tested gas from the Thomson Sand, the gas flowrates are shown in million cubic feet per day.

The figure above contains the well logs from the Thomson Sand interval for eight of the Point Thomson exploration wells. This figure shows how geologists trace the rock layers from one well to another. The black dashed line between the well name boxes at top corresponds to the dashed line on the map (A to A') to show how the cross-section proceeds across the field. Data from seismic surveys are used to fill in the gaps between the wells, and computer models create 3-D views of the subsurface geology.

FIGURE 2-3
Location of Exploration Wells in the Point Thomson Area, along with Sample Well Logs

To verify the information provided by the well logs, core is cut from various intervals to provide geologists with an intact sample of the rock sequences. Figure 2-4 shows examples of core recovered from the Point Thomson Unit #3 and North Staines River #1 wells, alongside the well logs through the reservoir. A total of over 1,500 feet of core was recovered from 10 of the Point Thomson exploration wells.

When hydrocarbons zones are detected, flow tests are often conducted to determine the rate of flow the formation is capable of and to obtain samples of reservoir fluids. Short-term flow tests were run on 11 of the Point Thomson wells, and fluid samples from six of these wells were analyzed. The map on Figure 2-3 (foldout) shows which wells were flow-tested and their flow rates, and the results are discussed in Section 2.3.2 below.

2.2.3 Modeling

Many technologies have been integrated in order to develop the Point Thomson Field and prepare for development drilling operations. A team of specialists consisting of reservoir engineers, geologists, geophysicists, and drilling engineers has analyzed available data, corroborated with various models, and reviewed the results internally and with colleagues in partner companies. This team is part of ExxonMobil's *Integrated Pore Pressure Prediction Team* (IP3 Team). The tools used in this process include seismic data, well data from exploration wells, and geologic models. Previously analyzed data have been re-analyzed using more advanced technology. This has resulted in a reliable understanding of the reservoir that can be used to more accurately predict formation behavior as wells are drilled. The reservoir analysis and modeling have provided information on small-scale differences from east to west or north to south. Future reviews conducted during the planning phase for each well will provide on-site personnel with a better prediction of expected well behavior. As wells are drilled, data gathered will be used to prove the modeling and further refine subsequent results for the Point Thomson reservoir. ExxonMobil has successfully used this team concept in Caspian Sea and Gulf of Mexico operations in higher pressure reservoirs. Figure 2-5 depicts this integration process.

Figure 2-6 depicts the *facies model* generated for Thomson Sand — an example of sophisticated geological computer modeling with the data generated by the seismic and exploration drilling programs. This figure gives a three-dimensional static view of the subsurface geology of the Thomson Sand reservoir looking at the area from the southwest. The vertical white lines represent the location of the exploration wells, which are identified by the blue boxes, while the red, green, and blue bands trace the rock types between the exploration wells. The geological model provides the detailed description of the reservoir for input to the dynamic reservoir-simulation model for predicting production performance.

2.3 POINT THOMSON DEVELOPMENT

2.3.1 Thomson Sand

The Thomson Sand gas reservoir is the target formation for the Point Thomson drilling program. This deep, high-pressure reservoir occurs below the Brookian, a discontinuous oil-bearing formation. Figure 2-7 shows a schematic view of the relative positions of the Thomson Sand and Brookian formations. The thickness of the Thomson Sand varies widely across the field, ranging from 0 feet up to a maximum penetrated thickness of 350 feet. A generalized cross-section of the Thomson Sand is shown in Figure 2-8. The rocks in the Thomson Sand reservoir range from conglomerates to

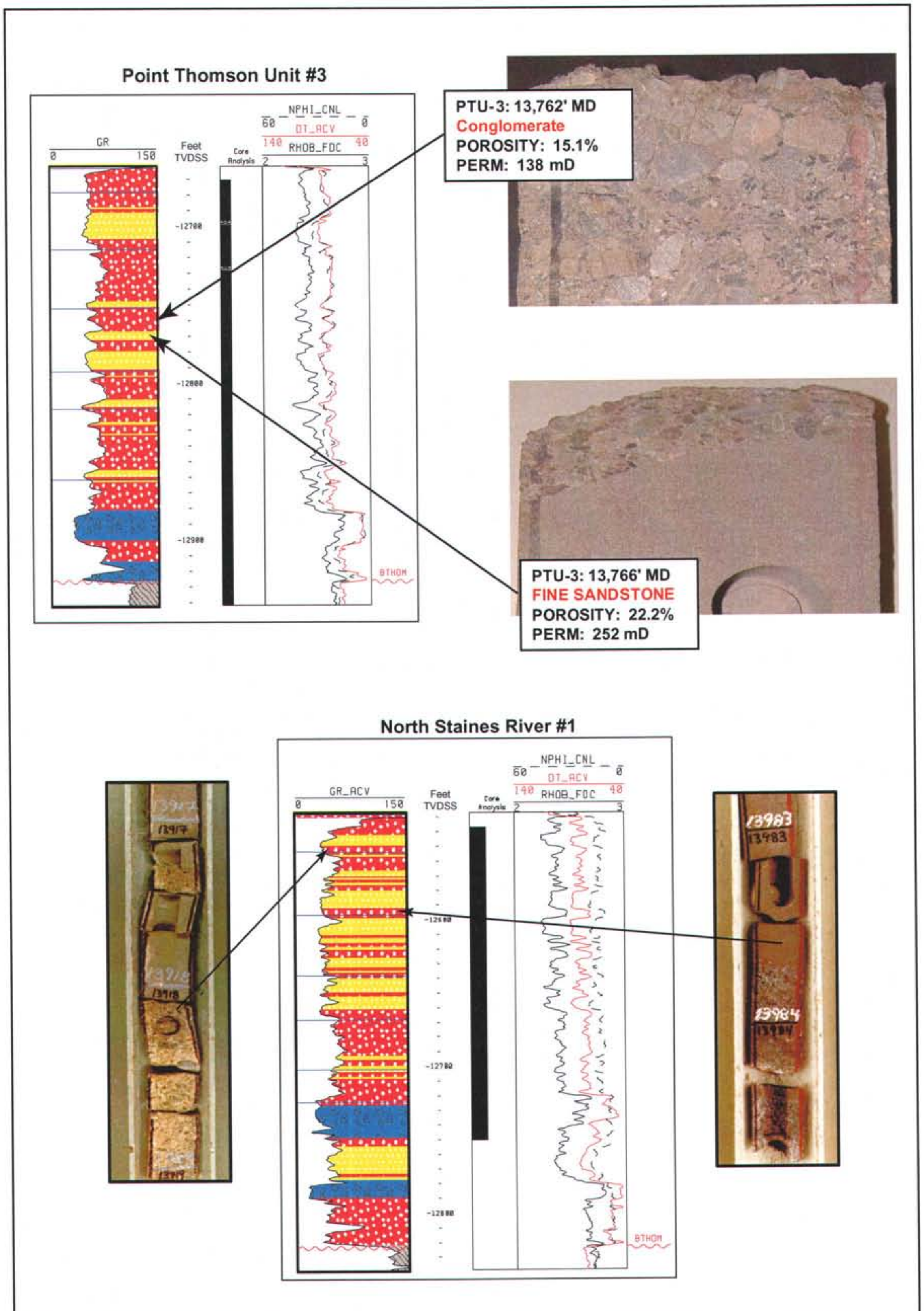


FIGURE 2-4
Examples of Point Thomson Exploration Well Logs with Cores

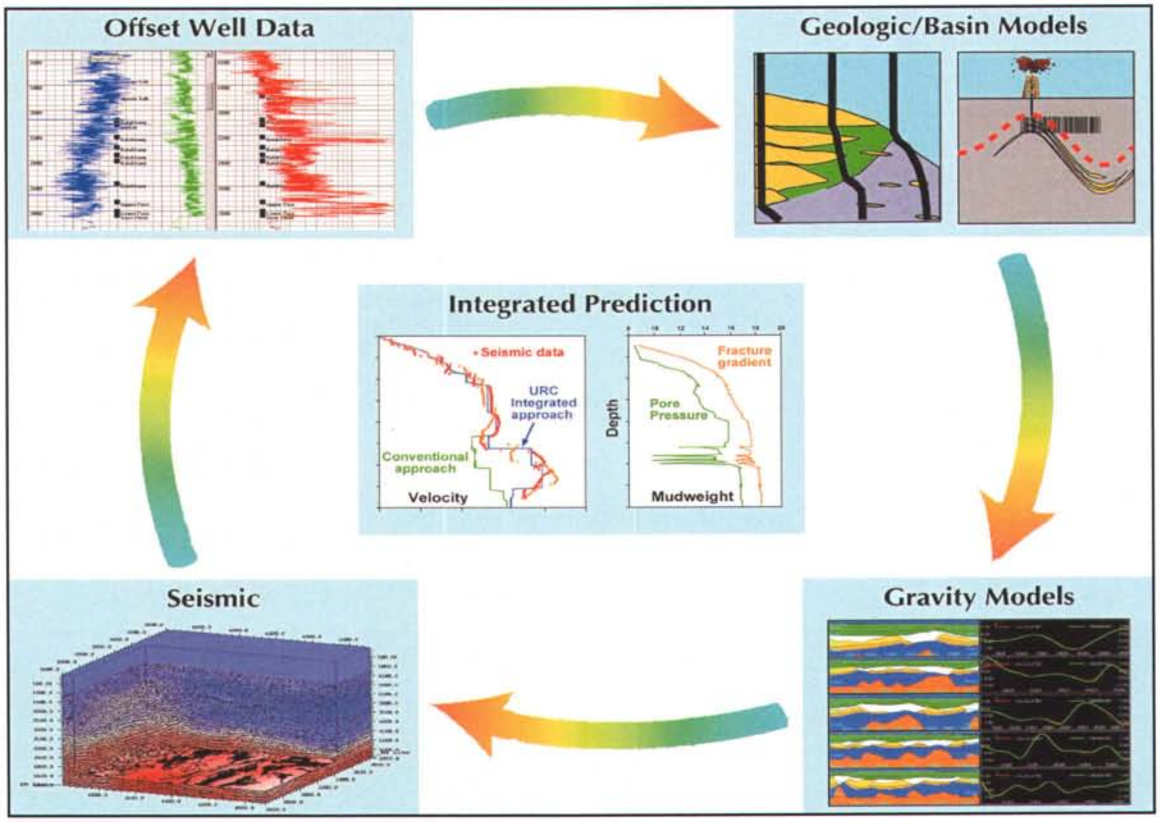


FIGURE 2-5
ExxonMobil Technology Integration for Predicting Well Behavior

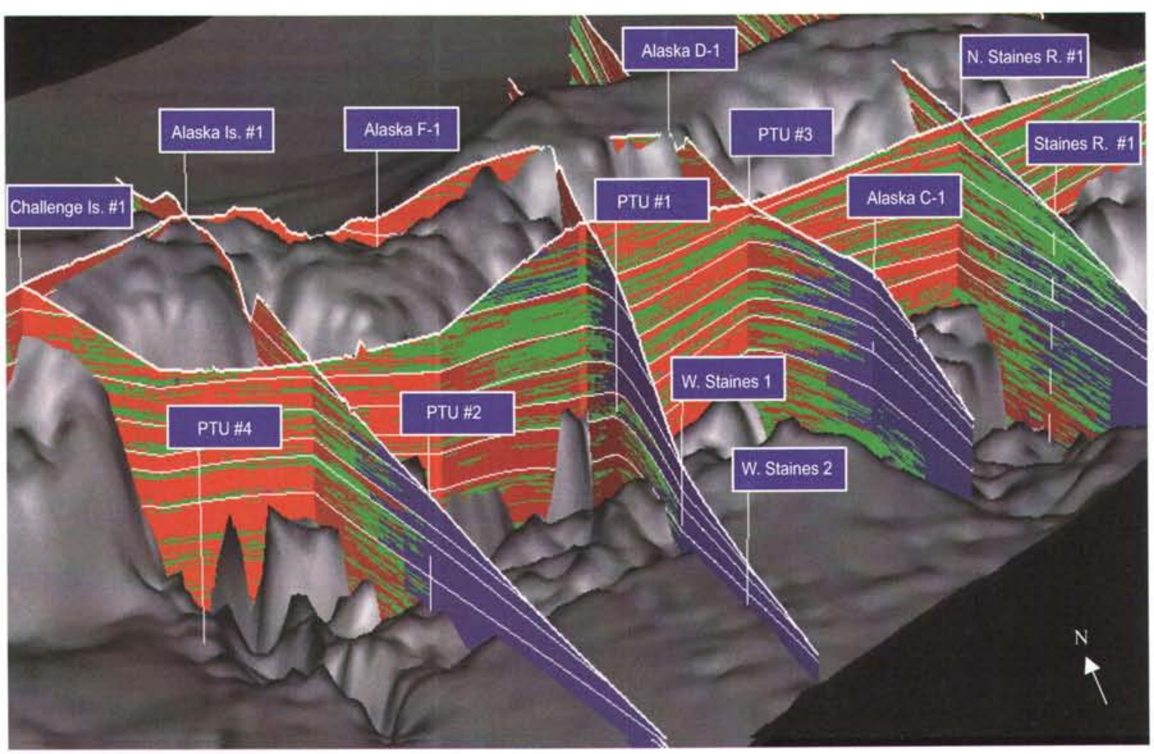


FIGURE 2-6
Point Thomson Facies Model, Showing the Thomson Sand

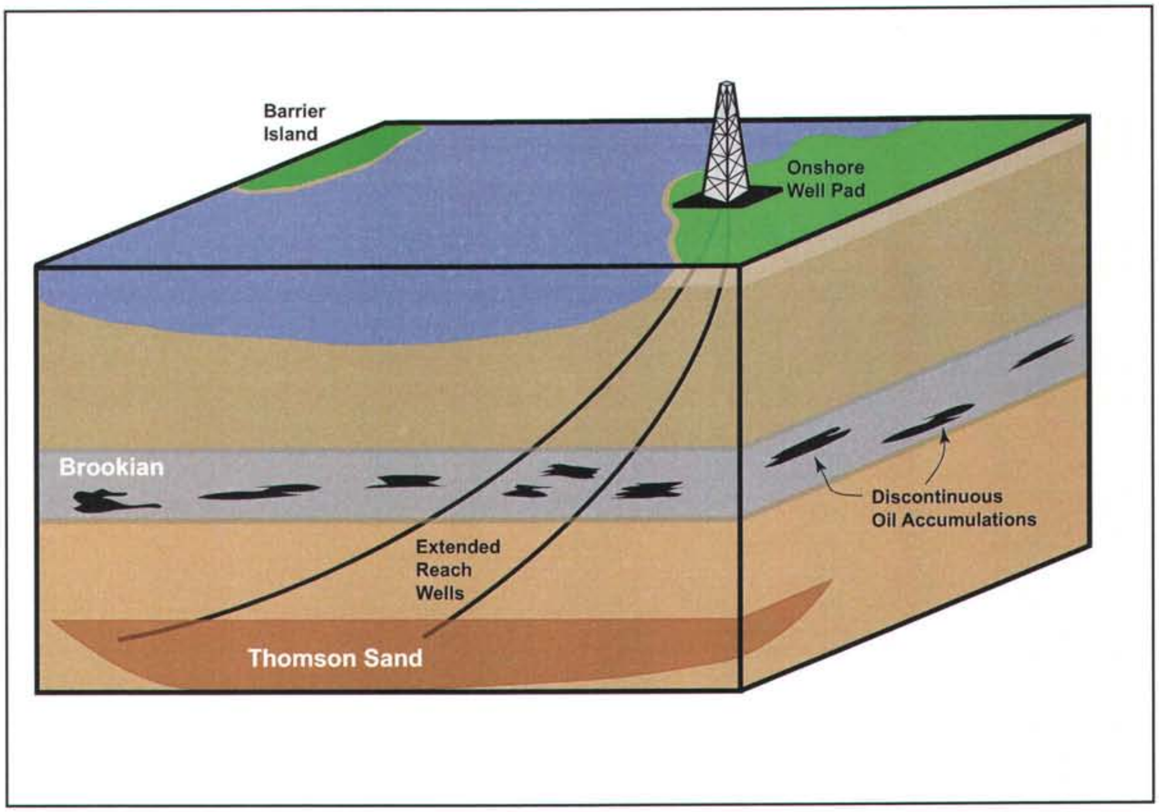


FIGURE 2-7
Schematic of Point Thomson Extended-Reach Drilling with Relative Positions of Brookian and Thomson Sand Formations

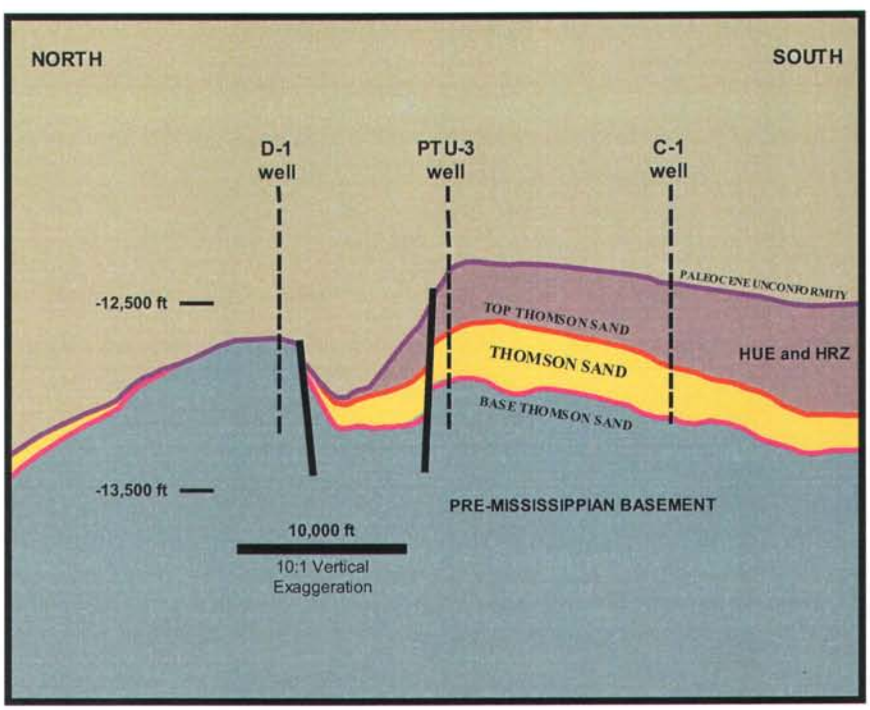


FIGURE 2-8
Generalized Structural Cross-Section Showing the Thomson Sand

sandstones to sandy mudstones. No true shales have been observed within the interval. Grain composition is dominated by dolomite, argillite, quartzite, and sedimentary rock fragments.

The Thomson Sand reservoir is estimated to contain over 8 trillion cubic feet of natural gas in place over an area of approximately 60,000 acres. The carbon dioxide concentration in the natural gas is approximately 4.5 percent. The natural gas is considered to be sweet (hydrogen sulfide is absent). The hydrocarbon liquids yield is expected to be about 55 to 60 barrels of hydrocarbon liquids per million standard cubic feet of produced natural gas.

2.3.2 Fluid Characterization

Once the geology of a reservoir is understood, the reservoir fluids must be characterized in order for reservoir engineers to predict the production rates and behavior of the fluids. Information on the fluids is also needed for oil spill contingency planning in order to predict the fate and behavior of these fluids if they were to be released at the surface. Samples of reservoir fluids from exploration well tests are often taken, and modeling techniques can be used to predict the characteristics of the fluids over a wide range of conditions for reservoir depletion planning and for facility design. During the Point Thomson exploration program described in Section 2.1, nine fluid samples from the Thomson Sand were collected and analyzed from six of the wells. Table 2-1 provides a summary of the well test data, while Figure 2-3 earlier in this section shows the locations of the tested wells.

A fluid characterization is a component-by-component description of the parameters necessary to perform calculations using an *equation of state.* In basic terms, an equation of state is a mathematical expression that relates pressure, volume, and temperature (PVT). A good equation-of-state fluid

TABLE 2-1
Sample Analysis Results from Point Thomson Exploration Well Testing

WELL	DRILL STEM TESTS	DEPTH (SSTVD FT)	GAS/OIL RATIO	API GRAVITY	DATA AVAILABLE
PTU #3	2	12,869 to 12,882	12,828	38 to 40.6	Comp, GOR, API
Alaska Island #1	3	12,832 to 12,856	12,195	37.7	Comp, GOR, API, DP, CCE, CVD, Sohio Extended Analysis
Alaska Island #1	6	12,832 to 12,856	15,152	37.7	Comp, GOR, API, DP, CCD, CVD
PTU #1	1	12,930 to 13,017	4,786	20.6	Comp, GOR, API, Chevron Extended Analysis
N. Staines R. #1	1	12,755 to 12,772	20,440	40.5	Comp, GOR, API
N. Staines R. #1	1	12,755 to 12,772	19,300	40.5	Comp, GOR, API, Phillips Extended Analysis
N. Staines R. #1	2	12,579 to 12,611 12,697 to 12,719	16,518	42.2	Comp, GOR, API, Phillips Extended Analysis
Staines R. State #1	1	12,996 to 13,006 13,014 to 13,029	1,197	10.1	Comp, GOR, API, BP, DiffLib
Alaska State C-1	2	12,859 to 12,991	5,176	36.3	Comp, GOR, API, CCE, CVD

characterization, which is made by adjusting the component parameters to match measured data, can model a multitude of physical and thermodynamic properties of reservoir fluids. The Thomson Sand fluid characterization is based on all data from the nine original fluid samples analyzed and does a good job of predicting the actual fluid properties measured (Figure 2-9). The good match obtained with this characterization allows use of the model to predict fluid properties over a wide range of conditions to understand reservoir behavior and design surface facilities.

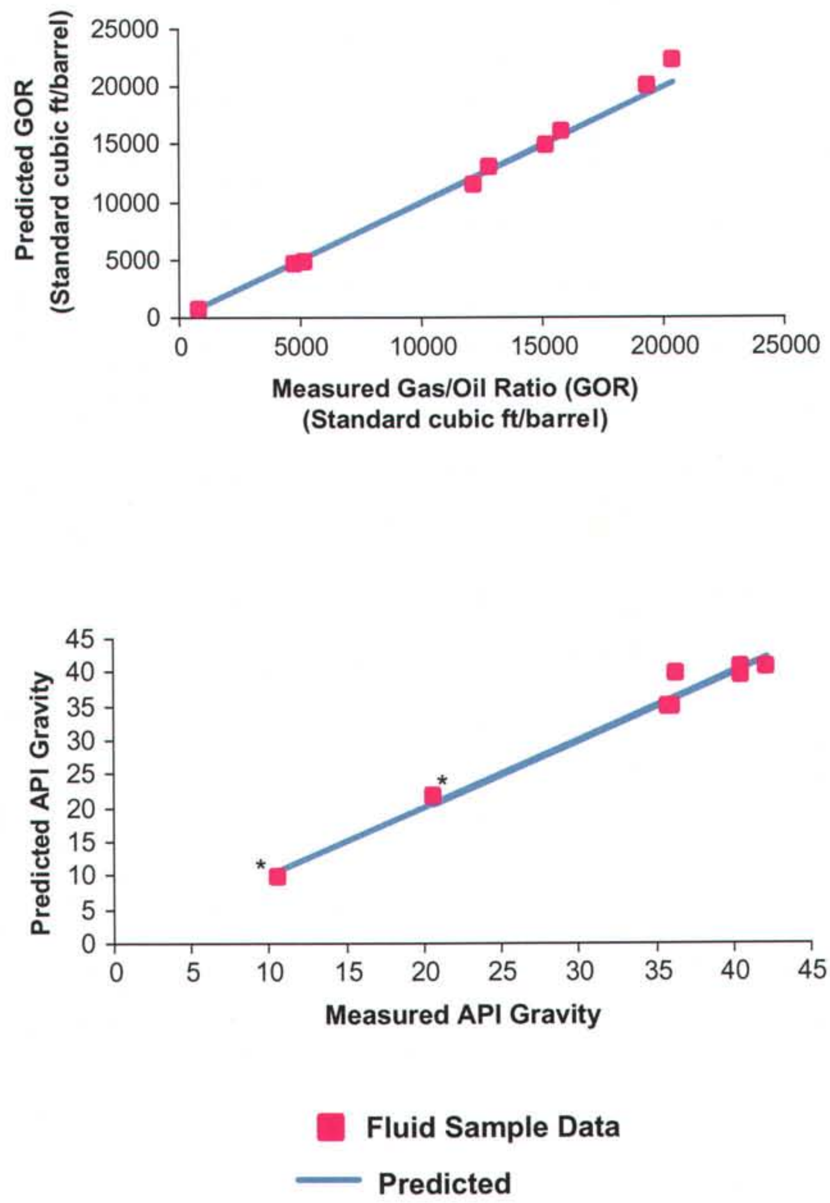
Table 2-2 shows the expected composition of the produced fluids based on the Thomson Sand fluid characterization. Reservoir engineers from ExxonMobil and other companies participating in the Point Thomson Unit cooperatively developed the fluid characterization summarized in Table 2-2. This fluid characterization was used as input for reservoir production modeling and to predict blow-out properties for contingency planning at Point Thomson (see Section 2.4).

2.3.3 Reservoir Development Plan

In oil and gas production, the term *condensate* applies to hydrocarbons that exist as vapor under initial reservoir conditions of temperature and pressure, but condense to a liquid with lower temperature and pressure during production as the fluid is brought to the surface and processed in surface facilities. Both crude oil and condensate are complex mixtures of primarily carbon and hydrogen compounds, but condensate contains more of the lighter hydrocarbon components (or

TABLE 2-2
Most Likely Composition of Point Thomson Gas Stream During First Year of Production (Mole Percent)

COMPONENT	PRODUCED GAS STREAM	INJECTED GAS	CONDENSATE TO BADAMI
N_2	0.6%	0.7%	0.0%
CO_2	4.4%	4.4%	0.0%
Methane	83.8%	87.1%	0.0%
Ethane	4.2%	4.2%	0.4%
Propane	1.7%	1.6%	3.8%
I-Butane	0.4%	0.3%	1.4%
N-Butane	0.6%	0.5%	3.1%
I-Pentane	0.2%	0.2%	1.6%
N-Pentane	0.3%	0.2%	2.0%
C_6	0.5%	0.2%	6.6%
C_7	0.4%	0.2%	7.7%
C_8	0.4%	0.1%	9.0%
C_9	0.3%	0.1%	7.2%
C_{12}	1.1%	0.1%	29.5%
C_{17}	0.7%	0.0%	18.5%
C_{27}	0.3%	0.0%	7.8%
C_{42}	0.0%	0.0%	1.2%
C_{65}	0.0%	0.0%	0.2%
C_{86+}	0.0%	0.0%	0.1%
Water	0.1%	0.0%	0.0%
TOTAL	~100%	~100%	~100%



*Crude oil samples

FIGURE 2-9
Comparison of Predicted Fluid Characterization
vs. Actual Well Test Sample Data for Point Thomson Reservoir Fluids

fractions) than does crude oil, which usually contains heavier hydrocarbon fractions known as *asphaltenes*. As a result, condensate properties such as API gravity and viscosity are typically much different than those of crude oil.

The Point Thomson project is a *gas cycling project* designed to recover the hydrocarbon liquids (condensate) contained in the natural gas of the Thomson Sand reservoir (Figure 2-10). Condensate will be extracted from the so-called *wet gas,* which is currently planned to be produced initially at approximately 1.4 billion cubic feet per day. The condensate will be shipped to market, while the remaining produced natural gas (termed *dry gas*) will be injected back into the Thomson Sand reservoir.

Most of the Thomson Sand reservoir lies under the nearshore waters of the Beaufort Sea. It is anticipated that the field will be produced from a minimum of 13 wells drilled from two onshore pads: one pad situated on the east side of the reservoir and one on the west side (Figure 2-11). This strategy will require an extended-reach drilling program with horizontal offsets up to 21,000 feet from the surface location — that is, the wells will begin on the pads and angle offshore as they are drilled to their bottom-hole targets in the reservoir. Production wells are planned to have large 7-inch tubing to enable high withdrawal rates. Once the condensate is removed, the dry gas will be compressed and injected back into the Thomson Sand through eight wells drilled from a third onshore pad (Central Well Pad) located towards the center of the field. In order to maintain high condensate production and minimize breakthrough of injected dry gas, the bottom-hole locations for the producing wells will be located at a distance from the more-centrally located dry-gas injection wells. Dynamic reser-

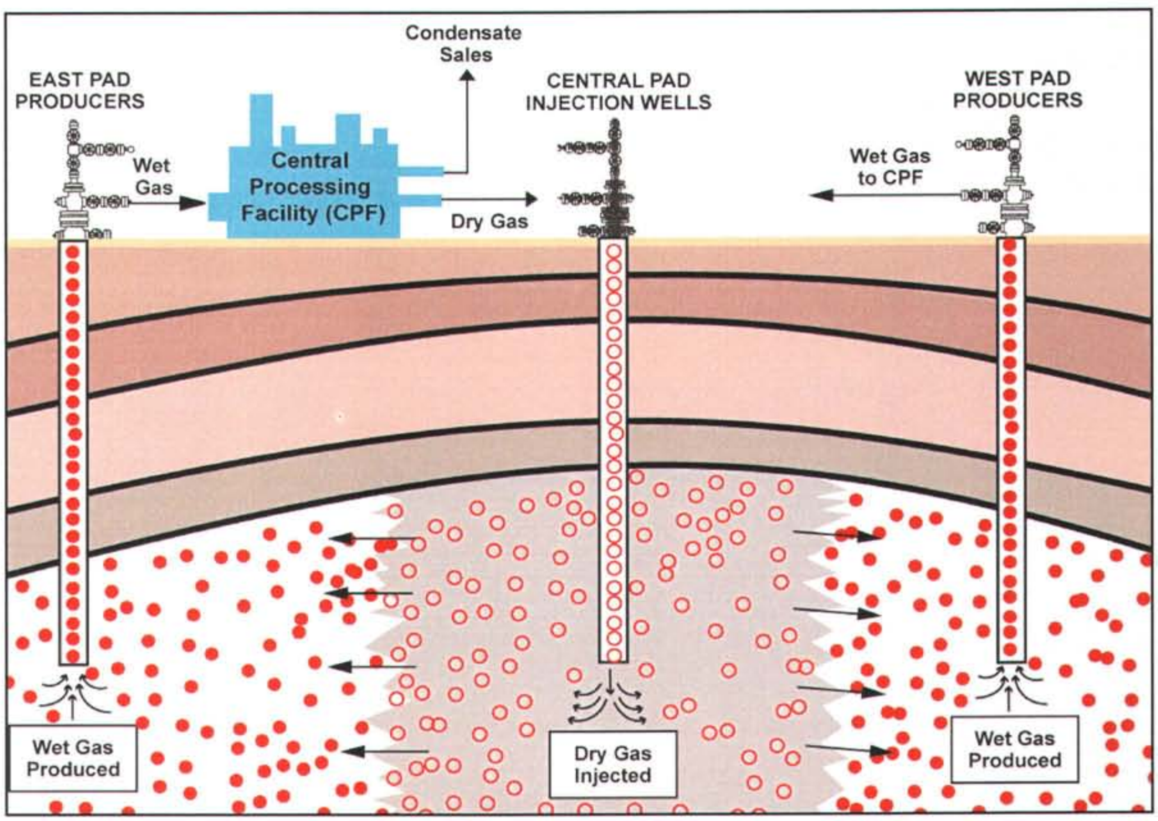


FIGURE 2-10
Schematic of Point Thomson Gas Cycling Process

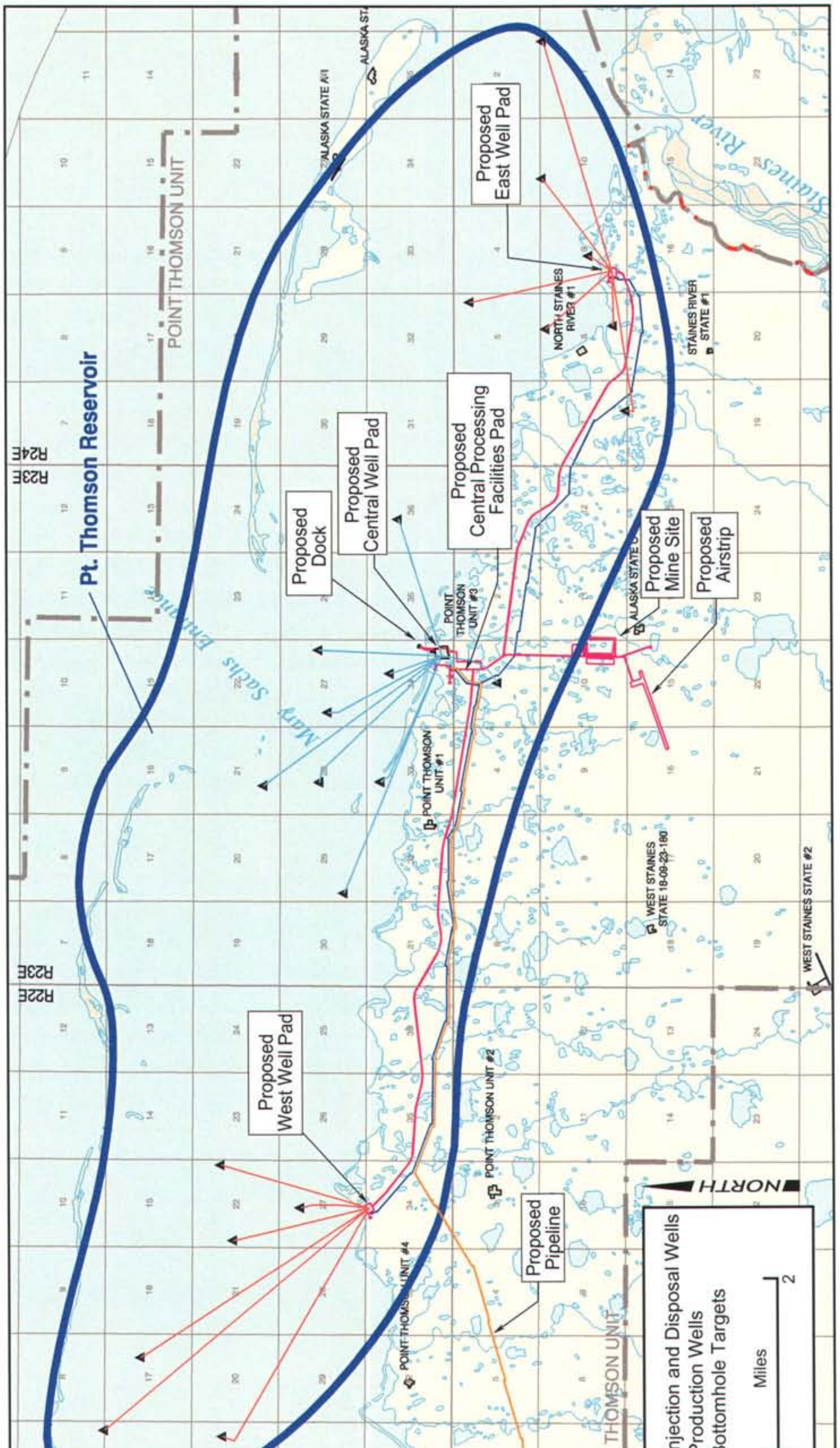


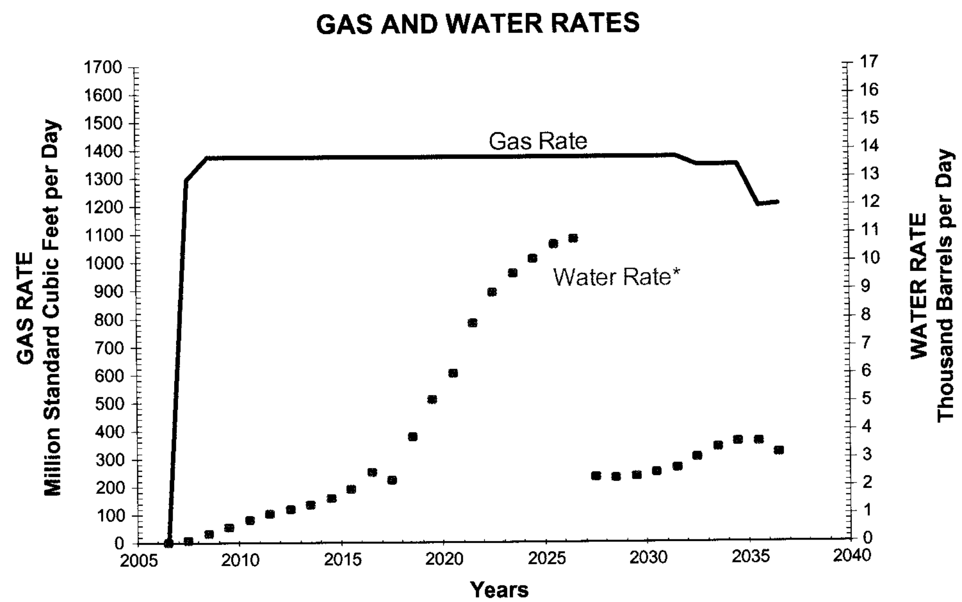
FIGURE 2-11
Proposed Point Thomson Development Wells (Based on February 2003 Project Description)

voir performance is predicted using ExxonMobil's state-of-the-art reservoir simulator (EM^{Power}). Condensate production rates are expected to peak early in the life of the project, once all the production and injections wells are completed and placed on-line (Figure 2-12). Ultimately, the Point Thomson Gas Cycling Project is expected to recover over 400 million barrels during its 30-year lifespan.

2.4 USE OF FLUID CHARACTERIZATION FOR CONTINGENCY PLANNING

The fluid characterization referred to previously was used to predict the condensate properties at the surface for blowout modeling and contingency planning. Contingency planners need to know the volume that could be released, how liquids will be deposited from a blowout plume, and how the liquids will move and weather once they are exposed to the environment. It is also important for their analysis to understand that unlike most crude oils, Point Thomson gas condensate is a relatively non-persistent hydrocarbon. Figure 2-13 shows a comparison of the range of constituents for Alaska North Slope crude oil and the Point Thomson condensate. As can be seen, approximately 65 percent of North Slope crude contains components in the range of diesel and heavier (i.e., containing more than 17 carbon atoms, or $>C_{17}$). Point Thomson condensate, on the other hand, is made up of only 27 percent of these fractions and has none of the heaviest fraction (*vacuum resid*) which contains asphaltenes. This fact is very important in considering the behavior of Point Thomson condensate if it were to be released into the environment in a well blowout or other spill incident. Much of the liquid condensate will quickly evaporate and disperse.

Section 4 discusses the modeling of blowout behavior that ExxonMobil conducted using the condensate properties described above. This modeling considered both unignited and ignited blowouts, and the fate of spilled condensate on water.



The sharp drop in water rate occurs because the well with the highest water production is shut in at this time.

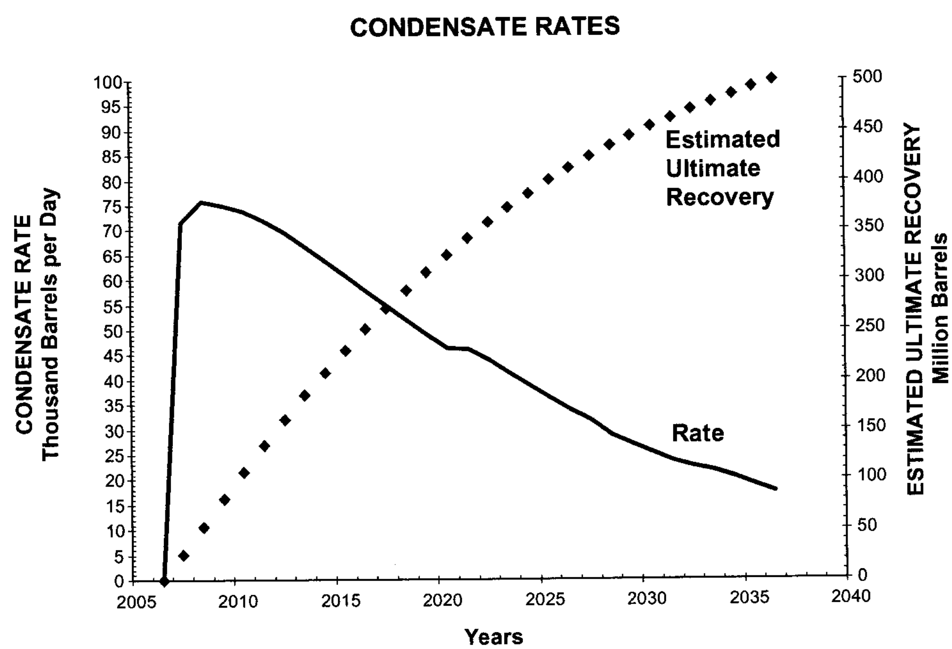
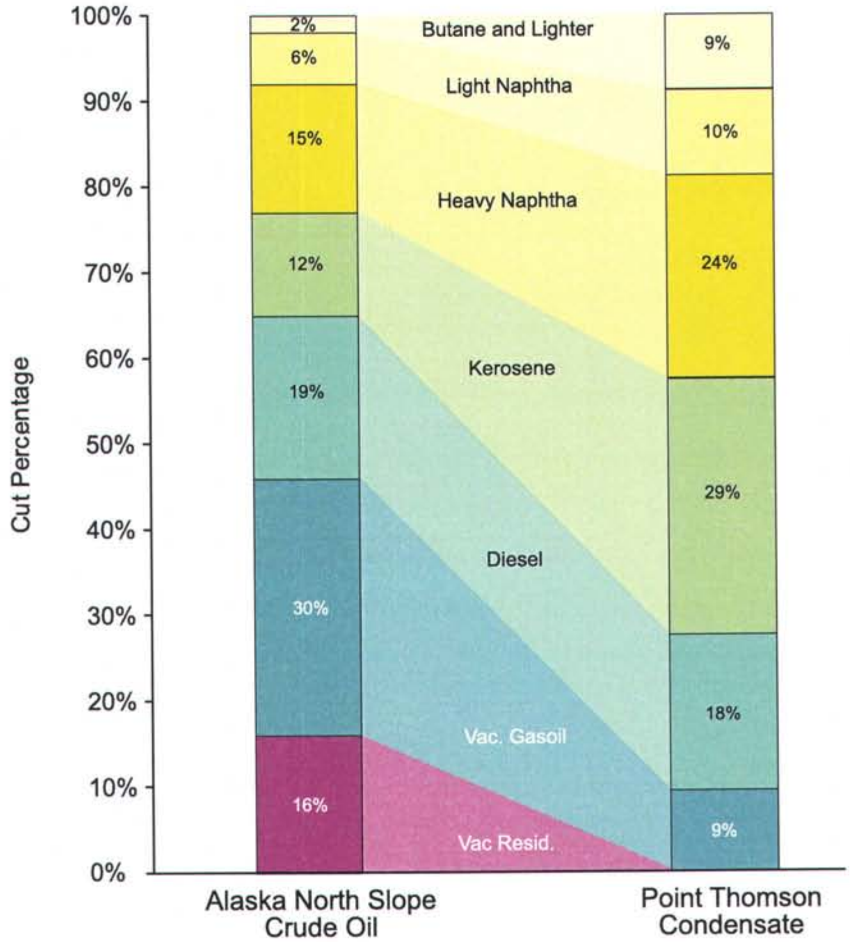


FIGURE 2-12
Model of Point Thomson Reservoir Flow Rates

COMMON CUT NAME	CARBON RANGE	BOILING POINT RANGE (°F)
Butane and Lighter	$C_1 - C_5$	Less than 90
Light Naphtha	$C_5 - C_7$	90 to 180
Heavy Naphtha	$C_7 - C_{12}$	180 to 380
Kerosene	$C_{12} - C_{17}$	380 to 530
Diesel	$C_{17} - C_{25}$	530 to 680
Vacuum Gasoil	$C_{25} - C_{60}$	680 to 925
Vacuum Resid.	C_{60} and above	925 to 1500+



Only about 27% of the constituents of Point Thomson condensate are heavier than C_{17} while 65% of Alaska North Slope crude is made up of these heavier cuts. Such lighter components are relatively non-persistent in the environment.

FIGURE 2-13
Comparison of Composition: Alaska North Slope Crude vs. Point Thomson Condensate

SECTION 3
POINT THOMSON DRILLING PROGRAM

ExxonMobil's drilling program for Point Thomson is based on the company's worldwide experience drilling high-pressure gas wells and on the wealth of geological data that are available from the extensive exploration drilling, seismic mapping, and reservoir modeling in the Point Thomson Unit. These data enable ExxonMobil's drilling engineers to design both their drilling techniques and well construction to accommodate expected geological conditions — the most important of which are the pressures and mechanical integrity of the formation in the open hole during drilling. The drilling program incorporates several important layers of protection to help ensure that pressures underground are controlled during drilling without fracturing the rock in the open hole. The most important protection comes from the drilling muds (also called drilling fluids) that are designed to control the underground pressures. Knowledge of the Point Thomson area permits drilling of wells with assurance that the mud weight not only remains above the formation pressure but also will not compromise the integrity of the formation.

The Point Thomson wells will be designed, drilled, and completed in accordance with the regulations and with the approval of the Alaska Oil and Gas Conservation Commission (AOGCC), which has jurisdiction over oil and gas wells in Alaska. The drilling program will incorporate several features that provide additional prevention measures beyond what is required by regulation. Special emphasis will be placed on well design, procedures, equipment, communication, and training to ensure the wells can be safely drilled, completed, produced, and maintained. While each well is being drilled, a minimum of two safety barriers — the drilling fluids and the blowout prevention equipment — will be in place at all times to ensure control of formation fluids. If one barrier is compromised, drilling will stop and the barrier restored before proceeding. The purpose of this philosophy is to prevent a single-point failure from escalating. For example, blowout prevention equipment and safety valves will prevent the uncontrolled release of reservoir fluids from the well if the drilling fluids fail and will facilitate restoration of the mud as the primary means for well control.

In the very unlikely event that all procedures, barriers, and hardware were to fail and a blowout occurred, the on-site Drilling Supervisor will have the authority to ignite the well after ensuring personnel safety. Ignition of the well will minimize the condensate impact on the environment and will complement subsequent well-capping operations. Well ignition is discussed in Section 5 of this document.

3.1 INTRODUCTION

As currently envisioned, the Point Thomson Gas Cycling Project will be developed by drilling and completing a minimum of 13 production wells and eight gas injection wells in the Thomson Sand, plus at least one Class I disposal well in the shallower Sagavanirktok. All production and injection wells will require directional drilling to reach the desired bottom-hole location. All bottom-hole targets lie beneath the nearshore Beaufort Sea, except for the Class I disposal well and one East Well Pad production well.

High pressure differentiates the Point Thomson wells from other North Slope wells. The Point Thomson production and gas injection wells are considered long-life, very prolific, high-pressure wells [bottom-hole pressure near 10,250 pounds per square inch (psi) and maximum surface pressure near 8,300 psi for producing wells and 10,500 psi for injection wells]. When completed, all wells will have surface-controlled subsurface safety valves (SCSSV). The Christmas trees on the wellheads will have remotely operated valves for the upper master valve and outer wing valve; all Christmas trees and valves will be rated for either 10,000 psi (producers) or 15,000 psi (injectors). The typical working pressure for similar equipment on the North Slope is 5,000 psi.

ExxonMobil will use drilling equipment and techniques that have been successfully applied on other high-pressure gas reservoirs around the world. ExxonMobil has experience drilling wells with bottom-hole pressures ranging from 12,000 psi to over 18,000 psi (Figure 3-1). While pressures such as those in the Point Thomson reservoir are unusual for North Slope production, they are not unique worldwide. Among the technologies ExxonMobil has developed while working in high-pressure areas since the late 1950s are the following:

- High-density mud systems.
- The dynamic kill process.
- Computer software for modeling well blowouts and the dynamic kill process.
- Cementing practices for preventing annular gas flow.
- Rigorous casing design procedures.
- Specific metallurgy for high-pressure sour-gas wells.
- Finite element analysis and qualification testing of connections for gas tightness.
- Continuous, real-time remote monitoring of wellbore conditions during drilling operations.

3.2 THE POINT THOMSON DRILLING PROGRAM

3.2.1 Overview

Drilling oil wells involves using specifically designed equipment to drill a series of holes and inserting steel pipe (known as *casing* or *tubulars*) at intervals based on mud weight to isolate weak formations and permit drilling deeper into the higher-pressure zones safely. A shallow, larger hole is drilled first, with each subsequent hole being smaller in diameter and deeper. Drilling mud weight is used to control pressures downhole, and the flow of mud removes drill *cuttings* (the ground-up earth created by the primary drilling tool, a drill bit). The tools that provide weight to the drill bit, such as drill collars and heavyweight drill pipe and stabilizers, along with the drill bit, comprise the *bottom-hole assembly* (BHA). After each hole section is drilled, casing is run and cemented in the hole to isolate specific formations. The casing makes it possible to increase the mud weight and provides sufficient mechanical integrity to control higher pressures further downhole. The mechanical properties (burst, collapse and tension) of the casing to be used at Point Thomson will meet or exceed regulatory requirements and are based on expected conditions within the formations.

Located behind the drill bit are specialized electronic detection instruments called *logging while drilling (LWD)* tools, which can be used to identify formation type and fluid content and to monitor hole conditions as drilling progresses. In addition to the LWD tools, ExxonMobil will use *pressure while drilling (PWD)* logging tools to directly measure bottom-hole pressure, the parameter that is

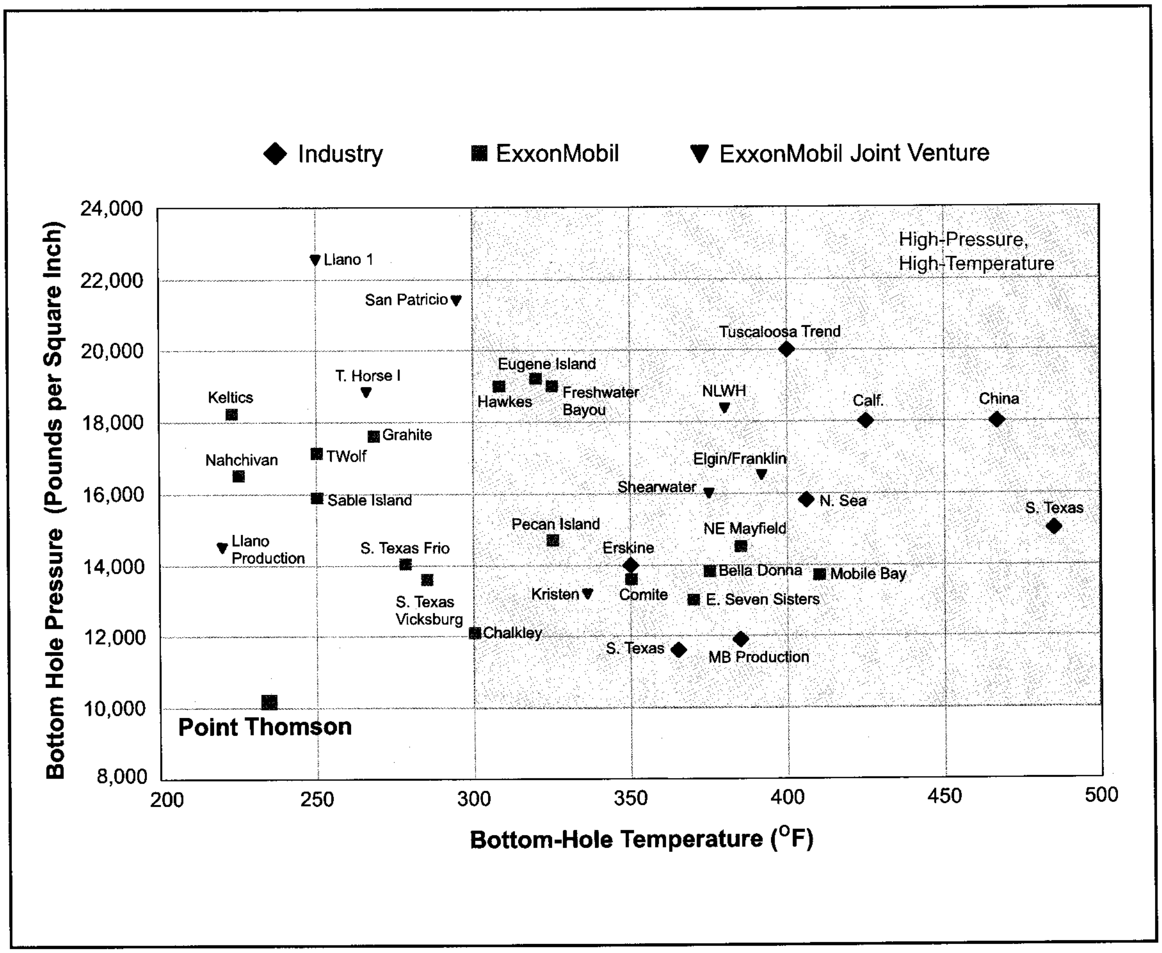


FIGURE 3-1
World Experience in High-Pressure, High-Temperature Drilling

most critical to maintaining overbalance in the well. All these logging tools provide real-time information on downhole conditions, and this information will be displayed at the driller's console as well as in Anchorage and Houston, Texas, to assist personnel in controlling well pressures.

In conjunction with the downhole logging tools, surface logging (called *mudlogging)* is used to identify the characteristics of the rock formations and the fluid content from the drill cuttings which the mud carries to the surface. The mudloggers also collect and process drilling data that are used to identify increasing formation pressure and assess the open-hole conditions. Supervisors, engineers, and rig-site geologists use this information, together with the electric logging data, to adjust the mud weight to control the well pressure and to provide mechanical stability to exposed formations.

The primary means of controlling downhole pressures is the drilling mud. Secondary means of controlling pressures include the blowout prevention (BOP) equipment, casing and cementing program, and pressure-testing protocols that follow after each casing is installed and cemented. Trained personnel are key to detecting changes in the well that could lead to a *kick*, or inflow of formation fluids into the well. A kick can occur only if the formation pressure exceeds the mud weight and the formation is permeable so that fluids can flow. When not handled correctly, a kick can escalate into a situation that releases downhole pressure and with it the potential for a release of uncontrolled formation fluids (i.e., blowout). Redundant systems in the Point Thomson drilling program will reduce the risk of such an occurrence.

Figure 3-2 provides a schematic of how the primary and secondary barriers — drilling mud and BOP equipment — work together to control downhole pressures. Drilling mud is kept in open-top tanks to allow sampling, testing, and monitoring of fluid levels. The drilling mud is then pumped downhole through the drill pipe that is inserted through the BOP equipment. The drilling mud exits the drill bit and moves back up the well.

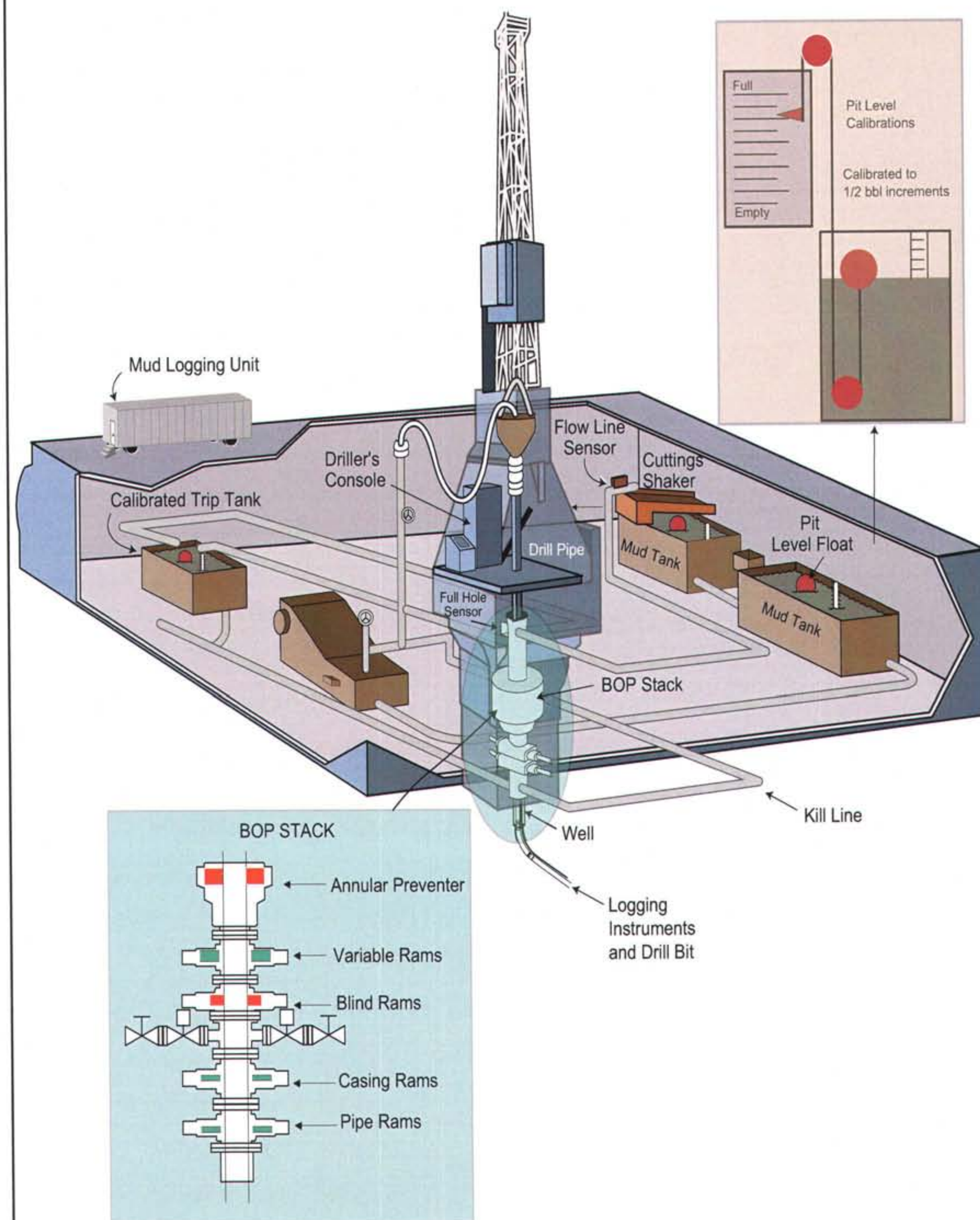
3.2.2 Point Thomson Drilling Fluids Program

As discussed above, the drilling muds, or fluids, used in drilling a well are critical because they keep formation fluids from entering the well. To ensure an ample supply of drilling mud is always available at Point Thomson, a complete mud plant and storage facility will be built to support drilling operations. ExxonMobil policy is that higher-pressure wells such as those at Point Thomson are drilled in an overbalanced condition. *Overbalanced drilling* is the name given to the practice where mud weight is maintained at a higher level than the pore pressure of the formations. Typical overbalance is approximately 250 psi greater than formation pressure to prevent flow while drilling or tripping (removing the drill string from the well bore).

The basis of any drilling fluids program is the *pore pressure* and the *fracture gradient* of the rock. Basically, the pore pressure is the pressure of the fluids in the reservoir — in the case of the Thomson Sand reservoir, this pressure is high at approximately 10,250 psi. Drilling engineers use another value to express pressure: *equivalent mud weight* in pounds per gallon (ppg), because mud weight is measured at the well site in these units. Fresh water weighs 8.34 ppg, while the mud planned for drilling the Thomson Sand is much heavier at approximately 16.0 ppg (formation pressure is about 15.4 ppg). Because drilling mud is the first line of well control, the weight of the mud must be sufficient to control the pore pressure in the open hole. Thus, a pore pressure of 15.4 ppg requires drilling mud with a minimum weight of 15.4 ppg to prevent flow. Adding an overbalance provides a greater margin against fluid influx while drilling and removing the drill string from the well. (When the drill string is raised in the well, a suction pressure called *swabbing* is sometimes created which can reduce the hydrostatic wellbore pressure. The rate at which the drill string is removed is limited to avoid swabbing in the well.)

Fracture gradient of the rock is a measure of the mechanical integrity of the formation rock. Drilling engineers must avoid fracturing the exposed rock with the weight of the drilling mud, since the drilling fluid would no longer be contained in the wellbore if the rock fractured. The 19 exploration wells in the Point Thomson area have given ExxonMobil drilling engineers an abundance of data to define the fracture gradient in the field. Table 3-1 shows the preliminary drilling fluids program planned for Point Thomson based on these data. On-site personnel will make additional adjustments to mud properties based on actual hole conditions encountered during drilling and on the analysis of drill cuttings. Mud weight generally increases as drilling proceeds deeper.

At Point Thomson, the casing setting depths have been selected to provide a sufficient operating window between the mud weight and both the pore pressure and fracture pressures to enable overbalanced drilling. This practice can be used at Point Thomson because the formation rock is of high mechanical quality thereby reducing the risk for loss of mud to the formation in any hole section. During the drilling process, the friction generated by circulating the mud from the bottom of the hole to the surface (outside the drill pipe) produces a pressure increase on the bottom of the hole — and



NOTE: This is a schematic drawing. The actual location of the illustrated equipment varies depending on the rig.

FIGURE 3-2
Schematic of Drill Rig Highlighting Blowout Prevention Systems

TABLE 3-1
Typical Point Thomson Drilling Fluids Program (Preliminary)

HOLE SIZE/SECTION			
Low-Angle Well (<17,000 ft MD)	High-Angle Well (>17,000 ft MD)	DRILLING FLUID TYPE	DRILLING FLUID WEIGHT RANGE (ppg)
20-in. Conductor (Preset)	20-in. Conductor (Preset)	N/A	N/A
16-in. hole	16-in. hole	Freshwater Gel	8.8 to 10.0
N/A	14-3/4-in. hole	Non-Aqueous Fluid	9.5 to 12.0
12-1/4-in. hole	12-1/4-in. hole	Non-Aqueous Fluid	9.5 to 13.5
8-1/2-in. hole	8-1/2-in. hole	Non-Aqueous Fluid	13.5 to 16.0

MD = measured depth, ppg = pounds per gallon

because pressure is equivalent to density, this incremental density plus the mud weight is referred to as *equivalent circulating density* (ECD). The ECD is quite important, because it narrows the operating window between fracture gradient and pore pressure (Figure 3-3).

Because mud is so important to well control, special sensors and instrumentation are employed to monitor the entire mud system. These sensors detect changes in volume, rate, pressure, gas content and temperature to assist the drill team in determining that the well is in an overbalanced condition at all times. The output of this instrumentation is displayed at the driller's console and a number of alternate locations.

Experience shows that the entrained gas in the drilling mud is one of the best local indicators that formation pressure is increasing. The mud gas level begins to increase as soon as the formation pressure rises. At Point Thomson, the mudloggers will continuously monitor the gas level in the mud to ensure that even small increases are detected. Some gas — the *background gas* — originates from the pore space within the rock that is drilled and is released because the rock has been ground up. The amount of this gas depends only on the gas content of the rock and does not usually depend on the relationship between hydrostatic pressure (the mud weight) and the pore pressure. This background gas provides the baseline from which any change or deviation may indicate formation pressure changes. Increasing background gas or increases in gas levels when there is no mud circulation are indicators of increasing formation pressure. The gas detected when the mud pump is turned off and a new joint of drill pipe is added is referred to as *connection gas*. In an overbalanced situation, the amount of connection gas is generally small because the mud weight largely offsets the formation pressure and swab effects of making the connection. When mud weight is only slightly greater than formation pressure, elevated and detectable levels of connection gas can result from the reduction of pressure produced by either halting the circulation or by the mild swab produced by lifting the drill string. The stepwise increase of connection gas at each connection is a credible indicator of a decline in the amount of overbalance.

ExxonMobil has developed a diagnostic technique called the *10/10/10 Test* to help evaluate whether an overbalanced situation still exists in the wellbore. This technique is applied at any point in the well but is most valuable when performed in the shale intervals overlying the productive zone (the Thomson Sand). At this point in the well, one necessary component for a kick is missing: the perme-

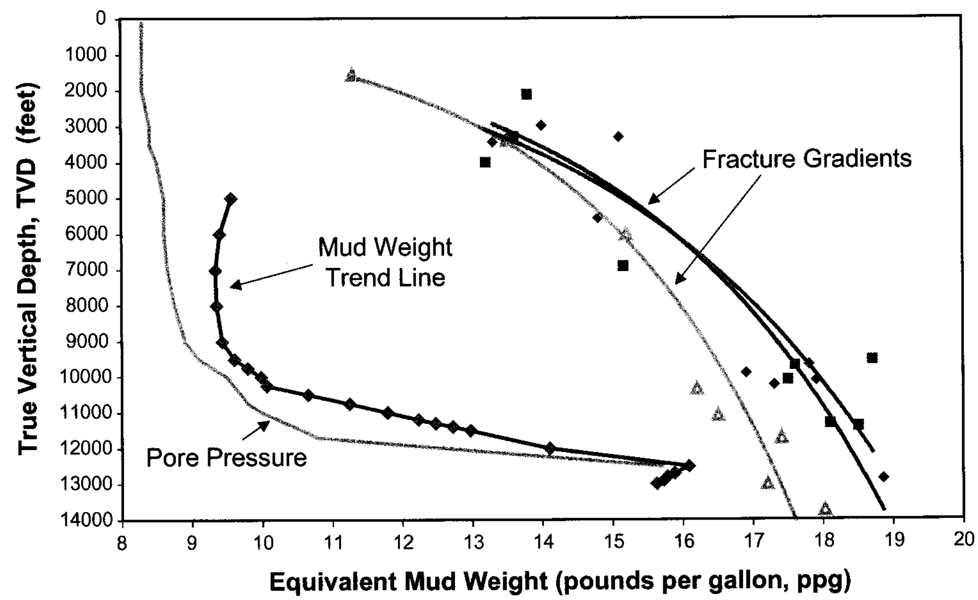


FIGURE 3-3
Drawing of Mud Weight between Pore Pressure and Fracture Gradients

able formation. Testing using the 10/10/10 Test can provide accurate and early diagnostics of the formation pressure before the potential kick interval is reached.

The 10/10/10 Test procedure involves:

a) Circulating the well for 10 minutes to establish background gas,
b) Discontinuing mud circulation for 10 minutes to reduce ECD,
c) Circulating the wellbore for an additional 10 minutes.

Then mud is circulated from the bottom of the well (without further drilling) to the surface (*"bottoms up"*) for evaluation. If the gas levels measured at the surface from bottoms up during step "b" are greater than "a" and "c", there is a positive indication of increasing pore pressure, and mud weight will be increased before further drilling. Conversely, if the gas measured from step "b" is less than "a" or "c", the wellbore is still sufficiently overbalanced. If it was necessary to increase the mud weight, additional 10/10/10 procedures are needed to confirm sufficient overbalance exists before further drilling progress. The mudlogging instrumentation is sensitive enough to detect even the smallest increase in gas — specifically, the gas increase associated with the combination of an increase in pore pressure and the reduction of ECD when making a connection.

The pressure while drilling (PWD) tool behind the drill bit complements these surface detection systems. The PWD sensor directly detects mud hydrostatic pressure just behind the drill bit and transmits the information to surface computers. The PWD tool is capable of recording the static (unmoving) mud pressure, the circulating mud pressure (pumps on), and the changes in downhole pressure while the pipe is moved up or down in the hole. These data are critical to:

- Validate surface measurements of mud weight and density,
- Determine actual ECD pressure in the well,
- Measure the pressure changes generated by axial pipe movement, and
- Determine the efficiency of the mud in removing drill cuttings from the well.

This information can help the drill team select the optimum mud weight, determine optimum flow properties, and choose the best drill-string handling procedures. Because each of these factors influences bottom-hole pressure, improved knowledge gained through these data helps to minimize the probability of kicks and well control events.

During the drilling process, the mud flow into and out of the well is monitored continuously, whether or not the mud is being circulated. Since the circulation system is a closed system, it is possible to identify any unwanted fluid influx or loss. Any unexpected changes in flow rate, volume, temperature, mud gas levels, or pressure would prompt additional attention to diagnose the well condition. This system supplements the monitoring and testing conducted by *mud engineers,* who maintain quality control on the mud. Mud engineers independently monitor mud volumes and routinely measure mud properties to ensure the mud is within specifications and make necessary adjustments as directed by the rig supervisor. In addition, the derrickman frequently measures the weight of the mud both entering and leaving the well and reports that weight over the intercom system to all drilling personnel.

During drilling, an active mud system and a backup reserve mud system are used to store and preserve drilling mud. However, during tripping, a trip tank with a volume of typically 50 barrels is used to measure small changes in mud volume. The well is monitored by measuring the volume of mud placed into, or displaced from, the well. This volume must be equal to the volume of steel (drill pipe and bottom-hole assembly) removed from, or installed into, the well.

Improper hole fill is an indicator of influx or lost returns. Generally, if the mud volume to fill the hole from the trip tank is less than expected while removing the drill string from the hole, an influx or swabbing could be indicated. Historically, many inflow or kick incidents have occurred during tripping when the downhole mud volume was not adequate to match the amount of steel removed. ExxonMobil policy specifies that personnel monitoring mud volumes must be able to detect a kick within 10 barrels of extra volume whether drilling or tripping, and exercises are repeated until proficiency is demonstrated.

In summary, ExxonMobil procedures for high-pressure reservoirs such as Point Thomson specify the following additional safety measures for the drilling fluid program:

- A mud weight sufficient to produce a pressure which is 250 psi higher than what is needed for downhole pressure control.
- Continuous monitoring by mud engineer(s), mudloggers, MWD/LWD and PWD staff, and rig crewmen.
- Calibration of pit volume gauges and instrumentation in the mud tanks to detect small volume changes and report that information to the drill crew.
- Detection of any formation inflow or kick within a 10-barrel volume change.
- Checking mud volumes after each section (*stand*) of drill pipe is removed from the well for the first 10 stands out of the hole on a trip, and every 5 stands thereafter if conditions are normal.
- Running back to the bottom of the hole and circulating bottoms up if improper fill-up occurs while tripping out of the hole.
- Maintaining a written record of hole fill during trips to allow for comparison of trends on successive trips.

3.2.3 Point Thomson Blowout Prevention Equipment

The second barrier for blowout prevention consists of the heavy blowout prevention (BOP) equipment bolted to the well. Blowout prevention equipment is specifically chosen based on the well design and on expected pressure and temperature. Figure 3-4 shows the configuration of the equipment planned for Point Thomson. The major component of blowout prevention equipment is known as a *BOP stack,* which consists of *blind rams*, *pipe rams,* and an *annular preventer*. The pipe rams are sets of valves designed to close around the drill pipe during drilling operations or around the casing in the event casing is being set in the hole. The blind rams seal the wellbore when there is no pipe in the hole. There are also variable-diameter rams available that can accommodate different sizes of pipe or casing. The annular preventer, which is the top element of the BOP stack, is designed to seal off an open hole or any-size pipe in the hole by hydraulically deforming packing material. The BOPs are closed using hydraulic fluid with pressure from an *accumulator unit* (shown in Figure 3-5) that is independently powered by both electric and pneumatic pumps. Although not often used, the ram-type preventers can be manually operated in the unlikely event all power sources and control lines were to fail.

ExxonMobil plans to have an extra set of rams in the BOP stack at Point Thomson, in addition to those rams required by AOGCC regulations. A BOP stack with four sets of rams and one annular preventer will be used to drill below surface casing. The rams and annular preventer will all be rated to 10,000 psi working pressure. Furthermore, all BOP equipment will be from the original equipment manufacturer.

The BOP stack is installed on the surface casing. Before the surface casing is installed, a special annular preventer (the *diverter*) is attached to the conductor casing. The diverter is not intended to shut in the well; rather it is used to divert any shallow gas away from the rig. Because shallow gas problems have not occurred at the Point Thomson field, the diverter will be initially employed as a precaution as required by AOGCC.

Another component of the BOP equipment is the *choke manifold*, which is attached to the BOP stack at the location shown in Figure 3-4. The manifold itself is a collection of valves that control wellbore pressures and route the fluids to devices used to remove entrained gas from the mud. The choke manifold is employed only when a BOP has been closed due to a well kick and it is necessary to circulate the formation fluids from the wellbore.

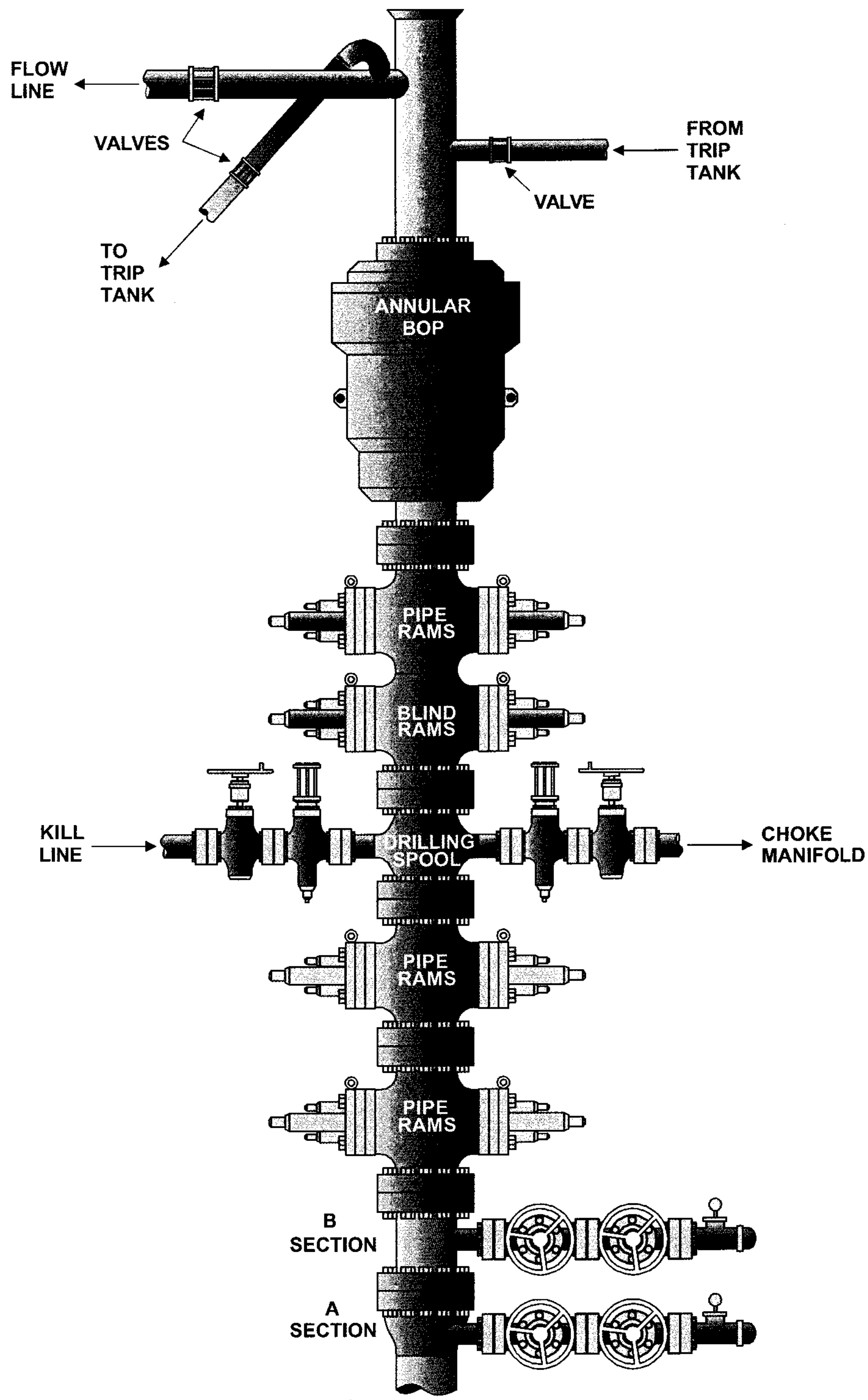


FIGURE 3-4
Schematic of Blowout Prevention Stack to Be Used at Point Thomson

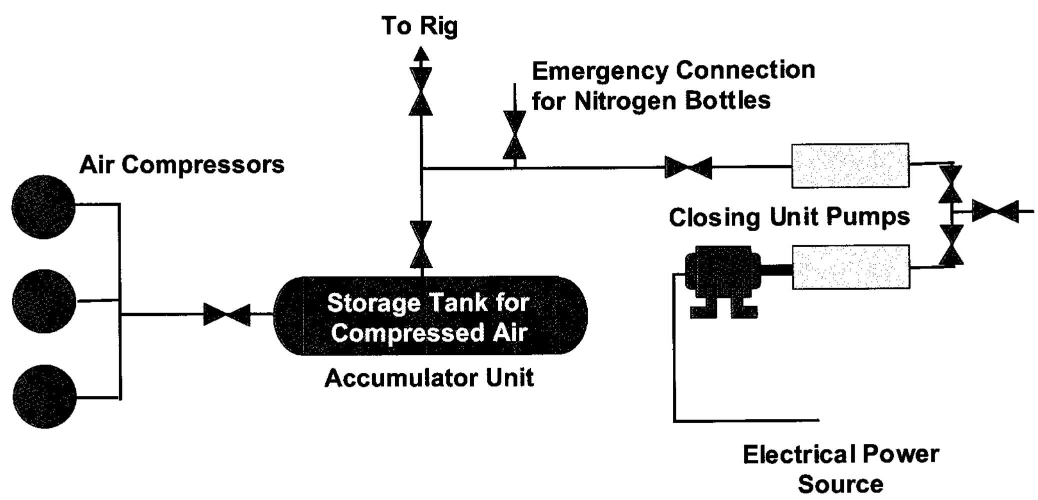


FIGURE 3-5
ExxonMobil Arrangements to Ensure Independent Redundancy in BOP Control Power Sources

The BOPs are intended to seal the annulus, which is the area between the casing and the drill pipe. In order to prevent flow up the inside of the drill pipe if a kick occurs — particularly on trips when the top of the drill pipe is open to the atmosphere — special valves located on the drill floor can be installed and closed. These valves secure the inside area of the drill pipe and prevent upward flow in the drill pipe but do permit pumping downward to control the well.

At Point Thomson, an auxiliary piece of fluid containment equipment — a *drill-string float valve* — will be installed in a specially designed piece of pipe just behind the drill bit (Figure 3-6). The float valve, which is spring-loaded, allows drilling mud to be pumped through, but closes and limits inflow of fluids from the formation while the drill-pipe valves are installed at the surface.

All of the preceding BOP equipment will be pressure-tested at installation and as required by AOGCC regulations during the course of drilling the well. The equipment will be tested before installation to the full rated working pressure of 10,000 psi; subsequent ram pressure tests will be in accordance with ExxonMobil policy and will meet or exceed AOGCC requirements. The annular preventer pressure test will be to 70 percent of rated working pressure — more than the 50 percent required by AOGCC. Furthermore, all well control training, operational practices, procedures, and rig equipment selection will also be conducted in accordance with AOGCC regulations and ExxonMobil standards.

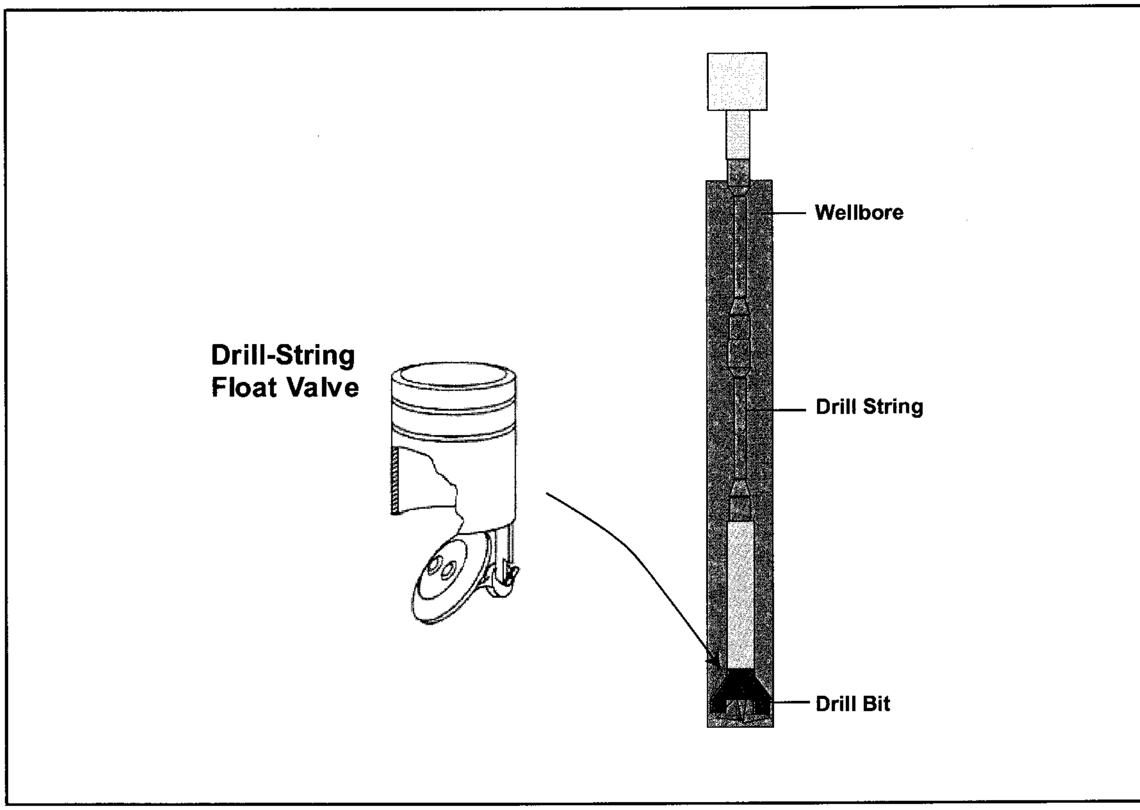


FIGURE 3-6
Drill String Float Valve for Use at Point Thomson

3.2.4 Point Thomson Casing Program

The primary functions of the casing strings placed in the well are to contain pressure and isolate weaker formations so that deeper drilling is possible. As discussed earlier, as the well is drilled deeper, the diameter of steel pipe used for casing the well is progressively smaller because the casing is placed concentrically within the previous casing string. Each string of casing pipe is cemented in place. The first and largest-diameter pipe to be set is the *conductor*, which gives structural integrity to the well and facilitates mud circulation in the early phase of drilling. The *surface casing* is the next string of pipe to be cemented into the well and serves as an anchor for the BOP equipment. *Intermediate* and *protective casings* isolate the formations between the surface casing and above the production zone. The *production liner* is a partial string of casing that is run and cemented across the productive interval of the well. After the production liner is placed, a string of tubing (*production tieback*) is run into the well to connect the production liner to the surface.

Internal forces, such as drilling or production fluids, and external forces from the formation exert pressure on casing. Internal forces can lead to a casing burst, while external forces can lead to a casing collapse. Casing and tubing are chosen based on these load conditions plus a safety factor. ExxonMobil's development well design, including casing seat locations, is based on Point Thomson exploration and appraisal well design, reservoir modeling, and North Slope drilling practices. The two basic well designs shown in Figure 3-7 have been drafted based on the length or *measured depth (MD)* of the well. The casing to be used in these wells is specifically chosen for strength, with a burst

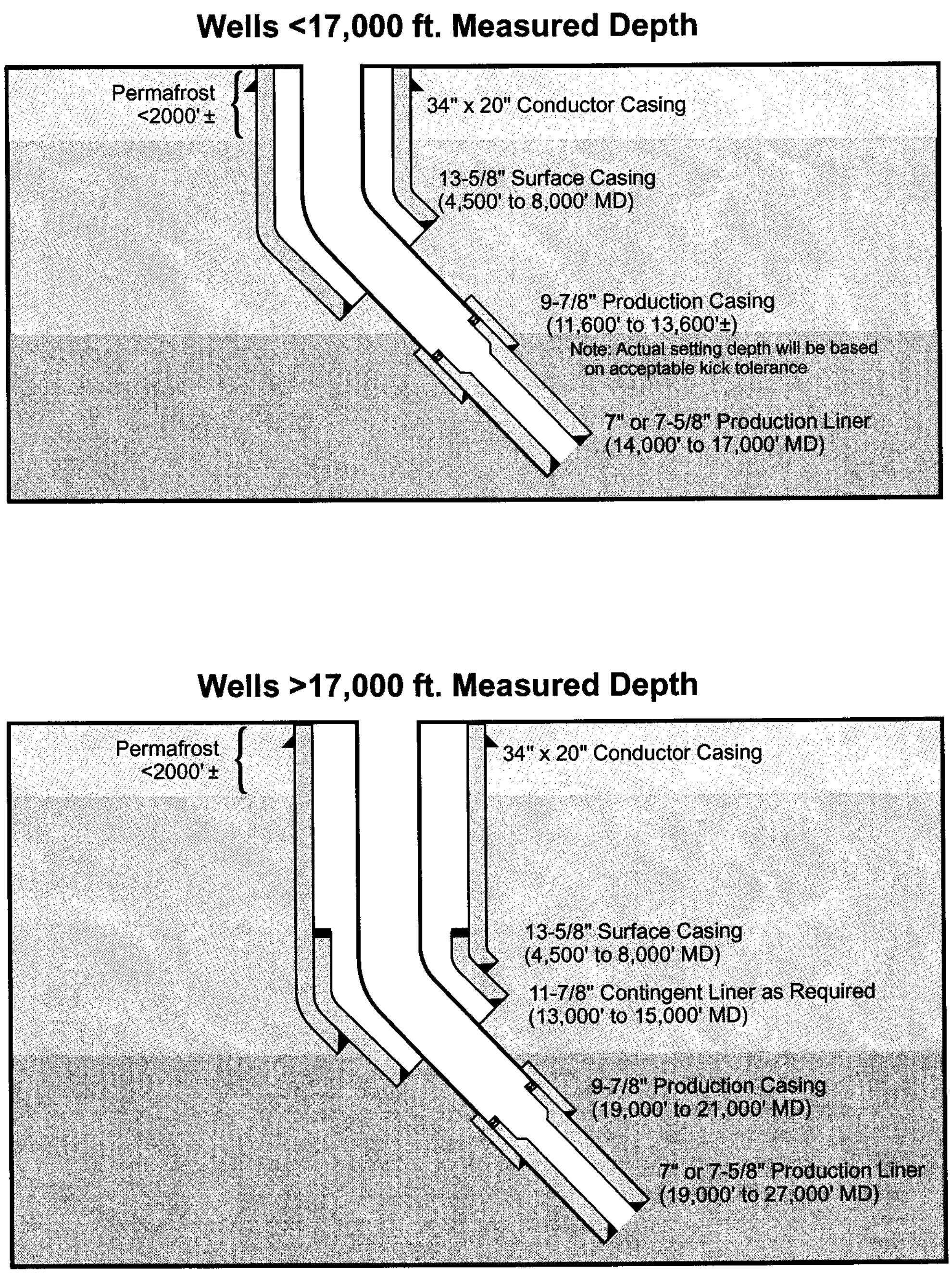


FIGURE 3-7
Point Thomson Well Casing Program

safety factor of 37.5 percent on surface and intermediate casing and 25 percent on production tubing, production casing, and liner. The collapse safety factor is 12.5 percent for tubing and production casing or 23.8 percent if protective casing (used as production casing) is subject to drilling wear. A key component of the casing program is that casing will be qualified before it is used in wells. This qualification process involves testing samples of casing to ensure that it has the required properties to withstand conditions in the Point Thomson reservoir.

A typical Point Thomson development well is anticipated to have the following casing strings (Table 3-2):

- **34"x20" Conductor Casing:** The conductor hole will be drilled, and the conductor will be cemented in place for all wells at approximately 80 feet true vertical depth (TVD) during drill pad construction. Conductors will be insulated and designed to minimize thawing of adjacent permafrost.
- **13-5/8" Surface Casing:** This casing will nominally be set within the Sagavanirktok Formation and isolates the permafrost. This string will provide well control integrity by placement of the casing into stronger formations, thus anchoring the BOP stack. This casing string will be cemented to surface.
- **11-7/8" Intermediate Casing:** This contingent casing will be used as required to ensure the protective/production casing on the deeper wells can be set in the pressure transition zone. If this casing is used, it will provide isolation to weaker zones that may cause mud loss.
- **9-7/8" Protective/Production Casing:** This casing string will be placed in the interval of increasing pressure to isolate all weaker zones above the casing shoe. It provides well control for deeper drilling into the production zones. The bottom 3,000 feet of this casing will be cemented, and the cement slurry will be designed to avoid annular gas flow while the cement sets.
- **Production Liner:** The well will reach total depth at the base of the Thomson Sand reservoir at approximately 13,300 feet TVD. Use of a production liner for isolating the

TABLE 3-2
Typical Point Thomson Production and Injection Well Casing Program (Preliminary)

CASING / HOLE SIZE			
Low-Angle Well (<17,000 ft MD)	High-Angle Well (>17,000 ft MD)	SETTING DEPTH (TVD)	FORMATION
20-in. Conductor (Preset)	20-in. Conductor (Preset)	±80 ft	N/A
13-5/8-in. Surface Casing/ 16-in. Hole	13-5/8-in. Surface Casing/ 16-in. Hole	±4,500 ft	Sagavanirktok (Tertiary)
N/A	11-7/8-in. Intermediate Casing/14-3/4in. Hole	As Required	
9-7/8-in. Protective/ Production Casing/ 12-1/4-in. Hole	9-7/8-in. Protective/ Production Casing/ 12-1/4-in. Hole	±10,800 ft	Canning (Lower Tertiary)
7-in. or 7-5/8-in. Production Liner/ 8-1/2-in. Hole	7-in. or 7-5/8-in. Production Liner/ 8-1/2-in. Hole	±13,300 ft	Thomson Sand (Lower Cretaceous)

MD = measured depth, TVD = true vertical depth producing formation will eliminate annular gas flow to the surface while cement is setting, which is possible with a full casing string. The production liner will extend from total depth back inside the 9-7/8" casing and will be fully cemented in place. The production liner will have a liner top packer at the top to ensure good sealing to the 9-7/8" casing.

As each string of casing is set in the hole and cemented in place, casing pressure tests will be run to ensure casing integrity, and then a *leak-off test* will be run to determine formation integrity (the end of the casing as cemented is called the *shoe*). Casing pressure testing will be to ExxonMobil and AOGCC requirements before the cement plug is drilled. After a successful test of the casing string is completed, between 20 and 50 feet of new hole will be drilled and then the leak-off test performed to confirm quality of the cement seal, verify formation integrity, and provide information used to identify the maximum mud-weight limitations for the next section of the well.

Casing setting depths, as outlined in Table 3-2, may be adjusted with new interpretation of mud weight and fracture predictions. Emphasis has been placed on reducing conductor and all casing sizes to minimize cuttings waste discharge. Detailed well designs will be included in the Permit to Drill applications submitted to AOGCC for approval.

3.2.5 Well Paths and Down-Hole Well Monitoring Equipment

AOGCC regulations require that surveys must be conducted to determine well location a minimum of every 500 feet drilled, if a well is going to be deviated from true vertical. ExxonMobil procedures dictate that continuous surveying be conducted for such wells in fields like Point Thomson. The company program also includes *measurement while drilling (MWD)* tools, *logging while drilling* tools *(LWD)*, and *pressure while drilling* (PWD) tools.

Wells at Point Thomson will be largely vertical through the permafrost and then deviate to their targets. This will provide additional separation from other wells as the hole is drilled deeper towards the ultimate bottom-hole target. It is envisioned that surface casing will extend through the section of the hole that defines the well deviation angle (Figure 3-7). This maximum hole angle will be maintained all the way to the reservoir target. This profile will minimize the hole angle required to reach the reservoir target. It is anticipated that the maximum hole angle for any of the wells will be 67°. To achieve these deviated well paths, special motorized equipment is used to steer the drill bit in any desired direction. Associated with these drilling tools are the MWD tools that provide information on the orientation of the bottom-hole assembly and direction of the wellbore. The MWD tools, which use magnetic north and inertial gyroscopes to locate the trajectory of the well bore, are basically surveying instruments located in the drilling assembly above the bit. Figure 3-8 shows a typical bottom-hole assembly incorporating these tools.

The other tools in the drill string (LWD and PWD) provide information pertaining to the rock and the fluid properties within those rocks. The LWD logging tools include the following:

- *Gamma ray,* which measures natural radioactivity used to distinguish shale from sand.
- *Resistivity,* which provides measurement of the conductivity of fluids in the rock, and is used to determine what type of fluids (oil, gas, water) are in the rock pore space.
- *Sonic,* which measures the void volume fraction of the bulk rock volume (porosity) which contains the formation fluids.
- *Density,* which is used to determine rock type to assist in describing to what point in the geologic strata the drilling has progressed.

FIGURE 3-8
Typical Bottom-Hole Assembly for MWD, LWD, and PWD

The information retrieved from the LWD tools can help the drill team to evaluate the geologic zone being drilled, the general amount and type of fluids in that zone, and the proximity of the wellbore to specific upcoming zones. This information allows the drill team to know not only where the bit is but also what lies ahead of the bit so that appropriate plans and preparations can be made before other rock layers are penetrated.

A brief description of the PWD tools was provided in Section 3.2.2 in conjunction with the discussion of the important role of mud in assuring well control. These pressure detection tools measure annular pressure and ECD, and transmit the data to the surface. PWD tools are located typically within 75 feet of the drill bit and gather data as the formation is being drilled. The data are analyzed with specific software and yield real-time information on downhole conditions.

Table 3-3 summarizes the data available through this well-monitoring system, while Figure 3-9 shows a typical computer display of the data. The computers at Point Thomson will be networked to ExxonMobil headquarters so that if the need arises, specialists from around the world can assist with Point Thomson well issues. This real-time analysis of well conditions is an important element of ExxonMobil's ability to safely drill wells in the Point Thomson Unit.

3.2.6 *ExxonMobil Pressure Hunt Team*

Although not required by regulation, a designated group of on-site personnel at Point Thomson will interpret the real-time drilling information previously discussed. This *Pressure Hunt Team* serves as an additional measure to prevent loss of well control. The team's mission is to detect overpressure, prevent a kick, and prevent lost returns of mud to the formation. In ExxonMobil drilling programs, the team usually consists of the following members: drilling supervisor (team lead), well site geologist, drilling engineer, paleontologist (if required), mudloggers, and rig hands such as the driller and derrickman. Before drilling starts, team members review the pressure-hunt goal established and their duties to help accomplish their mission. To establish the normal well pattern, all team members begin monitoring the well before higher pressures are encountered so that they are able to detect pressure increases. Team members receive additional specialized training.

TABLE 3-3
Real-Time Parameters Available to Well Site, Anchorage, and Houston

MUDLOGGING	**MWD/LWD**
MD, Bit Tracking	*Directional*
ROP, RPM, Torque	*Formation Evaluation*
Pressures	*Gamma*
Flow	*Resistivity*
String Weights	*Porosity*
Fluid Density	*Density*
Pit Volumes	*Sonic*
	Pressure While Drilling
CEMENTING	*Annular Pressure*
Pressure	*ECD*
Density	*Downhole WOB, Torque*
Flow Rate & Volume	

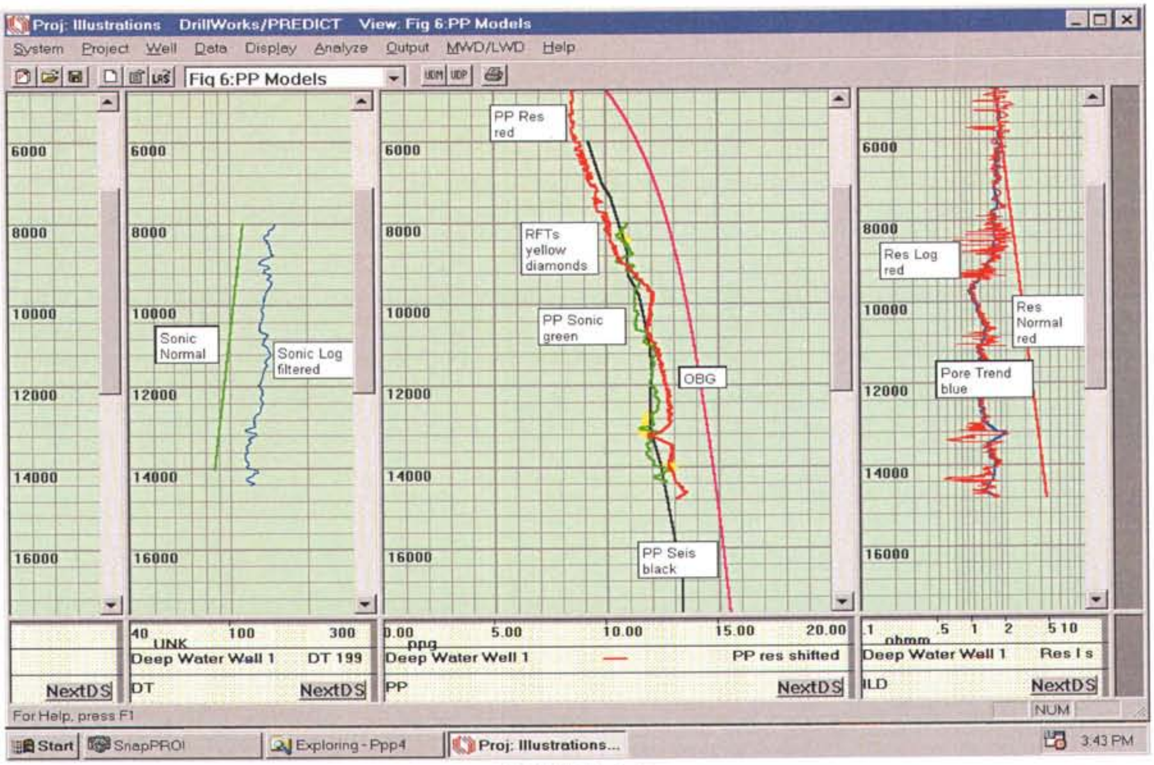


FIGURE 3-9
Sample Real-Time Computer Display of Well Logging Information

3.3 TRAINING

All persons-in-charge who participate in open-hole drilling or workover operations — such as toolpushers, drillers (or functional equivalent), or operations supervisors — are required to have sufficient training to ensure competent performance of assigned well-control duties. ExxonMobil conducts additional training that contains supplemental information specific to high-pressure drilling operations. Before startup, the rig team will have received a training program entitled *Training to Reduce Unexpected Events* (TRUE), which includes practices for high-pressure drilling.

A *pre-spud meeting* is conducted before drilling operations begin on each well. The detailed drilling program is presented to the entire rig crew and specialty contractors so that the entire team understands the plans for the well.

Appropriate personnel also participate in well-control proficiency drills according to ExxonMobil policy. Three types of drills are specifically run to maintain well control skills: *trip drills*, *pit drills*, and *power choke drills*. Trip drills are intended to reduce the time necessary for the driller to detect and react to changes in the well during a trip. The standard is to detect a 10-barrel gain in drilling mud volume within 1 minute and have the well shut in within 2 minutes. Pit drills are designed to reduce the time necessary for drillers, drill crew, mud engineers and mudloggers to detect and react to pit level changes. The industry standard for this drill is to detect a 10-barrel drilling-mud-volume gain within 2 minutes and have the well shut in within 2 minutes. The trip and pit drills are conducted with each crew until the crewmembers are proficient, and weekly thereafter. Both types of drills are unannounced.

Power choke drills are conducted after casing is set. Participants practice starting the well control pumps and operating the choke to gain proficiency in the timing and coordination required to bring pumps on line for kick circulation.

3.4 DRILLING SCHEDULE

ExxonMobil currently plans to mobilize the drilling rig(s) to the field over open water in the summer. The rig(s) and infrastructure will be prepared and the actual drilling will begin in October. Assuming year-round drilling, ExxonMobil estimates the time required for drilling and completing the planned 21 wells plus one disposal well at Point Thomson is 4.5 rig-years, which results in a period of approximately 34 months (October 2005 through July 2008). If seasonal drilling restrictions similar to those in place for other North Slope facilities were imposed, the estimated drilling and completion time at Point Thomson would increase to 6.6 rig-years. In this case, the surface holes would be drilled first, and deeper drilling would occur only during winter. Idle rig time would occur during the summers, and it would take until March 2009 to complete the wells (an additional 8 months).

ExxonMobil's drilling schedule is based on maximizing safety and efficiency, as well as ensuring the economic feasibility of the Point Thomson project. The schedule is based on drilling startup in the fall, immediately after the drill rig(s) are transported to Point Thomson by barge during the summer open-water season. This timing allows for drilling of the first wells into the Thomson Sand reservoir during winter, when any fluid release from a well-control incident could be more easily contained and cleaned up. Furthermore, the sequencing of wells with this schedule permits drilling the shortest-reach wells before the more-challenging long-reach wells. Under seasonal drilling restrictions, the sequencing of the wells would be driven by the need to schedule wells to fit the acceptable drilling window rather than drilling the less complex wells first. If wells had to be suspended above the target reservoir, subsequent wells could not be fine-tuned based on the knowledge gained from the previous wells.

The year-round drilling assumed in the drilling schedule has significant drilling safety benefits because each well can be drilled to completion before moving to the next well. This minimizes the operations required to suspend and reenter wells and to shutdown and restart the rig — operations that have a higher risk of well-control issues and human error while also introducing the risk of losing experienced crews. It also minimizes simultaneous drilling and production operations.

Year-round drilling also has significant environmental benefits. It minimizes the number of pad-to-pad rig moves, allows necessary moves to be made in the winter months on frozen roadways, and minimizes transfers of fuel, equipment, and mud supplies, as well as the disconnection and reconnection of lines and pipes. It allows for the Class I disposal well to be drilled first, providing for efficient disposal of drilling wastes, and minimizes air emissions from rig operations because it allows for early use of clean-burning natural gas to replace diesel for rig fuel. Two wells into the Thomson Sand are needed to make fuel gas available for drilling operations (one well produces, while the other is used to inject the condensate). If drilling starts in mid-October, it may not be possible to complete both wells and the Class I disposal well before seasonal restrictions begin the following spring. Finally, year-round drilling eliminates the need for maintaining the rig in standby and the attendant air emissions from burning fuel. The base schedule estimates a total of over 400 rig standby days under seasonal drilling restrictions.

Economically, year-round drilling provides significant benefits because it offers the quickest path to first production, maximizes throughput to the sales pipeline earlier in the development, and permits a single demobilization of drilling equipment. Seasonal restrictions on drilling, because of the necessary stop-and-start drilling operations required, result in a great cost penalty for the project, mainly because of the expense involved in standby time for the drilling rig and ancillary services. Drilling costs comprise nearly half the cost for the project.

3.5 COMPARISON WITH AOGCC REQUIREMENTS

As already discussed, ExxonMobil's drilling program for Point Thomson will meet or exceed AOGCC requirements. Table 3-4 summarizes the main components of ExxonMobil's program that prevent a blowout and compares them to AOGCC requirements, with emphasis on those practices that exceed what the regulations require. These components include the drilling fluid program, blowout prevention equipment, well directional surveys, casing and cementing program, Pressure Hunt Team and tools, and training. Some of the highlights of the drilling program include the following:

- An infield mud treatment plant will provide additional rig support and supply.
- The rig mud flow system will be upgraded using equipment with a higher pressure rating.
- The BOP equipment will include extra components beyond state requirements.
- Additional downhole tools will be used to help identify increases in formation pressure.
- Casing and tubing design safety factors will exceed AOGCC requirements, and casing, tubing, and connections will be prequalified.
- A specially trained Pressure Hunt Team will direct the identification of pressure transition zones and minimize the possibility of a hydrocarbon influx.
- Specific training and drills will focus on early detection of kicks and practices for high-pressure drilling.

3.6 DRILLING EMERGENCY RESPONSE PLAN

ExxonMobil is prepared to use a variety of techniques to re-establish well control in the event a kick escalates into a loss of control at the surface. Figure 3-10 graphically displays an analysis of historical industry data regarding well control techniques and the relative frequency each technique was used to regain control of blowing wells (Skalle et al., 1999). The data show that pumping mud and *bridging* (the process of the formation sloughing into the wellbore to shut off the pressure release) occurred most often to regain well control. Cementing operations and repairing/closing the BOPs are also frequently employed to control a blowout.

ExxonMobil has prepared specifically for Point Thomson an emergency response plan for well control incidents. The plan classifies well control events to provide the specific and immediate response actions. The classifications are Level 0 through Level 2/3. A Level 0 well kick is defined as any well control incident that requires the BOP stack or diverter system to be used due to excessive formation pressure or loss of hydrostatic overbalance pressure from the mud. Well kicks can often be controlled without significant delay in normal drilling operations. In the vast majority of cases, the Drilling Supervisors at the drilling location implement well killing procedures as the incident occurs without additional off-site support.

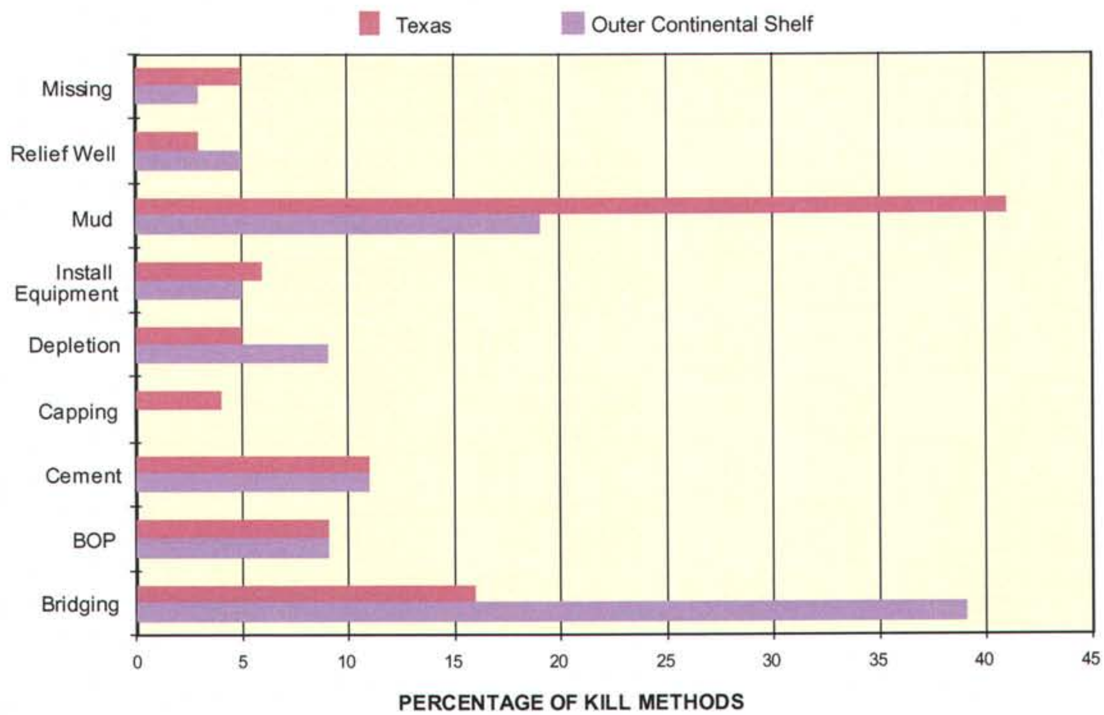
Well kick incidents that continue for more than 24 hours are considered Level 1 incidents, as in a well flow limited to subsurface formations. Team members may be brought in to assist in controlling

TABLE 3-4
Comparison of AOGCC Requirements with Point Thomson Drilling Program

AOGCC REQUIREMENTS	POINT THOMSON DRILLING PROGRAM
Drilling Fluid (Mud) Program	
• Sufficient weight so as to be heavier than expected formation pressures.	• Overbalance pressure will be approximately 250 psi higher than expected formation pressures.
• Maintain sufficient volume of mud to fill the expected well.	• The infield mud plant will provide ample capacity beyond wellsite reserve.
• Test mud once per 12-hour shift to make sure desired properties are maintained.	• Mud will be tested at least once every 6 hours during key portions of the well.
• Check mud level after 5 sections of drill pipe have been removed.	• Mud level will be checked after each stand for the first 10 stands and every 5 stands thereafter on each trip. • Anytime the well has not taken the correct amount of mud, the drill pipe must be run back to bottom.
• Visually observe mud tank to make sure correct amount of mud is taken by the hole.	• Fluid indicators will be calibrated to lowest practical limits. Written trip logs will be maintained for each trip and compared to previous trips.
• Drilling fluid (mud) monitoring equipment must be on-site and used to monitor mud density and salinity.	• Meet AOGCC requirements plus use PWD tools to measure directly the downhole pressure.
Blowout Prevention Equipment	
• Four preventers are required for operations with estimated surface pressure >5,000 psi.	• ExxonMobil will have an additional set of rams as a component of each BOP. There will be a total of 5 preventers rated to 10,000 psi in the BOP stack
• Two sets of pipe rams the size of drill pipe, one set of blind rams, and one annular preventer.	• BOP stack for drilling into the producing zone will be composed of three sets of pipe rams, one set of blind rams, and an annular preventer.
• Each BOP will be tested to 100% of working pressure, except that annular preventers need not be tested to more than 50% of working pressure.	• AOGCC requirement will be met, but the annular preventer will be tested to 70% of working pressure.
Well Directional Surveys	
• Directional surveys are required at no more than 500-foot intervals if the well is intentionally deviated from true vertical.	• Exceeds AOGCC requirements with continuous surveying.
Casing and Cementing Program	
• Casing and cementing program must be designed to provide suitable and safe operating conditions for the total measured depth.	• Casing and tubular connections will be analyzed with finite element analysis and prequalified through physical testing. • Technical specifications for metallurgical properties will be confirmed by testing. • A production liner instead of a full casing string will eliminate the possibility of annular gas flow to the surface. • Cement slurries will be designed to avoid annular gas flow.

TABLE 3-4 (Cont'd)
Comparison of AOGCC Requirements with Point Thomson Drilling Program

AOGCC REQUIREMENTS	POINT THOMSON DRILLING PROGRAM
Casing and Cementing Program (Cont'd)	
• No specific safety factors are required for producing wells. • Injection wells require 25% safety factor for tubing burst.	• ExxonMobil tubing and production casing design policy for this reservoir is a 12.5% collapse safety factor. • ExxonMobil tubing and production casing design policy for this reservoir is 25% burst safety factor and a 37.5% safety factor for surface and intermediate casing.
Pressure Hunt Team and Tools	
• Not required by regulation.	• ExxonMobil will have designated personnel on-site to prevent an underbalanced situation from occurring. • Logging while drilling will be employed to evaluate formation conditions including gamma ray and resistivity at a minimum, all in real time. • Pressure while drilling instrumentation will be used to monitor equivalent circulating density (ECD) in real time.
Training	
• Toolpushers, drillers and persons-in-charge must be trained in accordance with well control standards.	• In addition to well control certifications, field, rig and well-specific training will be provided for all operations personnel. • Training to Reduce Unexpected Events (TRUE) will be provided to all operations personnel. Crews will be trained in the warning signs of potential hazards and driller's response to prevent the hazard from developing. The drilling team will develop a specific action plan for each hole section to be incorporated into the drilling procedures.
• No kick detection standards specified.	• Appropriate crew members will be trained to detect formation inflow (kick) within 10 barrels or less.
• Drills shall be conducted if requested.	• Unannounced trip and pit drills will be conducted by each crew until proficient and as needed thereafter. • Power choke drills will be conducted after each casing string is set to enable rig hands to become familiar with pump startup and friction pressures, choke operation and response.



Source: Skalle et al., 1999

FIGURE 3-10
Analysis of Data Regarding Kill Methods for Blowouts in Texas and the Gulf of Mexico Outer Continental Shelf, 1960-1996

a Level 1 incident. Additional drilling mud supplies and pumps will be mobilized to the site as directed by the Operations Superintendent, who will be responsible for Level 1 responses.

A number of methods can be used to regain control for Level 0 and Level 1 incidents. Among the first used are closing the BOP stack and circulating (pumping) the influx to the surface through the choke manifold in such a manner that the bottom-hole pressure is maintained higher than formation pressure and any additional influxes are prevented. The mud prepared and circulated into the well for this operation would have a higher weight than the original mud in the hole. Once the wellbore is displaced with the new mud, the formation pressure is again safely overbalanced by the hydrostatic weight/pressure of the mud and drilling can proceed. For Level 1 incidents it may be necessary to use additional surface equipment for improved control of well fluids, or to pump cement or other specialty products into the wellbore.

Level 2/3 incidents are those involving loss of control at the surface and release of wellbore fluids. Level 2 incidents can be controlled with resources available in the region (state of Alaska), whereas Level 3 incidents require resources from outside the region. These incidents are directed by the

Drilling Operations Manager with support from a variety of emergency responders. In some instances, the Level 2/3 incident can be controlled by surface intervention methods such as activation of backup equipment, mechanical repairs, or pumping new mud very rapidly (*dynamic kill* method). In the event of a Level 2/3 incident which cannot be quickly controlled at Point Thomson, ExxonMobil has delegated authority to appropriate individuals to ignite the flowing well as the primary means of ensuring personnel safety and limiting environmental impact. Well control specialists would then be mobilized to the site to assist in regaining control through surface intervention of the well. Surface intervention in this instance would require removal of debris, extinguishing the well fire, installation of a special BOP stack, and then closing one or more of the BOPs.

3.7 CONCLUSION

The ExxonMobil drilling program for Point Thomson is designed to ensure that the wells are drilled safely and efficiently and that as many measures as possible are taken to control each well and prevent the release of reservoir fluids. The drilling program includes a mud system designed to contain formation pressure, real-time pressure measurement, a special Pressure Hunt Team to monitor these pressures during drilling, a conservative casing program designed to handle the high pressures, and a highly trained rig crew. ExxonMobil will apply technologies it has developed while working in high-pressure areas since the late 1950s.

Blowout prevention and safety measures will be in place at each stage of the drilling process and with each component of the drilling system. At least two independent safety barriers will be in place at all times, and rig personnel will receive rigorous training in handling well-control incidents. Furthermore, all aspects of the design of Point Thomson wells and the drilling equipment and practices to be used will meet, and many will exceed, regulatory requirements.

Finally, the drilling schedule planned for Point Thomson is designed to maximize safety and efficiency, as well as ensure the economic feasibility of the project. The year-round drilling schedule has significant safety benefits because each well can be drilled to completion before moving to the next well. This minimizes the operations required to suspend and reenter wells and to shutdown and restart the rig — operations that have a higher risk of well-control issues and human error.

SECTION 4
MODELING OF FATE AND BEHAVIOR OF A BLOWOUT PLUME

Despite the extensive measures taken to prevent the uncontrolled release of condensate from a blowout, the remote possibility exists that a blowout from the Thomson Sand reservoir could occur. As a result, ExxonMobil used specialized modeling tools to study the flow of hydrocarbons that would occur in a blowout situation, the dispersion of the ensuing plume and the liquid condensate falling from the plume, and the fate of liquid reaching the Beaufort Sea. This section presents the results of those modeling studies, which are based on the fluid characterization in Section 2.3.2 and on computerized modeling of flow from the reservoir into the wellbore. ExxonMobil's primary tool for modeling dynamic fluid flow in the reservoir and wellbore is EM^{Power}. ExxonMobil also elected to use special-purpose tools specifically designed to model behavior in a blowout situation:

- Titan Research and Technology's SCIPUFF model to predict the condensate falling from the plume,
- Applied Science Associates' OILMAP model to map the spill trajectory on water, and
- The SCREEN3 model to determine the air quality impact of a burning condensate blowout.

Based on the modeling studies, an unignited blowout at Point Thomson could release large quantities of gas and condensate due to the prolific nature of the Thomson Sand reservoir. In addition, if the blowout was not ignited, the released condensate could cover a large area of land and water, increasing both the logistical and tactical difficulties associated with a spill response. However, past experience and modeling show that an ignited blowout would not have a significant, lasting impact on air quality and would greatly reduce impacts to land and water. Condensate blowouts documented in the technical literature show that combustion efficiencies are extremely high, that a large percentage of the unburned condensates evaporate or disperse into the environment, and that the effectiveness of mechanical recovery of spilled oil is limited.

To minimize the volume of liquid condensate that could fall to water and/or land from a blowout, ExxonMobil procedures support voluntarily ignition within 2 hours if a blowout is releasing significant quantities of liquid. Both modeling results and documented case histories show that the effectiveness of voluntary ignition is independent of season — i.e., voluntary ignition significantly reduces the condensate discharge that reaches land and water. Section 5 discusses ExxonMobil's blowout ignition criteria.

4.1 BLOWOUT SIMULATIONS

The blowout modeling computer program, which relies on the characteristics of the reservoir fluid determined by the modeling described in Section 2.3.2, predicts the flow of hydrocarbons from the subsurface reservoir into and up the wellbore to the surface. Because blowouts do not occur instantaneously, but over time scales that vary from several minutes to several days, the computer models calculate the changes in pressures, flow rates, fluid densities, and wellbore contents as these quantities change over time. The pressures and fluid characteristics vary with distance between the reservoir and the earth's surface. The model assumes that the blowout fluids move unobstructed up the annulus between the 5-inch-diameter drill string and an 8.5-inch hole or the 9-7/8-inch-diameter casing.

The simulation begins by specifying the initial conditions in the reservoir and in the wellbore. Fluids in the reservoir are typically assumed to be in an equilibrium state. In normal drilling operations, the wellbore contains drilling mud, which, as discussed in Section 3, exerts hydrostatic pressure that keeps the hydrocarbons confined to the reservoir. To initiate flow in the simulated blowouts, the density of the mud is set at an artificially low and insufficient value to simulate a pressure imbalance that initiates flow.

Well-established mathematical equations simulate how fluids in the reservoir move when they are subjected to differences in pressure. The flow rates of the hydrocarbons through the reservoir depend on the properties of both the rock and the fluids. Important formation parameters include the permeability, which is a measure of fluid flow through the tortuous and interconnected pore spaces of the reservoir rock, and the reservoir thickness. The relatively high permeability and thickness of the Thomson Sand are among the reasons for potentially high flow rates in both controlled and uncontrolled flow situations. Similarly, the low viscosity of the gas and the high initial reservoir pressure also contribute to high well productivity.

In addition to these fundamental elements of flow in the reservoir, the mathematical model also considers factors like turbulent flow and wellbore geometry. As simulated time advances and more reservoir fluids are produced, pressures near and at base of the wellbore decline. The model calculates bottom-hole pressure versus time, which is a factor affecting wellbore flow.

The flow of liquids and gases in the wellbore is also integral to the blowout simulation. Equations that describe the movement of these fluids are solved repeatedly as the simulation steps forward in time, thereby continuously updating where the fluids are located, how fast they are moving, and how pressures throughout the wellbore vary with time. Because the wellbore contains only mud initially, the bottom-hole pressure is a function of the weight of the column of drilling mud. The flow of hydrocarbons from the reservoir eventually displaces all of the mud from the wellbore, and the fluid exiting the wellbore changes from mud to a mixture of gas and condensate.

The mathematical description of wellbore hydraulics is complex because the simulation must account for physically diverse phenomena: gravity that counters the upward force of flowing fluids, the interactions between the liquid and vapor phases, and pressure losses associated with friction and the acceleration of fluids to near-supersonic velocities. In addition, the conduit for flow is geometrically complicated. Typically an inclined annulus consists of either the borehole wall or steel casing in the well on the outside, and the varying diameters of the drill string on the inside. Finally, the rates and pressure of the fluids entering the wellbore must match the rates and pressures of the fluids exiting the formation, while the rates and pressure at the top of the wellbore must match the requirements for flow from an orifice to the atmosphere.

Based on the special-purpose blowout simulation, the expected flow rates that would be encountered in the unlikely event of a Point Thomson blowout are 465 million standard cubic feet per day of gas and 27,000 barrels of condensate per day.

4.2 PLUME DISPERSION AND SPILL FATE MODELING

Based on the characteristics of the reservoir fluids and behaviors determined above, three important components of a simulated blowout at Point Thomson were evaluated:

- The amount and distribution of liquid condensate that will fall to land and water from an unignited blowout plume,
- The on-water trajectory and fate of the liquid condensate, and
- The air quality impacts from an ignited blowout.

These consequence factors have an important bearing on the development of effective spill contingency planning for the Point Thomson development. To determine the most effective combination of personnel and equipment for response, spill response planners need to know the volume of condensate and how it will move in the environment. Furthermore, plans to voluntarily ignite a blowout as quickly as possible will be in place to reduce the risk to personnel and to minimize the amount of liquid condensate reaching the waters of the Beaufort Sea.

4.2.1 Fate of Unignited Blowout

A. Deposition of Liquid Condensate

ExxonMobil studied the simulated gas condensate plume from an unignited blowout at Point Thomson using a computer model known as SCIPUFF to determine the amount and distribution of the liquid condensate that would fall to earth. Condensate liquids produced from the Point Thomson reservoir contain volatile compounds that rapidly evaporate when released into ambient air. In the past, North Slope contingency plan scenarios for hypothetical blowouts involving black oils have been simulated using a dispersion model developed by S.L. Ross (ACS, 1999, Tactic T-6). This model is inappropriate for a condensate blowout because it cannot properly account for condensate vaporization in ambient air. SCIPUFF is a state-of-the-science puff dispersion model chosen because of its capabilities to:

- Account for droplet vaporization and fallout,
- Simulate the full distribution of particle sizes, and
- Simulate actual hourly-sequential meteorological data.

Furthermore, SCIPUFF is approved by the U.S. Environmental Protection Agency for regulatory applications [designated as an alternative model by the EPA in Appendix B of the *Guideline on Air Quality Models* (published as Appendix W to 40 CFR Part 51)]. EPA recommends SCIPUFF as an alternative model for use on a case-by-case basis for regulatory applications when no standard EPA-approved model applies. EPA's standard regulatory models are not appropriate for blowout applications with volatile condensate liquids.

The SCIPUFF model was developed by Titan Research and Technology (Titan, 2003), and it has been incorporated into the U.S. Defense Threat Reduction Agency's Hazard Prediction and Assessment Capability (HPAC) software. HPAC is used for planning and analysis, and military personnel use it in the field to rapidly determine consequences of dispersing chemical, nuclear, and biological agents. SCIPUFF has been validated against a number of laboratory and field experiments, demonstrating its usefulness for non-military applications.

SCIPUFF is a generalized Gaussian puff model that describes three-dimensional, time-dependent dispersion. A generalized puff description describes wind shear, and includes splitting and merging of puffs (Figure 4-1). Puff interactions allow description of nonlinear phenomena, including plume

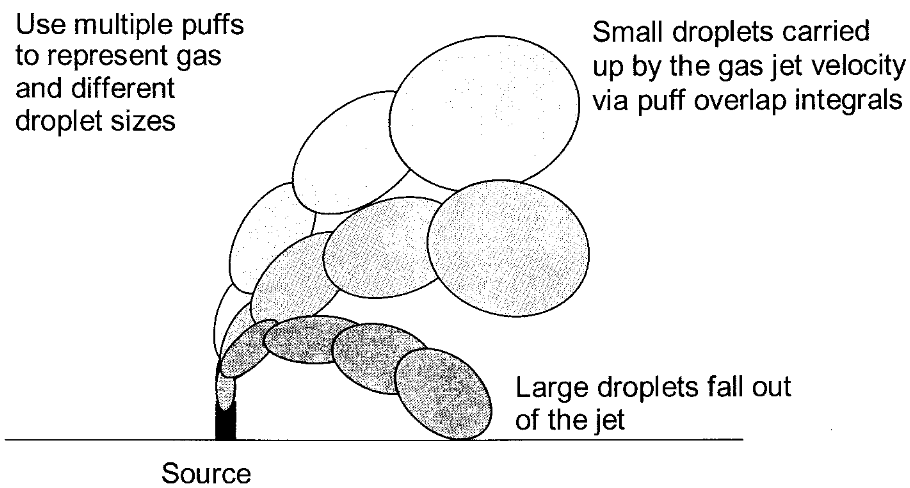


FIGURE 4-1
Schematic Plume Used in SCIPUFF Model

rise due to buoyancy and momentum. Generalized material description includes multiple droplet/particle size bins, and liquid droplet evaporation in addition to the vapor component. The output of the model is the mass of liquid that falls out of the blowout plume, as well as the width and area of the plume.

While the SCIPUFF model can simulate vaporization from liquid droplets in ambient air, it can only simulate a single hydrocarbon compound rather than the full multi-component composition of the blowout plume. ExxonMobil estimated condensate vaporization by simulating the liquid compound representing the largest fractional component of the liquid [i.e., dodecane (C_{12}); Table 4-1]. To estimate the percentage of dodecane vaporization during dispersion, the drop size distribution of the liquid was also estimated and input to the SCIPUFF model. Predicting liquid drop-size distribution for a well blowout is a difficult technical problem because no field data exist. For Point Thomson, data were calculated considering only sonic-to-subsonic mechanical breakup of the liquid flow;

TABLE 4-1
Summary of Condensate Characterizations for Release to the Atmosphere (Mole Percent)

COMPONENT	PRODUCED GAS STREAM	WELLHEAD LIQUID FOR BLOWOUT (290 PSIA @ 210°F)	WELLHEAD LIQUID FLASHED TO 40°F AND 14.65 PSIA	
N_2	0.6%	0.0%	0.0%	
CO_2	4.4%	0.5%	0.1%	
Methane	83.8%	5.3%	0.4%	
Ethane	4.2%	0.9%	0.3%	
Propane	1.7%	0.8%	0.6%	
I-Butane	0.4%	0.3%	0.3%	
N-Butane	0.6%	0.7%	0.7%	
I-Pentane	0.2%	0.5%	0.5%	
N-Pentane	0.3%	0.6%	0.6%	
C_6	0.5%	3.3%	3.6%	
C_7	0.4%	6.0%	6.4%	
C_8	0.4%	9.0%	9.6%	↑ Non-Persistent Components
C_9	0.3%	7.8%	8.3%	
C_{12}	1.1%	33.7%	35.9%	
C_{17}	0.7%	20.4%	21.8%	↓ More Persistent Components
C_{27}	0.3%	8.5%	9.1%	
C_{42}	0.0%	1.3%	1.3%	
C_{65}	0.0%	0.3%	0.3%	
C_{86+}	0.0%	0.1%	0.1%	
Water	0.1%	0.0%	0.0%	
TOTAL	~100%	~100%	~100%	

both supersonic mechanical breakup and thermodynamic flash breakup were ignored. The method was tested by successfully simulating the Uniacke condensate well blowout described in Section 4.3.2.

Conservative assumptions were used for the model. For example, the predictions of droplet size distribution used are conservative for Point Thomson well blowout cases because additional droplet breakup mechanisms of flashing and supersonic flows were ignored. It is expected that the plume will exceed the speed of sound as it exits the well, and this may produce even smaller droplet sizes. Furthermore, thermodynamic flashing of stream components typically produces very small drops. Wellbore hydraulics output from the well blowout modeling provided the input for plume and dispersion modeling.

Following are other key input parameters used for modeling the dispersion of the blowout plume:

- The drill pipe is in the hole (hole diameter 8.5 inches and drill-pipe outside diameter 5 inches).
- Flow rates are 465 million standard cubic feet per day of gas and 27,000 barrels of condensate per day.
- Blowout duration is 15 days.
- The condensate characteristics are those presented in Table 4-1.
- The water under the plume does not move; i.e., the deposited condensate behaves as if it hit land or solid ice. Another model, OILMAP, is used to forecast the on-water trajectory of the condensate.
- Two wind cases are used: *persistent* winds and *variable* winds based on observed wind data from the Point Thomson area.

In order to examine the condensate deposition field using realistic wind conditions, the hourly surface-wind records were analyzed from a meteorological station located just west of Point Thomson, and two sample 15-day periods were extracted (15-day periods were used since these represent the typical time covered in response scenarios in North Slope contingency plans). The wind records, which cover almost two years, were averaged over 15-day periods starting at midnight on each day of the record. Based on this analysis, two periods were chosen as examples of a persistent wind period and a variable wind period. All 15-day calculations were made using an air temperature of 5°C so that the effects of temperature on the liquid volatility did not complicate the comparison between the different model runs. The wind cases were used for this air modeling, as well as for the on-water fate and trajectory modeling discussed below.

Figures 4-2 and 4-3, respectively, present the results of the plume dispersion modeling for the persistent and variable wind cases, showing the area affected by condensate and the relative volume of the liquid deposition. In these figures, a map of the Point Thomson region is overlain with the modeling graphs.

In reviewing Figures 4-2 and 4-3, it is important to understand that the shaded areas represent the boundaries of condensate deposition and that for the portion that falls offshore, the plots ignore any movement of the water surface. Such movement would carry the deposited condensate away from the footprint of the plume and result in slick thicknesses far less than shown on the figures.

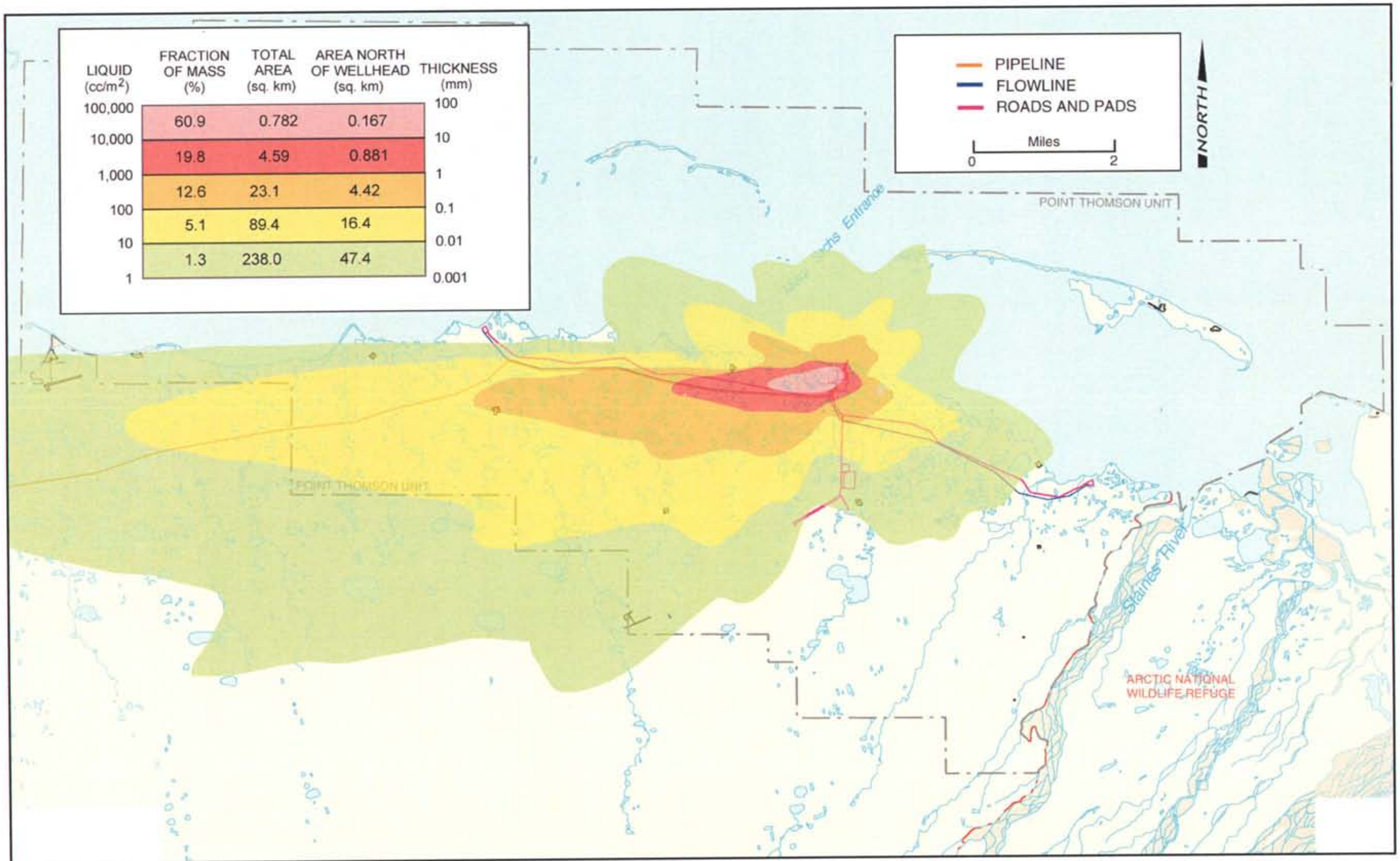


FIGURE 4-2
SCIPUFF Modeling Results for the Deposition of Condensate from a 15-Day Unignited Blowout for the Persistent Wind Case (Assuming no water movement)

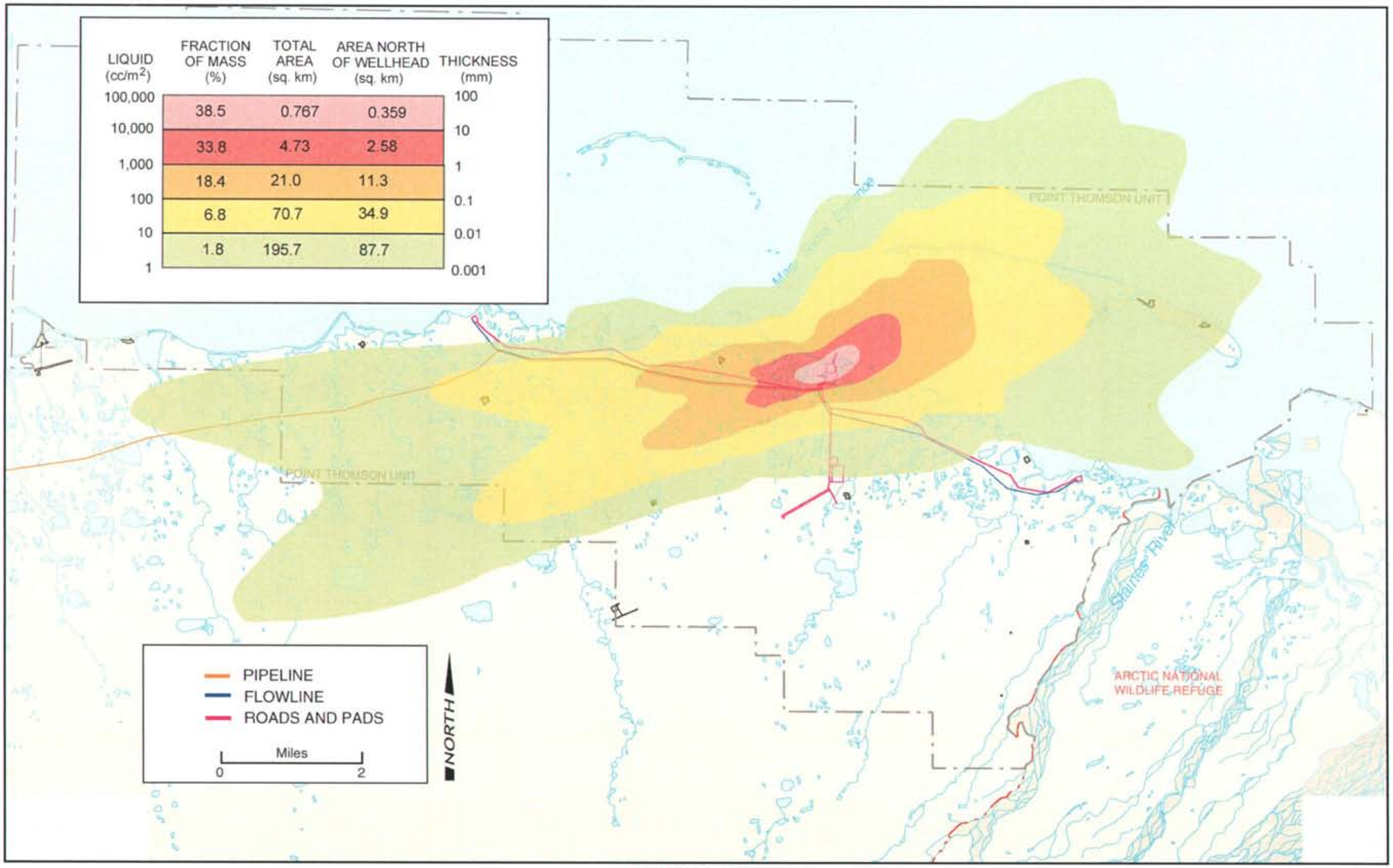


FIGURE 4-3
SCIPUFF Modeling Results for the Deposition of Condensate from a 15-Day Unignited Blowout for the Variable Wind Case (Assuming no water movement)

B. On-Water Trajectory and Fate

The application of the SCIPUFF model to a Point Thomson blowout produced footprints of condensate on the surface that could then be used as inputs for an on-water spill trajectory and fate model. Computerized trajectory models have been available for a number of years and are all based on several basic facts: an oil slick moves with the current at the speed of the current, the slick moves from the wind at 1 to 5 percent of the wind speed, and these two forces are additive. Recent advances in personal computer technology and speed now make it possible for trajectory models to include a Geographical Information System and embedded fate algorithms.

To model the trajectory and fate of the liquid condensate from an unignited Point Thomson blowout, ExxonMobil used Applied Science Associates' OILMAP model (ASA, 2003), which has been applied in a wide range of environmental conditions and with various oils. Trajectory predictions from this model have been validated for numerous spill incidents published in peer-reviewed technical literature. The fate algorithms have been validated in the laboratory and are from peer-reviewed literature.

The data requirements for the model are as follows:

- **Location Data:** High-resolution shoreline map of Beaufort Sea.
- **Fluid Characterization:** Inputs from condensate analysis (Table 4-1) to model physical parameters for condensate and for condensate falling out of the plume (for such parameters as viscosity, interfacial tension, and boiling point).
- **Ocean Current Data:** Wind-driven hydrodynamic data developed for the Beaufort Sea.
- **Wind Data:** Historical gridded wind data that the National Oceanic and Atmospheric Administration uses in meteorological modeling, and wind speed and direction derived from Point Thomson area data.
- **Sea Surface Temperature:** Assumed to be 5°C in open water conditions.
- **Spill Location:** Footprint of condensate deposition estimated from air dispersion modeling.
- **Release Duration and Timing:** Both the persistent wind case and variable wind case are based on actual wind data collected over two separate 15-day periods near Point Thomson.

Figures 4-4 and 4-5 show the OILMAP modeling results for the persistent wind case and variable wind case, respectively, for an unignited blowout. Each figure provides a map showing the trajectory of the slick, as well as graph showing the cumulative fate of the deposited condensate over 15 days as it strands on the shoreline, evaporates, enters the water column, or remains on the water's surface. To be conservative, the trajectory and fate analysis assumed that no cleanup is occurring. The oil available on the water's surface for containment and removal at the end of 15 days represents approximately 5 to 10 percent of the total released for both persistent and variable winds. Approximately 55 to 65 percent of the total released after 15 days has come ashore along the coast as far west as the Sagavanirktok Delta over 40 miles away. The rest has evaporated or entered the water column. Ignition within 2 hours would keep most of this liquid condensate from impacting land or water.

To be conservative, the trajectory and fate analysis assumed that no cleanup is occurring. In the persistent wind case for an unignited blowout, the oil available on the water's surface for containment and removal represents less than 5 percent of the total released after 15 days. Approximately 55 percent of the total released after 15 days has come ashore along coast as far west as the Sagavanirktok Delta over 40 miles away. The rest has evaporated or entered the water column. Ignition within 2 hours would keep most of this liquid condensate from impacting land or water.

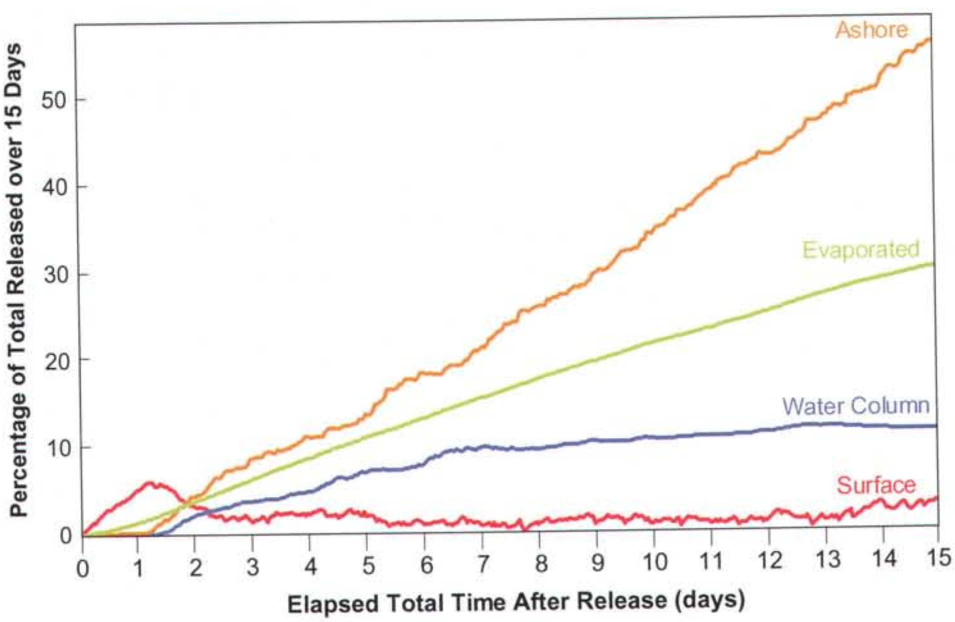


FIGURE 4-4
OILMAP Model Run for Unignited Point Thomson Blowout Case with Persistent Winds

To be conservative, the trajectory and fate analysis assumed that no cleanup is occurring. In the variable wind case for an unignited blowout, the oil available on the water's surface for containment and removal represents less than 10 percent of the total released after 15 days. Over 60 percent of the total released after 15 days has come ashore along coast nearly as far west as the Sagavanirktok Delta over 40 miles away. The rest has evaporated or entered the water column. Ignition within 2 hours would keep most of this liquid condensate from impacting land or water.

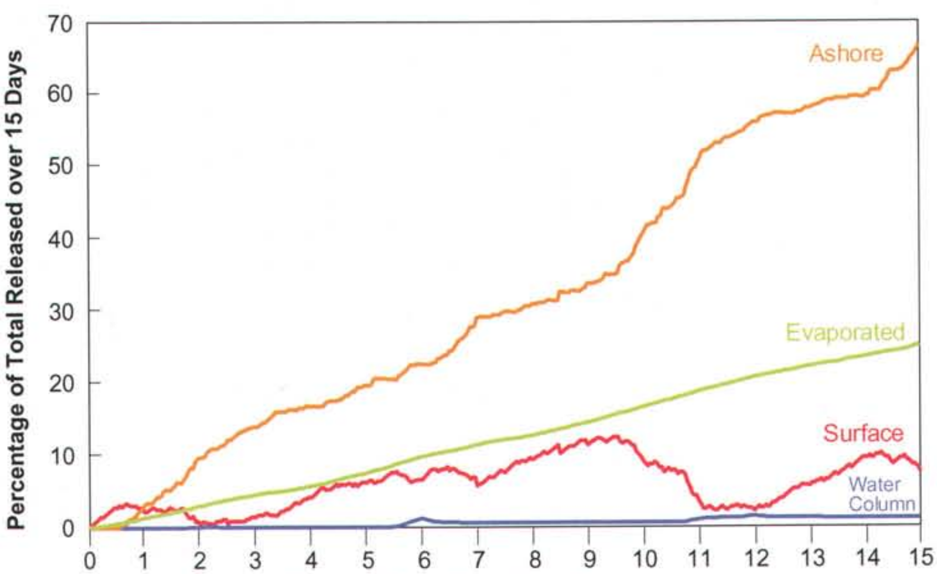


FIGURE 4-5
OILMAP Model Run for Unignited Point Thomson Blowout Case with Variable Winds

4.2.2 Fate of an Ignited Blowout

Voluntary ignition of a blowout is ExxonMobil's preferred alternative for the safety of on-site, response, and well-control personnel and for protection of the environment from large quantities of liquid condensate at Point Thomson. Two factors must be analyzed for an ignited blowout: the deposition of liquid condensate from the blowout plume for 2 hours (the maximum time until ignition) and the potential air quality impact of a burning blowout. In this case, the volume of liquid condensate reaching the environment drops dramatically to the volume spilled during the 2 hours before ignition (approximately 1,000 barrels), with a continuing deposition of less than 2 barrels per hour after ignition.

A. Deposition of Liquid Condensate

To map the liquid condensate deposition for the first 2 hours of a blowout, two meteorological periods were chosen to characterize the most frequently occurring wind direction and the wind that transports the condensate over water. For both conditions, a high wind speed period was selected in order to give a maximum downwind range for the deposition. The most frequent wind direction period was selected from the 15-day persistent wind used for the modeling described above for an unignited blowout. This direction was first determined for the 15-day record and was found to be from the east, with the wind from this direction nearly half the time. The period with this wind direction and the highest wind speed was then chosen (about 50 miles per hour).

The southerly wind period was selected from the variable wind data used for the unignited blowout. While this wind direction occurs with some frequency, it is unusual for the speed to exceed 10 miles per hour. To be conservative, wind speeds of approximately 11 miles per hour were chosen from the data.

Figures 4-6 and 4-7 show the deposition field after 2 hours for the most likely wind direction and worst-case direction, respectively. As with Figures 4-2 and 4-3, it is assumed that the water is stationary, resulting in worst-case deposition thicknesses.

B. Air Quality Impact of an Ignited Well Blowout

It is prudent to assess the potential air quality impacts of voluntarily igniting a condensate blowout to confirm that the air quality impact is lower than the regulatory thresholds designed to protect public health. However, while an air quality permit is necessary under state and federal rules for routine air emissions such as those from an oil processing facility, such a permit is not necessary for an unplanned, low-probability catastrophic event such as an ignited blowout. A burning blowout represents an extreme event. Events such as this may result in higher-than-permitted emissions, but do not require permit approval since they are short-lived and rare events.

The air pollutant of most concern from burning oil or condensate is particulate matter, and very small particles are the ones regulated by the U.S. Environmental Protection Agency (EPA) because the human lung cannot readily eliminate these particles once they are inhaled. To meet the National Ambient Air Quality Standards, concentrations of particulate matter less than 10 microns in diameter (referred to as PM_{10}) must be less than 150 micrograms per cubic meter as a 24-hour average.

ExxonMobil used the SCREEN3 model (EPA, 1995b) to determine if particulate matter emissions from a burning blowout at Point Thomson have the potential to create violations of the national

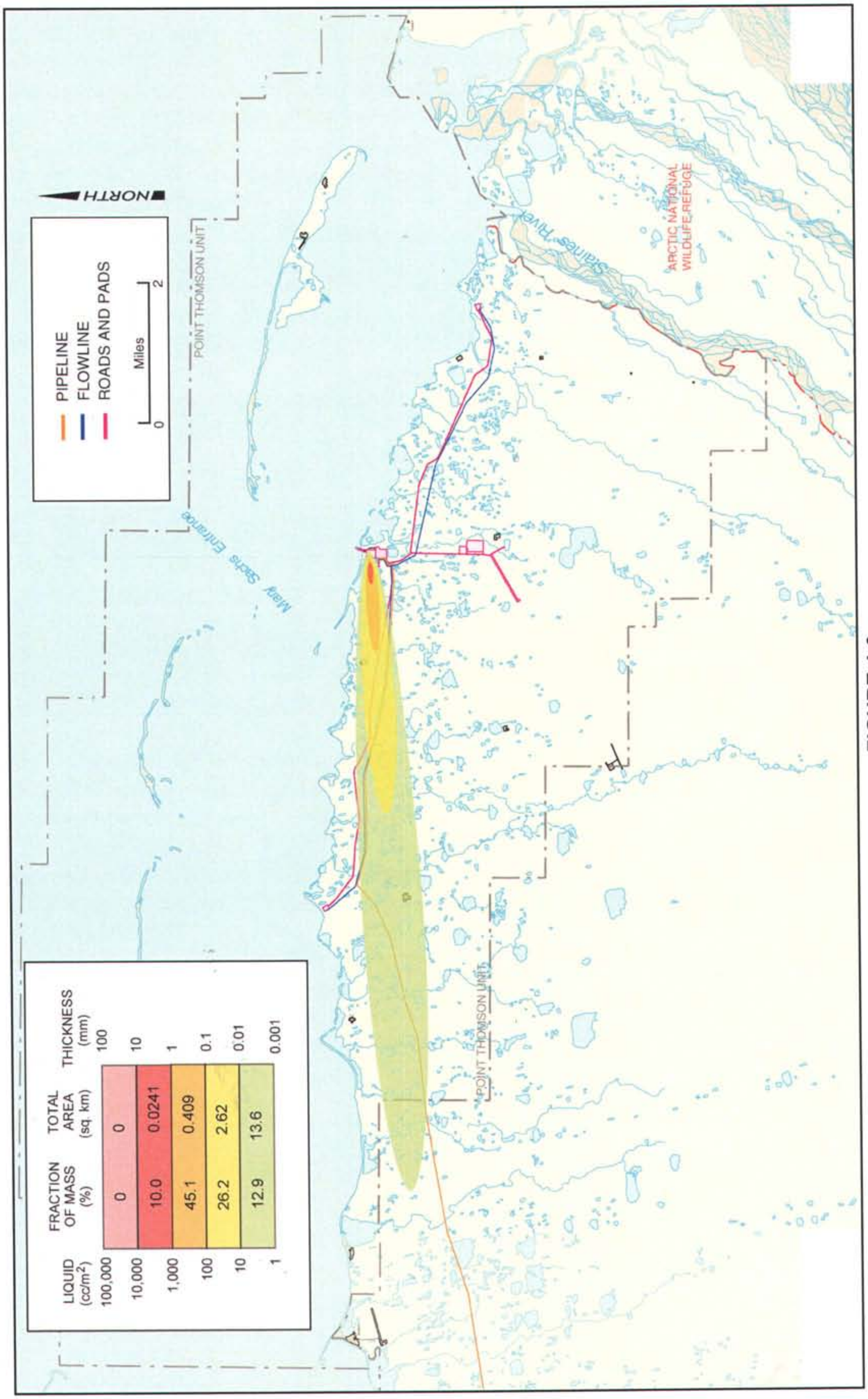


FIGURE 4-6
SCIPUFF Modeling Results for the Deposition of Condensate from Blowout Before Ignition for Most Common Wind Direction and Highest Speed (2 Hours) (Assuming no water movement)

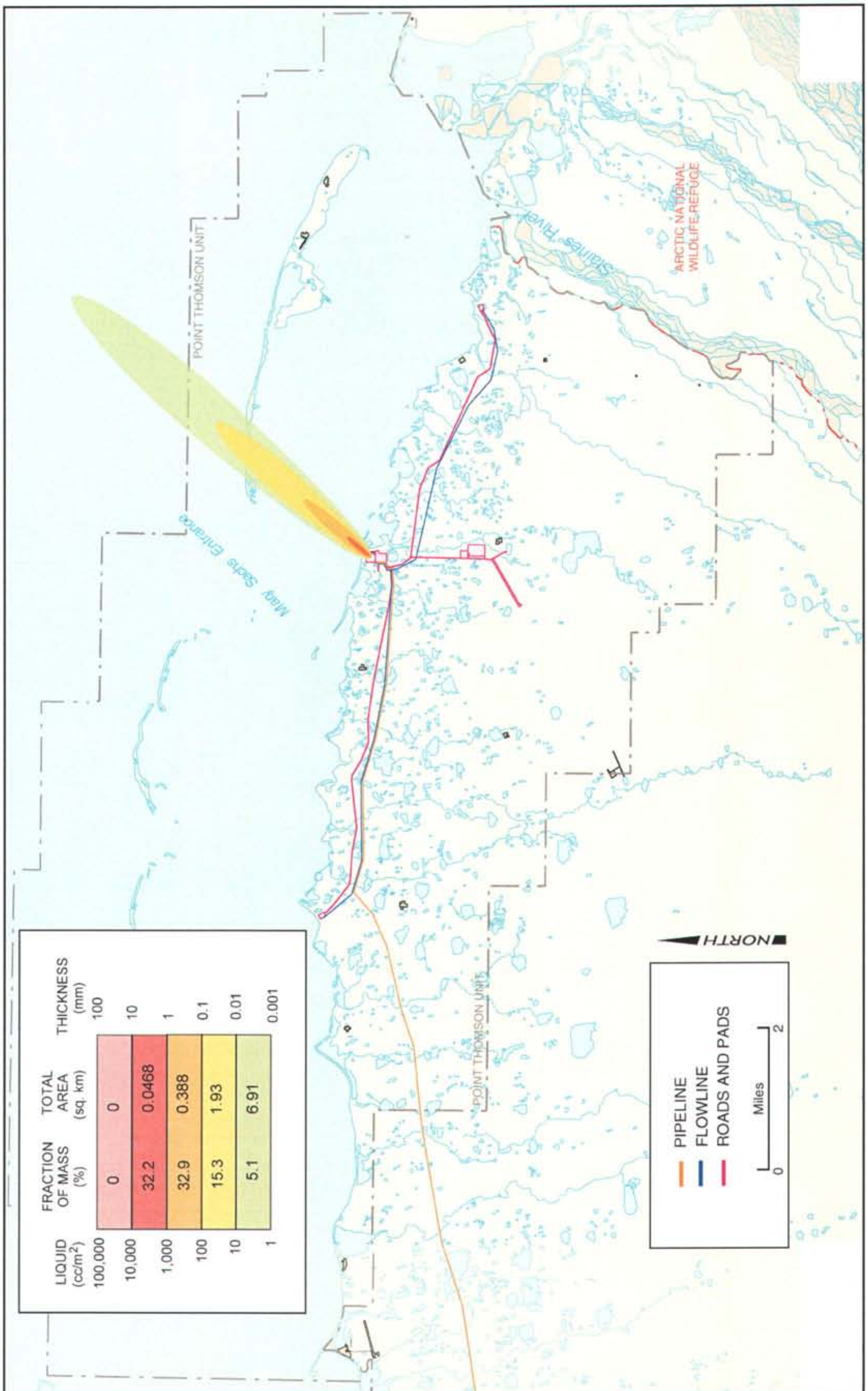


FIGURE 4-7
SCIPUFF Modeling Results for the Deposition of Condensate from Blowout Before Ignition for Worst-Case Wind (2 Hours)
(Assuming no water movement)

standards. EPA approves the use of this model as a conservative screening tool to determine compliance with standards. If SCREEN3 predicts no exceedance of a national standard, the EPA does not require additional, more detailed modeling. The SCREEN3 model is a generalized Gaussian plume model that is applicable to locations up to about 30 miles from the source and provides 1-hour ground-level concentrations for downwind locations.

ExxonMobil followed guidance contained in the EPA *Guideline on Air Quality Models* (EPA, 2001) to select SCREEN3 as the appropriate air quality model for the ignited well blowout case at Point Thomson. SCREEN3 was chosen because it:

- Can simulate dispersion from an open flame (i.e., elevated flare);
- Is applicable to non-reactive pollutant dispersion (e.g., PM_{10});
- Applies to sites in flat terrain and rural areas;
- Contains a full range of meteorological conditions (i.e., combinations of various wind speed and stability);
- Is overly conservative such that if predicted ground-level concentrations are below applicable ambient standards, no more complex modeling is required; and
- It is approved by EPA.

Measured particulate concentrations in the smoke plume from a burning condensate well are not available in the literature because well blowouts represent an emergency situation in which regaining control of the well is the primary concern. As a result, ExxonMobil consulted experts in the field in order to estimate the concentrations of particulates that can be expected at the wellhead.

The primary source of information was the John Zink Company of Tulsa, Oklahoma, which manufactures industrial flaring equipment (Schwartz, 2003, letter). Zink anticipates that a condensate blowout at Point Thomson will behave much like an industrial flare, which is designed for efficient combustion. Flare vendors are familiar with the destruction of similar hydrocarbon streams and flow-rates in providing industrial flares for onshore and offshore applications. Combustion of a Point Thomson blowout will be very efficient because the high velocity of the high-heating-value reservoir fluids exiting the well will lead to significant air entrainment. They estimate combustion efficiencies of over 99 percent for the gaseous components and approximately 90 percent or greater for the liquids. A study for Environment Canada stated that "condensate blowout combustion efficiencies are inevitably 100%, by virtue of the very high GOR's involved" (S.L. Ross and Energetex 1986).

ExxonMobil used a conservative estimate of 10 percent unburned liquids for the model, and a concentration of about 310 grams of soot per million BTU. These estimates were based on EPA's manual for emissions estimating (EPA, 1995a). ExxonMobil also used a conservative assumption that all unburned components of the smoke plume were particulates (in fact, unburned gaseous hydrocarbons would also be in the plume).

Once the combustion efficiency for the liquid and gaseous fractions was identified, estimates of soot emissions (i.e., PM_{10}) were calculated separately for each fraction and added together. Soot emission for the gaseous fraction was calculated using an emission factor for a lightly smoking flame based on EPA's emission estimating manual (EPA, 1995a) and the assumption that air entrained was three times the mass of the vented discharging hydrocarbon stream. Soot emissions for the liquid fraction were conservatively calculated by assuming all unburned liquid produces soot. As noted above, these fractions were added to estimate the total soot emissions from an ignited well blowout case.

Based on the results of the SCREEN3 modeling for Point Thomson, the maximum ground-level concentration of PM_{10} is predicted to be 65.6 micrograms per cubic meter and occurs within less than 2 miles (3 kilometers) from the wellhead. This concentration is well within the National Ambient Air Quality Standard of 150 micrograms per cubic meter. Figure 4-8 shows one-hour SCREEN3 results. To show how conservative the model results are, the projected emissions to reach the standard were plotted. In order to produce the emissions to reach this standard, the combustion efficiency would have to be less than 64 percent (Figure 4-9).

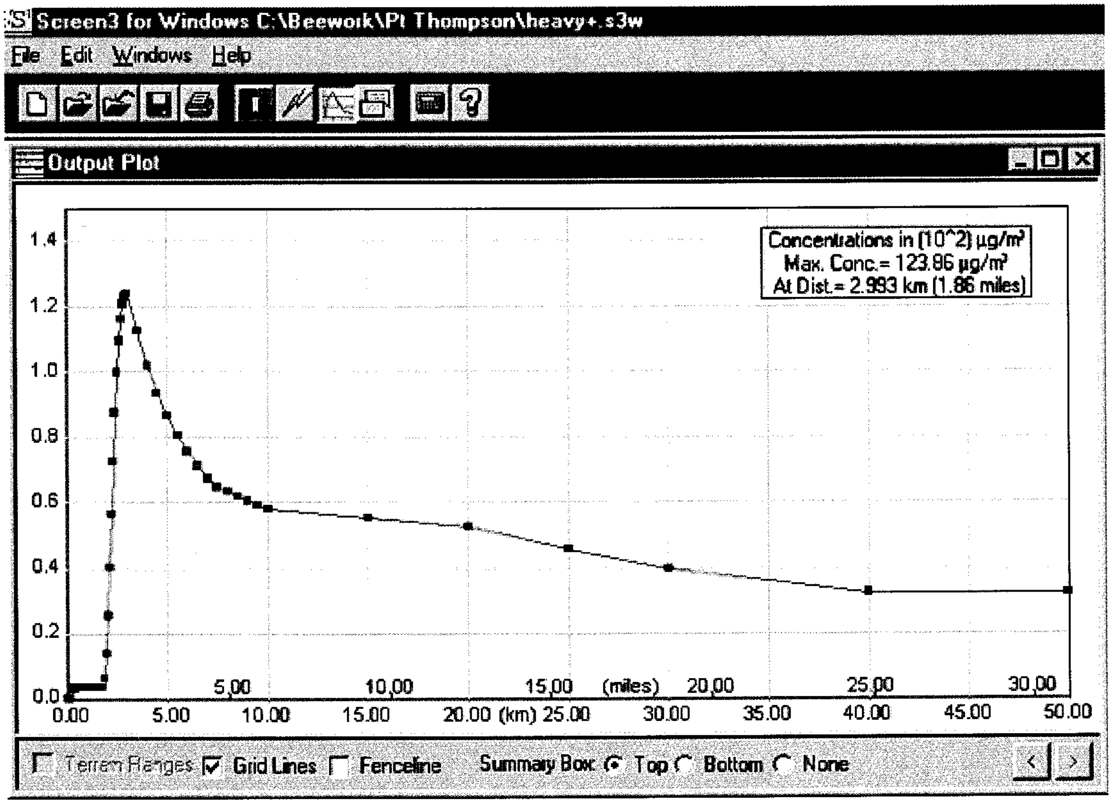
4.3 CASE STUDIES

ExxonMobil searched the technical literature and made extensive contacts with knowledgeable individuals to gather information on condensate releases, especially those involving well-control problems. Table 4-2 summarizes U.S. Coast Guard pollution reports regarding condensate releases along the U.S. Gulf of Mexico coast, and more detailed descriptions of three condensate blowouts and a pipeline spill reviewed in the literature are provided below. These pollutions reports and case studies confirmed that where condensate blowouts have occurred:

- Evaporation of released condensate was significant,
- The liquid was not persistent,
- Little environmental impact occurred,
- Well ignition, even accidental, was an effective means of source control, and
- The effectiveness of recovery of spilled oil was limited.

TABLE 4-2
U.S. Coast Guard Incident Reports for Condensate Spills

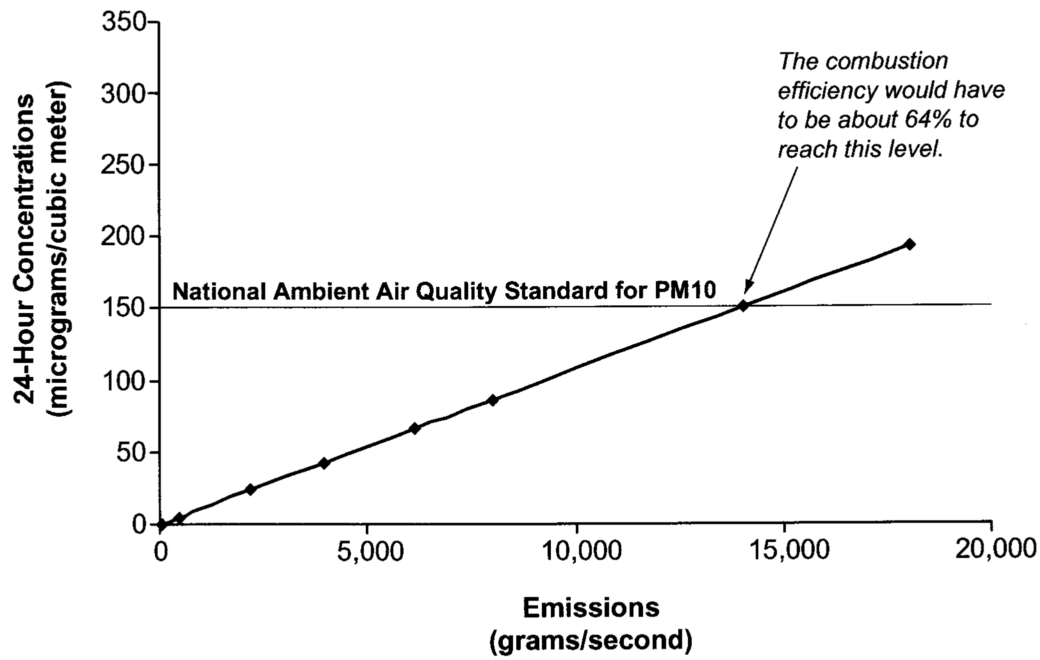
DATE	LOCATION	CAUSE	VOLUME (bbl)	SUBSTANCE	COMMENTS
5/15/92	Morgan City, Louisiana	Ship accident	310	47° API Condensate	Quickly evaporated and dispersed in water column
5/30/98	Gulf of Mexico, 20 miles offshore Texas	Spill from natural gas platform	0.5	Condensate	Not expected to persist long enough to impact shore because of small amount and condensate volatility
7/23/99	Gulf of Mexico, 30 miles offshore Louisiana	Pipeline spill	3,700	Light condensate	Silver and rainbow sheen
2/9/99	High Island, Texas	Spill from platform	10 to 30	38° API condensate	Sheen only; long-term persistence not expected
6/25/99	Bayou Chene, Louisiana	Venting from pump house on rig	--	Condensate, drilling mud, and crude oil	Release of formation water and condensate tended to hang low to the ground; no pollution outside hot zone
7/13/01	Gulf of Mexico, 25 miles offshore Texas	Gas blowout on platform	--	Gas and gas condensate	Gas and condensate plume was observable 250 ft above the rig and plume visibly dispersed 200 yd from release point; sheen extended 3 miles; no threat to coast



	CONCENTRATION IN MICROGRAMS PER CUBIC METER			
	1-HOUR	24 HOURS	NAAQS (24-HOUR)	% OF PM10 STANDARD
Gas Only	44.43	23.53	150	16%
Liquids Only	79.43	42.07	150	28%
Gas + Liquid	123.86	65.60	150	44%

NAAQS = National Ambient Air Quality Standard
PM_{10} = Particulate matter with a diameter of 10 microns or less

FIGURE 4-8
SCREEN3 Modeling Results for Point Thomson



NOTE: Emissions of particulates increase with decreasing combustion efficiency (EPA, 1995a, Section 13.5). ExxonMobil chose a combustion efficiency of 90% for a burning condensate blowout, while the efficiency would have to fall to 64% for air quality limits to be exceeded.

FIGURE 4-9
Projected Emissions to Reach the National Ambient Air Quality Standard for Particulate Matter (PM_{10})

4.3.1 The Lodgepole Blowout

The following summary is taken from the Lodgepole Blowout Inquiry Panel (1984a, b) and Baker (1991). The Amoco Dome Brazeau River 13-12-48-12 well near Lodgepole, Alberta, blew out of control from October 17, 1982 to December 23, 1982 — a total of 67 days. The initial flow estimates from the well were 49 million standard cubic feet/day of natural gas, 6,919 barrels/day of condensate, and 450 tonnes/day of hydrogen sulfide. The Alberta Energy Resources Conservation Board held an extensive public inquiry and issued a comprehensive report.

The well site was located in an uninhabited forest approximately 80 miles west of Edmonton, Alberta. The immediate area was relatively flat. For the first 15 days, the well was flowing through crimped, 4.5-inch drill pipe suspended in the blowout preventer. The emission rates during this period have been estimated at 14 to 28 million standard cubic feet/day of gas and 1,887 to 3,774 barrels/day of orange-colored condensate. Most of the condensate emitted during this period is believed to have settled to the ground near the well site. At the end of this period, the BOP was opened, theoretically to allow the drill pipe to drop into the hole to allow the BOP rams to close. Instead, the drill pipe came out of the hole, struck the rig, and ignited the well, which burned the surrounding forest and condensate. The fire lasted 13 days.

After the fire was extinguished and the surrounding debris was cleared, the flow rate though the unobstructed 9-5/8-inch casing was initially estimated to be 49 million standard cubic feet/day and 6,919 barrels/day of condensate for the next 11 days. In an addendum to the report, the Panel concluded, on the basis of well flow tests done the summer following the blowout, that the flow rate from the well was probably two and perhaps three times this initially estimated rate, involving 99 to 148 million standard cubic feet/day of gas and 13,837 to 20,756 barrels/day of condensate. Soil surveys following the blowout indicated that 7.4 acres around the site were saturated with condensate, 17.3 acres were heavily contaminated, 72 acres were moderately contaminated, and 1,559 acres had moderately low levels. Including the zone with light contamination, a total of approximately 3,830 acres were impacted by the condensate. The boundary of visible condensate extended 2.8 miles to the southeast of the well site, 0.9 miles north, and 1.2 miles east and west. The Panel concluded that most of this area was contaminated during the unignited phase of the blowout.

Operator representatives appearing at the inquiry testified that 40 percent of the condensate evaporated initially, leaving the remainder to settle; however, the basis for this is not given. Baker (1991) describes the fresh condensate as being 67 percent hydrocarbons with 13 or fewer carbon atoms.

On November 25, the well caught fire again and remained on fire until capped on December 23. *All the condensate emitted from the well was consumed in the gas fire, and most of the heavy concentrations of condensate on the surrounding ground were ignited and burned. The Panel noted that this burning proved to be a great advantage from the perspective of minimizing long-term contamination of surface water.*

4.3.2 The Uniacke Blowout

The following is excerpted from MARTEC (1984) and Environment Canada (1984a, b). These reports are also summarized in Carter et al. (1985) and Gill et al. (1985). The Uniacke blowout occurred on Canada's east coast on February 22, 1984, and continued for 10 days until March 3. The Uniacke well-site was located on the Scotian Shelf, about 12 miles north of Sable Island in 520 feet of water. The semi-submersible drilling unit *SDS Vinland* was drilling the well. The gas flow rate

Photo courtesy Mike Miller, Safety Boss

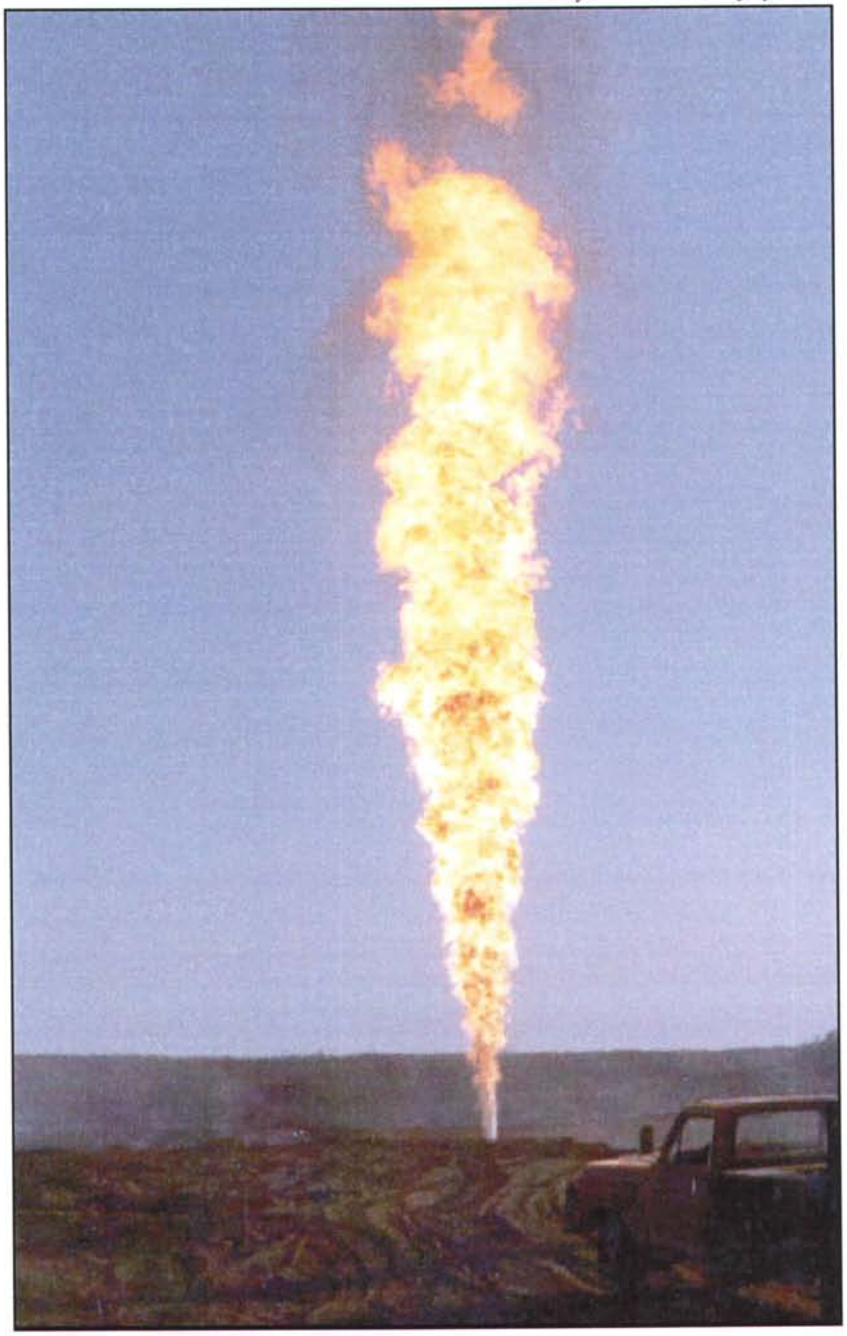


PHOTO 4-1
Photograph of the Burning Lodgepole Blowout in Alberta

This photo shows burning gas and condensate from the Lodgepole blowout near Lodgepole, Alberta, Canada, in 1982. The well was estimated to be releasing upwards of 150 million standard cubic feet/day of gas and 20,000 barrels/day of condensate. Note that there is virtually no smoke plume and that the fire begins some distance above the wellhead. See Section 4.3.1 for a detailed discussion of the blowout.

was estimated to be 38.8 to 60 million standard cubic feet/day. The condensate flow was estimated to be about 302 barrels/day at the beginning, dropping to as low as 31 barrels/day at the end of the blowout. The gas and condensate aerosol plume was estimated to rise about 33 feet above its point of exit at the rotary table on the drilling floor. The slick that formed from the condensate fallout was about 1,000 feet wide near the source and spread to a width of about 1,600 feet. Little condensate was seen on the sea closer than about 330 feet from the rig. This suggests that most of the condensate traveled as an aerosol in the gas plume and fell to the water's surface, rather than impinging on the rig, coalescing and running down to the water.

The well did not self-ignite, nor was it intentionally ignited. It was estimated that between 50 and 70 percent of the condensate volume evaporated in the air before reaching the water. This was determined through gas chromatography analysis which showed that the surface condensate samples taken about 650 feet to a mile from the rig had all evaporated by about 70 percent, with no components less than C_9 present. It is suggested that most of the evaporation took place while the condensate was airborne. Surface condensate was found up to 6 miles from the rig. Seventy-five percent of the slick area was estimated to be 1.8 microns or less thick. The remaining area was estimated to be less than 6 microns thick. The condensate did not form a water-in-oil emulsion. Hydrocarbons could be smelled in the air up to 6 miles from the source, but airborne condensate concentrations were below machine-detectable limits even close to the source. Naturally dispersed condensate was detected in the upper 66 feet of the water column, as far as 6 miles from the well, in concentrations generally below 100 parts per billion. The maximum in-water condensate concentration measured was 1.5 parts per million. The slick was observed to quickly dissipate once the well was capped, and *there were no visual observations of a residual slick on overflights on March 4th (the day after capping)*. The winds were from the west at approximately 12 miles per hour on March 3rd and 4th.

4.3.3 The Myette Point Blowout

The following is taken from Tischer et al. (2001) and Penland et al. (1999). On December 1, 1996, the State Lease 5706 No. 2 well in St. Mary's Parish near Franklin, Louisiana, blew out. The well was located at the end of a 2,500-foot-long dead-end canal extending east from the Atchafalaya River Basin. A second dead-end canal was located just east of the well-site and two nearby freshwater ponds. The surrounding area was characterized as hardwood bottomland freshwater swamp forest. Over the next 5 days, 4,700 barrels of a mixture of 75 percent condensate and 25 percent brine affected the surrounding canal, ponds, and forest. In total, 179.4 acres were affected, including 29.4 acres heavily oiled, 36 acres moderately oiled, and 114 acres lightly oiled. The maximum extent of condensate impact on the surrounding forest was 1,500 to 1,800 feet from the wellhead.

4.3.4 The Rockefeller Refuge Spill

The following is summarized from Hess et al. (1997) and Pahl et al. (1997). A follow-up study three years after the spill is described in Pahl et al. (1999). On March 13, 1995, a leak was detected in an offshore 16-inch gas pipeline submerged under a brackish marsh at the Rockefeller Wildlife Refuge on Louisiana's southwest coast. The leak resulted in the release of approximately 40 barrels of 40° to 42° API condensate into an area of some 50 acres. About 20 acres contained visible slicks of condensate on the water between the marsh plants, and the remainder contained only sheens. Since mechanical recovery efforts were severely impacting the marsh, in-situ burning was used to remove the condensate from about 20 acres of the affected area. A follow-up study three years after the burn concluded that the burned areas had recovered to the state of the surrounding reference marsh.

SECTION 5
WELL IGNITION CRITERIA

ExxonMobil's planned year-round drilling program at Point Thomson has extensive prevention measures to reduce the likelihood of a release of liquid hydrocarbons from a well blowout. ExxonMobil has planned a number of well design features and drilling procedures that go beyond what is required by state regulations and what is dictated by widely accepted industry standards. Nevertheless, the possibility exists — however remote — that all of these preventive measures could fail and an uncontrolled blowout could occur. A blowout would not be uncontrolled until the blowout prevention equipment — which has redundant well-closure systems — also fails.

To reduce the potential volume of a spill in the event of a blowout, the ExxonMobil on-site Drilling Supervisor has the authority to ignite the blowout after personnel safety has been assured. Figure 5-1 summarizes the decision process, which is discussed below. Based on a 2-hour response time before ignition, the maximum amount of condensate that would be released to land or water during the first 2 hours is approximately 1,000 barrels (after evaporation). After ignition, the amount of liquid condensate surviving ignition and reaching land or water would be negligible (less than 2 barrels per hour).

5.1 REMOVAL OF SPILLED CONDENSATE VS. IGNITION OF WELL

ExxonMobil's decision to ignite a blowout at Point Thomson within 2 hours or less revolves around two important considerations:

- The safety of all personnel on-site, including both spill response and well-control personnel, is the primary consideration in view of the extreme danger of an unintentional explosion from high volumes of gas and the subsequent combustion of pooled liquid hydrocarbons in the work area, and
- The extensive areas of light condensate accumulation that would result from an unignited gas condensate blowout plume would not be amenable to containment and/or removal.

Safety is the first and most important consideration because of the nature of such a blowout plume at Point Thomson, which could involve up to 465 million cubic feet per day of natural gas and 27,000 barrels per day of liquid condensate. Explosive vapor concentrations and pooled liquid hydrocarbons would be present and could limit access by personnel. This concern is not limited to the broken-ice and open-water periods; it applies year-round. During a significant gas condensate blowout, ExxonMobil's well-control contractor will not attempt to access the well with pooled hydrocarbons present in the work area because the pooled liquid could ignite and limit escape by personnel. Ignition of the plume will eliminate pooling and assure access and safety.

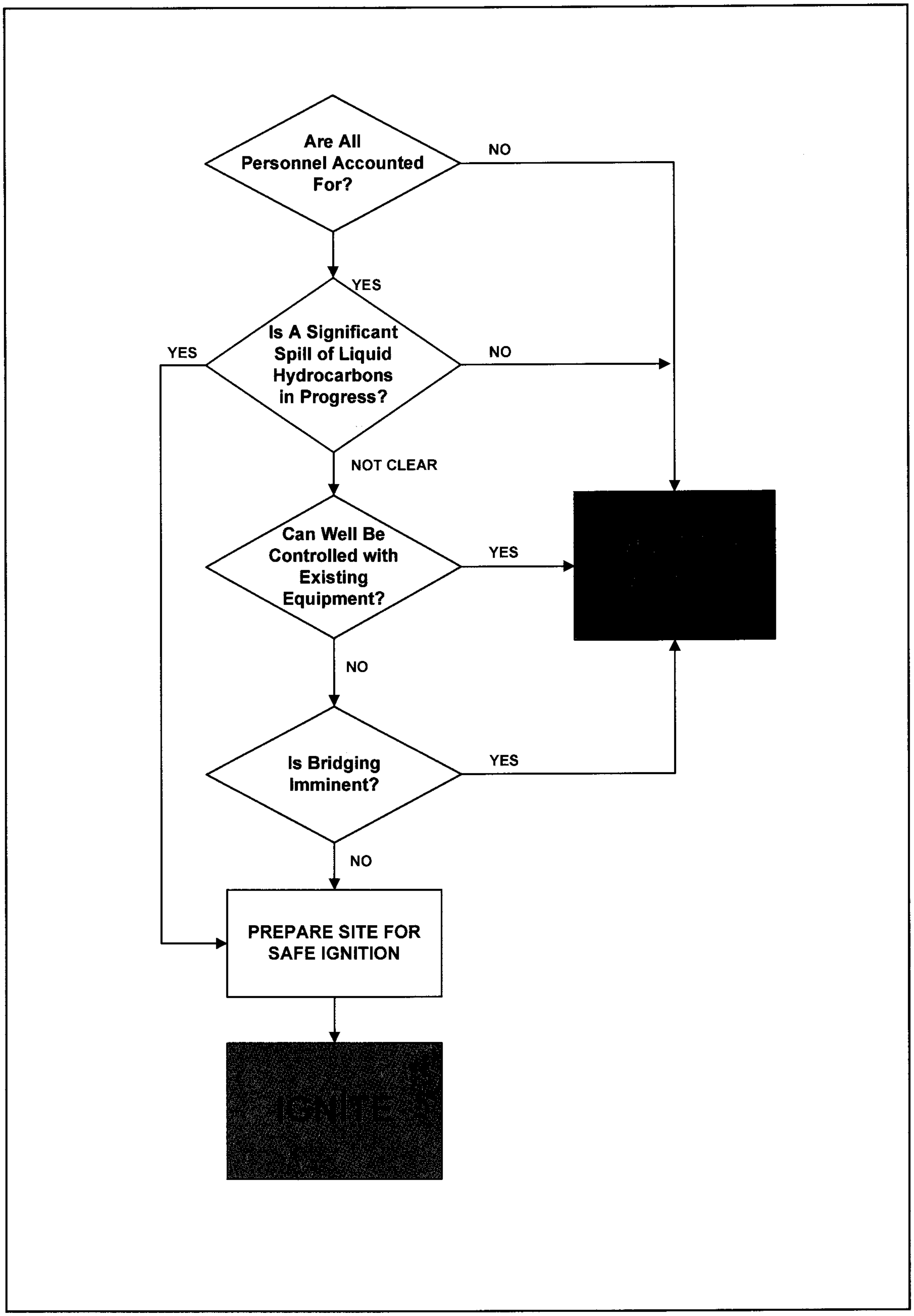


FIGURE 5-1
Decision Tree for Voluntary Blowout Ignition

The thinness of the expected liquid deposition pattern from an unignited blowout plume is not suitable for most spill containment and removal efforts. Figures 4-2 and 4-3 in Section 4 depict this deposition pattern, ignoring that condensate falling offshore will be moving constantly with surface currents. For the modeled persistent-wind scenario, approximately 92 percent of the nearly 70 square kilometers with condensate deposition consists of condensate 0.1 millimeter or less in thickness. For the variable wind case, condensate 0.1 millimeter or less in thickness occurs in nearly 90 percent of the more than 136 square kilometers of offshore coverage. Since these cases ignore the movement of the deposition with surface water, these estimates are very conservative. Such movement would carry the deposited condensate away from the outline of the plume and result in slick thicknesses far less than shown on the deposition figures.

From the standpoint of spill response, slick thicknesses between 0.1 and 0.01 millimeter represent the lower end of what is usually considered practical for concentrating with booms for skimming, burning, or dispersing (Allen, 2003, personal communication). The limited area of condensate greater than 0.1 millimeter thick may be effectively worked, but in an unignited blowout, response workers might not be able to enter this zone because of the danger of fire and explosion.

It is important to note the difference between the condensate slick produced by a Point Thomson blowout and that created by a batch release, say from a tank or pipeline. A batch release would likely cause a thicker slick in a relatively small area that would be more amenable to mechanical and non-mechanical response techniques. ExxonMobil and the industry as a whole remain committed to responding to all spill incidents, regardless of environmental conditions, providing that the safety of personnel can be assured. A sizeable inventory of spill containment and recovery equipment will be stationed at Point Thomson to respond to recoverable spills, and the full resources of Alaska Clean Seas and the North Slope Mutual Aid partners will be available to respond to an incident.

5.2 DECISION CRITERIA FOR WELL IGNITION

5.2.1 Are All Personnel Accounted for?

Human safety is of prime importance to ExxonMobil in all its operations. No decision to ignite a blowout is allowed until all personnel at the drillsite have been accounted for and have moved a safe distance away.

5.2.2 Are Significant Quantities of Liquid Hydrocarbons Being Released?

If the blowout is essentially all gas and there appear to be no liquid hydrocarbons, and the gas is not toxic, then there might be no reason to ignite the source. The gas would create no accumulated pollution on the surface or in/on the nearby sea. However, if liquid hydrocarbons are observed, then ignition of the source remains a possible course of action for minimizing the impact on the environment. Factors to be considered in evaluation of the fluids being released are:

- Is it an unrestricted, open-hole flow?
- Is there significant hydrocarbon liquid discharge?
- Are large quantities of condensate beginning to pool?

If the answers to these questions are yes, it would be prudent to immediately ignite the blowing well for environmental reasons, assuming the safety of all personnel has been assured. If the answers are no, the well should not be ignited immediately and further information-gathering is needed. An example would be a leaking flange or valve, in which case the on-site spill containment and cleanup equipment is adequate while opportunities to repair the problem are pursued.

If the answers to these questions are not obviously yes or no, then the decision to ignite the well will require judgment by the Drilling Supervisor and his team. The Drilling Supervisor will be instructed to make this decision with protection of personnel and the environment as the prime concern. To make this decision, the Drilling Supervisor will need to consider the following questions.

5.2.3 Can the Well Be Rapidly Controlled with Existing Equipment?

If it is not clear whether a significant spill of liquid hydrocarbons is in progress, the Drilling Supervisor will evaluate the potential for controlling the well with existing equipment such as blowout preventers (BOPs) that have simply not yet been activated, or pumping into the well to achieve a dynamic kill. These actions might include the repair of the BOP hydraulic control unit ("closing unit") or activation of a backup source of power for the control unit, such as nitrogen bottles to drive the unit's pneumatic pumps. If the equipment needs repair and can be safely repaired quickly, then ignition should be delayed until such repair and subsequent application of the equipment proves infeasible or it becomes obvious that repair will take several hours. If quickly and safely bringing the well under control with existing equipment is infeasible, voluntary ignition remains an option.

5.2.4 Is Bridging Imminent?

Statistically, it is highly likely that wellbore bridging will end a blowout. Bridging is a naturally occurring phenomenon in open wellbores with long lengths of exposed weak formations, or formations with large differential pressures at the wellbore walls. Unfortunately, bridging cannot be predicted with a high degree of accuracy. Some telling signs — e.g., flow rate decreasing with time or solids being expelled from the well — could indicate that bridging is likely or imminent. If no telling signs of bridging are observed, bridging is not likely. Expedient options are now exhausted, and final safety preparations must be addressed before the well can be ignited.

5.3 PREPARING THE SITE FOR SAFE IGNITION

The well will be ignited *only* when it is safe to do so. Once the Drilling Supervisor has determined that ignition is desirable, the site must be made safe for personnel during and after ignition. Ignition is contingent on:

- Activation of surface-controlled subsurface safety valves in adjacent wells,
- Selection of a safe approach and exit for the well igniters, and
- Confirmation that the point from which the well is ignited has gas concentrations below the lower explosive limit (LEL).

Other factors such as wind conditions, visibility, etc. must also be considered to ensure safety before ignition. To the extent possible, consideration should also be given to actions that would facilitate future access and surface intervention activities.

Before any wells are drilled, specific on-site personnel will be pre-designated as "well igniters," and they, together with the Drilling Supervisor, will be appropriately schooled in ignition techniques and equipment operation, with special emphasis on safety.

APPENDIX
HISTORY OF DRILLING RESTRICTIONS IN ALASKA

Alaska Department of Environmental Conservation (ADEC) regulations require contingency plans that explain how an operator will use mechanical containment and recovery techniques to a remove a response planning standard (RPS) volume of oil from the surface of the water within 72 hours. As with any facility in the nearshore or offshore Beaufort Sea, contingency planning for the Point Thomson Gas Cycling Project must take into account a simple fact: It is impossible to show that 100 percent of the response planning standard volume of oil for a blowout could be removed from a broken ice field using mechanical containment and recovery techniques.

Several North Slope fields with well sites either offshore or on the immediate shore are currently operating with a seasonal drilling restriction that prohibits the drilling of new wells or sidetracks from existing wells into major liquid hydrocarbon zones during the defined period of broken ice and open water. The restricted period typically begins on June 1 and ends with the presence of 18 inches of ice cover for one-half mile from the well site. From ADEC's perspective, the purpose of this seasonal drilling moratorium is to eliminate the environmental risk associated with a well blowout to the Beaufort Sea during broken ice or open water conditions. The basis for ADEC's decision is that plans for mechanical oil spill recovery do not meet the blowout response planning standard in broken-ice conditions.

While seasonal drilling restrictions were only recently applied to drilling of production wells, they have been part of the regulatory landscape for offshore exploration drilling in the Beaufort since the late 1970s. Since 2001, ADEC has also applied seasonal restrictions to exploration wells drilled by ConocoPhillips in the National Petroleum Reserve-Alaska. The following discussion traces the history of these restrictions and the evolution of ADEC response planning regulations. At the end of this appendix, Table A-1 gives a detailed chronology of events, while Figure A-1 provides in graphical format a summary of the history of drilling restrictions.

The Point Thomson project has been designed to include sufficient prevention measures and safeguards to reduce the risk of a blowout to the lowest possible level. These safeguards, combined with the nature of the Point Thomson condensate and the provision for wellhead ignition, should ensure that a seasonal drilling restriction is not necessary to "reduce the risk or magnitude of an oil discharge during periods when planned spill response methods are rendered ineffective by environmental limitations" — the criterion in ADEC regulations for imposing additional prevention measures when conditions prevent or severely limit a planned response.

A.1 EXPLORATION DRILLING RESTRICTIONS: 1979 TO PRESENT

Seasonal drilling restrictions were first applied to oil exploration drilling in the Beaufort Sea as a stipulation of the 1979 Joint Federal/State Beaufort Sea Lease Sale — the first lease sale for the

Beaufort Sea outer continental shelf. That lease sale restricted exploration drilling for seven months. At the time, regulators were concerned about Native subsistence whale hunting on the North Slope and about the ability of the industry to clean up oil spills in broken ice in the Beaufort Sea. In 1982, the restriction was modified to generally restrict drilling during the fall whale migration (August 1 through October 31 in the eastern Beaufort; September 1 through October 31 and April 15 through June 15 in the western Beaufort).

The State of Alaska established a system of restrictions based on two tiers (Tier 1 and Tier 2). Tier 1 prohibited drilling into oil-bearing strata:

- During periods of broken ice,
- Outside the barrier islands during open water, and
- Outside the barrier islands during the fall bowhead whale migration due to concerns about noise.

Tier 2 approval allowed for year-round drilling in oil-bearing strata except outside the barrier islands during the fall bowhead whale migration. However, to get Tier 2 approval, a lessee had to demonstrate compliance with applicable laws and regulations, including the capability to detect, contain, clean up, and dispose of spilled oil in broken ice conditions.

In 1983, the oil industry in Alaska — led by Shell, Amoco, Exxon, and Sohio — informed the agencies that it was ready to demonstrate Tier 2 capability. A joint industry/agency work group was formed, and regulatory agencies identified response capabilities requiring demonstration. In the summer of 1983, the industry conducted a series of six demonstrations (Photo A-1) on the North Slope to address the capability gaps that had been identified:

1. In-situ burning of oil in scattered ice.
2. Burning of oil in fire containment boom.
3. Operation of the *ARCAT* in broken ice (the *ARCAT* was an oil skimming vessel belonging at the time to Alaska Clean Seas at Prudhoe).
4. Operation of tugs and barges in broken ice.
5. Operation of rope mops from a barge in broken ice and open water.
6. Boom deployment in moving broken ice.

The first two demonstrations were conducted in an onshore pit that had been filled with water and chunks of sea ice, while the other demonstrations occurred offshore in the Beaufort. The fire-resistant containment boom used in the tests was developed by Spiltec and Shell Western E&P, Inc. The original design was refined, and eventually it was built and marketed by 3M as the 3M Fire Boom.

The industry published a report on the demonstrations in August 1983 (Industry Task Group, 1983), and in June 1984, ADEC and the Alaska Department of Natural Resources (ADNR) issued their *Final Finding and Decision Document Regarding the Oil Industry's Capability to Clean Up Spilled Oil During Broken Ice Periods in the Alaska Beaufort Sea* (ADEC and ADNR, 1984). The so-called Tier 2 decision stated that the industry had adequate response capability for spilled oil in broken ice and open water under the following conditions:

- The lessee complies with all laws and regulations,
- The lessee participates in a 5-year research and development program to improve the state

PHOTO A-1
Tier 2 Demonstrations in 1983

of the art of spill response in the Arctic, and
- Drilling personnel are trained in well control techniques.

The decision allowed drilling all year inside the barrier islands, but outside the barrier islands drilling was still not allowed during the fall bowhead whale migration.

The Tier 2 decision relied heavily on the industry's ability to ignite and burn oil in broken ice fields and on a commitment to ignite a blowout well after personnel safety had been assured. In the Tier 2 decision document, ADEC and ADNR commented as follows on the ignition of a blowout at the wellhead:

> "In the past, the evaluation by the State of the industry's oil spill cleanup capability during exploratory operations has focused on the capability of cleaning up oil once it entered broken ice fields. It was assumed that a very large percentage of the oil from a blowout would escape from the drilling island, and become mixed immediately in scattered floes of moving ice. This assumption was analyzed during this Tier 2 evaluation and was found to be incorrect if the well is drilled from a natural or gravel island and if the blowout is ignited." (ADEC and ADNR, 1984, p. 9)

ADEC and ADNR also concluded that:

> "In situ burning (excluding well ignition) is by far the most important component of Arctic oil spill response and cleanup if the oil enters moving broken ice. The technical group's work, the consultant's study, and the demonstrations clearly showed that the burning of spilled oil resulting from a blowout on a gravel island is one of the most efficient means of cleanup. This is based on one very crucial assumption: burning must take place close to the island near the spill source while the oil layer is relatively thick and easily combustible. Safety considerations are of the utmost importance in this situation. If the well is not ignited, burning in the immediate vicinity of the island will not be possible." (ADEC and ADNR, 1984, pp. 11-12)

The decision document goes on to say that:

> "...it is the State's finding that an adequate capability to clean up spilled oil in broken ice and during the open water period outside the barrier islands has been demonstrated for an exploratory operation if the well is drilled from a gravel or natural island or an approved drilling platform; if the lessee complies with all state and federal laws and regulations, including the submission and approval of an Oil Discharge Contingency Plan; if the lessee participates in a research and development program designed to further improve cleanup effectiveness during broken ice periods; and if drilling personnel have been trained in well control techniques."
>
> "This finding of adequacy is based on a large number of factors, including the likelihood of a large spill, the industry's extensive oil discharge contingency planning efforts, the availability of oil spill cleanup equipment, the relatively short periods of broken ice, and the likely effectiveness of mechanical recovery and burning at the wellhead and in situ." (ADEC and ADNR, 1984, pp. 40-41)

The State revisited the 1984 Tier 2 decision in both 1986 and 1990, and essentially reaffirmed the original decision as it applies to exploration drilling. The 1990 policy statement was signed by the commissioners of the Departments of Environmental Conservation, Fish and Game, and Natural Resources, and the Division of Governmental Coordination and remains in effect today (State of Alaska, 1990). The policy was never applied to production drilling. During the last half of the 1980s, the research and development work mandated by Tier 2 continued with a series of research projects conducted under the auspices of Alaska Clean Seas. Most of these projects centered on improving in-situ burning capability with fire-resistant containment booms and ignition systems deployed from helicopters.

Restrictions for exploration drilling continue to this day in the *Mitigation Measures and Lessee Advisories for the Beaufort Sea Areawide 2002 Competitive Oil and Gas Lease Sale* (ADNR, 2002). The advisories, which were issued by the State Division of Oil and Gas, state that "any tract or portion thereof in the Beaufort Sea areawide sale area may be subject to the March 1990 Beaufort Sea Seasonal Drilling Policy" and that this "measure will be reevaluated and updated periodically on the basis of experience and new information" (ADNR, 2002, p. 6).

A.2 SEASONAL RESTRICTION APPLIED TO PRODUCTION DRILLING NEAR THE BEAUFORT SEA

As noted above, seasonal drilling restrictions were first imposed on offshore exploration drilling in the Alaskan Beaufort Sea in 1979, and the regulatory agencies at the time did not intend to apply them to production drilling. Exploration drilling is often considered riskier than production drilling because less is known about the subsurface geology. Furthermore, Tier 2 approval for exploration drilling was predicated on the use of in-situ burning and well ignition as the primary response methods for an oil release from a well blowout.

In 1990, the regulatory framework for contingency planning began to evolve toward a requirement to plan to use mechanical response techniques to deal with a well blowout. The Alaska State Legislature amended the state's oil pollution law to require that contingency plan holders show that they can contain and control and remove from the waters of the state in 72 hours a "response planning standard" (RPS) volume of oil. The law requires that the holder of an oil discharge prevention and contingency plan have available:

> "sufficient oil discharge containment, storage, transfer, and cleanup equipment, personnel, and resources to meet the following response planning standards… For a discharge from an exploration or production facility or a pipeline, *the plan holder shall plan to be able to contain or control, and clean up the realistic maximum oil discharge in 72 hours.*" [AS 46.04.030(k)] (Emphasis added)

The requirements were designed to guide planning efforts, and a plan holder does not violate the law if he is unable to actually clean up a spill of the RPS in 72 hours. The legislature clearly specified that the requirements to meet the RPS "do not constitute cleanup standards that must be met by the holder of a contingency plan" [AS 46.04.030(l)]. The contingency plan must show how the plan holder will respond to such a spill and specify the equipment that would be used. The law further defines *containment and cleanup* as "all direct and indirect efforts associated with the prevention, abatement, containment, or removal of a pollutant, and the restoration of the environment to its former state..." and *response action* as an "action taken to respond to a release or threatened release of oil, including mitigation, cleanup, or removal" [AS 46.04.900 (5) and (17)].

Based on the amended state oil pollution law, ADEC issued revised spill contingency planning regulations in 1991. In implementing the law, ADEC interpreted the term *containment and cleanup* used in the RPS requirement as referring to mechanical response tactics only — i.e., the use of booms, skimmers, pumps, and vessels. The section of the ADEC regulations on content requirements for oil discharge prevention and contingency plans states that a contingency plan must contain:

> "A description of the actions to be taken to contain and control the spilled oil, including, as applicable, boom deployment strategies, construction of temporary berms, and other methods" and a description of the "actions to be taken to recover the contained or controlled oil using mechanical methods, including plans and provisions for skimming, absorbing, or otherwise recovering the contained or controlled product from water or land." [18 AAC 75.425(e)(1)(F)(vii)]

The ADEC regulations also require that a plan define the *realistic maximum response operating limitations* (RMROL), with a description of "any measures that will be taken to compensate for those periods when environmental conditions exceed this maximum" [18 AAC 75.425(e)(3)(D)]. The RMROL requirement is further defined in the section of the regulations on approval criteria for contingency plans:

> "In designing a spill response, severe weather and environmental limitations that might be reasonably expected to occur during a discharge event must be identified. The plan must use realistic efficiency rates for the specified response methods to account for the reduction of control or removal rates under those severe weather or other environmental limitations that might reasonably be expected to occur. *The department will, in its discretion, require the plan holder to take specific temporary prevention measures until environmental conditions improve to reduce the risk or magnitude of an oil discharge during periods when planned spill response methods are rendered ineffective by environmental limitations.*" [18 AAC 75.445(f)] (Emphasis added)

In essence, the ADEC regulations require operators to use mechanical response equipment and techniques to develop the plan for responding to an RPS spill, although the enabling statute is not so specific. Operators must further define what environmental conditions — e.g., fog, wind, ice, etc. — will prevent the planned response from cleaning up the RPS volume in the required 72 hours. ADEC has the discretion to impose additional prevention measures on a facility or operation to *reduce the risk or magnitude* of an oil discharge when RMROL conditions are reached. The presence of broken ice in the nearshore Beaufort sea is one condition that meets the criteria for RMROL.

The difficulty of using mechanical response actions in broken ice has always been recognized, but the issue lay somewhat dormant when offshore exploration in the Alaskan Beaufort Sea essentially came to a halt in the late 1980s. In 1997, however, there was renewed interest in the ability to effectively clean up oil spills in broken ice conditions because of BP's plans to develop the offshore Northstar field. As this discussion progressed, the realities of responding to oil spills in broken ice conditions conflicted with the state regulatory planning constraints described above.

In the spring of 1997, ACS, industry, and ADEC spearheaded the formation of the joint Industry/ Agency North Slope Spill Response Project Team ("Project Team") in response to concerns of both agencies and industry that spill response capability for the North Slope needed to be re-evaluated in light of proposed new offshore development such as Northstar. Also, both the agencies and industry felt that the industry should develop a unified North Slope response plan under the auspices of ACS and to resolve a set of issues that had arisen during ADEC review of renewal applications for the state-approved contingency plans for existing North Slope facilities. ADEC plan reviewers and industry plan developers had reached an impasse over what assumptions to use for response scenarios to meet the response planning standards.

The Project Team consisted of representatives from the following agencies and organizations:

- Alaska Clean Seas
- Alaska Department of Environmental Conservation
- Alyeska Pipeline Service Company
- ARCO Alaska, Inc.
- BP Exploration (Alaska) Inc.
- North Slope Borough
- U.S. Coast Guard
- U.S. Environmental Protection Agency
- U.S. Minerals Management Service

The Project Team was supported by a steering committee of higher-level managers and by a tactics committee which developed a set of oil spill scenarios designed to address requirements for the range of North Slope facilities and the variety of agencies involved in plan review. Based on these scenarios, the Project Team eventually agreed upon a set of assumptions regarding such variables as wind speed, wave height, skimmer efficiency, etc. for individual contingency plans to use in developing scenarios. These assumptions were jointly agreed to by ACS and ADEC and were published in the ACS *Technical Manual*, which was first issued in March 1999 to serve as the basis for ACS member-company contingency plans (ACS, 1999).

In August, 1998, ADEC prepared a report entitled *Preliminary Analysis of Oil Spill Response Capability in Broken Ice* to support the department's request for additional information regarding BP's contingency plan for its Northstar development. In that report, ADEC discussed its rationale for considering seasonal drilling restrictions:

> "Although the risk of a blowout is very small and indeed the risk of a blowout that discharges an oil fountain into the air is an even much smaller risk, the law is based upon planning for a realistic maximum spill regardless of the probability of that event. *Since current drilling practices maximize safety, there does not appear to be additional safety procedures that could supplement current practices when drilling a well. Rather, the risk reduction opportunities are opportunities of timing the drilling to avoid the short broken ice season in both spring and fall.*" (ADEC 1998, p. 21-22) (Emphasis added)

The report contained ADEC's intention to require five barge-based response systems in order for BP to obtain approval for Northstar's contingency plan. ADEC then approved the Northstar plan with a condition for three barge-based response systems and for testing the containment and recovery effectiveness of those systems in broken ice.

PHOTO A-2
An ACS Response Vessel Maneuvers a Minibarge in a Broken Ice Field during Equipment Tests in the Nearshore Beaufort in 2000

In 1999, ADEC incorporated a seasonal drilling restriction for some production wells into a final coastal zone consistency determination. The restriction prohibited drilling of the first development well into targeted hydrocarbon formations during broken ice or of other development wells into untested hydrocarbon formations during broken ice. ADEC stated its rationale as follows:

> "This condition is reasonable and necessary to ensure the plan holder's compliance with *specific temporary measures until environmental conditions improve to reduce the risk or magnitude of an oil discharge during periods of broken ice when planned spill response methods are rendered ineffective by environmental limitations*, as required by 18 AAC 75.445(f)." (Emphasis added)

In the fall of 1999, ACS conducted tests of the response barge *Endeavor* to demonstrate the response capability during broken ice that was claimed in the contingency plans for existing facilities immediately adjacent to the Beaufort Sea. In the fall 1999 barge tests, the barge grounded on a shoal immediately east of West Dock, and the barge was not fully outfitted to support the response operation. The exercise showed that while it may be appropriate for some spring break-up conditions, ACS' barge-based response tactic was not applicable to fall freeze-up. The combination of growing ice, and subfreezing air and water temperatures meant that alternatives would be needed.

Following the barge test, ADEC determined that the plan holder was not in compliance with its approved oil discharge prevention and contingency plans. The two parties then entered into negotiations that resulted in "compliance orders by consent." The COBCs were voluntary agreements that allowed the plan holder to be in compliance with the contingency plans while working out differences with ADEC. Based on these agreements, a seasonal drilling restriction was accepted for development drilling at these facilities rather than acquire additional barge-based response systems that ADEC would otherwise require for approval of the contingency plans' scenarios for response in broken ice. ACS also conducted additional tests during the spring and fall of 2000 to further evaluate the effectiveness of response equipment in broken ice. The chief finding was that ice coverage of one-tenth constituted the RMROL for tactics using booms and skimmers.

During the same time frame, North Slope operators convened a group of technical experts to further investigate available options to deal with oil spills in ice-infested water and to more clearly define the RMROLs. The team was composed of ACS operations personnel, industry representatives, and oil spill response experts. The principal conclusion of this team with regard to spill response during freeze-up in the nearshore Beaufort Sea was that *"mechanical containment and recovery techniques have limited application for a large spill especially from an open-orifice blowout"* (D.F. Dickins et al. 2000, p. viii, emphasis added). The team concluded that additional equipment will not improve a mechanical containment-and-recovery operation during fall freeze-up and spring break-up.

In 2002, oil discharge prevention and contingency plans for marine shoreline facilities were issued. Section 2.1.7 of those plans commits to a seasonal drilling restriction as an additional prevention measure. The plans said that the plan holder will:

> "...prohibit the drilling of new wells or sidetracks from existing wells...into major liquid hydrocarbon bearing zones during the defined period of broken ice and open water. This period begins on June 1 each year and ends with the presence of 18 inches of continuous ice cover for one-half mile, in all directions, from the [facility]... The purpose of this drilling moratorium is to eliminate the environmental risk associated with a well blowout to the Beaufort Sea during broken ice or open water conditions."

In February 2002, ADEC did grant a request to allow year-round drilling for gas-cap injection wells to be drilled for reservoir pressure maintenance in the Prudhoe Bay field. The ADEC decision was based on the fact that black oil would not be encountered in the wells and that any liquid potential released from a well-control problem would be non-persistent condensate.

TABLE A-1
Chronology of Seasonal Drilling Restrictions for the Alaskan Beaufort Sea

DATE	EVENT	SUMMARY
1979	1979 Joint Federal/State Beaufort Sea Lease Sale	The lease sale stipulations restricted exploration drilling to winter months when the Beaufort Sea was ice-covered to protect bowhead whales as they migrate along the Alaska coastline in September or October. Allowed companies to drill exploratory wells only from November 1 through March 31 each year with the possibility of extensions to May 15 in some locations.
1979	ABSORB	Alaskan Beaufort Sea Oilspill Response Body formed: forerunner of Alaska Clean Seas.
February 1982	Tier 2 Committees Formed	Joint agency/industry Steering Committee and Technical Committee formed to address criteria for Tier 2 approval.
May 14, 1982	Tier 1 and Tier 2 Drilling Restrictions	ADNR revised the 1979 seasonal drilling restrictions to prohibit drilling operations in major hydrocarbon-bearing formations during periods of broken ice until oil industry lessees adequately demonstrated the capability to clean up spilled oil in broken ice. The May 1982 restriction required a complete shutdown of drilling operations from May 15 to October 31 in major hydrocarbon-bearing formations outside the barrier islands. Inside the barrier islands, drilling was halted from May 15 until the sea was free of ice and during the fall whale migration.
February 1983	Industry Readiness to Demonstrate	Industry Task Group (Amoco, Exxon, Shell, and Sohio) notifies ADNR and ADEC that they were ready to demonstrate cleanup capabilities required for Tier 2 approval. State established Tier 2 Steering Committee and Tier 2 Technical Committee with state, federal, borough, and industry representatives.
April 1983	Industry Assessment of Spill Response Capability	Industry Task Group publishes *Oil Spill Response in the Arctic: An Assessment of Containment, Recovery, and Disposal Techniques*, which provides a summary of "state of the art procedures related to containment, recovery, disposal, and logistical support activities for a major oil spill within the Alaskan Beaufort Sea."
April-June 1983	Gap Identification	Regulatory agencies identify response capabilities requiring demonstration.
June-July 1983	Industry Tier 2 Demonstrations	Industry works with state, federal, and borough agencies to design and conduct six tests to demonstrate specific response capabilities: • In-situ burning of oil in scattered ice • Burning of oil in fire containment boom • Operation of ARCAT in broken ice • Operation of tugs and barges in broken ice • Operation of rope mops from a barge in broken ice and open water • Boom deployment in moving broken ice
August 1983	Industry Report on Demonstrations	Industry Task Group publishes report *Oil Spill Response in the Arctic Part 2: Field Demonstrations in Broken Ice.*
September 1983	ADEC Evaluation of Tier 2 Demonstrations	SL Ross issues report *Evaluation of Industry's Oil Spill Countermeasures Capability in Broken Ice Conditions in the Alaskan Beaufort Sea* for ADEC. SL Ross concludes that "ignition of the well is by far the most important countermeasures step" for a 10,000 bbl/day blowout during broken ice (assumes 95% burned at wellhead).

TABLE A-1 (cont'd)
Chronology of Seasonal Drilling Restrictions for the Alaskan Beaufort Sea

DATE	EVENT	SUMMARY
April 1984	Industry Technical Documentation Report	Industry Task Group publishes *Oil Spill Response in the Arctic Part 3: Technical Documentation*. This report is a practical guide to the cleanup techniques identified during the demonstrations.
May 15, 1984	ADNR Tier 2 Decision	Year-round drilling inside the barrier islands; 10-month drilling season outside the barrier islands, where drilling into oil-bearing formations is prohibited from August 15 until whales leave the area. Based on finding that oil industry possesses adequate capability to clean up oil spills in broken ice. While there are times and conditions when cleanup effectiveness would be low, the industry's overall capability is adequate based on: • Effectiveness of burning at the wellhead • The ability to burn and mechanically recover oil once it reaches the marine environment • Low risk of a spill To get permission for year-round drilling, companies must: • Drill from a gravel or natural island or from an approved drilling structure • Participate in a 5-year oil spill research and development program • Train personnel in spill prevention • Have access to fire resistant booms and igniters • Take appropriate measures to prevent spills from entering the Beaufort Sea • Conduct bowhead whale monitoring programs
May 1986	State Seasonal Drilling Restriction Policy	State reaffirms the Tier 2 decision.
March 1990	State Seasonal Drilling Restriction Policy	State of Alaska (ADF&G, ADEC, ADNR, Division of Governmental Coordination) reiterates 1984 Tier 2 decision on drilling exploratory wells in broken ice. *The policy does not address production drilling.*
1990	OPA 90	Congress passes the Oil Pollution Act of 1990.
1990	Alaska Oil Spill Commission Report	Maintains that burning is only viable option during ice season, and burning by concentrating oil with booms largely untested.
June 1990	House Bill 567	Alaska Legislature amends state oil pollution law to mandate 72-hour "response planning standard" (RPS).
October 1991	Revised ADEC Spill Regulations	ADEC finalizes new spill regulations based on House Bill 567 (18 AAC 75); operators must plan *mechanical* response to meet response planning standard and give ADEC discretion to impose additional prevention measures during times when mechanical response would be ineffective.
1997	Industry/Agency North Slope Spill Response Project Team	Team formed. Tactics Team coordinates work on ACS *Technical Manual*.
1997	BAT Regulations	ADEC amends 18 AAC 75 to include requirement for best available technology (BAT) evaluation.
June 1998	Report on Broken Ice Response to Blowout	*Evaluation of Cleanup Capabilities for Large Blowout Spills in the Alaskan Beaufort Sea during Periods of Broken Ice* by S.L. Ross Environmental Research Ltd for the Industry/Agency North Slope Spill Response Project Team. Concludes that cleanup of a well blowout to broken ice would be ineffective, but that ignition of the well could eliminate between 74% and 99% of the blowout volume.

TABLE A-1 (cont'd)
Chronology of Seasonal Drilling Restrictions for the Alaskan Beaufort Sea

DATE	EVENT	SUMMARY
August 1998	ADEC Analysis of Broken Ice Capability	ADEC's report entitled *Preliminary Analysis of Oil Spill Response Capability in Broken Ice* was prepared to support the department's request for additional information on BP's Northstar contingency plan. This report suggested that as many as 5 response barges would be required to obtain ADEC's approval for the Northstar blowout scenario.
January 29, 1999	Endicott Contingency Plan Renewal Approved	ADEC approves contingency plan for BP's Endicott field with a seasonal drilling restriction as a condition of approval (no drilling of development wells into previously untested hydrocarbon formations during broken ice periods). Approval also requires 2 barge-based response systems for broken ice response.
February 4, 1999	Final CZM Consistency Determination on Northstar	Stipulation 141 imposes a seasonal drilling restriction: • No drilling of first development well into targeted hydrocarbon formations during broken ice • No drilling of other development wells into untested hydrocarbon formations during broken ice
March 1999	ACS Technical Manual	ACS publishes the *Technical Manual*, which forms the basis for rewritten contingency plans for North Slope fields.
October 20, 1999	ACS Fall Equipment Tests	ADEC required deployment of ACS Tactic R-19A to determine RMROL for the tactic (response in broken ice). Tests show that the combination of growing ice, and subfreezing air and water temperatures means that alternatives to Tactic R-19A are required.
November 2, 1999	Northstar Contingency Plan First Approved	ADEC approves initial Northstar contingency plan with conditions: • Availability of 3 spill response barges • Continued R&D through participation in MORICE • Drills and exercises, including ACS tactics for broken ice response • Revision of ACS *Technical Manual* • Demonstration of personnel training
February and May 2000	ACS Study Team Workshop	Purpose of team "to further investigate available options to deal with oil spills in ice-infested waters and to more clearly define the realistic maximum response operating limitations (RMROL)."
April 2000	International Oil in Ice Workshop	Sponsored by ACS and held in Anchorage.
May 2000	Compliance Order by Consent for Endicott and PBU	ADEC and BP/ARCO sign compliance orders by consent for the Endicott and Prudhoe Bay Unit (East and West Operating Areas) contingency plans.
May 2000	COBC for Northstar	ADEC and BP sign the compliance order by consent for the Northstar contingency plan.
July 2000	ACS Spring Equipment Tests	Designed to meet stipulations in compliance orders by consent between ADEC and North Slope plan holders for broken ice response. Exercises measure the operating limits of three sets of on-water equipment in broken ice. • Tactic R-19A (*Arctic Endeavor*): operating limit of containment and recovery systems found at ice coverage of less than 10 percent • Minibarge shuttling through broken ice • Transiting the *Beaufort 20* barge • Command, control, communications, and aircraft spotting • Hovercraft use

TABLE A-1 (cont'd)
Chronology of Seasonal Drilling Restrictions
for the Alaskan Beaufort Sea

DATE	EVENT	SUMMARY
October 2000	ACS Fall Equipment Tests	Tests of barge-based containment boom and skimmers show RMROL in fall freeze-up ice conditions.
November 2000	Revision of COBC for Northstar	ADEC and BP sign revised compliance order by consent for the Northstar contingency plan.
December 2000	Oil Spills in Ice Discussion Paper	ACS issues report, which contains a review of spill response, ice conditions, oil behavior, and monitoring for the Alaskan Beaufort Sea. A principal conclusion is that mechanical containment and recovery techniques have limited applicability for a large spill during break-up or freeze-up. The report confirms the findings of the 1998 SL Ross report, which were further reinforced by the fall 1999 and spring 2000 ACS deployment tests.
Winter 2001	NPRA Exploration Wells	ADEC imposes seasonal drilling restrictions on ConocoPhillips exploration wells in the National Petroleum Reserve – Alaska.
August 2001	ADEC Approval of Amended Northstar Contingency Plan	ADEC agrees to 2 barge systems rather than 3 because BP agreed to limit the drilling of new wells and the sidetracking of existing wells at Northstar to threshold depths above major hydrocarbon accumulations during the spring broken ice, summer open water, and fall freeze-up periods. Only Northstar has barge system in its approved contingency plan.
August 2001	Point Thomson Project Description	ExxonMobil issues the first draft of the project description for its proposed Point Thomson Gas Cycling Project.
January 2002	Northstar Contingency Plan Renewal Approved for 3 Years	BP includes seasonal drilling restriction from June 1 to presence of 18 inches of continuous ice cover for one-half mile in all directions from Northstar. Purpose is to "eliminate environmental risk associated with a well blowout to the Beaufort Sea during broken ice or open water conditions." As a result, ADEC requires only one response barge since a well blowout scenario is no longer needed.
February 2002	ADEC Allows Year-round Drilling for Gas Cap Wells	A letter from ADEC to BP authorizes year-round drilling for gas cap injection wells in the Prudhoe Bay Unit because it is unlikely that black oil could be released.

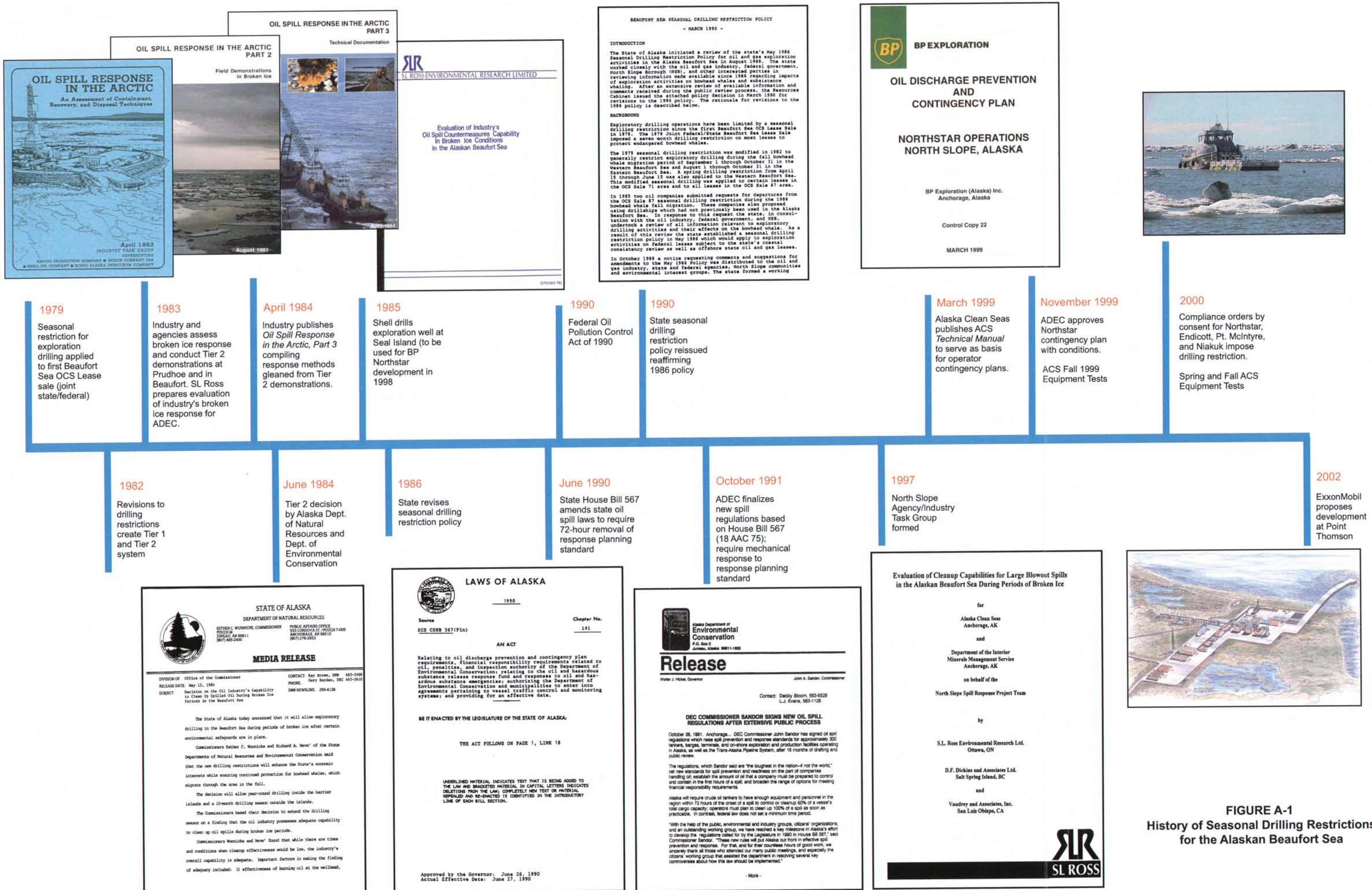


FIGURE A-1
History of Seasonal Drilling Restrictions for the Alaskan Beaufort Sea

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