5.19 RELIABILITY AND SAFETY

The transportation of natural gas by pipeline involves some risk to the public in the event of an accident and subsequent release of gas. The greatest hazard is a fire or explosion following a major pipeline rupture.

Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is not toxic but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death. Methane has an ignition temperature of 1,000 degrees Fahrenheit (°F) and is flammable at concentrations between 5 and 15 percent in air. Unconfined mixtures of methane in air are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. It is buoyant at atmospheric temperatures and disperses rapidly in air. If constructed, this proposed Project will be the first major large-diameter natural gas pipeline in the United States with a maximum allowable operating pressure (MAOP) of 2,500 pounds per square inch gauge (psig).

5.19.1 Safety Standards

The United States Department of Transportation (USDOT) is mandated to provide pipeline safety under Title 49, U.S.C. Chapter 601. The USDOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) oversees the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards which set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve safety. The PHMSA ensures that people and the environment are adequately protected from the risk of pipeline incidents. This work is shared with state agency partners and others at the federal, state, and local level. The Natural Gas Pipeline Safety Act at 49 U.S.C. 60105 provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards, while 49 U.S.C. 60106 permits a state agency that does not qualify under 49 U.S.C. 60105 to perform certain inspection and monitoring functions. A state may also act as the USDOT's agent to inspect interstate facilities within its boundaries; however, the USDOT is responsible for enforcement actions. The majority of the states have either certifications or agreements with USDOT under the Natural Gas Pipeline Safety Act, while nine states act as interstate agents. The State of Alaska does not have a either a certification or an agreement with USDOT under the Natural Gas Pipeline Safety Act.

However, the Alaska Department of Natural Resources (ADNR), Division of Oil and Gas currently operates the Petroleum Systems Integrity Office (PSIO) whose mission is "to maximize the safe and stable flow of oil and gas resources to market by ensuring appropriate oversight and maintenance of oil and gas equipment, facilities, and infrastructure" (ADNR 2011a). At this time, the State of Alaska, through the PSIO and the PHMSA have agreed "…to coordinate and cooperate in the regulation and oversight of oil and gas production and transportation in the State of Alaska…" through a letter of intent signed by the PHMSA and State of Alaska representatives in May 2007. The letter of intent agreed to the development of a plan to coordinate oversight of facilities and activities related to oil and natural gas production and transportation; development of risk assessment procedures; coordination of inspections of oil and gas production and transportation facilities; infrastructure integrity data sharing; and joint public outreach programs (ADNR 2011b).

Further, the AGDC was issued a right-of-way (ROW) lease by the State of Alaska for the proposed Project on July 25, 2011, (ADNR 2011c) which is included as Appendix M. The ROW lease not only grants the AGDC a gas pipeline corridor for construction of the proposed Project, but also contains a comprehensive sequence of stipulations that will direct all aspects of the pipeline design, construction, and operation in conjunction with applicable PHMSA regulations.

The USDOT pipeline standards are published in 49 Code of Federal Regulations (CFR) 190 to 199. 49 CFR 192 specifically addresses natural gas pipeline safety issues. The pipeline and aboveground facilities associated with the proposed Project must be designed, constructed, operated, and maintained in accordance with the USDOT Minimum Federal Safety Standards in 49 CFR 192. The regulations are intended to ensure adequate protection for the public and to prevent natural gas facility incidents and failures. 49 CFR 192 prescribes minimum requirements for: the selection and qualification of pipe and components; design of pipe; design and installation of pipeline components and facilities; welding; constructing; and protection from external, internal, and atmospheric corrosion; the minimum leak-test and strength-test requirements for pipelines; minimum requirements for operation; minimum requirements for maintenance; minimum requirements for operator qualification; and minimum requirements for an integrity management program.

49 CFR 192 also defines area classifications, based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards (660 feet) on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1 – Location with 10 or fewer buildings intended for human occupancy;
- Class 2 – Location with more than 10 but less than 46 buildings intended for human occupancy;
- Class 3 – Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month period; and
- Class 4 – Location where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. Pipelines constructed on land in Class 1 locations must be installed with a minimum depth cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil and 24 inches in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (specifically, 10.0 miles in Class 1; 7.5 miles in Class 2; 4.0 miles in Class 3; and 2.5 miles in Class 4). Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, MAOP, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas. Preliminary class locations for the proposed Project have been developed based on the relationship of the pipeline centerline to other nearby structures and manmade features. Class locations based on current population density for the proposed Project are listed in Table 5.19-1 and depicted geographically in Figure 5.19-1. Approximately 710.8 miles of the proposed Project route would be located in Class 1; 53.9 miles would be in Class 2; and 6.0 miles would be in Class 3. No Class 4 areas would be encountered along the proposed Project route. No safety class information has been provided for the Denali National Park Route Variation.

If a subsequent increase in population density adjacent to the ROW indicates a change in class location for the pipeline, the AGDC would have to reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness, if required, to comply with the USDOT code of regulations for the new class location.

TABLE 5.19-1 U.S. Department of Transportation Classifications for the Proposed Pipeline Project

Milepost		Pipeline Length (Miles)			Minimum Wall Thickness[a]	
Begin	End	Class 1	Class 2	Class 3	(Inches)	Project Segment
0.0	87.8	87.8	--	--	0.595	GCF to MP 540
87.8	88.3	--	0.5	--	0.714	GCF to MP 540
88.4	170.3	82.1	--	--	0.595	GCF to MP 540
170.3	170.7	--	0.4	--	0.714	GCF to MP 540
170.7	179.4	8.7	--	--	0.595	GCF to MP 540
179.4	179.9	--	0.5	--	0.714	GCF to MP 540
179.9	245.9	66.0	--	--	0.595	GCF to MP 540
245.9	246.4	--	--	0.5	0.857	GCF to MP 540
246.4	466.2	219.8	--	--	0.595	GCF to MP 540
466.2	477.0	--	10.8	--	0.714	GCF to MP 540
477.0	527.5	50.5	--	--	0.595	GCF to MP 540
527.5	529.7	--	--	2.2	0.857	GCF to MP 540
529.7	530.3	--	0.6	--	0.714	GCF to MP 540
530.3	538.3	8.0	--	--	0.595	GCF to MP 540
538.3	539.3	--	--	1.0	0.857	GCF to MP 540

TABLE 5.19-1 U.S. Department of Transportation Classifications for the Proposed Pipeline Project

Milepost		Pipeline Length (Miles)			Minimum Wall Thickness[a]	
Begin	**End**	**Class 1**	**Class 2**	**Class 3**	**(Inches)**	**Project Segment**
539.3	539.6	--	--	0.3	0.857	GCF to MP 540
539.6	554.9	15.3	--	--	0.595	GCF to MP 540/ MP 540 to MP 555
554.9	566.2	11.3	--	--	0.595	MP 540 to MP 555/ MP 555 to End
566.2	568.0	--	1.8	--	0.714	MP 555 to End
568.0	661.7	93.7	--	--	0.595	MP 555 to End
661.7	663.7	--	2.0	--	0.714	MP 555 to End
663.7	673.7	10.0	--	--	0.595	MP 555 to End
673.7	678.5	--	4.8	--	0.714	MP 555 to End
678.5	680.5	--	--	2.0	0.857	MP 555 to End
680.5	708.9	--	28.4	--	0.714	MP 555 to End
708.9	736.4	27.4	--	--	0.595	MP 555 to End
Mainline Total		**680.6**	**49.8**	**6.0**		
FL 0.0	FL 29.4	29.4	--	--	0.595	Fairbanks Lateral
FL 29.4	FL 33.6	--	4.1	--	0.714	Fairbanks Lateral
FL 33.6	FL 34.4	0.8	--	--	0.595	Fairbanks Lateral
Fairbanks Lateral Total		**30.2**	**4.1**	**0.0**		
Grand Total		**710.8**	**53.9**	**6.0**		

[a] Based on pipeline pressure standards per location class, Michael Baker Jr., Inc. 2011.

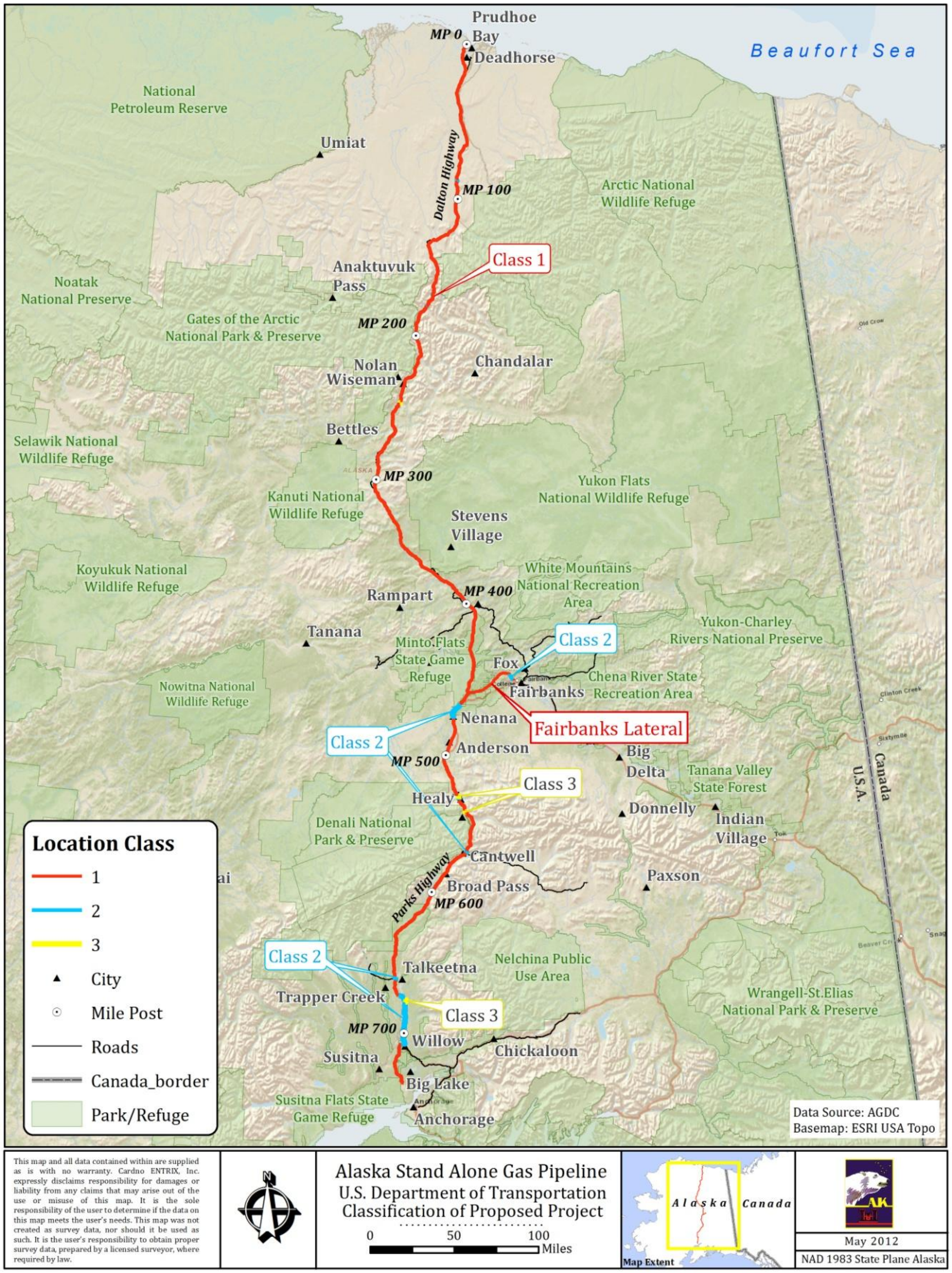

FIGURE 5.19-1 U.S. Department of Transportation Classifications for the Proposed Pipeline Project

The Pipeline Safety Improvement Act of 2002 requires operators to develop and follow a written integrity management program that contains all the elements described in 49 CFR 192.911 and addresses the risks on each transmission pipeline segment. Specifically, the law establishes an integrity management program which applies to all high consequence areas (HCA). The integrity management program is an additional layer of regulatory requirements, beyond the operations, maintenance, and other 49 CFR 192 requirements, for pipelines in HCA.

The USDOT has published rules that define HCAs as locations where a gas pipeline accident could do considerable harm to people and their property and requires an integrity management program to minimize the potential for an accident. This definition satisfies, in part, the Congressional mandate for the USDOT to prescribe standards that establish criteria for identifying each gas pipeline facility in a high density population area.

The HCAs may be classified in one of two ways. In the first method, an HCA includes:

- Current Class 3 and 4 locations;
- Any area in Class 1 or 2 where the potential impact radius[1] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle[2]; or
- Any area in Class 1 or 2 where the potential impact circle includes an identified site.

An identified site is an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period; a building that is occupied by 20 or more persons on at least 5 days a week for any 10 weeks in any 12-month period; or a facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

In the second method, an HCA includes any area within a potential impact circle which contains:

- Twenty or more buildings intended for human occupancy: or
- An identified site.

Once a pipeline operator has determined the HCAs along its pipeline, it must apply the elements of its integrity management program to those segments of the pipeline within HCAs. USDOT regulations specify the requirements for the integrity management plan at 49 CFR 192.911. The HCAs have been determined based on the relationship of the pipeline centerline to other nearby structures and identified sites.

The AGDC has identified approximately 15 miles containing HCAs along the proposed Project route. The AGDC did not specify if any HCAs would be located along the Denali National Park Route Variation. In addition, to maintain compliance with the pipeline classification and pipeline integrity management regulations in 49 CFR 192, the AGDC would continue to monitor for

1 The potential impact radius (in feet) is calculated as the product of 0.69 and the square root of the MAOP of the pipeline in psig multiplied by the square of the pipeline diameter in inches.

2 The potential impact circle is a circle of radius equal to the potential impact radius.

potential class location changes and HCAs throughout the life of the proposed Project. Monitoring would include the AGDC's aerial and ground inspections, review of aerial photography of the route, and surveillance during activities associated with operation. The pipeline integrity management rule for HCAs requires inspection of the entire pipeline for HCAs every 7 years.

The USDOT prescribes the minimum standards for operating and maintaining pipeline facilities, including the requirement to establish a written plan governing these activities. Each pipeline operator is required to establish an emergency plan that includes procedures to minimize the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for:

- Receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- Establishing and maintaining communications with local fire, police, and public officials and coordinating emergency response;
- Emergency system shutdown and safe restoration of service;
- Making personnel, equipment, tools, and materials available at the scene of an emergency; and
- Protecting people first and then property and making them safe from actual or potential hazards.

The USDOT requires that each operator establish and maintain liaison with appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency and to coordinate mutual assistance.

In accordance with 49 CFR 192, the AGDC would develop an Operations and Maintenance (O&M), Emergency Response, and other plans that would outline safety measures that would be implemented during normal and abnormal operation. The AGDC would conduct a public education program that would include information regarding participation in the "One-Call" program, hazards associated with the unintended release of natural gas, unintended release indicators, and reporting procedures.

5.19.2 Pipeline Accident Data

The USDOT requires all operators of natural gas transmission pipelines to notify the USDOT of any significant incident and to submit a report within 20 days. Significant incidents are defined as any leaks that:

- Caused a death or personal injury requiring hospitalization;
- Involve property damage of more than $50,000, in 1984 dollars[3];

[3] $50,000 in 1984 dollars is approximately $106,000 as of January 2010 (U.S. Department Of Labor 2010).

- Result in highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or
- Result in liquid releases resulting in an unintentional fire or explosion.

During the 20 year period from 1991 through 2010, a total of 1,137 significant incidents were reported to PHMSA on the more than 300,000 total miles of natural gas transmission pipelines nationwide.

Additional insight into the nature of significant incidents may be found by examining the primary factors that caused the failures. Table 5.19-2 provides a distribution of the causal factors as well as the number of each incident by cause.

TABLE 5.19-2 Natural Gas Transmission Pipeline Significant Incidents by Cause 1991-2010

Cause	Number of Incidents	Percentage
Corrosion	259	22.8
Excavation[a]	209	18.4
Pipeline Material, Weld or Equipment Failure	21	1.8
Natural Force Damage	236	20.8
Outside Force[b]	134	11.8
Incorrect Operation	57	5.0
All Other Causes[c]	221	19.4
TOTAL	**1,137**	**100.0**

[a] Includes third party damage.
[b] Fire, explosion, vehicle damage, previous damage, intentional damage.
[c] miscellaneous causes or unknown causes.
Source: PHMSA 2011.

The dominant incident cause is corrosion constituting 22.8 percent of all significant incidents. The pipelines included in the data set in Table 5.19-2 vary widely in terms of age, pipe diameter, and level of corrosion control. Each variable influences the incident frequency that may be expected for a specific segment of pipeline.

The frequency of significant incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, since corrosion is a time-dependent process.

The use of both an external protective coating and a cathodic protection system[4], required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe.

[4] Cathodic protection is a technique to reduce corrosion (rust) of the natural gas pipeline that includes the use of an induced current or a sacrificial anode (like zinc) that corrodes at faster rate to reduce corrosion. A description

Outside forces, excavation, and natural force damage are the cause in 51.0 percent of significant pipeline incidents (see Table 5.19-2). These result from the encroachment of mechanical equipment such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geologic hazards; weather effects such as winds, storms, and thermal strains; and willful damage (Table 5.19-3).

Older pipelines have a higher frequency of outside forces and excavation incidents partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipelines, which have a greater rate of outside forces incidents. Small diameter pipelines are more easily crushed or broken by mechanical equipment or earth movements.

Since 1982, operators have been required to participate in "One Call" public utility programs in populated areas to minimize unauthorized excavation activities in the vicinity of pipelines. The "One Call" program is a service used by public utilities and some private sector companies (e.g., oil pipelines and cable television) to provide preconstruction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts.

TABLE 5.19-3 Outside Force, Excavation, and Natural Force Incidents by Cause[a] 1991-2010

Cause	No. of Incidents	Percent of all Incidents
Third party excavation damage	178	44.6
Operator excavation damage	25	6.3
Unspecified equipment damage	5	1.3
Previous damage due to excavation	1	0.3
Heavy Rain/Floods	66	16.5
Earth Movement	36	9.0
Lightning/Temperature/High Winds	16	4.0
Unspecified Natural Force	15	3.8
Vehicle (not engaged with excavation)	41	10.3
Fire/Explosion	9	2.3
Previous mechanical damage	4	1.0
Intentional damage	1	0.3
Unspecified outside force	2	0.5
TOTAL	**399**	**100.2[b]**

[a] Excavation, Outside Force, and Natural Force from Table 5.19-2.

[b] Total does not equal 100 due to rounding.

of corrosion protection and detection systems proposed to be employed on the proposed Project can be found in Section 2.2.5 of this EIS.

5.19.3 Impact on Public Safety

The significant incident data summarized in Table 5.19-2 include pipeline failures of all magnitudes with widely varying consequences.

Table 5.19-4 presents the average annual fatalities that occurred on natural gas transmission lines over a 20-year period (1991-2010) and over a 5-year period (2006-2010). Annual fatalities for the period of 1991-2010 averaged two fatalities. Annual fatalities over the period of 2006-2010 averaged three fatalities.

TABLE 5.19-4 Annual Average Fatalities – Natural Gas Transmission Pipelines

Year	Fatalities
1991-2010[a]	2
2006-2010[b]	3

[a] 20 year average.

[b] Total of 15 fatalities.

Source: PHMSA 2011

The majority of fatalities from pipelines are due to incidents on local distribution pipelines. These are natural gas pipelines that distribute natural gas to homes and businesses after transportation through natural gas transmission pipelines. In general, these distribution lines are smaller diameter pipes, plastic pipes, and older pipelines which are more susceptible to damage. In addition, distribution systems do not have large ROWs and pipeline markers common to the larger natural gas transmission pipelines, such as those under the proposed Project.

The nationwide totals of accidental fatalities from various manmade and natural hazards are listed in Table 5.19-5 in order to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. Direct comparisons between accident categories should be made cautiously, however, because individual exposures to hazards are not uniform among all categories. Furthermore, the fatality rate from natural gas pipelines is more than 25 times lower than the fatalities from natural hazards such as lightning, tornados, floods, or earthquakes.

The available data show that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 1991 to 2010, there were an average of 57 significant incidents and two fatalities per year. The number of significant incidents over the more than 300,000 miles of natural gas transmission lines indicates the risk is low for an incident at any given location. The operation of the proposed Project would represent only a slight increase in risk to the nearby public.

TABLE 5.19-5 Nationwide Accidental Deaths

Type of Accident	Annual No. of Deaths
All accidents	123,706
Motor Vehicle	43,945
Poisoning	29,846
Falls	22,631
Injury at work	5,025
Drowning	3,443
Fire, smoke inhalation, burns	3,286
Floods[a]	93
Lightning[a]	57
Tornado[a]	57
Natural gas transmission pipelines[b]	2

[a] NOAA 2009.

[b] PHMSA 2011

Source: U.S. Census Bureau 2007 (unless otherwise noted).

5.19.3.1 Terrorism and Security Issues

Following the terrorist attacks of September 11, 2001, terrorism has become a safety and security concern for energy facilities and is an important consideration for the design, construction, and operation of energy facilities. Both international and domestic terrorism have changed the way pipeline operators as well as regulators must consider pipeline security, both in approving new projects and in operating existing facilities. The likelihood of future attacks of terrorism or sabotage occurring along the proposed Project is unpredictable and the continuing need to construct facilities to support the development of the natural gas industry in Alaska is not lessened by the threat of any potential future acts. Moreover, the arbitrary risk of such acts does not support a finding that this particular Project should not be constructed.

Design, construction, and operations elements already integrated into the proposed Project provide a level of security from such a threat including buried construction of the pipeline; locked security fencing surrounding aboveground facilities; regular air and ground inspection of the pipeline route; and regular visitation to aboveground facilities by O&M crews. Additionally, specialized training in pipeline security awareness for pipeline employees is recommended by the Transportation Security Administration. Further, specific information including pipeline design and integrity; security risks; and HCAs are frequently kept confidential from the public in order to maintain a higher level of security.

5.19.3.2 ASAP Design Approach

According to 49 CFR 192.317: "The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads." The AGDC would complete route investigations to ensure pipeline integrity is maintained for potential arctic hazards caused by thermal interaction of the buried pipeline with the subsurface conditions. When the buried pipeline operates above the freeze point temperature in initially frozen soil, the soil could thaw, with subsequent loss of support and settlement of the pipeline. When the buried pipeline operates below the freezing temperature in initially thawed soil, frost heave could occur, with subsequent vertical upward movement of the pipeline. In both cases, the pipeline could experience stress due to the differential movement of the pipeline.

To keep stress within acceptable limits and compliant with 49 CFR 192 requirements and related industry standards, the AGDC is employing a design approach to develop limiting curvatures which can be monitored through state-of-art pipeline pigging technology. The limiting curvature criterion is derived from consideration of limiting tensile and compressive strains capacities of the pipe material. The limiting curvature of the pipe is used for design screening of the route terrain units and for developing operational monitoring using pipeline in-line inspection (ILI) tools that detect pipeline movement (e.g., high-resolution geometry pigs). The criteria are used to screen pipe route segments which do not exceed the criteria limits, after evaluation of the interaction of the pipe material, its operating characteristics, and the segment route subsurface behavior. Those segments that are determined to potentially exceed the curvature criteria limits are subject to mitigative actions to reduce the pipe response to within acceptable bounds.

The approach would be validated through Project-specific data collection and testing that considers the proposed Project materials, route alignment and soils, and operational conditions. The AGDC will address specific design details such as pipe wall thicknesses, grade, and design factors for: road crossings, river crossings, bridge crossings, railroad crossings, Trans Alaska Pipeline System (TAPS) crossings, populated areas, and major geologic fault locations during detailed design. The AGDC plans to employ a stress-based design and to also include provisions to prevent and mitigate an excessive bending strain. For a discussion of the proposed Project design approach, see *Alaska Stand Alone Gas Pipeline/ASAP Design Methodology to Address Frost Heave Potential (prepared for the AGDC by Michael Baker Jr., Inc., 6/9/2011)* located in Appendix N.

The integrity of this design approach is ensured through the proposed Project quality assurance plans and operational safety and integrity management plans. Probabilities and consequences of pipeline failure will be addressed during detailed design and will result in emergency response plans and other proposed Project mitigation features. As with all other aspects of the proposed Project, all plans and features will be reviewed and approved in accordance with the State ROW Lease Stipulations found in Appendix M.

Further, the AGDC will comply with all Federal and state pipeline safety regulations in the design, construction, and operation of the pipeline, and in particular, those specified in 49 CFR Parts 191, 192, and 199. If necessary, the AGDC will apply for a special permit from the PHMSA, as governed by 49 CFR 190.341. The AGDC will continue to work with the PHMSA as the proposed Project develops.

The proposed Project will be constructed in areas that have historically experienced forest fires. PHMSA safety standards relating to responding to emergencies and natural disasters, including fires, will be considered for design and construction of the proposed Project. The pipeline will be buried with at least 3 feet of cover for over 99 percent of the alignment. Due to the depth of cover, a forest fire would have no safety impact on the buried portions of the proposed Project. Block valves, other above ground appurtenances, and facility locations would be maintained to provide adequate buffers and defensible space from potential fires.

Forest fires are not considered an instantaneous threat. Should a facility or valve location be threatened, there would be sufficient time to muster resources to protect the proposed Project and/or shut down the transportation of gas until the fire risk has passed. The great majority of the proposed Project is located near a highway for access to the buried and aboveground facilities. As a comparison, over 23,000 kilometers (14,200 miles) of gas transmission pipelines in Alberta are constructed in areas, like Alaska, which experience numerous forest fires each summer. Further, TAPS is constructed in areas which experience annual forest fires as it transects Alaska and is above ground for a significant portion of its length.

5.19.4 NGL Spill Scenario

If there were a pipeline rupture, the leak detection system would close the pipeline isolation valves, which are spaced at a maximum of 20 miles apart. In a 20-mile section of the pipeline at operating conditions, the gas would contain the equivalent of approximately 1,745 barrels (bbls) of propane and 164 bbls of butane 80 percent / pentane 20 percent. In the case of a rupture, any release would be nearly all NGL vapor. The boiling point of propane at atmospheric pressure is -43.8°F while the boiling points of butane and pentane are 31.1°F and 97°F respectively. Winter temperatures could likely cause the butane and pentane components to initially remain in a liquid state. However, if any liquids formed, much of the volume would quickly evaporate due to the volatile nature of NGLs. The consequences of an accidental spill of NGLs as a result of a pipeline rupture could include fire and/or explosion of NGL vapors. Potential spill impacts are likely to be short-term and low magnitude due to the volatility of NGL components. However, a small portion of the NGLs may not easily vaporize but may remain to potentially migrate through soils and enter the groundwater if spill cleanup procedures were not implemented.

5.19.5 References

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