Chapter Six: Specific Issues Related to Oil and Gas Exploration, Development, Production, and Transportation

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Chapter Six: Specific Issues Related to Oil and Gas Exploration, Development, Production, and Transportation

A. Geophysical Hazards

The primary geophysical hazards within the sale area include earthquakes, faulting, shore-ice movement, permafrost and frozen-ground phenomena, waves, coastal erosion, seasonal flooding, overpressured sediments, and shallow gas deposits and hydrates. These geohazards could impose constraints on exploration, production, and transportation activities associated with possible petroleum development, and should be considered prior to the siting, design, and construction of any facilities.

1. Faults and Earthquakes

Faults and folds are mapped on the surface and in the subsurface across the sale area. Geologic and seismic evidence indicate that recent and historic seismic activity varies across the sale area. In the western side, little evidence of any Quaternary movement exists, with no evidence of displacement of Pleistocene or Holocene deposits, and no recent seismicity associated with faults (Craig and Thrasher, 1982; AEIC, 2006). However, evidence of deformation in Pleistocene deposits east of the lease sale area exists and earthquakes in the eastern lease sale area indicate that seismic hazards should be considered (Dinter et al., 1990).

A number of potentially shallow faults are mapped north of the Arctic Platform. Included in these faults are the upper extensions of detached listric growth faults that exist deep in the Brookian[1] section. These faults are mapped in the greatest detail in the Camden Bay area northeast of the area of interest. Some of these faults may have been reactivated in the late Cenozoic and can have several tens of meters of offset. Shallow faults are mapped beneath the outer shelf, west of Cape Halkett, and are reported to show from 3 to 10 meters of Quaternary offset (Grantz and Biswas, 1983).

In contrast to the rest of the Beaufort shelf, the Camden Bay area is seismically active. This region is located at the northern end of a north-northeast trending band of seismicity that extends north from east-central Alaska (Biswas and Gedney, 1979). Since monitoring began in 1978, a large number of earthquakes, ranging from magnitude one to over five, have been recorded in this area, with the majority of events clustering along the axis of the Camden anticline[2]. The largest earthquake recorded in the area was a magnitude 5.3 event located 30 km north of Barter Island in 1968. In this region, the Tertiary and Quaternary units dip away from and are truncated at the top of the Camden anticline, indicating that it has been growing in recent geologic time. The faults in this region trend northwest-southeast, parallel to the hinge line,[3] and as they approach and intersect the axis of the Camden anticline, they offset progressively younger units. This suggests that these faults are older hinge line-related structures that were reactivated during late Tertiary and Quaternary by the uplift of the Camden anticline.

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[1] The Brookian section began about 100 million years ago and continues into the late Tertiary.
[2] An "anticline" is a fold, the core of which contains the stratigraphically older rocks; it is convex upward. The opposite is called a syncline (American Geological Institute, Glossary of Geology, 1973).
[3] Generally, a hinge line refers to a line or boundary between a stable region and a region undergoing upward or downward movement (American Geological Institute, Glossary of Geology, 1973).

North of the sale area, on the outer Beaufort shelf and upper slope are gravity faults that are related to large rotational slump blocks (Grantz and Dinter, 1980).[4] South of these slumps, which bound the seaward edge of the Beaufort Ramp, these faults have surface offsets ranging from 15 meters to as high as 70 meters (Grantz, et al., 1982). Grantz, et al., (1982) have inferred that these faults have been active in recent geologic time based on the age of the faults and therefore pose a hazard to bottom-founded structures in this area. Large-scale gravity slumping of the blocks here could be triggered by shallow-focus earthquakes centered in Camden Bay or in the Brooks Range.

Figure 6.1 shows the locations of recorded earthquake epicenters in the sale area. Most of the seismicity in the region is shallow (less than 20 miles deep), indicating near-surface faulting. Recent significant events include two magnitude 5 earthquakes in the eastern part of the sale area, one in 1993 and one in 1995. The largest event in the region was a magnitude 5.3 earthquake north of Kaktovik in 1968 (Combellick, 1998).

Algermissen et al., (1991) estimate a 10 percent probability of exceeding 0.025 g[5] earthquake-generated horizontal acceleration in bedrock during a 50-year period in the eastern part of the sale area. The estimated 10-percent-in-50-year acceleration decreases to 0.01 g in the western part of the area. For comparison, ground acceleration in Anchorage during the great 1964 earthquake was estimated at 0.16 g. In isolated areas throughout the sale area underlain by thick, soft sediments, the ground accelerations are likely to be higher than in bedrock, due to amplification. However, thick permafrost beneath most of the area may cause the earthquake response of sediments to be more like bedrock, which would limit amplification effects and would also tend to prevent earthquake-induced ground failure, such as liquefaction.

It is standard industry practice that facility siting, design, and construction be preceded by site-specific, high-resolution, shallow seismic surveys that reveal the location of potentially hazardous geologic faults. These surveys are required by the state prior to locating a drilling rig. Facility planners are encouraged to consult with the American Petroleum Institute's publication, "*Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions, Second Edition*," December 1, 1995 (Reaffirmed: January 2001). This document contains considerations that are unique for planning, designing, and constructing Arctic systems.

The sale area lies within seismic zones 0 and 1 of the Uniform Building Code (on a scale of 0 to 4, where 4 represents the highest earthquake hazard), and earthquake potential is low. Regardless, all structures in the sale area should be built to meet or exceed the Uniform Building Code requirements for zone 1 (Combellick, 1994).

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[4] A "slump block" is the mass of material torn away as a coherent unit during a block slump. The rotation refers to the apparent fault-block displacement in which the blocks have rotated relative to one another, so that alignment of formerly parallel features is disturbed (American Geological Institute, Glossary of Geology, 1973).
[5] Gravitational acceleration. One g equals an acceleration rate of 32 feet per second per second.

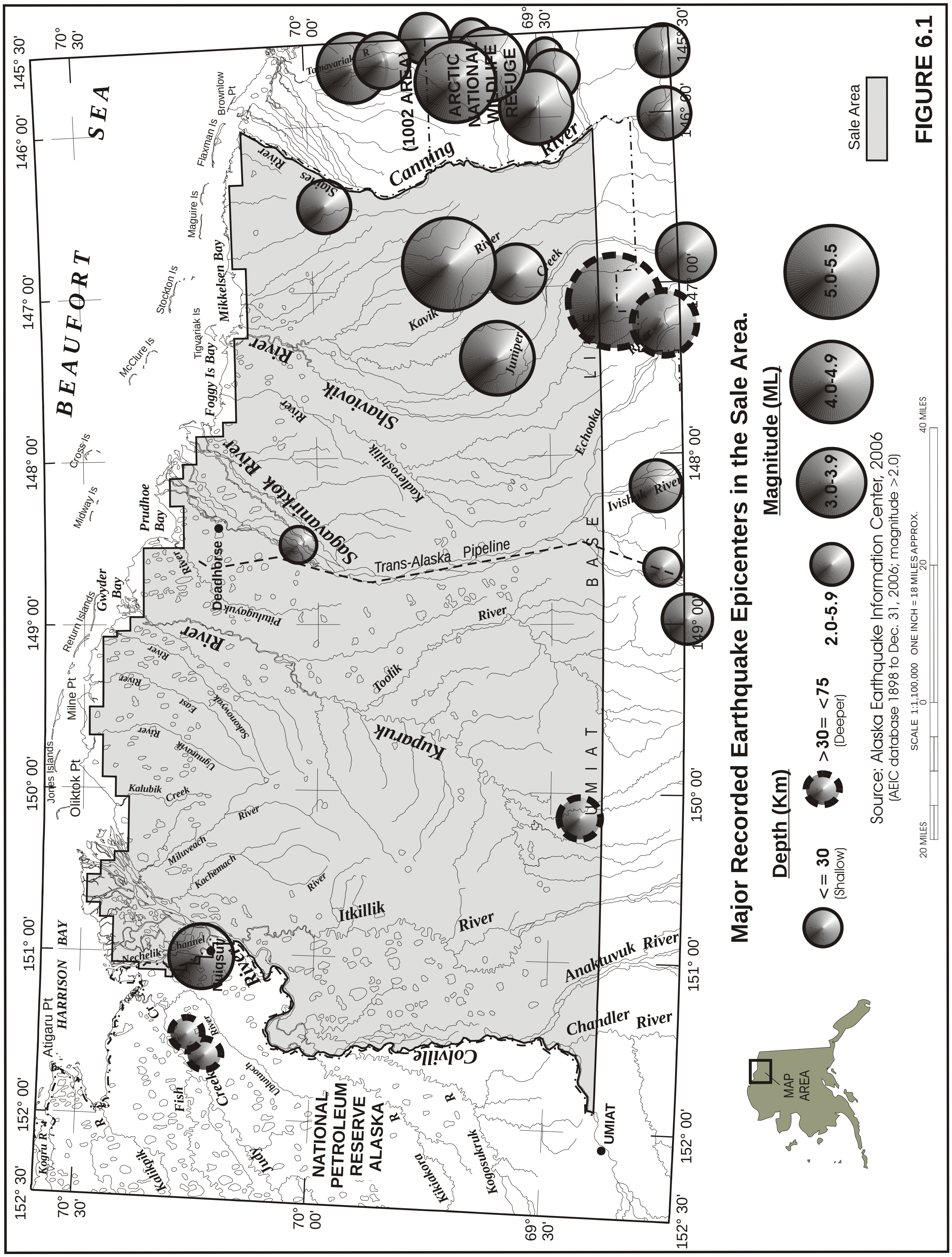
Major Recorded Earthquake Epicenters in the Sale Area.
Depth (Km)
<= 30
(Shallow)
>30= <75
(Deeper)
Magnitude (ML)
2.0-5.9
3.0-3.9
4.0-4.9
5.0-5.5
Source: Alaska Earthquake Information Center, 2006
(AEIC database 1898 to Dec. 31, 2006; magnitude >2.0)
Sale Area
BEAUFORT SEA
ARCTIC NATIONAL WILDLIFE REFUGE
(1002 AREA)
NATIONAL PETROLEUM RESERVE ALASKA
Trans-Alaska Pipeline
UMIAT BASE LINE
Deadhorse
UMIAT
MAP AREA

FIGURE 6.1

2. Ice Push

Ice push is the process whereby ice blocks are forced onshore by strong wind or currents. Ice push can transport sediment from the coast inland, resulting in the formation of ridges or mounds. Throughout the Beaufort Sea, ice push and ice override events can transport and erode significant amounts of sediment. It is most important on the outer barrier islands where ice push ridges up to 2.5 meters high, extending 100 meters inland from the beach have been identified (Hopkins and Hartz, 1978a). Over most of the Arctic coast, ice-push rubble is found at least 20 meters inland with boulders in excess of 1.5 meters in diameter (Kovacs, 1984). A number of accounts of ice push events have been documented where man-made structures have been damaged along the Beaufort coast. In January of 1984, ice over-topped the Kadluck, an 8-meter-high caisson-retained drilling island located in Mackenzie Bay (Kovacs, 1984). Ice override hazards are highest on spits and bluff margins. Piled-up ice at the base of a bluff can provide a ramp for additional ice to ride up onto the bluff top (Mason et al., 1997).

Ice push has the potential to alter shorelines and nearshore bathymetry, which in the longer term may pose a threat to nearshore facilities with increased erosion. Design parameters to mitigate the effects of ice push are similar to those employed to resist sea ice and coastal erosion forces. These include concrete armoring, berm construction, and coastal facility setbacks.

3. Onshore Permafrost and Frozen Ground

Permafrost exists throughout most of the Arctic coastal plain and is, for the most part, a relict[6] feature overlain by a thin layer of seasonally frozen sediment. Permafrost thickness has been measured from numerous onshore wells indicating that it thins from east to west. East of Oliktok Point, it is 500 meters thick, whereas west of the Colville River it is 300 to 400 meters thick (Osterkamp and Payne, 1981). The depth of seasonal thaw is generally less than one meter below the surface and two meters beneath the active stream channels. Ice content varies throughout the region from segregated ice to massive ice in the form of wedges and pingos, and is the highest in the fine-grained, organic-rich deposits and the lowest in the coarse granular deposits and bedrock (Collett et al., 1989).

Increased thawing of permafrost is often initiated by both natural (forest fire, floods, and erosion) and human-made ground disturbances (Richter-Menge et al., 2006). Ground settlement, due to thawing, occurs when tundra overlying permafrost is disturbed or when a heated structure is placed on the ground underlain by shallow, ice-rich permafrost, and the proper engineering measures are not taken to adequately support the structure and prevent the building heat from melting the ground ice. In addition, the seasonal freeze-thaw processes will cause frost jacking of nonheated structures placed on any frost-susceptible soils unless the structures are firmly anchored into the frozen ground with pilings or supported by non-frost-susceptible fill (Combellick, 1994a). Frost susceptibility is highest in fine-grained alluvium, colluvium, thaw-lake deposits, and coastal-plain silts and sands; moderate in alluvial-fan deposits and till; and lowest in coarse-grained floodplain deposits, alluvial terrace deposits and gravelly bedrock (Carter et al., 1986; Carter and Galloway, 2005; Ferrians, 1971; Yeend, 1973a, b). Case studies indicate that permafrost degradation can result in landslides and suggest that landslide frequency may increase in permafrost environments as climate warms (Huscroft and others, 2004). Ground subsidence, increased erosion, change in the hydrologic regime and the other potential impacts of permafrost degradation described above will negatively impact infrastructure as climate warms unless new mitigation techniques are adopted (Report of the Alaska Regional Assessment Group, 1999).

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[6] A “relict” feature pertains to a mineral, structure, or feature of a rock that represents those of an earlier rock and which persist in spite of processes tending to destroy it (American Geological Institute, Glossary of Geology, 1973).

Frozen-ground problems are successfully mitigated through siting, design, and construction, as demonstrated at Prudhoe Bay and elsewhere. Structures, such as drill rigs and permanent processing facilities, should be insulated to prevent heat loss into the substrate. Pipelines can be trenched, back-filled, and chilled (if buried) or elevated to prevent undesirable thawing of permafrost. In addition, ADNR regulates winter travel across the tundra and authorizes travel only after determining that the tundra is sufficiently frozen and protected by ample snow cover so that the travel will not have major environmental effects such as permafrost degradation.

Long-term records indicate that permafrost temperatures at the depth of zero seasonal temperature variations in permafrost (20 m) are warming on the North Slope (Richter-Menge et al., 2006). As a result, continued monitoring of permafrost stability and continued assessment of mitigation techniques are necessary.

4. Waves, Storm Surge, and Coastal and River Erosion

Waves provide energy for erosion and can cause flooding if wave heights are sufficient to inundate onshore areas. Wave heights along the Beaufort coastline are low throughout most of the year because pervasive ice cover reduces potential fetch. However, during the fall open-water season, a considerable fetch develops both seaward and shoreward of barrier islands. During this time, fetch of around 800 km can result in storm waves 7 to 9 meters high. Such waves are effective erosive agents capable of removing significant amounts of material from beaches, cliff faces and barrier islands (Appel, 1996). Wind-induced storm surges can raise sea level as much as 3 meters, increasing erosion and potentially transporting ice and water onshore. An additional meter of surge height may result when low atmospheric pressures are associated with storms (Reimnitz and Barnes, 1974).

Even with the short open-water season along the Beaufort coastline, the wave action, in combination with the melting of coastal permafrost, can cause dramatic rates of coastal erosion. Average rates of erosion across the Beaufort coastline range from 1.5 to 4.7 meters per year with short term erosion rates of 30 meters per year. In one case, near Oliktok Point, the coastline eroded 11 meters during one two-week period (Hopkins and Hartz, 1978a).

The highest rates of erosion occur along the coastal promontories where the bluffs are composed of fine-grained sediments and ice lenses, and where thermal erosion, a dynamic process involving the wearing away by thermal means (melting ice) and by mechanical means (hydraulic transport), is the dominant process. In some areas, beaches have been formed from the gravel eroded from bluffs composed of coarse-grained deposits and act to partially isolate those bluffs from wave action. In other areas, where the bluffs are composed of fine sediment, the sand eroded from the bluffs does not form protective beaches, causing the bluffs to erode more rapidly. In the Harrison Bay area, where the bluffs are composed primarily of coarser-grained sediments, the average retreat rates are between 1.5 to 2.5 meters per year (Craig et al., 1985).

The only prograding (advancing) shoreline areas along the Beaufort coastline occur off the deltas of major rivers. In those areas, the rate of progradation is very slow. The progradation rate of the Colville River delta was estimated to be 0.4 meters per year (Reimnitz et al., 1985).

Factors influencing the nature of erosion along the North Slope coastline also affect erosion along the region’s rivers, although the driving forces (currents, waves with a short fetch) are somewhat different. Permafrost and sediment cohesiveness are important factors in determining the river bank erodibility. High erosion rates occur along the braided channels, which usually develop in areas composed of noncohesive sediment (Scott, 1978). In a study along the Sagavanirktok River, aerial photographs showed a maximum erosion rate of 4.5 meters per year during a 20-year period. In this area, most of the erosion appeared to occur in small increments during breakup flooding and was concentrated in specific areas where conditions were favorable for thermo-erosional niching (Combellick, 1994).

Erosion rates, river bank and shoreline stability, and the potential impacts of waves and storm surge must all be considered in determining facility siting, design, construction, and operation. They must also be considered in determining the optimum oil and gas transportation mode. Structural failure can be avoided by proper facility setbacks from coasts and river banks.

5. Seasonal Flooding

Floods occur annually along most of the rivers and many of the adjacent low terraces due to the seasonal snowmelt and ice jams (Rawlinson, 1993). Spring ice breakup on the rivers in the region often occurs over the first few days of a three-week period of flooding in late May through early June. Up to 80 percent of the flow occurs during this period (Walker, 1973). Spring floodwaters inundate large areas of the deltas, and on reaching the coast, spread over stable ground and floating ice up to 30 km from shore (Arnborg et al., 1967; Barnes et al., 1988; Reimnitz et al., 1974; Walker, 1974). When the floodwater reaches openings in the ice, it rushes through with enough force to scour the bottom to depths of several meters by the process called strudel scouring (Reimnitz and others, 1974).

In addition to the seasonal flooding, many of the rivers along the coast are subject to seasonal icing prior to the spring thaw. This is due to the overflow of the stream or groundwater under pressure, and in the areas of repeated overflow, the residual ice sheets often become thick enough to extend beyond the flood-plain margin. These large overflows and residual ice sheets have been documented on the Sagavanirktok, Shaviovik, Kavik, and Canning Rivers (Dean, 1984; Combellick, 1994).

Storm surges along the Beaufort coast frequently occur in the summer and fall. Sea-level increases of 1 to 3 meters have been observed, with the largest increases occurring on the westward-facing shores. Storm surges can also occur from December through February, although the sea-level elevation changes are generally less than in summer and fall. Decreases in the elevation of the sea level can occur and do so more frequently during the winter months (MMS, 1995c).

Seasonal flooding of lowlands and river channels is extensive along major rivers that drain into the sale area; thus, measures must be taken prior to facility construction and field development to prevent losses and environmental damage. Pre-development planning should include hydrologic and hydraulic surveys of spring breakup activity as well as flood-frequency analyses. Data should be collected on water levels, ice flow direction and thickness, discharge volume and velocity, and suspended and bedload sediment measurements for analysis. Also, historical flooding observations should be incorporated into a geophysical hazard risk assessment. All inactive channels of a river must be analyzed for their potential for reflooding. Containment dikes and berms may be necessary to reduce the risk of floodwaters that may undermine facility integrity.

6. Overpressured Sediments

Along the central Beaufort region, extremely high pore pressures can be expected to be found where Cenozoic strata (sedimentary layers) are very thick, such as in the Kaktovik, Camden, and Nuwuk Basins. Onshore, in the Camden Basin, high pore pressures have been measured in both the Tertiary and Cretaceous formations where the burial depths of the Tertiary strata exceeded 3,000 meters (Craig et al., 1985).

In the Point Thomson area, the pore pressure gradients were measured as high as 0.8 pounds per square inch per foot (psi/ft) in sediments at burial depths of 4,000 meters. In this area a pore pressure gradient of 0.433 psi/ft is considered normal (Hawkings et al., 1976). High pore pressures have also been measured throughout the Cenozoic strata of the Mackenzie Delta in the Canadian Beaufort. Here, the pore-pressure gradients were measured as high as 0.76 psi/ft and have been observed at depths as shallow as 1,900 meters (Hawkings et al., 1976).

Drilling mud in the wellbore is mixed to a specific density that will equal or slightly exceed the pressure in the formation. When formation pressures exceed the weight of the drill mud in the wellbore, the result can be a kick[7] or blowout; accordingly, encountering over-pressured sediments while drilling can result in a blowout or uncontrolled flow. The risk of a blowout is reduced by identifying locations of overpressured sediments via seismic data analysis, and then adjusting the mud mixture accordingly as the well is drilled. If a kick occurs, secondary well control methods are employed. The well is shut-in using the blowout prevention (BOP) equipment installed on the wellhead after surface casing is set. The BOP equipment closes off and contains fluid pressures in the annulus and the drillpipe. BOP equipment is required for all wells and surface and subsurface safety valves are required to automatically shut-off flow to the surface.

7. Shallow Gas Deposits and Natural Gas Hydrates

Shallow pockets of natural gas have been encountered in boreholes throughout the Arctic, both onshore and offshore. This gas usually exists in association with faults that cut Brookian strata, and as isolated concentrations in the Pleistocene coastal plain sediments (Grantz et al., 1982). The presence of shallow gas has been inferred from studies by Boucher et al. (1980), Craig and Thrasher (1982), Sellmann et al. (1981), and Grantz et al. (1982). Sediments in which gas has accumulated are a potential hazard if penetrated during drilling as well as for any manmade structures on top of them.

Natural gas hydrates commonly occur offshore under low-temperature, high-pressure conditions (Macleod, 1982) as well as at shallower depths associated with permafrost (Kvenvolden and McMenamin, 1980). In the central Beaufort, gas hydrates have been found at shallow depths under permafrost along the inner shelf (Sellmann et al., 1981) as well as onshore at Prudhoe Bay (Kvenvolden and McMenamin, 1980). During drilling, the rapid decomposition of gas hydrates can cause a rapid increase in the pressure in the wellbore, gasification of the drilling mud, and the possible loss of well control. If the release of the hydrate gas is too rapid, a blowout can occur, and the escaping gas could be ignited. In addition, the flow of hot hydrocarbons past a hydrate layer could result in hydrate decomposition around the wellbore and the loss of strength of the affected sediments. If this happened and the well was shut-in for a period, the reformation of the hydrates could induce high pressures on the casing string (MMS, 1995c).

Because gas hydrates and shallow gas deposits pose risks similar to overpressured sediments, the same mechanisms for blowout prevention and well control are employed to reduce the danger of loss of life or damage to the environment. For more detail on oil spills and their effects, see Chapter Five. For a discussion of oil spill prevention and response, see Section C of this chapter.

8. Mitigation Measures

The following are summaries of some applicable mitigation measures and lessee advisories designed to mitigate potential impacts of geophysical hazards. For a complete listing of mitigation measures and lessee advisories see Chapter Seven. Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

- The siting of facilities will be prohibited within at least 500 feet of all fish-bearing waterbodies. Additionally, the siting of facilities will be prohibited within one-half mile of

[7] A kick is a condition where the formation fluid pressure (pressure exerted by fluids in a formation) exceeds the hydrostatic pressure (pressure exerted by mud in the borehole) resulting in a “kick”; formation fluids enter the borehole.

the banks of the main channel of the Colville, Canning, Sagavanirktok, Kavik, Shaviovik, Kadleroshilik, Echooka, Ivishak, Kuparuk, Toolik, Anaktuvuk and Chandler Rivers.

- The state discourages the use of continuous-fill causeways. Approved causeways must be designed, sited, and constructed to prevent significant changes to nearshore oceanographic circulation patters and water quality characteristics. Causeways and docks must not be located in river mouths or deltas. Each proposed structure is reviewed on a case by case basis and may be permitted if the director, in consultation with ADF&G, ADEC and the North Slope Borough, determines that the structure is necessary for field development and no practicable alternatives exist. A monitoring program may be required.
- Pipelines must utilize existing transportation corridors and must be designed to facilitate the containment and cleanup of spilled fluids. Onshore pipelines must be buried where soil and geophysical conditions permit. All pipelines, including flow and gathering lines, must be designed, constructed, and maintained to assure integrity against climatic conditions, geophysical hazards, corrosion and other hazards.
- Pursuant to regulations 18 AAC 75 administered by ADEC, lessees are required to have an approved oil discharge prevention and contingency plan (C-Plan) prior to commencing operations. Pipeline gravel pads must be designed to facilitate the containment and cleanup of spilled fluids. Containers with a total storage capacity of greater than 55 gallons that contain fuel or hazardous substances shall not be stored within 100 feet of a waterbody.

B. Likely Methods of Transportation

A discussion of specific transportation alternatives for oil from the sale area is not possible at this time because strategies used to transport potential petroleum resources depend on many factors, most of which are unique to an individual discovery. The location and nature of oil or gas deposits determine the type and extent of facilities necessary to develop and transport the resource. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed. Generally speaking, modern oil and gas transportation systems usually include the following major components: 1) pipelines; 2) marine terminals; 3) tank vessels. Oil and gas produced in the sale area would most likely be transported by a combination of these depending on the type, size and location of the discovery.

If commercial quantities of oil are found in the sale area, the oil will go to market via the trans-Alaska pipeline system (TAPS), a 798-mile pipeline from Prudhoe Bay to Valdez. From Valdez, the oil is transported to markets in Cook Inlet, the U. S. West Coast, and the U. S. Gulf Coast using tankers. In-field gathering lines bring the oil from individual well sites to processing facilities for injection into TAPS.

Buried or elevated pipelines are the only feasible means for transporting oil and gas from developed fields to TAPS and a gas pipeline system, if constructed. The advantages and disadvantages of the two options are set forth below. It is possible that a transportation system used for oil or gas from the sale area will be buried in sections and elevated in sections, much like TAPS. The mode of transport from a discovery will be an important factor in determining whether future discoveries can be economically produced – the more expensive a given transportation option is, the larger a discovery will have to be in order to be economically viable.

1. Elevated Pipelines

Elevated pipelines are typically used in North Slope oil field development to prevent heat transfer from the hot oil in the pipeline to frozen soils, since heat would degrade the permafrost. Elevated pipelines are relatively easy to maintain and visually inspect for leaks; however, above-ground pipelines can restrict caribou and other wildlife movements unless provisions are made to allow for their safe passage. Additionally, the cumulative effect of roads and adjacent pipelines can create a barrier to caribou crossing.

Pipelines elevated at least 5 feet have been shown to be effective except when they were in proximity to roads with moderate to heavy traffic (15 or more vehicles/hour). Roads with low levels of traffic and no adjacent parallel pipeline are not significant barriers to movement of caribou. The most effective mitigation is achieved when pipelines and roads are separated by at least 500 feet, according to the Alaska Caribou Steering Committee (Cronin et al., 1994). The mitigation measures require above-ground pipelines be elevated a minimum of 7 feet. Lessees must consider increased snow depth in the sale area in relation to pipe elevation and ADNR, through consultation with ADF&G, may require additional measures to mitigate impacts to wildlife movement and migration. Additionally, lessees are encouraged in planning and design activities to consider the recommendations for oil field design and operations contained in the final report of the Alaska Caribou Steering Committee.

2. Buried Pipelines

Buried pipelines are feasible in the Arctic, provided that the integrity of the frozen soils is maintained. Such pipeline configurations have been used for portions of the Milne Point area and Alpine developments. Some important considerations regarding long sections of buried pipe include: cost, which depends on length, topography, soils, and distance from the gravel mine site to the pipeline; buried pipe is more difficult to monitor and maintain, however, significant technological advances in leak detection systems have been made that increase the ease with which buried pipelines can be monitored; buried pipelines may involve increased loss of wetlands because of gravel fill; and buried pipelines are sometimes not feasible from an engineering standpoint because of the thermal stability of fill and underlying substrate (Cronin et al., 1994).

3. Tankers

Tankers are currently used in Alaska to transport oil from Cook Inlet and from the Alyeska Terminal in Valdez. The biggest disadvantage for tankers is the potential for a large oil spill such as the Exxon Valdez spill in Prince William Sound in 1989 (see Oil Spill Risk below).

4. Mitigation Measures

Any product ultimately produced from sale tracts will have to be transported to market. It is important to note that the decision to lease oil and gas resources in the state does not authorize the transportation of any product. If and when oil or gas is found in commercial quantities and production is proposed, final decisions on transportation will be made through the local, state, and federal permitting processes. Those processes will consider any required changes in oil spill contingency planning and other environmental safeguards, and will involve public participation. The state has broad authority to withhold, restrict, and condition its approval of transportation facilities. In addition, both the North Slope Borough and the federal government have jurisdiction over various aspects of any transportation alternative.

The following are summaries of some applicable mitigation measures and lessee advisories designed to mitigate potential impacts of transportation. For a complete listing of mitigation measures and lessee advisories see Chapter Seven. Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

- Pipelines must utilize existing transportation corridors and must be designed to facilitate the containment and cleanup of spilled fluids. Onshore pipelines must be buried where soil and geophysical conditions permit. All pipelines, including flow and gathering lines, must be designed, constructed and maintained to assure integrity against climatic conditions, geophysical hazards, corrosion and other hazards.

- Pipelines must be designed and constructed to avoid significant alteration of caribou and other large ungulate movement and migration patterns. At a minimum, above-ground pipelines must be elevated seven feet. Ramps or pipeline burial may also be required to facilitate caribou movement. ADNR, through consultation with ADF&G, may require additional measures to mitigation impacts to wildlife.
- The siting of facilities will be prohibited within at least 500 feet of all fish-bearing waterbodies. Additionally, the siting of facilities will be prohibited within one-half mile of the banks of the main channel of the Colville, Canning, Sagavanirktok, Kavik, Shaviovik, Kadleroshilik, Echooka, Ivishak, Kuparuk, Toolik, Anaktuvuk and Chandler Rivers.
- Lessees must avoid siting facilities in sensitive habitats and important wetlands.
- Lessees are advised in planning and design activities to consider the recommendations for oil field design and operations contained in the final report to the Alaska Caribou Steering Committee.
- The state discourages the use of continuous-fill causeways. Approved causeways must be designed, sited and constructed to prevent significant changes to nearshore oceanographic circulation patters and water quality characteristics. Causeways and docks must not be located in river mouths or deltas. Each proposed structure is reviewed on a case-by-case basis and may be permitted if the Director, in consultation with ADF&G, ADEC and the North Slope Borough, determines that the structure is necessary for field development and no practicable alternatives exist. A monitoring program may be required.
- Pursuant to regulations 18 AAC 75 administered by ADEC, lessees are required to have an approved oil discharge prevention and contingency plan (C-Plan) prior to commencing operations. Pipeline gravel pads must be designed to facilitate the containment and cleanup of spilled fluids. Containers with a total storage capacity of greater than 55 gallons that contain fuel or hazardous substances shall not be stored within 100 feet of a waterbody.

C. Oil Spill Risk, Prevention and Response

1. Oil Spill History and Risk

The risk of a spill exists any time crude oil or petroleum products are handled. Oil spills associated with the exploration, development, production, storage and transportation of crude oil may occur from well blowouts or pipeline or tanker accidents. Petroleum activities may also generate chronic low volume spills involving fuels and other petroleum products associated with normal operation of drilling rigs, vessels and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels and other vehicles used in exploration and development activities. A worst case oil discharge from an exploration facility, production facility, pipeline, or storage facility is restricted by the maximum tank or vessel storage capacity or by a well's ability to produce oil. Companies do not store large volumes of crude at their facilities on the North Slope; rather produced oil is processed and transported as quickly as possible. This reduces the possible size of a potential spill on the North Slope.

The oil and gas industry has been actively exploring and producing North Slope resources for more than three decades. In this time, the vast majority of oil, produced fluid, seawater and other industry-related spills have been less than 10 gallons (1/4 bbl), with very few larger than 100,000 gallons (2,380 bbl) (BLM, 2005, citing NRC, 2003). The probability of a spill larger than 1 million gallons is extremely low (*Ibid.*, citing USDOI BLM and MMS, 1998). The 2003 National Research Council report *Cumulative Environmental*

Effects of Oil and Gas Activities on Alaska's North Slope, concluded that, while small spills have occurred in the fields, the spills have not been large or frequent enough to have accumulated effects (NRC, 2003). The report also noted, however, that a large spill in open water would have substantial effects, as current clean-up methods are not effective at removing oil from marine waters, particularly waters with floating ice (*Ibid*.).

a. Exploration and Production

Spills related to petroleum exploration and production must be distinguished from those related to transportation because the phases have different risk factors and spill histories. Exploration and production facilities in the sale area may include onshore gravel pads; drill rigs; pipelines; and facilities for gathering, processing, storage and moving oil. These facilities are discussed below. Spills occurring at these facilities are usually related to everyday operations, such as fuel transfers. Cataclysmic spills are rare at the exploration and production stages because spill sizes are limited by production rates and by the amount of crude stored at the exploration or production facility.

The most dramatic form of spill can occur during a well blowout, which can take place when high pressure gas is encountered in the well and sufficient precautions, such as increasing the weight of the drilling mud, are not effective. The result is that oil, gas, or mud is suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers, which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by the AOGCC.

A blowout that results in an oil spill is extremely rare and has never occurred in Alaska. Natural gas blowouts have occurred; however, at the Cirque No. 1 well in 1992. The accident occurred while ARCO workers were drilling an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took two weeks to plug the well (Anchorage Times, 1992). In 1994, a gas kick occurred at the Endicott field 1-53 well. BP Exploration was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was killed three days later by pumping heavily weighted drilling muds into it (Schmitz, 1994; ADN, 1994a).

b. Pipelines

The pipeline system that carries North Slope crude from the development area includes gathering lines and pipelines that carry the crude to treatment facilities and to Pump Station 1, where the oil enters TAPS for transport to the port of Valdez. Pipelines vary in size, length and amount of oil contained. A 14-inch pipeline can store about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a five mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from the pipeline.

In January 1994, a pipeline break caused by wind-induced vibration occurred at a Prudhoe Bay drill site. Response to the oil spill was swift and approximately 360 bbl were recovered of an estimated 300-400 bbls spilled. (Alaska Journal of Commerce, 1994; Schmitz, 1994). A leak in a Kuparuk pipeline carrying oil to a processing facility was also discovered in 1994. About 6,000 square feet of surrounding tundra was affected, but there was no danger to the nearby Ugnuravik River (Anchorage Daily News, 1994).

In 2006 the oil and gas industry, general public and local, state and federal regulators, became acutely aware of potentially widespread pipeline corrosion issues on the North Slope. On March 2, 2006, more than 200,000 gallons (4,790 bbls) from a transit line in Prudhoe Bay spilled over approximately two acres of tundra – the largest spill in Prudhoe history (ADN, 2006a). The cause of the leak was internal microbiological corrosion of the pipeline (PN, 2006b). A one-quarter inch hole formed in the bottom of the pipeline in a section that had been buried under a caribou crossing. The snow covered the leak, causing delayed detection; ultimately the odor exposed the leak to a worker (PN, 2006b). An ADEC report issued in April 2006 stated that spill alarms went off for four consecutive days in late February; however the alarms were dismissed by operators monitoring the system as false (ADN, 2006a). Crews recovered over 60,000 gallons of the spilled oil, and, after the $6 million cleanup was completed, ADEC estimated the tundra suffered minimal environmental damage (PN, 2006a; ADN, 2006a). BP Exploration Alaska, the Prudhoe Bay operator, had not pigged the pipeline that leaked to test for internal corrosion since 1998 (ADN, 2006a).

Additionally, on March 9, 2006, spill responders found 500 gallons of oily water that had leaked from a gathering line in the Kuparuk unit and another 200 gallons were collected in a catch basin (PN, 2006d). The cause of the leak was also determined to be holes caused by internal corrosion.

On August 6, 2006, BP announced that it needed to shut down the Prudhoe Bay field in order to address pipeline corrosion issues (PN, 2006c). A corrosion test detected a small leak in a transit line and the entire eastern operating area was completely shut in. In response to the August 2006 shutdown, transit lines were pigged weekly and continuous corrosion inhibitor was added to the transit lines (PN, 2007b). BP is currently in the process of replacing the entire transit system in the Prudhoe Bay area (except for Lisburne), a task that will take until the end of 2008 (PN, 2007b).

Despite the oil spills, the State Pipeline Coordinator's Office's (SPCO) August 2006 report on surveillance of North Slope common carrier lines found the lines generally in good operating condition. The SPCO regulates common carrier pipelines; it does not regulate or inspect the transit and gathering pipelines. The SPCO's compliance oversight team focused on corrosion issues and found that in the past three years, all of the pipeline operators have run smart pigs through the pipelines regulated by the SPCO. Other monitoring techniques include radiographic testing, magnetic flux leakage, the use of coupons, and regular ground and aerial inspections. Additionally, each pipeline has a leak detection system that issues an alarm when the amount of fluids delivered from the pipeline differs from the amount entering. The report indicates the most significant corrosion issue on the Kuparuk and Endicott pipelines is external corrosion. The Milne Point Pipeline appears to have a higher rate of internal corrosion, and the SPCO report states that operators have increased pigging. The Badami pipeline has some internal corrosion but it does not appear to threaten safe pipeline operations. Finally, the Alpine pipeline did not appear to have significant corrosion problems (SPCO, 2006). The SPCO will coordinate with the USDOT to confirm that lessees are meeting requirements for pipeline integrity management.

The 2006 oil spills brought the issues of corrosion and pipeline monitoring to the top of the state's agenda. Increased awareness, both statewide and nationally, brought forth a number of changes in both the public and private sectors. To begin, operators assert they are monitoring corrosion more closely, including pigging transit and common carrier lines on a regular basis, and updating and strictly enforcing best industry standards for routine maintenance practices. The state has also taken a closer look at pipeline corrosion issues and has expanded efforts to monitor and regulate both gathering and common carrier lines. Additionally, in 2006, ADEC promulgated new regulations (18 AAC 75) regarding education, preparation for spills, and spill response.

Additionally, state and federal officials are currently investigating the pipeline corrosion issues, including whether companies deliberately avoided pipeline maintenance in order to boost profits, and whether company officials ignored repeated information regarding the corrosion and other necessary maintenance issues. The federal government is also investigating whether state officials knowingly ignored poor industry habits, including routine pipeline maintenance procedures.

c. Marine Terminals and Tanker Vessels

No marine terminals are located on the North Slope due to the presence of ice for most of the year. The Valdez terminal receives North Slope crude through TAPS, stores it and loads it onto tanker vessels for transport to the west coast of the United States and Pacific Rim. Most North Slope crude is transported to the U.S. west coast.

Petroleum hydrocarbons may enter Port Valdez harbor from ballast water that is off-loaded from incoming tankers. The water is treated to remove residual petroleum hydrocarbons and then discharged via a submarine diffuser into the inlet (Jarvella 1987:582). A four year, pre- and post-operational study undertaken by the University of Alaska (Jarvella 1987, citing Colonell 1980) concluded that no adverse effects on the fjord were presently evident (Jarvella 1987:582). Monitoring continues under National Pollutant Discharge Elimination System (NPDES) permits.

The stationary nature of exploration, production and terminal facilities and the predictability of maximum spill rates based on production rates and storage amounts somewhat simplifies the development and implementation of oil spill contingency plans for those facilities. In contrast, the mobile nature of tankers, the large volumes carried and the exposure to marine hazards places tankers at higher risk for oil spills. A badly damaged tanker can spill millions of gallons of oil in a matter of hours.

A tanker accident can result in the release of large quantities of oil in a short time, causing severe environmental damage. An oil spill in a marine water setting is also much more difficult to contain than one on land since ocean currents and tidal actions carry the oil over a much larger area. An example of the potential magnitude of a tanker spill is the March 1989 *Exxon Valdez* spill, the largest recorded spill in U.S. waters (nearly 261,900 bbls). Oil from the *Exxon Valdez* contaminated fishing gear, fish, and shellfish, killed numerous marine birds and mammals, and led to the closure or disruption of many Prince William Sound, Cook Inlet, Kodiak, and Chignik fisheries (Alaska Office of the Governor, 1989).

2. Oil Spill Prevention

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. Some of these prevention measures are presented as mitigation measures in Chapter Seven, and some are discussed at the beginning of this section. Prevention measures are also described in the oil discharge prevention and contingency plans that the industry must prepare prior to beginning operations. Thorough training, well-maintained equipment and routine surveillance are important components of oil spill prevention. Additionally, technical design of pipelines and other facilities at the plan of operations phase reduces the chances of oil spills.

The oil industry employs, and is required to employ, many techniques and operating procedures to help reduce the possibility of spilling oil, including:

- Use of existing facilities and roads;
- Waterbody protection, including proper location of onshore oil storage and fuel transfer areas;
- Use of proper fuel transfer procedures;
- Use of secondary containment, such as impermeable liners and dikes;
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife;
- Consolidation of facilities;
- Placement of facilities away from fishbearing streams and critical habitats;
- Siting pipelines to facilitate spilled oil containment and cleanup; and
- Installation of pipeline leak detection and shutoff devices.

Each well has a blowout prevention program that is developed before the well is drilled. Operators review bottom-hole pressure data from existing wells in the area and seismic data to learn what pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance. Blowout prevention (BOP) equipment is installed on the wellhead after the surface casing is set and before actual drilling begins. BOP stacks are routinely tested in accordance with government requirements (BP, 1996a).

Wells are drilled according to the detailed plan. Drilling mud and well pressures are continuously monitored, and the mud is adjusted to meet the actual wellbore pressures. The weight of the mud is the primary well control system. If a kick (sudden increase in well pressure) occurs, the well is shut-in using the BOP equipment. The BOP closes off and contains fluids and pressures in the annulus and in the drillpipe. Technicians take pressure readings and adjust the weight of the drilling mud to compensate for the increased pressure. BOP drills are performed routinely with all crews to ensure wells are shut-in quickly and properly. Rig foremen, tool pushers, drillers, derrick men and mud men all have certified training in well control that is renewed annually (BP, 1996a).

If well control is lost and there is an uncontrolled flow of fluids at the surface, a well control plan is devised. The plan may include instituting additional surface control measures, igniting the blowout, or drilling a relief well. Regaining control at the surface is faster than drilling a relief well and has a high success rate. A blowout may bridge naturally due to the pressure drop across the formations. Under these conditions, reservoir formations flow to equalize pressure and the resulting bridging results in decreased flow at the surface. The exact mechanical surface control methods used depend on the individual situation. Operators may pump mud or cement down the well to kill it; replace failed equipment, remove part of the BOP stack and install a master valve; or divert the flow and install remotely-operated well control equipment (BP, 1996a).

While operators consider mechanical surface control methods, they also begin planning to drill a relief well by assessing the situation and determining the location for the relief well. Additionally, logistical plans to move another drill rig to the site are necessary. Conditions may require the construction of an ice or gravel pad and road. The operator will look for the closest appropriate drill rig. If the rig is in use, industry practice dictates that, when requested, the operator will release the rig for emergency use. Arranging for and drilling a relief well could take from 10 to 15 weeks depending on weather, cause of the blowout, choice of surface location and depth of the well (BP, 1996a).

Leak detection systems and effective emergency shut-down equipment and procedures are essential in preventing discharges of oil from any pipeline which might be constructed in the sale area. Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The number and spacing of the block valves along the pipeline will depend on the size of the pipeline and the expected throughput rate (Nessim and Jordan, 1986). Industry on the North Slope currently uses the volume balancing method, which involves comparing input volume to output volume.

The technology for monitoring pipelines is continually improving. Leak detection methods include acoustic monitoring, pressure point analysis, ultrasound, radiographic testing, magnetic flux leakage, the use of coupons, regular ground and aerial inspections, and combinations of some or all of the different methods. The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. Design and use of “smart pigs,” data collection devices that are run through the pipeline while it is in operation, has greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. Pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems.

Leak detection methods include acoustic monitoring, pressure point analysis, and combinations of some or all of the different methods (Yoon, Mensik, and Luk, 1988). The approximate location of a leak can be determined from the sensors along the pipeline. A computer network is used to monitor the sensors and signal any abnormal responses. In recent years, computer-based leak detection through a Real-Time Transient Model has come into use. This technology can minimize spills from both new and old pipelines (Yoon and Mensik, 1988a).

A similar technology for detecting leaks in oil and gas pipelines is termed Pressure Point Analysis (PPA). The method uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989). Automated leak detection systems such as PPA operate 24 hours per day and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

Three other systems can be employed which detect leaks down to 0.12 percent of rated capacity (100 bbl per hour). These include Line Volume Balance, Deviation Alarms, and Transient Volume Balance.

Line Volume Balance. LVB checks the oil volume in the pipeline every 30 minutes. The system compares the volume entering the line with the volume leaving the line, adjusting for temperature, pressure, pump station tank-level changes, and slackline conditions.

Deviation Alarms. There are three types of deviation alarms: pressure, flow, and flow rate balance. Pressure alarms are triggered if the pressure at the suction or discharge of any pump station deviates beyond a certain amount. Flow alarms are triggered if the amount of oil entering a pump station varies too much from one check time to the next. Flow rate balance alarms are triggered if the amount of oil leaving one pump station varies too much from the amount entering the next pump station downstream. This calculation is performed on each pipeline section about six times a minute.

Transient Volume Balance. TVB can both detect whether a leak may be occurring and identify the probable leak location by segment, especially with larger leaks. While the LVB leak detection system monitors the entire pipeline, the TVB system individually monitors each segment between pump stations. Since the TVB indicates in which area a leak may be occurring, focused reconnaissance and earlier response mobilization are possible (Alyeska Pipeline, 1999).

LEOS. Another detection system that is available is LEOS (Leck Erkennung und Ortangs System), a leak detection and location system manufactured by Siemens AG. The system has been in use for 21 years and in over thirty applications.

LEOS consists of a three-layer gas-sensor tube that is laid next to the pipeline. The inner layer is a perforated gas transport tube of modified PVC. A diffusion layer of EVA surrounds and allows gasses to enter the inner tube. A protective layer of braided plastic strips forms the outer layer. The tube is filled with fresh air, and the air is evacuated through a leak detector at regular intervals. If leak occurs, hydrocarbon gasses associated with the leak enter the tube and are carried to the gas detector. The system is totally computer controlled, self-checking and re-setting. Background gasses are calibrated at setup and checked regularly. The system will pick up previous contamination and organic decomposition. The location of the leak is determined by monitoring the time that leaked gas arrives at the detection device.

The system is very low maintenance and will last the life of the pipeline. Special protective adaptations will be made for the cold temperatures in which the system will operate and for the backfill installation method that will be used to install the pipeline. The tube will be placed in a protective cover, and the system will be tested continuously as the segments are installed. LEOS will be strapped to the oil pipeline next to the poly spacers that will separate the gas line from the oil line. The system will detect leaks from both lines, and operators will be able to tell the difference between the two. Engineers estimate that it will take about 5 to 6 hours for leaked molecules to migrate to the LEOS tube. The air inside the tube will be evacuated and tested every 24 hours

Smart Pigs. Design and use of "smart pigs," data collection devices that are run through the pipeline while it is in operation, has greatly enhanced the ability of a pipeline operator to detect internal and external corrosion and differential pipe settlement in pipelines. These pigs can be sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems. The Trans Alaska Pipeline System (TAPS) operation has pioneered this effort for Arctic pipelines. The technique is now available for use worldwide and represents a major tool for use in preventing pipeline failures.

FLIR. Conoco Phillips utilizes a comprehensive FLIR (Forward Looking InfraRed) pipeline monitoring program in the Kuparuk oil field to assist in detecting pipeline leaks and corrosion. Infrared sensors have the ability to sense heat differentials. Since Kuparuk oil flows from the ground at temperatures in excess of 100F, a leak shows up as a "hot spot" in a FLIR video. In addition, water-soaked insulation surrounding a pipeline is visible because of the heat transfer from the hot oil to the water in the insulation and finally to the exterior surface of the pipeline. FLIR is effective 80 percent of the time in discovering water-soaked insulation areas that have produced corrosion on the exterior wall of the pipeline (ARCO, 1998).

FLIR also has applications in spill response and was used to image spills at both Prudhoe Bay and Kuparuk. The video frames were processed and registered into a GIS map database. The map database with the overlaid picture of the spill site was then used to quickly and accurately determine the area of the spill. This action allowed swift and accurate reporting of the spill parameters to the appropriate agencies. The video footage of the spill area allowed the incident command team to receive near real-time information in IR and color. This information permitted timely decisions to be made and the results of those decisions to be reviewed with the subsequent fly-over zone site. Various agencies involved in the process were able to see and verify the results of the cleanup process (ARCO, 1998).

To ensure safe operation, pipeline operators would follow the appropriate American Petroleum Institute recommended practices. They would inspect the pipelines regularly to determine if any damage was occurring and would also perform preventive maintenance. Preventive maintenance includes installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections.

No oil or gas may be transported until the operator has obtained the necessary permits and authorizations from federal, state, and local governments. ADNR and other state, federal, and local agencies will review the specific transportation system when it is actually proposed.

If pipelines are used in the development of the sale area, operators must follow the appropriate American Petroleum Institute recommended practices. Regular inspection of the pipelines to determine if any damage was occurring would be required, as would regular maintenance, including installing improved cathodic protection, using corrosion inhibitors and continuing regular visual inspections. If and when oil or gas is found in commercial quantities and production is proposed, final decisions on transportation will be made through the local, state, and federal permitting processes. Those processes will consider any required changes in oil spill contingency planning and other environmental safeguards, and will involve public participation.

The fixed location of loading facilities at marine terminals improves oil spill response and contingency planning. Additionally, Oil Pollution Act of 1990 requires that single-hull tankers in Alaska be replaced by double-hull tankers by 2010. All tanker crews participate in spill prevention and response training and substance abuse testing. The oil discharge prevention and contingency plans for vessel operations contain more detailed information regarding spill prevention programs.

3. Oil Spill Response

a. Incident Command System

An Incident Command System (ICS) response is activated in the event of an actual or potential oil or hazardous material spill. The ICS system is designed to organize and manage responses to incidents involving a number of interested parties in a variety of activities. Since oil spills usually involve multiple jurisdictions, the joint federal/state response contingency plan incorporates a unified command structure in the oil and hazardous substance discharge ICS. The unified command consists of the Federal On-Scene Coordinator, the State On-Scene Coordinator, the Local On-Scene Coordinator and the Responsible Party On-Scene Coordinator. The ICS is organized around five major functions: command, planning, operations, logistics, and finance/administration (ADEC, 2006).

The Unified Command jointly makes decisions on objectives and response strategies; however, only one Incident Commander is in charge of the spill response. The Incident Commander is responsible for implementing these objectives and response strategies. If the Responsible Party is known, the Responsible Party Incident Commander may remain in charge until or unless the Federal On-Scene Coordinator and the State On-Scene Coordinator decide that the Responsible Party is not doing an adequate job of response (ADEC, 2006).

b. Response Teams

The Alaska Regional Response Team (ARRT) monitors the actions of the Responsible Party. The Team is composed of representatives from 15 federal agencies and one representative agency from the state. The ARRT is co-chaired by the U.S. Coast Guard and Environmental Protection Agency. ADEC represents the state of Alaska. The team provides coordinated federal and state response policies to guide the Federal On-Scene Coordinator in responding effectively to spill incidents. The Statewide Oil and Hazardous Substance Incident Management System Workgroup, which consists of ADEC, industry, spill cooperatives, and federal agencies, published the *Alaska Incident Management System* (AIMS) for oil and hazardous substance response (ADEC, 2006).

Each North Slope operator identifies a spill response team (SRT) for their facility, and each facility must have an approved spill contingency plan. Company teams provide on-site, immediate response to a spill event. The responders first attempt to stop the flow of oil and may deploy boom to confine oil that has entered the water. The responders may deploy boom to protect major inlets, wash-over channels, and small inlets. Finally, deflection booming would be placed to enclose smaller bays and channels to protect sensitive environmental areas. If the nature of the event exceeds the facility's resources, the Responsible Party calls in its response organization. The Spill Response Team (SRT):

1) identifies the threatened area;
2) assesses the natural resources, i.e., environmentally sensitive areas such as major fishing areas, spawning or breeding grounds;
3) identifies other high-risk areas such as offshore exploration and development sites and tank-vessel operations in the area;
4) obtains information on local tides, currents, prevailing winds, and ice conditions; and

5) identifies the type, amount, and location of available equipment, supplies and personnel.

The next action would be containment. It is especially important to prevent oil spills from reaching the Beaufort Sea where they could spread rapidly over a large area. Cleanup activities continue as long as necessary, without any time frame or deadline. A winter spill might require initial on-site response followed by further cleanup of oil melting out of the ice in the spring or summer (MMS, 1990).

c. Training

Individual members of the SRT train in basic spill response; skimmer use; detection and tracking of oil; oil recovery on lakes; river booming; radio communications; ATV, snowmobile, and four-wheeler operations; oil discharge, prevention, and contingency plan review; communication equipment operations; Arctic survival; oil spill burning operations; pipeline leak plugging; and spill volume estimations.

d. Response Organizations

Alaska Clean Seas (ACS) is a non-profit spill response organization for the North Slope operators between the Colville and Canning rivers, including the TAPS corridor to Pump Station No. 4 and the three-mile offshore limit of state waters. ACS provides personnel, material, equipment and training response capability for use in support of its members in preparing from, responding to, and cleaning up a hazardous spill on the North Slope (ACS, 2007). ACS maintains approximately 70 full-time staff, all of whom are available for response operations. Approximately half of ACS's staff is located in the fields, where they perform daily spill response and preparation duties under the direction of ACS's member companies (ACS, 2007).

Immediate spill response requirements are met through the use of Spill Response Teams (SRTs) comprised of company and contractor employees at each of the fields who voluntarily enlist in their particular field's SRT. The SRTs are integrated into a single North Slope Spill Response Team (NSRT), comprised of 115 field responders per shift, each of which has or will receive a minimum of 24 hours of hazardous materials (HAZWOPER) training. The North Slope Operators who furnish the SRTs from their employee and contractor staffs have committed to make the SRT's available on a Slope-wide basis for up to 36 hours upon call-out (ACS, 1995).

ACS and the North Slope operators employ a "tiered system" for responding to spills. Small, non-emergency spills are cleaned up by the Operator or ACS personnel. Spills requiring the resources of ACS and the responsible party's SRT are considered "Level I" spills. Depending on activity levels and the duration of work to do, off-site contractor-supplied personnel may be used to complete the cleanup and may be obtained through one or more of the master agreements which ACS maintains with labor contractors (ACS, 1995).

If a spill requires more than the resources of ACS and the RP, it is considered to be a Level II spill. Additional manpower resources would be obtained through mutual aid. Mutual aid is a system that utilizes SRTs from companies other than that of the responsible party. Such spills usually require some longer term cleanup. Under its master service agreements, ACS can obtain 100 contract responders within 36 hours (ACS, 1995).

If a spill exceeds the resources available on the North Slope, it is classified as a Level III spill. These types of spills will not only receive initial response from the full North Slope Response Team (NSRT), but will likewise require the work of off-site contract responders under ACS's master service agreements (ACS, 1995).

ACS established a central Incident Command Post at Deadhorse as a control point for oil spill response radio and telephone systems for the entire North Slope area, extending north from 68 degrees latitude (approximately Cape Seppings on the Chukchi Sea) and east to the Canadian border, including a range of several hundred miles offshore in the Chukchi Sea. This radio and telephone communications system is capable of being rapidly deployed by sea, land, or air to local and remote areas in support of offshore exploration or oil spill response actions. Remote control circuits for 10 permanent very high frequency (VHF) repeaters and marine coast stations, installed at strategic locations in the production area and pipeline corridor, are routed via private microwave circuits into the system. Other high frequency (HF) and ultra high frequency (UHF) radios are also connected to the system. Communication is then possible among all users, whether marine-based radios, company headquarters or supply depots, ICP, hand held portable radios, or aircraft radios. This gives each member company access to all of the radio systems, regardless of the type of radio it is using. ACS also has eight mobile VHF radios and about 150 handheld radios for field use in its oil spill response program (ACS, 1991a; ADEC, 2006). ADEC has three permanently installed VHF repeaters in Lisburne, Kuparuk, and the ADEC office in Deadhorse, along with three portable VHF repeaters (ADEC, 2006).

Other operational equipment includes four INMARSAT satellite telephone systems, operating independently of wires and separate from the VHF, UHF, and other radio systems, at Deadhorse on the North Slope. The name INMARSAT is derived from “international, marine, satellite.” The system can reach anywhere in the world via satellite. An INMARSAT system can be mounted on a boat in such a way that, regardless of heavy seas or other disturbance, the antenna beam cannot be shaken off the satellite and communication disconnected. Ships, barges, aircraft, oil spill response agencies, ground personnel, and anyone with a telephone can be reached via this system. The equipment can be used immediately in case of an emergency anywhere in the state (Wheeler, 1991).

ACS and member companies own spill containment and clean-up equipment totaling over $50 million, including: more than 300,000 feet of oil containment boom; 185 skimmers; eight helitorch aerial ignition systems; 96 vessels; two 128-barrel and twelve 249-barrel mini-barges; various sizes of storage tanks and bladders; and wildlife hazing and stabilization equipment (ACS, 2007). ACS also provides arctic-oriented spill response training to member companies, contractors, village response teams and government agencies. ACS averages over 34,000 student hours, with over 450 classes annually (ACS, 2007).

Important aspects of response are planning, preparation and practice. North Slope and Beaufort Sea operators and state and federal agencies participate in a mutual aid drill at least once each year.

4. Cleanup and Remediation

Cleanup plans for terrestrial and wetlands spills must balance the objectives of maximizing recovery and minimizing ecological damage. Many past cleanup operations have caused as much or more damage than the oil itself. All oils are not the same, and knowledge of the chemistry, fate and toxicity of the spilled oil can help identify those cleanup techniques that can reduce the ecological impacts of an oil spill. Hundreds of laboratory and field experiments have investigated the fate, uptake, toxicity, behavioral responses, and population and community responses to crude oil (Jorgenson and Carter, 1996).

The best techniques are those that quickly remove volatile aromatic hydrocarbons. This is the portion of oil that causes the most concern regarding the physical fouling of birds and mammals. To limit the most serious effects, it is desirable to remove the maximum amount of oil as soon as possible after a spill. The objective is to promote ecological recovery and not allow the ecological effects of cleanup to exceed those caused by the spill itself. Table 6.1 lists cleanup objectives and techniques that may be applicable to each objective. Table 6.2 compares the advantages and disadvantages of cleanup techniques for crude oil in terrestrial and wetland ecosystems (Jorgenson and Carter, 1996).

Table 6.1 Objectives and Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems

Objectives	Cleanup Techniques
Minimize:	
Movement of oil	Absorbent booms Sand bagging Sheet piling
Surface-water contamination	Same as above
Soil infiltration	Flood surface
Soil and vegetation contact and oil adhesion	Flood surface Use surfactants to reduce adhesion
Vegetation damage	Use boardwalks to reduce trampling Use flushing instead of mechanical techniques Perform work when vegetation is dormant
Thawing of Permafrost	Avoid vegetation and surface disturbance
Wildlife contact with oil	Fencing to prevent wildlife from entering site Plastic sheeting to prevent birds from landing on site Guards to haze wildlife Devices to haze wildlife
Acute and chronic toxicity of oil to humans, fish, and wildlife	Removal of oil Enhance biodegradation of remaining oil
Waste disposal	Use flushing Avoid absorbents and swabbing
Cost	Remove oil as fast as possible Achieve acceptable cleanup level quickly to minimize monitoring
Liability	Achieve acceptable cleanup level
Maximize:	
Recovery potential of tundra ecosystems	All of the above Add nutrients to aid recovery of plants
Worker safety	Air testing, training, clothing

Source: Adapted from Jorgenson, 1996

Table 6.2 Advantages and Disadvantages of Techniques for Cleaning Up Crude Oil in Terrestrial and Wetland Ecosystems

Technique	Advantage	Disadvantage	Recommended
Wildlife:			
Fencing	Keeps out large mammals	Does not keep out birds	Yes
Plastic sheeting	Keeps out both birds and mammals	Can no longer work area	Sometimes
Wildlife guard	Flexibility to respond	Higher cost	Sometimes
Devices	Lower cost	Animals become habituated	No
Containment:			
Absorbent booms	Contains floating oil, quickly deployed	Misses water soluble oil	Yes
Sand bags	Contains both floating and soluble fractions, follows tundra contours	Slower to mobilize, some leakage	Yes
Sheet piling	Maximum containment	Slow to install, doesn't fit contours well	Sometimes
Earthen berms	Can easily be adapted to terrain, heavy equipment rapidly can create berms	Destroys existing vegetation and soil	No
Snow/ice berms	Can be used during winter cleanup or to prevent runoff during breakup	Can only be used during freezing periods	Yes
Contact:			
Flooding	Keeps heavy oil suspended	Spreads out oil	Yes
Surfactants	Reduces stickiness, aids removal, and reduces volatilization	Reduces effectiveness of rope mop skimmer	Yes
Thickening agents	Untried, aids physical removal	Must be well drained, physical removal more difficult	No
Access:			
Boardwalks	Reduces trampling	None	Yes
Removal:			
Complete excavation	Eliminates long-term liability	Eliminates natural recovery, disposal costs	Sometimes
Partial excavation	Quickly reduces oil levels, less waste to dispose of than complete excavation	Causes partial ecological damage, disposal costs, still long-term liability	Sometimes
Burning	Low cost, high removal rate	Little testing, ecological damage	Sometimes
Flushing, high pressure	High removal rate	High ecological damage	No
Flushing, low pressure, cold	Moderate removal rate, little damage, easy waste disposal	Spreads oil, not as effective as warm water	No
Flushing, low pressure, warm	High removal rate, little vegetation damage, easy disposal of waste	Spreads oil	Yes
Aeration	Accelerates volatilization	Volatiles lost to air, may pose risk to humans	Yes
Raking	Can target hot spots	Partial vegetation damage	Sometimes
Cutting and trimming	Targets hot spots, reduces stickiness	Partial vegetation damage	Sometimes

Technique	Advantage	Disadvantage	Recommended
Swabbing	Targets hot spots	Not very effective, adds to waste disposal, adds to trampling	No
Oil skimmers and rope mops	Removes heavier oil, works well with flooding, lowers disposal costs	Requires personnel to push oil to skimmer, adds to trampling	Yes
Vacuum pumping	Removes surface and miscible oil, works well with flooding, lowers disposal cost	None	Yes
Biodegradation	Removes low levels of hydrocarbons, non-destructive, lowers disposal costs	Long-term monitoring, site maintenance, may require wildlife protection	Yes

Source: Adapted from Jorgenson, 1996

After a spill, the physical and chemical properties of the individual constituents in the oil begin to be altered by the physical, chemical, and biological characteristics of the environment; this is called weathering. The factors that are most important during the initial stages of cleanup are the evaporation, solubility and movement of the spilled oil. As much as 40 percent of most crude oils may evaporate within a week after a spill. Over the long term, microscopic organisms (bacteria and fungi) break down oil (Jorgenson and Carter, 1996).

Cleanup phases include initial response, remediation and restoration. During initial response, the responsible party: gains control of the source of the spilling oil; contains the spilled oil; protects the natural and cultural resource; removes, stores and disposes of collected oil; and assesses the condition of the impacted areas. During remediation, the responsible party performs site and risk assessments; develops a remediation plan; and removes, stores and disposes of more collected oil. Restoration attempts to re-establish the ecological conditions that preceded the spill and usually includes a monitoring program to access the results of the restoration activities (Jorgenson and Carter, 1996).

5. Regulation of Oil Spill Prevention and Response

a. Federal Statutes and Regulations

Section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 U.S.C. §9605), and §311(c)(2) of the Clean Water Act, as amended (33 U.S.C. §1321(c)(2)) require environmental protection from oil spills. CERCLA regulations contain the National Oil and Hazardous Substances Pollution Contingency Plan (40 C.F.R. §300). Under these regulations, the spiller must plan to prevent and immediately respond to oil and hazardous substance spills and be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator (FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will respond to the spill, and then seek to recover cleanup costs from the responsible party.

The Oil Pollution Act of 1990 (OPA 90) requires the development of facility and tank vessel response plans and an area-level planning and coordination structure to coordinate federal, regional, and local government planning efforts with the industry. OPA 90 amended the Clean Water Act (§ 311(j)(4)), which established area committees and area contingency plans as the primary components of the national response planning structure. In addition to human health and safety, these area committees have three primary responsibilities:

1. prepare an area contingency plan;

2. work with state and local officials on contingency planning and preplanning of joint response efforts, including procedures for mechanical recovery, dispersal, shoreline cleanup, protection of sensitive areas, and protection, rescue and rehabilitation of fisheries and wildlife; and
3. work with state and local officials to expedite decisions for the use of dispersants and other mitigating substances and devices.

In Alaska, the area committee structure has incorporated state and local agency representatives, and the jointly prepared plans coordinate the response activities of the various governmental entities that have responsibilities regarding oil spill response. The area contingency plan for Alaska is the Unified Plan. Since Alaska is so large and geographically diverse, the federal agencies have found it necessary to prepare sub-area contingency plans, also discussed in the Government Contingency Plans section below.

OPA 90 also created two citizen advisory groups: the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils.

b. Alaska Statutes and Regulations

As discussed in Chapter One, ADEC is the agency responsible for implementing state oil spill response and planning regulations under AS 46.04.030. As of publication of this final finding, the following statutes and regulations are in effect. These provisions are subject to change in the future, particularly in response to recent spill activities. In 2006, ADEC adopted new regulations (18 AAC 75) for monitoring oilfield flowlines, new construction and maintenance standards which apply to oil tanks and pipeline facilities. Additionally, ADEC is placing increased emphasis on oil spill prevention training.

ADF&G and ADNR support ADEC in these efforts by providing expertise and information. The industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNR reviews and comments to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans (C-plans).

c. Industry Contingency Plans

C-plans for exploration facilities must include: a description of methods for responding to and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable drilling equipment; and an operations plan to mobilize and drill a relief well. If development and production should occur, additional contingency plans must be filed for each facility prior to commencement of activity, as part of the permitting process. Any vessels transporting crude oil from the potential development area must also have an approved contingency plan.

AS 46.04.030 provides that unless an oil discharge prevention and contingency plan has been approved by ADEC, and the operator is in compliance with the plan, no person may:

1. operate an oil terminal facility, a pipeline, or an exploration or production facility, a tank vessel, or an oil barge, or
2. permit the transfer of oil to or from a tank vessel or oil barge.

Parties with approved plans are required to have sufficient oil discharge containment, storage, transfer, cleanup equipment, personnel, and resources to meet the response planning standards for the particular type of facility, pipeline, tank vessel, or oil barge (AS 46.04.030(k)). Examples of these requirements are:

- The operator of an oil terminal facility must be able to "contain or control, and clean up" a spill volume equal to that of the largest oil storage tank at the facility within 72 hours.

That volume may be increased by ADEC if natural or manmade conditions exist outside the facility that place the area at high risk (AS 46.04.030(k)(1)).

- Operators of exploration or production facilities, or pipelines, must be able to "contain, control, and cleanup the realistic maximum oil discharge within 72 hours." (AS 46.04.030(k)(2)). The "realistic maximum oil discharge" means "the maximum and most damaging oil discharge that [ADEC] estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on (1) the size, location, and capacity; (2) ADEC's knowledge and experience with such; and (3) ADEC's analysis of possible mishaps." (AS 46.04.030(r)(3)).

Discharges of oil or hazardous substances must be reported to ADEC on a time schedule depending on the volume released, whether the release is to land or to water, and whether the release has been contained by a secondary containment or structure. For example, 18 AAC 75.300(a)(1)(A)-(C) requires the operator to notify ADEC as soon as it has knowledge of the following types of discharges:

- Any discharge or release of a hazardous substance other than oil;
- Any discharge of or release of oil to water; and
- Any discharge or release, including a cumulative discharge or release, of oil in excess of 55 gallons solely to land outside an impermeable secondary containment area or structure.

The discharge must be cleaned up to the satisfaction of ADEC, using methods approved by ADEC. ADEC will modify cleanup techniques or require additional cleanup techniques for the site as ADEC determines to be necessary to protect human health, safety, and welfare, and the environment (18 AAC 75.335(d). ADF&G and ADNR advise ADEC regarding the adequacy of cleanup.

A C-plan must describe the existing and proposed means of oil discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation (AS 46.04.030; 18 AAC 75.425(e)(2)(E)). A C-plan and its preparation, application, approval, and demonstration of effectiveness require a major effort on the part of facility operators and plan holders. The C-plan must include a response action plan, a prevention plan, and supplemental information to support the response plan (18 AAC 75.425). These plans are described below.

The Response Action Plan (18 AAC 75.425(e)(1)) must include an emergency action checklist of immediate steps to be taken if a discharge occurs. The checklist must include:

1. names and telephone numbers of people within the operator's organization who must be notified, and those responsible for notifying ADEC;
2. information on safety, communications, and deployment, and response strategies;
3. specific actions to stop a discharge at its source, to drill a relief well, to track the location of the oil on open water, and to forecast the location of its expected point of shoreline contact to prevent oil from affecting environmentally sensitive areas;
4. procedures for boom deployment, skimming or absorbing, lightening, and estimating the amount of recovered oil;
5. plans, procedures, and locations for the temporary storage and ultimate disposal of oil contaminated materials and oily wastes;
6. plans for the protection, recovery, disposal, rehabilitation, and release of potentially affected wildlife; and
7. if shorelines are affected, shoreline clean up and restoration methods.

The Prevention Plan (18 AAC 75.425(e)(2)) must:

1. include a description and schedule of regular pollution inspection and maintenance programs;
2. provide a history and description of known discharges greater than 55 gallons that have occurred at the facility, and specify the measures to be taken to prevent or mitigate similar future discharges;
3. provide an analysis of the size, frequency, cause, and duration of potential oil discharges, and any operational considerations, geophysical hazards, or other site-specific factors, which might increase the risk of a discharge, and measures taken to reduce such risks; and
4. describe existing and proposed means of discharge detection, including surveillance schedules, leak detection, observation wells, monitoring systems, and spill-detection instrumentation.

The Supplemental Information Section (18 AAC 75.425(e)(3)) must:

1. include bathymetric and topographic maps, charts, plans, drawings, diagrams, and photographs that describe the facility, show the normal routes of oil cargo vessels, show the locations of storage tanks, piping, containment structures, response equipment, emergency towing equipment, and other related information;
2. show the response command system; the realistic maximum response operation limitations such as weather, sea states (roughness of the sea), tides and currents, ice conditions, and visibility restrictions; the logistical support including identification of aircraft, vessels, and other transport equipment and personnel;
3. include a response equipment list including containment, control, cleanup, storage, transfer, lightering, and other related response equipment;
4. provide non-mechanical response information such as in situ burning or dispersant, including an environmental assessment of such use;
5. provide oil spill primary response action contractor information;
6. include a detailed description of the training programs for discharge response personnel;
7. provide a plan for protecting environmentally sensitive areas and areas of public concern; and
8. include any additional information and a detailed bibliography.

The Best Available Technology Section (18 AAC 75.425(e)(4)) must:

1. identify technologies applicable to the applicant's operation that are not subject to response planning or performance standards;
2. for each applicable technology listed, the plan must identify and analyze all available technologies; and
3. include a written justification that the technology proposed to be used is the best available for the applicant's operation.

The Response Planning Standard Section (18 AAC 75.425(e)(5)) must include a calculation of the applicable response planning standards, including a detailed basis for the calculation of reductions, if any, to be applied to the response planning standards.

The current statute allows the sharing of oil spill response equipment, materials, and personnel among plan holders. ADEC determines by regulation the maximum amount of material, equipment, and personnel that can be transferred, and the time allowed for the return of those resources to the original plan holder (AS 46.04.030(o)). The statute also requires the plan holders to "successfully demonstrate the ability to carry out the plan when required by [ADEC]" (AS 46.04.030(r)(2)(E)). ADEC regulations require that exercises (announced or unannounced) be conducted to test the adequacy and execution of the contingency plan. No more than two exercises are required annually, unless the plan proves inadequate. ADEC may, at its discretion, consider regularly scheduled training exercises as discharge exercises (18 AAC 75.485(a) and (d)).

d. Financial Responsibility

Holders of approved contingency plans must provide proof of financial ability to respond (AS 46.04.040). Financial responsibility may be demonstrated by one or a combination of 1) self-insurance; 2) insurance; 3) surety; 4) guarantee; 5) approved letter of credit; or 6) other ADEC-approved proof of financial responsibility (AS 46.04.040(e)). Operators must provide proof of financial responsibility acceptable to ADEC as follows:

- Crude oil terminals: $50,000,000 in damages per incident
- Non-crude oil terminals: $25 per incident for each barrel of total non-crude oil storage capacity at the terminal or $1,000,000, whichever is greater, with a maximum of $50,000,000
- Pipelines and offshore exploration or production facilities: $50,000,000 per incident.
- Onshore production facilities:
    - $20,000,000 per incident if the facility produces over 10,000 barrels per day of oil;
    - $10,000,000 per incident if the facility produces over 5,000 barrels per day of oil;
    - $5,000,000 per incident if the facility produces over 2,500 barrels per day but not more than 5,000 barrels per day of oil; and
    - $1,000,000 per incident if the facility produces 2,500 barrels per day or less of oil.
- Onshore exploration facilities: $1,000,000 per incident.
- Crude oil vessels and barges: $300 per incident, for each barrel of storage capacity or $100,000,000, whichever is greater
- Non-crude oil vessels and barges: $100 per barrel per incident or $1,000,000, whichever is greater, with a ceiling of $35,000,000
- The coverage amounts are adjusted every third year based on the Consumer Price Index. AS 46.04.045.

e. Government Contingency Plans

In accordance with AS 46.04.200, ADEC must prepare, annually review, and revise the statewide master oil and hazardous substance discharge prevention and contingency plan. The plan must identify and specify the responsibilities of state and federal agencies, municipalities, facility operators, and private parties whose property may be affected by an oil or hazardous substance discharge. The plan must incorporate the incident command system, identify actions to be taken to reduce the likelihood of occurrence of “catastrophic” oil discharges and “significant discharges of hazardous substances” (not oil), and designate the locations of storage depots for spill response material, equipment, and personnel.

ADEC must also prepare and annually review and revise a regional master oil and hazardous substance discharge prevention and contingency plan (AS 46.04.210). The regional master plans must contain the same elements and conditions as the state master plan but are applicable to a specific geographic area.

6. Mitigation Measures

Recognition of the difficulties of containment and clean up of oil spills has encouraged innovative and effective methods of preventing possible problems and handling them if they arise. Oil spill prevention, response, and cleanup and remediation techniques are continually being researched by state and federal agencies and the oil industry. Although the risk of impact from a spill cannot be reduced to zero, such risk can be minimized through preventive measures, monitoring, and rigorous response capability.

The following are summaries of some applicable mitigation measures and lessee advisories designed to mitigate potential impacts of spills. For a complete listing of mitigation measures and lessee advisories see Chapter Seven. Additional site-specific and project-specific mitigation measures may be imposed as necessary if exploration and development take place.

- Pipelines must utilize existing transportation corridors and must be designed to facilitate the containment and cleanup of spilled fluids. Onshore pipelines must be buried where soil and geophysical conditions permit. All pipelines, including flow and gathering lines, must be designed, constructed and maintained to assure integrity against climatic conditions, geophysical hazards, corrosion and other hazards.
- The siting of facilities will be prohibited within at least 500 feet of all fish-bearing waterbodies. Additionally, the siting of facilities will be prohibited within one-half mile of the banks of the main channel of the Colville, Canning, Sagavanirktok, Kavik, Shaviovik, Kadleroshilik, Echooka, Ivishak, Kuparuk, Toolik, Anaktuvuk and Chandler Rivers.
- Lessees must avoid siting facilities in sensitive habitats and important wetlands.
- The state discourages the use of continuous-fill causeways. Approved causeways must be designed, sited and constructed to prevent significant changes to nearshore oceanographic circulation patters and water quality characteristics. Causeways and docks must not be located in river mouths or deltas. Each proposed structure is reviewed on a case-by-case basis and may be permitted if the Director, in consultation with ADF&G, ADEC and the North Slope Borough, determines that the structure is necessary for field development and no practicable alternatives exist. A monitoring program may be required.
- Pursuant to regulations 18 AAC 75 administered by ADEC, lessees are required to have an approved oil discharge prevention and contingency plan (C-Plan) prior to commencing operations. Pipeline gravel pads must be designed to facilitate the containment and cleanup of spilled fluids. Containers with a total storage capacity of greater than 55 gallons that contain fuel or hazardous substances shall not be stored within 100 feet of a waterbody.
- Secondary containment is required for fuel or hazardous substance storage and containers with an aggregate capacity of greater than 55 gallons shall not be stored within 100 feet of a waterbody or within 1,500 feet of a current surface drinking water source.
- Store sites shall be protected from leaking or dripping fuel and hazardous substances by the placement of drip pans or other surface liners designed to catch and hold fluids under the equipment, or using an impermeable liner or suitable mechanism.
- During fuel or hazardous substance transfer, secondary containment or a surface liner must be used. Appropriate spill response equipment, sufficient to respond to a spill of up to five gallons, must be on hand and trained personnel shall attend transfer operations at all times.
- Vehicle refueling shall not occur within the annual floodplain.
- A fresh water aquifer monitoring well, and quarterly water quality monitoring, is required down gradient of a permanent storage facility.