3.13 POTENTIAL RELEASES

3.13.1 Introduction

This section addresses the potential for releases of oil products or crude oil that could occur during construction and operation of the proposed Project. The purpose of this section is to discuss the types of threats to pipeline and tank integrity (failure to contain oil as designed) and construction equipment that could result in such a release and identify the receptors that could be affected by a release. The description of potential releases is based on information provided in the 2011 Final Environmental Impact Statement (Final EIS) and the 2013 Draft Supplemental EIS, as well as new circumstances or information relevant to environmental concerns that have become available since the publication of the Final EIS, including the proposed reroute in Nebraska. The information that is provided here builds on the information provided in the Final EIS and, in many instances, replicates that information with relatively minor changes and updates; other information is entirely new or substantially altered.

Specifically, the following information, data, methods, and/or analyses have been substantially updated in this section from the 2011 document:

- The discussion on the characteristics of diluted bitumen (dilbit) has been further developed.
- The descriptions of dilbit, synthetic crude oil (SCO), and Bakken shale oil have been further developed.
- A comparison has been made between the characteristics of crude oil from around the world.
- The discussion on threats to pipeline integrity, including corrosion and security, has been expanded.
- The discussion on spill volume distribution has been revised based on Pipeline and Hazardous Material Safety Administration (PHMSA) data.

The following information, data, methods, and/or analyses have been substantially updated from the 2013 Draft Supplemental EIS:

- The discussion of Facility Response Plan (FRP)/Emergency Response Plan (ERP) and other relevant document approvals has been updated.
- The discussion of the Oil Spill Liability Trust Fund and the obligations and liabilities of responsible parties has been expanded.
- The discussion of crude oils and their behavior when released to surface water (e.g., sinking) has been expanded.
- Additional recent references on dilbit characteristics have been incorporated.
- The discussion of human health exposure to crude oil has been expanded.
- The discussion on Safety and Risk Analysis has been expanded.
- A discussion of industry standards and practices in reducing the potential for spills has been added.

- New information on dilbit corrosivity from the National Academy of Sciences (NAS) has been added.
- The general characteristics of the types of crude oil that could be transported by the proposed Project have been updated.
- The discussion on dilbit and diluent characteristics and composition has been expanded.
- A discussion on changes to dilbit characteristics during a release event has been added.
- Integrity threat definitions have been clarified.
- The discussion of pipeline security, standard security measures, and policies and procedures to address intentional damage has been expanded.
- In response to public and agency comments, text has been revised throughout the section where necessary.

For the combined risk of potential releases and environmental impacts from a spill, an Independent Engineering Assessment was prepared by Battelle Memorial Institute (Leis et al. 2013), and a third-party consultant Environmental Review of the TransCanada Keystone XL was prepared by E^{x}ponent (E^{x}ponent 2013).

Summary

The proposed Project could potentially release hazardous products during construction and crude oil during operations if damage were to occur to the pipeline or its associated components. A release over a period of time is considered a leak. If a leak enters the environment, it is considered a spill. In general, causes of releases for oil pipelines include:

- External corrosion (i.e., the metal of the pipeline reacts with the environment, causing the pipeline to rust on the outside of the pipe, similar to rust on a car);
- Internal corrosion (i.e., same as external corrosion, except the metal reacts with the contents inside the pipeline);
- Stress corrosion cracking (i.e., pressure and temperature changes cause the pipeline to expand and contract, which compromises the pipeline coating and renders the pipeline susceptible to corrosion, subsequently resulting in the development and progression of cracks in the pipeline);
- Manufacturing (e.g., defects in the original characteristics of the pipe, such as low-strength material or substandard threading, which result in compromised integrity of the pipe);
- Construction (e.g., a defect in the welding of the pipe);
- Equipment (e.g., unusual wear and tear of pipeline components, such as valves);
- Third-party damage (e.g., a backhoe digging nearby strikes the pipe);
- Incorrect operations (i.e., human error made by pipeline operators); and
- Weather-related and other natural forces (e.g., flooding contributes to stream bank erosion that exposes the pipe or a landslide ruptures the pipe).

The magnitude of an oil spill impact would be influenced by the type of receptors that might be exposed to the oil. The two primary types of receptors are High Consequence Areas (HCAs), as defined by the U.S. Department of Transportation (USDOT), and other resources that could be affected by a spill. An HCA is defined as a High Population Area (HPA), Other Populated Area (OPA), Commercially Navigable Waterway (CNW), or Unusually Sensitive Area, such as a sole-source drinking water supply. Other resources include soils, sediments, terrestrial vegetation, wildlife, water resources, cultural resources, and socioeconomic resources.

Three hypothetical spill volumes were developed for this Final Supplemental EIS and were based on PHMSA historic data:

- *Small*—up to 50 barrels[1] (bbl) (2,100 gallons); 79 percent of relevant PHMSA reported incidents[2] are small;
- *Medium*—greater than 50 bbl (2,100 gallons) to 1,000 bbl (42,000 gallons); 17 percent of relevant PHMSA-reported incidents are medium; and
- *Large*—greater than 1,000 bbl (42,000 gallons); 4 percent of relevant PHMSA reported incidents are large.

TransCanada Keystone Pipeline, LP (Keystone) has prepared written procedures to address response actions to prevent and control a spill event. These procedures are provided in Appendix I, Spill Prevention, Control, and Countermeasure (SPCC) Plan and ERP.

The Oil Spill Liability Trust Fund may be utilized should federal intervention be required to ensure rapid and effective response to oil spills. Section 1001(32)(B) of the Oil Pollution Act of 1990 (OPA 90) states that in the case of an onshore facility, any person owning or operating the facility is the responsible party. If there were an accidental release that could affect surface water, no matter what the reason, Keystone would be liable for all costs associated with cleanup and restoration, as well as other compensations, up to a maximum of $350 million, per OPA 90 (U.S. Department of Homeland Security 2012). However, this statutory $350 million liability limit does not apply where the incident was directly caused by 1) gross negligence or willful misconduct or 2) the violation of an applicable federal safety construction or operating regulation by Keystone or a person acting pursuant to a contractual relationship with Keystone. This topic is discussed further in Section 4.13.5.2, Safety and Spill Response, in subsection Spill Liability and Responsibility.

The behavior of crude oils released to flowing water or other surface water features depends on the streamflow and response time to the spill. As with any crude oil, key components of oil would evaporate and biodegrade over time, resulting in a weathered oil that could potentially sink (U.S. Environmental Protection Agency [USEPA] 1999). In flowing water systems, sinking oil could be transported downstream without the obvious surface oiling of stream banks. Sinking oil could be deposited in river or stream bottoms and become a continual source of oil as changing water flows released the deposited oil. Methods to detect submerged oil include sediment sampling in streams and rivers and the use of sonar or remote and diver-operated

[1] One barrel equals 42 U.S. gallons.
[2] The terms *incident* and *accident* can be used interchangeably or with specified definitions in various agency reports and databases. For the purposes of this report, the term *incident* has been selected for consistency.

underwater video detection systems in still waterbodies such as lakes and ponds. This topic is discussed further throughout Section 4.13, Potential Releases.

The combined implementation of industry standards and practices would aid in reducing the potential for spill incidents associated with the proposed Project. The standards were developed by the National Association of Corrosion Engineers (NACE), International and American Society of Mechanical Engineers (ASME), and other industry leaders. The U.S. Department of State (the Department), in consultation with PHMSA, has determined that these standards and practices, combined with PHMSA regulatory requirements and the set of proposed Project-specific Special Conditions developed by PHMSA, would result in a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the proposed pipeline system, similar to that required in HCAs as defined in 49 Code of Federal Regulations (CFR) 195.450. Appendix B, Potential Releases and Pipeline Safety, describes how each of the Special Conditions increases public safety over and above the applicable current CFR requirements (see Section 4.13.5.1, PHMSA Special Conditions).

An FRP, which would include the proposed Project-specific ERP, would be prepared and submitted to PHMSA prior to initiating operation of the proposed Project, in accordance with requirements of 49 CFR Part 194. These plans rely on final permitting requirements and detailed design and construction information. A proposed Project-specific, worst-case spill scenario including location, available resources, and response actions would be addressed in the FRP/ERP once the final permitting, detailed design, and construction information were available. A general discussion of worst-case discharges is provided in Appendix P, Risk Assessment. Under current regulations, Keystone would be required to submit the FRP/ERP for review 6 months prior to operation of the proposed Project. PHMSA would provide the FRP/ERP to the USEPA for their review.

Human health can be affected due to short-term and long-term exposure to crude oil and the hazardous chemicals that make up crude oils. Exposure to crude oil can occur through ingestion, inhalation of vapors, and dermal (contact with skin) and ocular exposure (contact with surface of the eye). Human health risks from short-term and long-term exposure to crude oil and the hazardous chemicals that make up crude oils are discussed further in Section 3.13.4.1, High Consequence Areas.

Connected actions of the proposed Project include the Bakken Marketlink Project, the Big Bend to Witten 230-kilovolt (kV) Transmission Line, and electrical distribution lines and substations. These connected actions would be constructed in areas similar to the proposed Project route; the Bakken Marketlink Project could result in a spill to nearby resources and could present similar threats, but because of the short pipeline length, the worst-case spill size would be expected to be less than that of the proposed Project.

3.13.2 Crude Oil Characteristics

The physical and chemical properties of the crude oils that would be transported by the proposed pipeline would not be unique to the proposed Project; petroleum quality requirements of crude oil would be specified by the National Energy Board and the Federal Energy Regulatory Commission tariffs (18 CFR 341). A comparison of the crude oil that would be transported by the proposed pipeline with other conventional crude oils indicates that the characteristics of the proposed Project's crude oil would be generally comparable to those of conventional crude oils (Been and Wolodko 2011, Penspen Integrity 2013). Naphthenic acid, organic sulfur, and chloride salt concentrations in dilbit crude oils are comparable to conventional Alberta heavy crudes (Zhou and Been 2012). These compounds are stable and not considered to be corrosive at pipeline operating temperatures. Additionally, dilbit density and viscosity ranges are comparable to those of heavy crudes. This supports the expectation that shipments of dilbit at Keystone's stated operating temperatures would be typical of crude oil with similar density and viscosity levels (NAS 2013). A comparison of incident data from Alberta pipeline systems with data from U.S. pipeline systems (see Section 4.13.2.4, Pipeline Incident Information Sources) indicates that some Alberta pipelines that have likely shipped dilbit, SCO, or Bakken shale oil (due to their proximity to the oil sands) are not more prone to failure than other pipeline systems carrying conventional crude oils. Further discussion of crude oil characteristics and potential causes and frequencies of pipeline failure is provided below, as well as in Section 4.13, Potential Releases.

Liquid crude oil is traditionally referred to as petroleum and is composed primarily of hydrocarbon compounds. Traditionally, the term *petroleum* has referred only to liquid crude oil; however, current common usage of the term also includes gaseous and solid materials such as natural gas and bitumen. The composition of crude oil varies depending on the source and processing. Most crude oils are more than 95 percent hydrocarbons, with nitrogen, oxygen, varying amounts of sulfur, and traces of other elements.

Light crude oil is a mixture that has a low density and flows freely at ambient temperatures. Heavy crude oil is referred to as *heavy* because its density is higher than that of light crude oil. The American Petroleum Institute (API) has introduced the term *API gravity* to measure how heavy or light a petroleum liquid is compared to water. If an oil's API gravity is greater than 10°, the oil is less dense than water and thus floats on water; if an oil's API gravity is less than 10°, the oil is denser than water and thus sinks in water. In this sense, API gravity is used to compare the relative densities of petroleum liquids. There are different definitions of light and heavy crude oil. Unless otherwise specified, in this section, *light oil* is defined as any liquid petroleum with an API gravity greater than 31.1° (corresponding to a density less than 870 kilograms per cubic meter [kg/m^3]), *heavy oil* is defined as any liquid petroleum with an API gravity less than 22.3° (corresponding to a density greater than 920 kg/m^3), and *medium oil* is defined as any liquid petroleum with an API gravity between 22.3° and 31.1°.

In addition, Canadian heavy crude oil is also usually sour (i.e., has a higher sulfur content), with sulfur contents between 2.52 percent and 4.82 percent (mean of 3.27 percent) by weight based on the data from 25 types of heavy crude oils (Enbridge 2011). Typically, crude oil with a sulfur content greater than 2 percent by weight is considered sour. While the sulfur in dilbit is at the high end of the range for crude oils, it is bound with hydrocarbons and is not a source of corrosive hydrogen sulfide (NAS 2013).

Crude oils may differ in their solubility, toxicity, persistence, and other properties that affect their impact on the environment. The following characteristics are of particular importance with respect to environmental effects from a spill:

- Specific gravity—determines whether the oil would sink or float upon release to a waterbody. In the discussions of crude oil in this section of the Final Supplemental EIS, API gravity is used to describe this characteristic rather than specific gravity. If a crude oil has an API gravity greater than 10°, it is less dense than water and would float on water.[3] If a crude oil has an API gravity less than 10°, it would sink in water.
- Viscosity—a measure of how easily the oil would flow. Typically, viscosity increases (meaning it does not flow as easily) as temperature decreases. This is an important consideration, as air temperatures along the length of the proposed pipeline corridor may range from well below freezing in winter to in excess of 100 degrees Fahrenheit (˚F) (38 degrees Celsius [˚C]) in summer.
- Pour point—the lowest temperature at which the oil changes from a free-flowing liquid to a material that does not flow freely.
- Proportions of volatile and semivolatile fractions—an indicator of 1) the portion of oil that would more readily evaporate, 2) the portion of oil that would more likely physically persist in the environment as it weathers, and 3) the portion of oil that could dissolve or disperse into an aquatic environment and cause potential toxicological effects on animals and plants.
- Proportion of polycyclic aromatic hydrocarbons (such as naphthalene), many of which are considered key toxic components of crude oils.
- Proportions of other elements and compounds, including sulfur and metals.

3.13.3 General Description of Proposed Pipeline Transported Crude Oils

The crude oil that would be transported by Keystone as part of the proposed Project would originate from a variety of different sources and locations. The crude oil types for the proposed Project would range from a light crude oil (such as SCO or shale oil found in the Bakken formation) to a heavy crude oil (such as those found in the Western Canada Sedimentary Basin [WCSB], which is produced from bitumen).

Bitumen is a form of petroleum that occurs naturally in a solid or semi-solid state. Bitumen includes a wide variety of reddish-brown to black materials that are semi-solid and viscous to brittle in character. Canadian oil sand bitumen is composed primarily of high-molecular-weight hydrocarbons, commonly referred to as asphaltines. Canadian oil sands are a mixture of roughly 90 percent clay, sand, and water, and 10 percent bitumen. The dark, sticky sands look similar to topsoil, but can flow when warmed. Colder temperatures reduce the ability of the bitumen to flow and can cause the bitumen to have the appearance of a semi-solid. Raw bitumen is semi-solid to solid, depending on ambient temperatures and, therefore, must be altered into a form that can be transported via pipeline. There are two basic methods used to render bitumen transportable by pipeline: 1) bitumen is processed into SCO, or 2) bitumen is mixed with a suitable diluent, as described below, creating what is known as dilbit. Either of these products

[3] Dilbit sinking is further discussed in Section 4.13.5.2, Safety and Spill Response.

may be transported by the proposed Project. Based on current production projections and the commercial demand at Gulf Coast refineries for WCSB heavy crude from the oil sands, the majority of crude oil that would likely be transported by the proposed Project is expected to be in the form of dilbit (EnSys Energy 2010). Given the concentration of upgrading units in the Gulf Coast region and the economic incentives to run heavy crudes given light-heavy oil price differentials, this region is seen likely to remain a key source of heavy crude demand (Section 1.4, Market Analysis). Additional information regarding chemical characteristics and physical properties of SCO and dilbit are included in Section 3.2 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Transportation Research Board (TRB) Special Report 311: *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines* (NAS 2013) discusses in greater detail the sources of bitumen, types of diluents, and the resulting dilbit, as well as SCO properties of Canadian crude oil imported into the U.S. *In situ* recovery[4] accounts for an increasing percentage of Canadian bitumen production compared to mined bitumen. The bitumen recovered during *in situ* recovery is processed into SCO in Canada to be better suited for long-distance transportation by pipeline. The resulting crude oil has lower water and sediment content than mined bitumen. Although the diluents consist of low-molecular-weight hydrocarbons, shipments by pipeline of dilbit do not contain a higher percentage of these light hydrocarbons than do other crude oil pipeline shipments (NAS 2013).

3.13.3.1 Synthetic Crude Oil

SCO is produced from bitumen through a refinery conversion process that turns heavy hydrocarbons into lighter hydrocarbons. The conversion process typically includes the removal of sulfur, resulting in a *light sweet* SCO. The precise composition of SCO varies. Because some composition information may be considered proprietary information by the shipper, generic properties of SCO are listed in Table 3.13-1. The properties of one example of SCO, Suncor Synthetic A Crude Oil, are presented in Table 3.13-2. As shown in Table 3.13-2, the characteristics of WCSB SCO and dilbit are similar to those of conventional crude oils.[5]

3.13.3.2 Dilbit

Dilbit is bitumen mixed with a diluent so it can be transported by pipeline. The composition of the dilbit is only provided here generically because the particular type of bitumen and diluents blend produced is variable and is typically a trade secret. A common condensate stream (liquids derived from natural gas) is currently the primary type of diluent used for Canadian heavy crude. Diluent consists of condensates, ultra-light sweet crudes, and refinery and upgrader naphtha streams from several supply sources. Typically, dilbit uses approximately 25 percent of condensate, where companies use either their own supply sources of light hydrocarbons or purchase the above condensate stream. According to the Saskatchewan Condensate Monthly Report dated September 1, 2012 (Crudemonitor 2012b), the composition of gas condensate is

[4] *In situ* recovery refers to the use of thermal technologies such as steam injection to separate deep underground bitumen from oil sand and thin the bitumen so that it can be pumped to the surface using a well, rather than using mining methods.

[5] The website crudemonitor.ca provides a library of current and historical crude oil stream characteristics and was a key source of the characteristic values used in the assessment of impacts that would result from a potential release.

mainly light hydrocarbons such as iso-butene, n-butane, iso-pentane, n-pentane, and hexanes. Material Safety Data Sheets (MSDSs) (for informational/planning purposes only) for two types of diluents, naphtha and natural gas condensate, assuming a maximum diluent mix, are provided in Appendix Q. It is important to note that the chemical make-up of the diluents can vary greatly from source to source. The bitumen-diluent mixture with bitumen from the oil sands is generally similar to heavy sour crude, which is discussed in more detail. SCO may also be used as a diluent for bitumen, in which case the commodity is known as synbit (bitumen diluted with SCO). Properties of generic dilbit are shown in Table 3.13-1.

Table 3.13-1 Summary of General Characteristics for Types of Crude Oil Similar to Those That Would Be Transported by the Proposed Project

Characteristic	Synthetic Crude Oil[a]	Diluted Bitumen[b]	Bakken Shale Oil[c]
Density	na	na	827 kg/m^3
API gravity[d]	31°-38°	20°-22°	38°-40°
Viscosity	na	52 to 96 centistokes at 38°C	na
Flammability	na	Class B, Division 2: Flammable Liquids	Class B, Division 2: Flammable Liquids
Composition	Gas oils (petroleum), hydrodesulfurized 60% Naphtha (petroleum), hydrotreated heavy 10-30% Naphtha (petroleum), hydrotreated light, 3-7% Butane 1-5% Hydrogen sulfide (H_2S) 0.001-0.01% BTEX 1-1.5%	Bitumen 40-70% Diluent (mixture of Light naphtha and/or Natural gas condensate) 30-60% BTEX 1-1.5%	Light hydrocarbons <40% Pentanes 3-4% Hexanes 4-6% Heptanes 6-8% Octanes 6-8% Nonanes 4-6% Decanes 1-3% BTEX 1-3%
Flash point[e]	-31˚F (<-35°C)	-31˚F (-<-35°C)	-31˚F (-<-35°C)
Toxicity[f]	na	Class D, Division 2, Subdivision A: Very Toxic Material	na
Solubility in water[f]	Insoluble in cold water[e]	Insoluble[g]	Insoluble
Pour point	-5.8˚F (-21˚C)	-22˚F (-30˚C)	-25˚F(-32˚C)
Sulfur	0.25%	3.6%	0.17-0.20%
Other properties	Oxides of carbon, and nitrogen, aldehydes form upon combustion. Hazardous sulfur dioxide and related oxides of sulfur may be generated upon combustion.		

[a] Husky Energy 2011
[b] Imperial Oil 2002
[c] Crudemonitor 2012a; 5-year average was used for numbers.
[d] Crudemonitor 2012b
[e] Tasprailis 2013 (for fresh oil using ASTM D 92 methodology)
[f] USEPA 2000
[g] Insoluble, but volatile organic compound and semivolatile organic compound constituents are soluble (e.g., benzene, toluene, polycyclic aromatic hydrocarbons).
Notes: na = not available; kg/m^3 = kilogram(s) per cubic meter; BTEX = benzene, toluene, ethylbenzene, and xylenes

3.13.3.3 Bakken Shale Oil

Shale oil is found in sedimentary rock formations that are characterized by very low permeability. In these formations, the flow of oil from the rock to an extraction well is limited by the low-permeability, fine-grained nature of the rock, which is the basis for the common term *tight oil*. Recovery of oil trapped in these low-permeability rocks requires well stimulation techniques (i.e., physical or chemical actions performed on a well to improve the flow of oil or gas from the formation rock to the well bore).

The Bakken shale oil from Montana is light and sweet (containing less than 0.42 percent sulfur). The main properties of Bakken shale oil are shown in Table 3.13-1. An MSDS (for informational/planning purposes only) for Bakken sweet crude, assuming a maximum volatile hydrocarbon composition, is provided in Appendix Q, Crude Oil MSDS.

3.13.3.4 Summary of SCO, Dilbit, and Bakken Shale Oil Characteristics

Table 3.13-1 summarizes the general characteristics of an SCO, dilbit, and Bakken shale oil. These crude types are similar to the types of crude oil that would be transported by the proposed Project. Table 3.13-2 provides additional information on characteristics of potential proposed Project crude oil types.

3.13.3.5 Dilbit vs. Crude Oil

As discussed previously, dilbit is formed when a diluent is added to bitumen, a form of petroleum that exists naturally in a solid state and is comprised primarily of asphaltenes. Asphaltenes are comprised primarily of heavy hydrocarbons, nitrogen, oxygen, sulfur, and traces of heavy metals like nickel and vanadium. The diluent component of Canadian dilbit is typically a combination of condensate stream, ultra-light sweet crudes, and naphtha streams. As an example, Condensate Blend, commonly referred to as CRW, is an aggregate of several light sweet streams blended and used as a diluent (Crudemonitor 2013). A summary of the composition of CRW, based on 5-year averages, is presented in Table 3.13-3 below.

Table 3.13-3 Composition of CRW

Parameter (vol%)	CRW (5-Year Average)
iso-Butane	0.51
n-Butane	2.84
iso-Pentane	14.41
n-Pentane	15.13
Hexanes	16.55
C7-C12	40.95
C13-C30+	9.40

Source: Crudemonitor 2013

Bitumen is mostly composed of heavy hydrocarbons, while diluent is composed of light compounds that will typically volatilize when exposed to air. When diluent is added to bitumen to form dilbit, the combined product is a flowable liquid petroleum with a viscosity similar to that of heavy crude oil. Other forms of crude oil tend to consist mostly of a variety of mid-range compounds (i.e., those compounds that are lighter than water, but too heavy to volatilize into the atmosphere). Dilbit, on the other hand, is composed mostly of compounds from both ends of the spectrum (i.e., diluent, which is light and composed of volatiles, and bitumen, which is heavy and occurs naturally in a semi-solid state) (Song 2012).

When combined to form dilbit, bitumen and diluent generally flow together as a uniform liquid. Exposed to air, the diluent component of dilbit will volatilize over time, gradually separating itself from the bitumen component. However, since the exposed surface area of flowing liquid within the pipeline is negligible, significant changes in the composition of dilbit due to volatilization do not occur during transportation. The ratio of diluent to bitumen in dilbit is such that it will still flow at the lowest pipeline operating temperature (42°F (6°C)). Like other crude oils, the viscosity of dilbit decreases rapidly as operating temperatures increase during transportation. Changes in dilbit viscosity with temperature closely follow those of heavy conventional crude oil (Tsaprailis 2013).

A notable difference between dilbit and other forms of crude is its capacity to precipitate out in water. After a period of several days in water, the diluent in dilbit will eventually volatilize into air or dissolve into water, leaving the heavy bitumen behind to sink or become suspended. This could occur with dilbit more so than with other forms of crude due to the higher percentage of heavy compounds present (Tsaprailis 2013).[6] As an example, heavy components, as shown in Table 3.13-1, comprise approximately 10 to 30 percent of SCO in comparison with dilbit, which consists of approximately 40 to 70 percent heavy bitumen.

Natural attenuation of residual oil is often considered a remedial option for the removal of crude oils. Significant components of conventional crude oils include straight hydrocarbon chains and light compounds, both of which biodegrade relatively easily. Dilbit, on the other hand, is largely comprised of branched hydrocarbon chains and heavy hydrocarbons, which are less readily biodegradable. A biodegradation study conducted by the USEPA in response to the 2010 Enbridge dilbit spill in the Kalamazoo River in Michigan concluded that only 25 percent of the residual hydrocarbons impacting the river could be reasonably removed by natural attenuation (USEPA 2013).

Due to the capacity for dilbit to precipitate out in water and its resistance to biodegradation, in the event of a release to a waterbody, more difficult cleanup scenarios (e.g., dredging) for dilbit may be expected than with other types of crude oil. In the event of a land release, however, the opposite is expected to be true. Vertical and horizontal dispersion of dilbit in sandy soil, loamy soil, and topsoil occurs at a slower rate than other crude oils, including heavy crudes with similar viscosities (Tsaprailis 2013). In addition, following a land release, the lighter components of dilbit will gradually volatilize, thereby increasing the viscosity and further impeding dispersion.

[6] Other factors, including salinity and the presence of floating sediments, may also influence the capacity for crude oils to sink or become suspended in water.

Table 3.13-2 Comparison of Global Crude Oil Characteristics

Parameter	Unit	Bakken Crude (North Dakota)[b, d]	Mixed Sweet Blend (Canada)[a]	Ekofisk (Norway)[c]	Qua Iboe (Nigeria)[b]	Azeri Light (Azerbaijan)[c]	Suncor Synthetic A (Canada)[a, d]	Iranian Heavy[b]	Arabian Heavy (Saudi Arabia)[b]	Lloyd Blend (Canada)[a]	Western Canadian Select[a, d]	Western Canadian Blend[a]	Fosterton (Canada)[a]	Maya (Mexico)[b]	Hondo Monterey (California)[b]	Boscan (Venezuela)[b]
Gravity	API	42.1	39.5	38.42	35.8	34.8	33.1	30.0-31.0	27	20.8	20.6	20.6	20.5	20.2	18.3	10.9
Density	g/ml		0.83	0.832		0.85	0.86	0.89	0.89	0.93	0.93	0.93	0.93	0.93	0.94	1
Sulfur	wt%		0.44	0.22	0.12	0.15	0.19	1.20-1.65		3.52	3.49	3.17	3.24		4.7	4.6
MCR	wt%		1.94				ND			9.57	9.61	8.59	9.66			
Sediment	ppmv									333	360	299	207			
TAN	mg KOH/g			0.13		0.26			0.1	0.81	0.93	0.73	0.2			
Benzene	vol%	0.28	0.29	0.12		0.1	0.05	0.083	0.36	0.2	0.16	0.1	0.02	0.075	0.093	0.012
Toluene	vol%	0.92	0.85	0.64		0.33	0.24	0.25	1.89	0.35	0.29	0.18	0.11	0.278	0.21	0.018
Ethyl Benzene	vol%	0.33	0.25				0.14	0.13	1.11	0.06	0.06	0.06	0.17	0.11	0.075	0.012
Xylenes	vol%	1.4	1.1				0.51	0.51	3.46	0.32	0.29	0.25	0.3	0.374	0.2323	0.03
Salt	ptb									56.8	49.1	74.3	13			
Nickel	mg/L		4.3	2.3	3.3	3	ND	22.6		58.5	57.4	45.5	47.8	45.5		117
Vanadium	mg/L		8.3	2.1	0.3	0.7	ND	81		130.7	137.7	98.6	109	257		1320
Butanes	vol%	7.5	3.66				1.7			1.83	2.08	0.63	1.02			
Pentanes	vol%	6.4	3.47				2.96			4.48	4.21	3.69	0.89			
Hexanes	vol%	2.4	5.84				4.01			4.15	3.78	3.08	1.8			
Heptanes	vol%	10	7.19				3.51			2.97	2.74	2.51	2.13			
Octanes	vol%	8.9	7.24				4.47			2.12	2.13	2.16	3.05			
Nonanes	vol%	3.7	5.58				3.8			1.48	1.52	1.85	3			
Decanes	vol%		2.49				2.02			0.7	0.71	0.85	1.42			

Source: exp Energy Services Inc. 2012

Note: Green columns illustrate representative characteristics of crude oil types similar to those that would be transported by the proposed Project.
[a] 5-year averages from CrudeMonitor.ca
[b] Data from Environment Canada's Crude Oil Properties Database
[c] Data from Statoil Crude Oil Assay
[d] Western Canadian Select[7], Suncor Synthetic A and Bakken crude oils are representative types that would be transported by the proposed Project.
Notes: ND indicates measurement below instrument threshold; MCR = micro carbon residue; TAN = total acid number; g/ml = grams per milliliter; wt% = weight percent; ppmw = parts per million weight; mg KOH/g = milligrams of potassium hydroxide per gram; vol% = percent volume; ptb = pounds per thousand barrels; mg/L = milligrams per liter

[7] Diluted bitumen (dilbit)

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Crude oil from the Bakken region is a light crude oil which contains up to 40 percent volatile fraction and, compared to dilbit, has a more evenly distributed range of hydrocarbon densities including intermediate hydrocarbons. Initially, a release to the ground surface of Bakken crude would generally be expected to flow overland in similar fashion to dilbit. As the lighter hydrocarbons volatilize, the viscosity of both crudes would increase, thereby slowing the overland movement of the release. However, since more intermediate hydrocarbons are present in Bakken crude, the viscosity of Bakken crude could theoretically not increase as much as that of dilbit. Therefore, assuming spill conditions were equal, the extent of overland flow of Bakken could be slightly more than that of dilbit; however, the increased extent would likely not be discernible. In a water environment, a release of Bakken crude could initially be expected to float on or near the water's surface. As the lighter hydrocarbons volatilize, the density would increase, like dilbit, and the heavier hydrocarbons could subsequently sink and be suspended in the water column or drop to the sediment base. Since heavy hydrocarbons comprise 40 to 70 percent of dilbit, compared to only 15 to 40 percent of Bakken crude, a larger volume of sunken material would be expected to result from a release of dilbit than Bakken. However, since there is more combined volatile and intermediate hydrocarbons fraction present in Bakken crude, a release of Bakken crude could result in dissolution of more constituents to water than that of dilbit. Additional discussions pertaining to the effects and propagation of crude oil releases to the environment are presented in Section 4.13.3.

3.13.3.6 Flammability and Explosion Potential

By federal definition, crude oil is considered to be flammable when it has a flash point lower than 100°F (37.8°C) (16 CFR 1500.3, 2011). Most fresh oils are initially considered flammable by this flash point definition. The flash point is determined by the lowest boiling point components (volatiles). The flash point of fresh dilbit is initially lower than that found in other oil types and comparable to that of a diluent. However, medium, heavy, and dilbit crude oils move into the non-flammable classification after a short weathering period due to the loss of much of the volatile components. Consequently, the flash point of dilbit, which is governed by the 20 to 30 percent volume diluent component, will increase as the diluent is evaporated due to weathering (Tsaprailis 2013). Studies indicate that flash point temperatures increase significantly after weathering due to the evaporation of volatiles within both conventional crude oils and dilbit, and dilbit was found to behave similarly to conventional heavy crude oil after weathering, with similar flash points and weight losses. Under study, all weathered flash point values were above 100°F (37.8°C), with weathered dilbit having a flash point of 190°F (88°C). This suggests that the flammability and explosion potential of a dilbit release would be reduced as the dilbit undergoes weathering (Tsaprailis 2013).

Crude oils are flammable petroleum products; however, for an ignition to occur, the following conditions must be met:

- Vapors produced from the oil must be above the lower flammability limit of the vapor;
- Sufficient oxygen must be available; and
- An ignition source must be present.

If crude oil were released outside the pipeline and an ignition source were present, it could potentially ignite under certain conditions. During a release event, crude oils, including dilbit, are initially flammable; however, as the crude oil undergoes weathering, the degree of flammability is reduced. The extent of the reduction is dependent on several factors, including the type of oil. Fires and explosions are discussed further in Section 4.13.3.4, Types of Spill Impact.

Within a closed pipeline, there is insufficient oxygen and an ignition source is not present; therefore, an explosion within a closed pipeline is unlikely.

3.13.3.7 Acidity and Corrosivity Potential

Naphthenic acids are natural compounds in many petroleum sources, including bitumen from oil sands. (Naphthenic acids are not present in SCO.) Under extreme temperatures found at refineries, naphthenic acids can create what is referred to as naphthenic acid corrosion. Research indicates that naphthenic acids are not corrosive at pipeline temperatures and may protect pipelines from corrosion (Messer et al. 2004, Been and Wolodko 2011, Penspen Integrity 2013). The petroleum industry uses a measurement known as the total acid number (TAN) to qualitatively measure the potential for an oil to produce corrosion problems. The measurement of TAN is an indicator, although not a direct measurement, of naphthenic acid content in crude oil. TAN values for heavy WCSB and dilbit are similar to TAN values measured in other heavy crude oil from around the world (Aske et al. 2001, Table 4). This is consistent with information in presentations organized by NAS in July 2012 (NAS 2012), which reported that the TAN of dilbit is comparable with that of conventional crude. With a TAN greater than 1.0, dilbit is considered to be an acidic crude; heavy crude is moderately acidic (Asia Pacific Energy Consulting 2007). Although dilbit has a higher acid content than many other crude oils, the stable organic acids that raise the acidity levels are not corrosive at pipeline temperatures (NAS 2013).

Corrosion due to naphthenic acid is observed primarily at the very high temperatures found in refinery systems (typically, 644 to 788˚F [340 to 420˚C]). Pipelines may be exposed to naphthenic acid, but metal loss like that found in refinery crude systems is not typically observed because of the much lower operating temperature of pipeline systems.

Some oil sand bitumen crudes have been characterized as corrosive by the classical naphthenic models used in chemistry. However, after decades of cumulative operation, only a very few naphthenic acid corrosion cases have been observed in crude units in U.S. refineries and none have been observed in pipelines. Messer et al. (2004) propose a new theory for the corrosivity of naphthenic acids in oil sand bitumen crudes, in which two types of naphthenic acids are introduced: corrosive acids with low molecular weights, and non-corrosive and inhibitive acids with high molecular weights. According to Messer et al., the hot extraction wash of the raw oil sand mixture in dilbit appears to preferentially remove the higher water-soluble fraction of corrosive acids, leaving the less corrosive and less water-soluble fraction. The naphthenic acid type surviving the dilbit thermal hydro-processing tends to be of the inhibitive, non-corrosive type (Messer et al. 2004).

Dettman 2012 and Friesen et al. 2012 discuss two physicochemical characteristics of dilbit related to its corrosive behavior in pipelines: TAN and sulfur content. As discussed above, a diluent is added to bitumen to create dilbit and, therefore, the original organic acid found in bitumen would also be diluted. Bitumen naphthenic (organic) acid content prior to dilution is on the order of 0.3 percent by weight (TAN = 3 milligrams potassium hydroxide per gram [mg KOH/g]) (Dettman 2012). After dilution, the TAN could be reduced to 1.6 mg KOH/g or less.

The recent 5-year average evaluation of Western Canadian Select (dilbit) shows TAN at less than 1.0 mg KOH/g (Table 3.13-2).

A CanmetENERGY study conducted with crude oil data gathered in 1995 indicated a weak correlation between TAN numbers below 1.0 mg KOH/g and corrosion rates at ambient temperatures (Dettman 2012, Friesen et al. 2012). Various TAN numbers produced unnoticeable changes in metal corrosion rates (Friesen et al. 2012). Dilbit corrosivity rates could remain low even for higher TAN values unless temperature is increased close to the naphthenic acid boiling point (530°F [280°C]) (Dettman 2012). The operating temperature of the proposed Project is expected to be approximately between 42 and 135°F (6 and 57°C).

More important to pipeline corrosion is the hydrogen sulfide (H_2S) concentration (Zhou et al. 2013). Sulfur compounds, like H_2S, tend to form iron sulfides and, therefore, could threaten the steel walls of the pipeline. Although much of these are removed during the bitumen extraction/treatment process, some remain in the dilbit. Elemental sulfur is chemically bound to crude oil hydrocarbons, which account for the majority of sulfur content in a crude oil (Dettman 2012). The iron sulfides produced by dilbit are insoluble in oil and, as a result, the H_2S concentration in dilbit is generally lower than in conventional crude oils (Zhou et al. 2013). Under controlled hydraulic conditions in the pipeline (low shear flow), a protective film of iron sulfide could form on the pipeline walls to reduce the internal corrosion effect (Dettman 2012). The remaining sulfur compounds in dilbit would not be in free form, which means they would be strongly attached to hydrocarbons and not a source of corrosive hydrogen sulfide at pipeline temperatures (NAS 2013).

3.13.3.8 Pipeline and Component Integrity Threats

For the discussion on pipeline component integrity threats, the terms *release*, *leak*, and *spill* are used as follows:

- A release is a loss of integrity (failure to contain oil as designed) from a pipeline;
- A leak is a release over time; and
- A spill is the liquid volume of a leak that escapes a containment system (if present) and enters the environment.

There are a number of threats to pipeline component integrity that could cause a release. The term *threat* is used to describe a mechanism that could lead to a pipeline failure. The term *cause* means an action or lack of action that directly leads to or results in a pipeline spill. In this sense, threats have the potential to create the conditions for loss of integrity, and causes have created a release.

ASME B31.8S *Managing System Integrity of Gas Pipelines* (ASME 2010) and API 1160 *Managing System Integrity for Hazardous Liquid Pipelines* (API 2001) were used to identify potential pipeline and component integrity threats. The following threats could apply to the proposed Project during construction and operations, and are described in more detail below:

- External corrosion (e.g., the metal of the pipeline reacts with the environment, causing the pipeline to rust on the outside of the pipe, similar to rust on a car);
- Internal corrosion (e.g., the metal reacts with the contents inside the pipeline);

- Stress corrosion cracking (SCC) (e.g., pressure and temperature changes causes the pipeline to expand and contract, which compromises the pipeline coating and renders the pipeline susceptible to corrosion, subsequently resulting in the development and progression of cracks in the pipeline);
- Manufacturing (e.g., defects in the original characteristics of the pipe (e.g., low-strength material or substandard threading), which result in compromised integrity of the pipe);
- Construction (e.g., a defect in the welding of the pipe);
- Equipment (e.g., unusual wear and tear of pipeline components, such as valves);
- Third-party damage (e.g., a backhoe digging nearby strikes the pipe);
- Incorrect operations (e.g., human error made by pipeline operators); and
- Weather-related and other natural forces (e.g., flooding contributes to stream bank erosion that exposes the pipe or a landslide ruptures the pipe).

These threats are categorized into three time-related groups, according to ASME B31.8S (ASME 2010):

- Time-dependent—primary threats that could be addressed by ongoing and periodic assessments; these include external corrosion, internal corrosion, and SCC.
- Stable—threats that exist but do not materialize unless activated by a change in operations or the surrounding environment; these include manufacturing defects, construction defects, and equipment defects.
- Time-independent—threats that do not fall under the preceding categories; these include third-party damage, incorrect operations, and weather-related and other natural forces.

Alberta, Canada pipeline performance data from 1990 to 2005 show that overall incident frequency for crude oil pipelines is similar to the incident frequency based on U.S. performance data. Alberta pipelines are relevant because the proposed Project could transport crude oil of similar physical and chemical characteristics to that transported by Alberta pipelines. Figure 28 of the report provides estimates of incident frequencies from crude oil pipelines in Alberta (Alberta Energy and Utilities Board 2007). The 1990 to 2005 average is 1.9 incidents per 1,000 kilometer-years, which is approximately 3.0 incidents per 1,000 mile-years. This is very similar to the PHMSA crude oil incident rate of 3.1 incidents per 1,000 mile-years for pipelines and reported elements from 2002 to July 2012, as shown in Appendix K, Historical Pipeline Incident Analysis, Table 4. In addition, corrosion is the main cause of spills in Alberta crude oil pipelines, accounting for 37.7 percent of the incidents. This compares to the U.S. data for pipeline systems (34.4 percent in the PHMSA dataset from Figure 2 of Appendix K, Historical Pipeline Incident Analysis).[8]

[8] See also Energy and Utilities Board—Pipeline Performance in Alberta, 1990-2005 in Section 4.13.2.5, PHMSA Historical Data, of this Final Supplemental EIS.

3.13.3.9 Time-Dependent Threats

Time-dependent threats include corrosion and SCC. Corrosion is defined as the deterioration of a material, usually a metal, by chemical reaction with its environment. The rate at which a metal will corrode is primarily governed by the environment. Corrosion is a process where the metal of the pipe oxidizes because an electric current flows through and induces the pipeline metal to combine with oxygen, creating a non-metallic byproduct (known as rust). In order for corrosion to develop, an oxidizing agent (most commonly water) needs to be present to oxidize the steel used for pipelines. For a pipeline, water can be present inside the pipe, originating from the fluid being transported, or it can be present outside, such as from soil moisture (API 2001). The characteristics of the water present (e.g., acidity due to the corresponding presence of other chemicals/contaminants in the transported material) can also significantly affect the nature of the resulting corrosion. The following methods are typically used to control or mitigate corrosion on pipelines:

- Proper material selection;
- Controlling water and sediment content/accumulation in the pipeline;
- Exterior protective paints and coatings;
- Corrosion treatment chemicals;
- High-resolution in-line inspection tools;
- Dielectric insulation; and
- Cathodic protection.

Three corrosion threats commonly associated with pipelines (external corrosion, internal corrosion, and SCC) are discussed below.

External Corrosion

External corrosion occurs when pipeline walls or seam welds weaken from contact with moist soil or water. External corrosion can be accelerated by microbial activity (ASME 2010). A pinhole is a term used to describe a very small hole (i.e., roughly the size of a pinhead) that could form in a pipe. This hole size is common in corrosion cases, and is typically associated with low leak-rate, long-duration spills. The following factors could cause external corrosion or affect the rate at which external corrosion occurs:

- Exposure time—external corrosion thins the pipeline wall and weakens the pipe material strength. If the pipeline wall were exposed to the corrosive conditions over a sufficient time, weakening of pipe strength and a loss of pipeline integrity could result in a breach of the pipeline wall or failure of a pipeline weld under normal operating conditions. This could then result in a leak or spill.
- Coating—industry standards require that all new steel pipelines, such as the pipeline that would be used for the proposed Project, be coated with fusion-bonded epoxy (FBE) to create a physical barrier between the pipe and the surrounding soil, significantly reducing or eliminating the mechanism for developing rust. Over time, this coating could incur damage, exposing the pipe to moisture, which could result in corrosion. The corrosion generally

occurs evenly over a large portion of the pipeline surface. This type of external corrosion is referred to as general or uniform corrosion (NACE International 2012c).

- Cathodic protection—this counters the effect of corrosion by supplying electrical current to a pipe in order to prevent corrosion at defects or holes that form in the coating where the external environment could come into contact with the steel surface. The proposed pipeline would employ cathodic protection.
- Pitting—pitting is a type of external corrosion where there is a surface defect in the metal of the pipeline, a scratch in the coating, or an area where the coating has broken down. These small areas can then be exposed to moisture in the area surrounding the pipeline, causing the pipe to corrode (NACE International 2012a). The water or moisture connects the metal in the pipeline to the surrounding soil. From there, electric currents can flow naturally between the soil and the pipeline, inducing the pipeline metal to combine with oxygen, resulting in rust. The effects can be increased with pitting, as the current discharges tend to be localized at defects, scratches, or holes in the pipeline coating (Beavers and Thompson 2006). As a result of pitting, pinholes can form.
- Stray currents—man-made underground facilities (e.g., electric lines and piping) can also influence external corrosion rates as they distribute stray electric current fields. In the absence of mitigation measures, once corrosion is initiated, the presence of stray electric currents can result in a high rate of external corrosion and can result in rapid perforation of the pipeline wall (Beavers and Thompson 2006).
- Seasonal variability—local soil conditions (and corrosiveness) can vary from season to season.
- Long-line corrosion cells—pipelines passing through different types of soil may experience differential rates of corrosion due to differences in electrical conductivity in different soil types (American National Standards Institute/NACE International 2008). For example, a pipeline passing from clay soils to sandy loam soils may experience natural pipeline currents leading to loss of metal by anodic dissolution, which would result in the removal of metal from the surface of the pipe to the corresponding electrolyte (in this case, the soil).
- Microbial activity—bacteria are commonly found in soil and water and can contribute to pipeline corrosion. The two basic categories of bacteria are aerobic (oxygen-using) and anaerobic (non-oxygen-using). Both types can be present in the same environment depending on temperature, moisture, nutrient supply, and other factors. Aerobic bacteria are more abundant where oxygen is plentiful, and anaerobic bacteria are more abundant in oxygen-deficient environments. Both types of bacteria can contribute to conditions that could cause external and internal corrosion of pipelines (API 2001). Anaerobic bacteria are found in stagnant bodies of water, heavy clay soils, swamps, bogs, and in most areas that have moisture, organic materials, low oxygen, and some form of sulfates. Some anaerobic bacteria do not directly attack the steel but can create changes in soil chemistry that could increase corrosion activity. Anaerobic bacteria are also found in salt water-bearing formations. Aerobic bacteria can also contribute to corrosion of buried steel structures. If sufficient organic matter or other biodegradable material resides on pipe coating scratches, crevices of pipe repairs, or other pipe surface deformities, bacteria may use these materials and produce

carboxylic acids that could lead to corrosion. These bacterial processes may result in a pipe corrosion mechanism.

Internal Corrosion

Internal corrosion occurs when pipe walls or seam welds deteriorate due to contact with water, bacteria, or chemical contaminants contained in the material transported in the pipeline. Common contaminants, which include oxygen, H_2S, carbon dioxide, or chlorides, can form types of acids. The nature and extent of the corrosion that may occur are a function of the concentration and combination of these various corrosive constituents within the pipe, as well as the operating conditions of the pipeline. Internal corrosion can cause thinning of the pipe wall and weakening of the pipeline's mechanical strength. A sufficient loss of mechanical strength can result in a breach of the pipeline wall or failure of a pipeline weld from loss of structural integrity.

The mechanisms for internal corrosion are similar to those of external corrosion, except that the source of internal corrosion is the product flowing through the pipeline rather than the pipeline's surrounding environment. Internal corrosion can occur at locations where sediment and water (basic sediment) can separate. Underneath deposited sediment, a corrosive water film can form on the pipe wall. It is this localized water that can foster corrosion. Typical dilbit diluents exhibit hydroscopic properties (i.e., they absorb water). The proposed pipeline design indicates that the flow of dilbit would be at pressures greater than 1,100 pounds per square inch when leaving a pump station and drop to 50 pounds per square inch at the inlet of the next pump station approximately 50 miles downstream. According to Been (2012), the nominal velocity of flow in the pipeline would be approximately 5.6 miles per hour. The continuous pumping and pressure gradient would create the conditions necessary for water to be carried with the flowing crude oil (entrainment), which would tend to reduce or eliminate the corrosion threat.

Constituents that potentially contribute to corrosion inside a pipeline include sediment and water that can enter the pipeline with the oil being transported (Ironside 2012). Internal corrosion can occur if these constituents settle on the pipe bottom and establish a corrosion point. Higher density/viscosity crudes have a greater propensity to carry sediment. However, dilbit and SCO, typically carry approximately 25 percent less sediment than conventional heavy oils (Ironside 2012). To manage sediment and water, and consistent with Special Condition 34, Internal Corrosion, Keystone would limit basic sediment and water (BS&W) to 0.5 percent by volume and report BS&W testing results to PHMSA in the annual report. Keystone would also report upset conditions causing BS&W levels above the limit.

Erosion-corrosion is a corrosion action arising from the combined action of electrochemical reaction and mechanical abrasion. Metal alloy pipes are susceptible to wear as a consequence of fluid motion. Increasing fluid motion increases the rate of erosion-corrosion, in particular with solutions when bubbles and particles are present (Callister 1999). Turbulent flow inside the pipeline also increases the corrosion rate. Mitigation to reduce erosion-corrosion effects includes system design to eliminate drastic pipe diameter reductions, elbows, and other areas of flow impingement. Minimization of particles and bubbles in pipeline contents also reduces the effects of this type of corrosion. The potential for this type of corrosion is not unique to dilbit and is also observed in pipelines transporting conventional crude, as documented in the PHMSA database.

Several sources suggest that this corrosion potential for dilbit is similar to the potential for other crude oils transported in U.S. pipelines (Penspen Integrity 2013, Been and Dupuis 2012, Zhou et. al. 2013, Been and Wolodko 2011). According to the NAS TRB Special Report 311 (NAS 2013), dilbit does not have unique or extreme properties that make it more likely than other crude oils to cause internal degradation to transmission pipelines from corrosion or erosion. Dilbit has density and viscosity ranges that are comparable with those of other crude oils. It is moved through pipelines in a manner similar to other crude oils with respect to flow rate, pressure, and operating temperature (NAS 2013).

Some of the available data regarding corrosion for dilbit-carrying and conventional-crude-carrying pipelines are listed below:

- Although the TAN in dilbit is generally higher than conventional crude oil, based on averages of approximately 5 years, the acids are too stable to be corrosive under transmission pipeline temperatures (Been and Wolodko 2011, NAS 2013).
- Dilbit sulfur content is comparable to the sulfur content in other crude oils, and the production of H_2S, which could increase the occurrence of corrosion, is not expected at the pipeline operating temperatures (NAS 2013).
- No evidence of increased sediment erosion in dilbit pipelines, compared to other crude oil pipelines, has been observed in Alberta. Sediment content is managed to be below the limit set by regulatory agencies and industry (Been and Wolodko 2011).
- Dilbit viscosity is comparable to those of conventional heavy crude oils, and there is no evidence of increased corrosion or other potential pipeline threat due to viscosity (Been and Wolodko 2011, NAS 2013).
- Higher pipeline operating temperatures in dilbit pipelines do not correlate to increased corrosion rates (NAS 2013).
- Temperatures above 140°F (60°C) have indicated a higher rate and extent of coating failure, but it has also been shown that, in the presence of cathodic protection, the pipe would remain protected, and blistering and coating failure does not present an integrity threat to a pipeline (Been et al 2005). No stress corrosion cracking failures have been reported for FBE coatings in over 40 years of experience (Been and Wolodko 2011).[9]
- Transmission pipeline failure rates in Alberta are comparable to those in the United States (Been 2011).

Stress Corrosion Cracking

SCC is the cracking of a material produced by the combined action of corrosion and applied stress (Beavers and Thompson 2006, NACE International 2012b). SCC results when microscopic cracks form and coalesce under stress, forming a macroscopic crack (API 2001). The crack eventually expands to produce a failure that results in a breach of the pipeline integrity and subsequent release of pipeline contents. A characteristic of SCC is the development of groups of

[9] The Keystone XL pipeline would be coated with FBE, which is considered permeable to the cathodic protection current.

longitudinal surface cracks in the pipe that link up to form long, shallow flaws (Beavers and Thompson 2006).

Pipelines expand and contract slightly in response to temperature changes and normal operational cycling of the pipeline internal pressure. This expansion and contraction can cause stress cracks to develop in the pipeline if the temperature variation or pressure cycling is outside the design range. External forces acting on the system may also apply stress, which could create metal fatigue. Examples are vibration sources (e.g., from an active railway crossing) and frost heaving (depending on the soil and seasonal characteristics of the area).

SCC may progress in four stages. In Stage 1, the conditions for the initiation of SCC develop at the pipe surface. The pipe coating detaches, corrosion or rust develops, and the pipe surface may become pitted or uneven. Cracks begin to form in Stage 2, and continued initiation, growth, and crack coalescence occur in Stage 3. In Stage 4, large cracks coalesce and pipeline failure occurs, resulting in a leak.

The effect of SCC is a weakening of the pipeline's mechanical strength. A sufficient loss of mechanical strength through growth and interlinking of the stress-corrosion cracks can result in a breach of the pipeline wall from loss of structural integrity under normal pipeline operating conditions. SCC is controlled by pipeline stress management during pipeline installation and operation in conjunction with external and internal corrosion controls. If stress-corrosion cracks develop, pipeline inspections could reduce the likelihood of a pipeline release by identifying areas that need repair or replacement, or by causing a modification in the pipeline operating conditions.

According to the NAS TRB Special Report 311 (NAS 2013), dilbit and other heavy crude oils have similar densities and viscosities and flow through pipelines at the same rate and within comparable temperatures and pressures ranges. For these reasons, the likelihood of external damage from the operating parameters of a dilbit pipeline does not have a higher propensity for cracking transmission pipelines with comparable density and viscosity (NAS 2013).

3.13.3.10 Stable Threats

Stable threats are those that exist constantly over time and do not manifest unless activated by a change in operations or the surrounding environment.

Manufacturing

Manufacturing threats are defects in the mainline pipe or pipe seams created during manufacturing of the pipeline components. Pipe mill-related anomalies fall into this category (ASME 2010). Examples are lower steel grade, inclusions or imperfections in the steel, deformed joints, and substandard threading. The most common long-term scenarios for material-related pipeline leaks are those in which inadequate materials lead to corrosion. Manufacturing defects also may result in a weakening of the mechanical strength of the pipe body or weakening of the pipe welds over time. A sufficient loss of mechanical strength can result in a breach of the pipeline wall or failure of a pipeline weld under normal pipeline operating conditions. Manufacturing defects are controlled by pre-commissioning inspections and surveys after the pipeline is put into operation.

PHMSA (2009) has identified a manufacturing integrity issue with respect to high-grade mainline pipe. Tests that have been conducted on installed mainline pipe have shown that some of the pipe material has yield strengths, tensile strengths, and/or chemical compositions that do not meet the requirements of the API, Specification for Line Pipe—5L (API 5L), for PSL 2, and the specified pipe grade. Yield strengths below the specified minimum yield strength have been reported and yield strengths up to 15 percent lower than the strength values on the pipe manufacture-produced mill test report have also been reported. In some cases, the affected pipe may successfully pass strength-testing methods contained in current specifications, but may lead to a future pipeline integrity issue. The presence of low-yield-strength mainline pipe installed in a pipeline system may result in increased susceptibility to excessive pipe expansion or rupture during the pre-in-service field hydrostatic strength test.

Special conditions related to pipe design and construction (Appendix B, Potential Releases and Pipeline Safety) have been specified to address the above, in addition, the revised Permit Application specifies that the mainline pipe for the proposed Project would be constructed of API 5L PSL 2 X-70M high-strength steel (a grade of steel that has a yield and tensile strength that exceeds the needs of the planned operating condition of the pipeline). This specification accounts for the range of pipeline operating temperatures, pressures, and product compositions planned for the pipeline diameter, grade, and operating stress levels, including maximum pressures and minimum temperatures allowed for pipeline operation.

Construction

Construction threats are incidents that occur in the field during construction and up to the time of commissioning that may affect a pipeline's structural integrity. Construction threats can include: 1) a defective weld around the circumference of the pipe (girth weld); 2) a defective fabrication weld; 3) a pipe wrinkle, bend, or buckle; and 4) stripped threads, broken pipe, and coupling failure (ASME 2010). Dents occurring during construction that may affect welds or pipe body integrity are also included in this category.

Residual stress present in the pipe body due to pipe bending, buckling, or incorrect pipe-laying is a threat that may lead to a release event provided it is sufficient to locally weaken the pipeline integrity. Mechanical removal of metal during construction is considered a threat (e.g., gouges, cavities, or grooves) since corrosion tends to develop quickly in pipe areas with defects. The pipe-welding process and the pipe-laying process in general are factors that can affect pipe integrity.

The PHMSA Special Conditions related to pre-commissioning quality inspection and detection of construction defects are intended to help ensure high-quality construction standards to minimize the potential for defects. Testing and inspection that take place during pre-commissioning reduce, but do not eliminate, the chance of a leak due to construction threats.

Equipment

An equipment threat is the potential for equipment, including the pipe body itself, to not accomplish its intended design, operational, or functional purpose. A malfunction may include repairable and irreparable failures of pipeline (both linear and discrete) elements. A linear element is related to pipe body or weld seams that connect the pipe. A discrete element is equipment such as pumps, tanks, and non-pipe controls and valves. The equipment also comprises non-metal parts such as seals and rings, plus all the Supervisory Control and Data Acquisition (SCADA) components that assist in monitoring and controlling the pipeline system. The root causes of equipment malfunction could relate to failures in design, operation, or manufacturing if they are not clearly traceable to the construction phase. The following are some examples of potential equipment malfunctions:

- A pressure sensor may stop working and allow for abnormal pressures to develop without triggering alarms;
- Since the pipeline system is expected to be remotely operated, a SCADA malfunction, such as a level sensor that is not properly reading the content level, may also have the potential to result in a loss of containment by overfilling a tank to which the pipeline is connected; and
- Field power blackouts, software glitches, false alarms, and other factors may trigger an automated or human response that might lead to the accidental release of pipeline inventory.

A number of equipment malfunction scenarios could result in a pipeline leak. Wear and tear of valve seals or rings could result in immediate leaks, while the failure of SCADA controls at a critical time may result in an escalation scenario of varying consequences. For all these reasons, leaks from linear and discrete equipment may range from small (less than 50 bbl) to large volumes (greater than 1,000 bbl).

3.13.3.11 Time-Independent Threats

Time-independent threats include third-party damage, incorrect operations, and weather-related and other natural forces. These are discussed below.

Third-Party Damage

A third-party damage threat consists of potential actions of the pipeline operator and/or other parties that could create conditions affecting the pipeline system integrity. Three primary sub-threats comprise potential third-party damage threats: 1) unintentional damage inflicted by the pipeline operator, contractors, or third parties (instantaneous or immediate failure post-construction); 2) intentional damage or vandalism (post-construction); and 3) previously damaged pipe (such as dents or gouges created during manufacturing or construction) (ASME 2010). These threats may directly damage the pipeline system to the point of producing a leak. Excavation is a common action in which the pipeline is subject to an external mechanical force that could result in a pipe failure. Other less common actions include impact by a motor vehicle on aboveground facilities, detonation of an explosive substance, or earth movement related to nearby excavations or heavy traffic over a buried pipeline.

According to the NAS TRB Special Report 311 (NAS 2013), none of the properties or operating parameters of dilbit transportation in transmission pipelines is different from those of other crude oils. Pipelines would be no more vulnerable to impact damage due to the characteristics of dilbit. Additionally, dents, gouges, and scratches to exposed pipe; loss of pipeline support; change in pipeline alignment; and loss of cover due to third-party activities are related third-party threats (API 2001).

Engineering of the proposed Project would help address intentional damage, such as sabotage and terrorism, by considering Transportation Security Administration (TSA) Pipeline Security Guidelines. In April 2011, the TSA Pipeline Security Branch updated the TSA Pipeline Security Guidelines, which provide recommendations for pipeline industry security practices. These updated guidelines also incorporate changes to the Department of Homeland Security threat advisory system. The TSA has also developed a National Terrorism Advisory System Threat

Level Protective Measures Supplement to the TSA Pipeline Security Guidelines. These guidelines contain a series of progressive security measures to reduce vulnerabilities to pipeline systems and facilities during periods of heightened threat conditions. Keystone's confidential Corporate Security Policy and Information Security Policy provide direction and oversight for its Security Management Program. Keystone has stated these policies reference a number of operating procedures, plans, processes, and internal procedures, which together make up the Security Management Program. Accountability for the Security Management Program is held at the Executive Vice President level, with the responsibility for implementation held by the Director, Corporate Compliance and Corporate Security, and the Director, Information Services Governance and Security. Keystone asserts that the TSA Pipeline Security Guidelines are a very significant part of their existing Security Management Program and are specifically covered in their Physical Security Operating Procedure and Critical Facility Procedures. Their Corporate Security Program was reviewed by members of the TSA Pipeline Security group through their Corporate Security Review process. Keystone also employs the above-noted procedures, processes, and security vulnerability assessments to identify potential risks, implement the appropriate physical or cyber security measures, and address the TSA Pipeline Security Guidelines with respect to physical and cyber security.

Incorrect Operations

Although many pipeline operations are automated, personnel still serve a primary role in those operations. Human errors made by a pipeline operator's involvement can lead to the incorrect operation of the system, which in turn may cause a release. One example of an operating error is personnel operating a line valve that will over-pressurize other discrete equipment, resulting in a failure. In addition, extensive delays or prolonged lack of adequate maintenance can lead to a leak. Incorrect SCADA readings may induce a controller to mistakenly divert inventory and overfill storage tanks. If a field inspection routine is bypassed or simply fails to identify a worn seal, a leak could occur. Transient pipeline hydraulic events (temporary change of pressure, volume, or temperature) are also included in this category if they are due to human error. These events may lead to large pressure forces and fluid acceleration into the system. The disturbances may result in pump and other equipment failures, component fatigue, and even pipe rupture.

Weather-Related and Other Natural Forces

Weather-related and other natural force threats include natural hazards whose magnitudes or characteristics might cause damage to the pipeline system.[10] This threat comprises four primary sub-threats: 1) natural earth movement and/or avalanche; 2) heavy rains, floods, or extreme inclement weather; 3) extreme ambient conditions, including ice-loading on exposed structures and fire; and 4) lightning.

Some natural hazards such as earthquakes, floods, and tornadoes have the capacity to directly damage the pipeline and cause a leak. For example, an earthquake could affect the stability of the buried pipe. Tornadoes could damage or temporarily interrupt communications with the monitoring systems or directly damage aboveground elements such as tanks, pumps, sensors, small pipes, and support equipment. Flooding could damage pumps, short out electrical systems and components, or even create corrosive conditions. Heavy rains, snowfall, and high winds may

[10] Please refer to the Section 4.14, Greenhouse Gases and Climate Change.

produce conditions that would affect the system integrity over time. Long-term exposure of aboveground facilities to these weather events could increase wear and tear or weathering, and potentially cause corrosion. Mud slides or soil washout may affect the foundation of exposed pipeline segments, and the undistributed pipe weight may create stress that would cause linear elements to leak. Lightning and wild fires are unlikely to damage the system integrity directly, but could cause the loss of SCADA, crude oil overheating, or damage to the coating of exposed pipe at aboveground facilities.

3.13.3.12 Potential Spill Sources

For the purpose of this section, the following spill sizes are defined for spills related to construction activities, maintenance activities, and operation of the proposed pipeline:

- Small spill (less than 50 bbl);
- Medium spill (50 to1,000 bbl); and
- Large spill (greater than 1,000 bbl).

Construction

The proposed Project, as with most construction projects, has the potential for a release of hazardous fluids during material handling (e.g., delivery or dispensing of fuels, lubricating oil, hydraulic fluid). The possibility exists that during construction, a full gasoline or diesel tank truck could be involved in an accident (e.g., collision or roll-over) and release all or part of its cargo to the environment. Delivery vehicles carrying drums of lubricating or hydraulic fluids could also release hazardous fluids to the environment due to accidents. The areal extent of these types of spills would likely be limited unless they occurred near to or at an open waterbody.

The potential for small spills from construction machinery and operating equipment (e.g., small, intermittent leaks and drips of lubricating oil, hydraulic or transmission fluids, fuels, or similar products) would be almost certain to occur and are typical of most large construction projects. These types of spills—usually occurring in construction areas, equipment storage yards, construction camps, and pipe yards along the route—generally would be identified and managed by equipment operators and/or contractor personnel on site.

Operation

According to the NAS TRB Special Report 311 (NAS 2013), pipeline operations are the same for shipments of dilbit as for shipments of other crude oils. Operational practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their operational practices in transporting dilbit. Operational spills from the proposed Project could originate from the pipeline, pump stations, mainline valves, delivery points, or at any location along the pipeline. As noted above, most small spills are related to pinhole-type corrosion leaks along the body of the pipe or by leaks from valves, flanges, pumps, or other equipment. However, crude oil exiting a pinhole may create a medium to large spill due to the difficulties for SCADA or aerial surveillance to detect such a leak. Many of these components would be located in pump stations or delivery points along the proposed pipeline route. A pinhole-sized leak caused by defects in materials or faulty construction/fabrication of the pipeline and resulting in drips could occur along any segment of the pipeline. As the majority of the pipeline would be buried, these small, continuous-type releases may go unnoticed for an extended period until the spill is expressed on the surface. This volume of spill generally would remain within the pipeline right-of-way unless the oil was released adjacent to a channel or surface waterbody that could facilitate spreading.

Based on PHMSA data, medium spills (50 to 1,000 bbl) generally occur in association with physical damage to the pipeline (e.g., crack/tear, excavation damage, weld failure). The effects of corrosion or erosion (external or internal) on the proposed pipeline could cause a structural weakness to a section of pipe or pipe joint, which may lead to a pipeline failure along the route. Unauthorized excavation, construction, or drilling in the vicinity of the proposed pipeline could cause direct damage to the pipeline or other pipeline components at any location along the route; however, these types of activities are generally associated with urban or suburban areas. Soil erosion along the topographic highs and lows or near river or stream crossings along the route are also potential locations where spills may occur.

Large spills (greater than 1,000 bbl) are generally associated with severe damage to or complete failure of a major pipeline component. While many of the causes listed above for medium spills could apply to large spills, it is the degree of damage and the location of the spill that generally differentiates medium spills from large spills. For the proposed Project, roughly every 800 feet of mainline pipe could contain 1,000 bbl of oil.

Maintenance

According to the NAS TRB Special Report 311 (NAS 2013), pipeline maintenance practices are the same for shipments of dilbit as for shipments of other crude oils. Maintenance practices are designed to accommodate the range of crude oils in transportation. The study did not find evidence indicating that pipeline operators change or would be expected to change their maintenance practices in transporting dilbit. Small spills may occur during maintenance activities (e.g., valve replacement, pump service, inspection [pigging], or cleanouts) and generally would be expected to occur in or near pump stations, metering facilities, or other aboveground infrastructure locations. Many of these releases are typically attributed to the spilling of residual product during the removal of a pipeline component or bleeding of pressure or product from lines prior to line-breaking type activities. Most small releases associated with maintenance activities are generally identified and managed in a timely fashion.

The Historical Pipeline Incident Analysis (see Appendix K) shows that the majority of medium and large spills are generally not associated with maintenance activities. There are few sources for large (1,000 to 31,000 bbl) spills at maintenance facilities, and once a leak is identified during maintenance activities, spill response is typically rapid and limits the volume of the spill.

A technician or mechanic performing maintenance on the pipeline is usually trained or supervised by person/persons familiar with the reporting or appropriate response actions needed to prevent medium or large releases from occurring.

3.13.4 Potential Spill Receptors

The magnitude of an oil spill impact would be influenced by the type of receptors that might be exposed to the oil. Below are the descriptions of identified spill receptors broken into two main categories: HCAs and other resources. Definitions for HCAs are from the USDOT Federal Register, Title 49 of the CFR Part 195. Other resources are defined in this Final Supplemental

EIS and described below. Figure 3.13.4-1 illustrates the organization of HCAs by the USDOT and how other resources are organized in this Final Supplemental EIS to evaluate potential spill impacts.

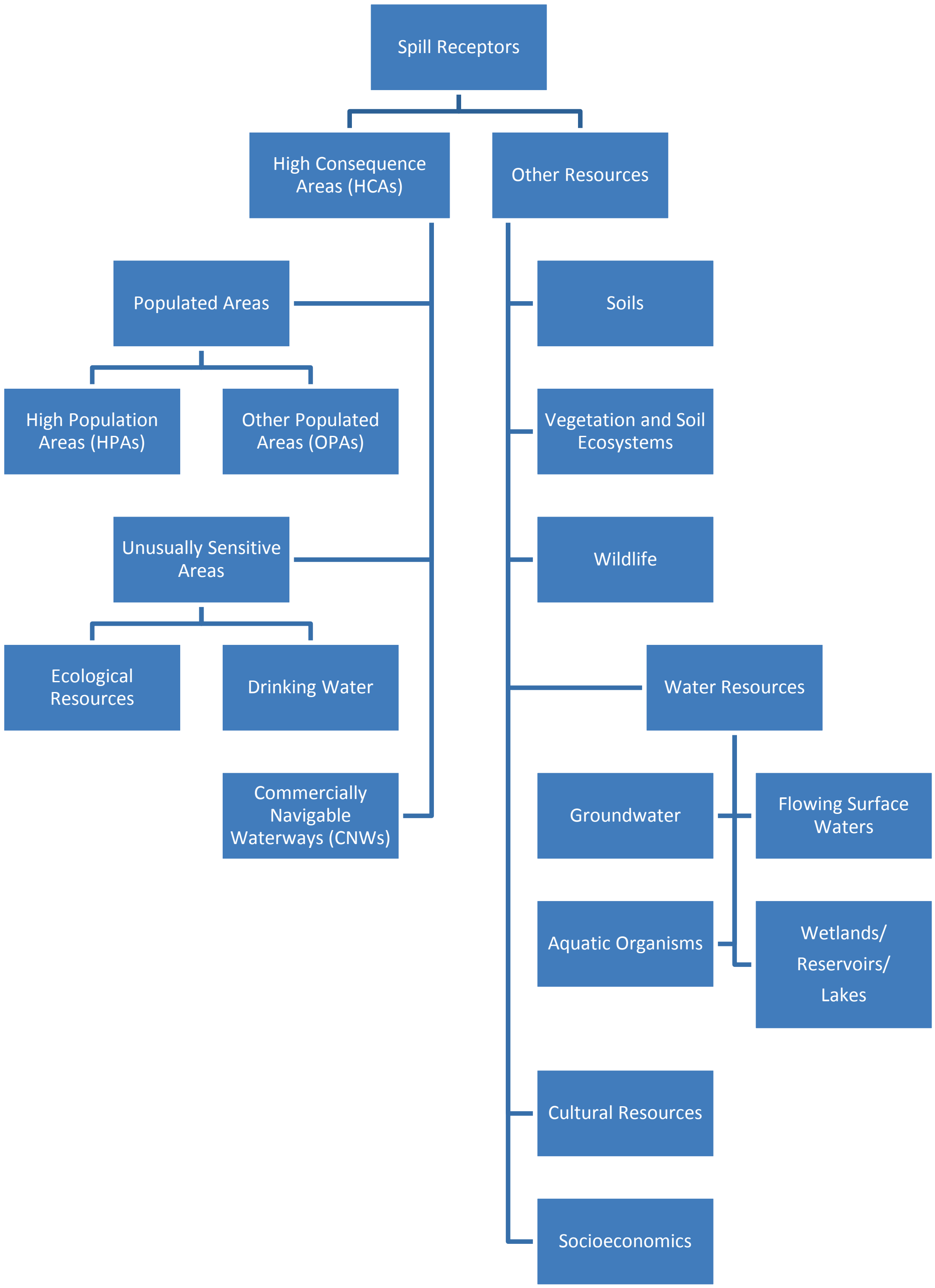

Figure 3.13.4-1 Identified Potential Spill Receptors

3.13.4.1 High Consequence Areas

HCAs are defined in 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) Subpart F for pipeline integrity management. An HCA is defined as an HPA, OPA, CNW, or Unusually Sensitive Area, including a sole-source drinking water supply.

The *Pipeline Risk Assessment and Environmental Consequence Analysis*, Table 4-12, (see Appendix P, Risk Assessment) identifies the types and lengths of HCAs crossed by the proposed Project route. These HCA data are compiled from a variety of data sources, including federal (e.g., USEPA) and state agencies (e.g., fish and game, environmental quality, hydrology, etc.). Keystone has conducted a preliminary evaluation of HCAs crossed or located downstream of the proposed pipeline route. Portions of the proposed pipeline route in which a release could potentially affect HCAs would be subject to higher levels of inspection and repair criteria (per 49 CFR 195). In addition, at least 6 months prior to beginning pipeline construction, Keystone would review—with the appropriate PHMSA Regional Directors—how HCAs that could be affected were identified and how the design of the pipeline associated with these segments is protective (see Section 4.13.5.1, PHMSA Special Conditions). As a result of a preliminary HCA evaluation, some proposed valve locations were moved and additional valves were added to protect HCAs from potential impact.

Populated Areas

In the event of a spill, the effects on populated areas would depend on the size of the spill and the size of the population in the impacted area. For this reason, populated areas are divided into two categories by the USDOT: HPAs and OPAs. HPAs contain 50,000 or more people and have a population density of at least 1,000 people per square mile. These areas are defined and delineated by the Census Bureau as urbanized areas. OPAs contain concentrations of people and include incorporated or unincorporated cities, towns, villages, or other designated residential or commercial areas, with population densities less than 1,000 people per square mile. The population data used in this report have been updated to include the results of the 2010 Census.

This population division is used to improve the risk analysis, as urban areas may be more susceptible to the impacts of an oil spill. Possible effects of a spill on populated areas include interruptions in daily activities such as access to safe drinking water, decreased air quality, socioeconomic effects, or temporary relocation of population in impacted areas during spill containment and cleanup procedures.

Based on current production projections and the commercial demand at Gulf Coast refineries for WCSB heavy crude from the oil sands, the majority of crude oil that would likely be transported by the proposed Project would be dilbit (EnSys 2010). However, SCO would also be transported by the pipeline.

As stated in the API 2003 report to the USEPA, the following was asserted in comparing SCO with conventional crude oil:

> Synthetic crude oil, from upgraded tar sands, is compositionally similar to high quality conventional crude oil (>33º API). The conventional technologies such as delayed and fluid coking, hydrotreating, and hydrocracking, used to upgrade heavy crude oils and bitumens, are used to convert tar sands into a crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to USEPA . . . to support the position that tar sands-derived synthetic crude oil is

comparable to conventional crude oils for health effects and environmental testing, a position with which EPA concurred.

A study on the human exposure symptoms related to the Kalamazoo, Michigan dilbit spill concluded that exposure symptoms were comparable to crude oil (Stanbury et al. 2010). Similarly, the Robust Summary of Information to the USEPA identified that SCO meets the definition of crude oil by the standardized Chemical Abstract Service registry of chemical information and provided a detailed characterization of physio-chemical and toxicological results (API 2003, API 2011). Human health can be affected due to exposure to crude oil and the hazardous chemicals that make up crude oils. Exposure to crude oil can occur through ingestion, inhalation of vapors, dermal exposure (contact with skin), and ocular exposure (contact with surface of the eye). Vapors from spilled oil could lead to human health effects depending on the intensity and duration of exposure. According to the Centers for Disease Control and Prevention (CDC) (2010a and 2010b) and the National Library of Medicine (2012), the short-term exposure effects[11] due to each of these pathways may include the following:

- Mild stomach disturbances, transient nausea, gastrointestinal tract disturbances, and self-limiting diarrhea due to ingestion of a small amount of crude oil (less than 8 ounces). The main risk of the ingestion of crude oil is aspiration of hydrocarbons into the lungs caused by vomiting, which could result in significant lung injury and possibly chemical pneumonitis.
- Irritation of the respiratory system due to inhalation of fresh crude oil. This can cause dizziness, rapid heart rate, headaches, confusion, aplastic anemia, nausea, and/or vomiting. Inhalation hazards of weathered crude oil are less of a concern because the concentrations of the toxic volatile hydrocarbons are greatly reduced following the weathering process.
- Irritation of the respiratory system due to inhalation of burning crude oil. This may harm the passages of the nose, airways, and lung by causing shortness of breath, difficulty breathing, coughing, itching, and black mucous.
- Mild to moderate irritation of the skin depending on the amount and duration of exposure. This can include reddening of the skin, edema (swelling), and burning. Dermal effects can worsen with exposure to sunlight because trace compounds, such as polycyclic aromatic hydrocarbons (PAHs), in the oil are more toxic when exposed to light. Also, depending on the skin sensitivity of the individual, skin effect may be more pronounced after smaller or shorter exposure periods.
- Defatting of the skin due to prolonged skin exposure to crude oil. This also increases the possibility of dermatitis from secondary skin infections.
- Slight stinging, temporary redness, and watery eyes due to ocular exposure.

According to the Michigan Department of Community Health, after the Enbridge 6B pipeline dilbit oil release in 2010, people in the immediate vicinity of the spill experienced some of these short-term effects including headaches, nausea, coughing, and watery/burning eyes. These symptoms are consistent with potential health effects associated with acute exposure to crude oil (Stanbury et al. 2010). Coming into contact with the oil that still remains in floodplains, on

[11] Includes residents, sensitive receptors, sensitive individuals, and spill response workers exposed to the spilled crude.

riverbanks, in the sediment at the bottom of the Kalamazoo River, and in Morrow Lake could cause skin irritation, which could stop if there was no further exposure.

Long-term exposure effects of crude oil have not been researched as rigorously as the constituents of crude oil. Most research indicates that the long-term effects of exposure to crude oil would be similar to the long-term effects of the chemicals that make up crude oil including, but not limited to, benzene, toluene, ethylbenzene, xylene, H_2S, and PAHs (CDC 2010b). Similar to short-term effects, exposure to these chemicals can occur through ingestion, inhalation of vapors, dermal exposure, and ocular exposure. According to the CDC (CDC 2010b), the long-term exposure effects due to each of the chemicals listed above are as follows:

- Benzene is a known carcinogen and long-term exposure can adversely affect bone marrow and cause anemia, leukemia, and possibly death.
- Long-term exposure to toluene may affect the nervous system or kidneys.
- Long-term exposure to ethylbenzene has been observed in animal studies to cause damage to the kidneys, inner ear, and hearing.
- Long-term exposure to xylene may cause impaired reaction time, impaired concentration and memory, and changes in the liver and kidneys.
- Long-term exposure to H_2S may cause permanent or long-term effects including headaches, impaired attention span, impaired memory, or impaired motor function.
- Symptoms of long-term exposure to PAHs may include chronic bronchitis, chronic cough irritation, bronchogenic cancer, and dermatitis.

Although these constituents represent the more toxic individual components present in crude oil, they are generally present in low percentages by comparison to refined petroleum products such as gasoline. Crude oils generally contain a high percentage of heavier hydrocarbons (e.g., carbon number C35 and higher, such as asphaltenes), which do not exhibit significant toxicity or bioavailability. The primary concerns for these heavier hydrocarbon compounds are often more aesthetic or physical in nature rather than toxicological.

Although there is the potential for long-term exposure by the public, long-term exposure effects would likely only be seen in people who were directly interacting with crude oil for multiple hours a day for an extensive period of time (i.e., spill cleanup professionals). These individuals should be trained in appropriate personal protective equipment for the task, exposure limits, work/rest schedule, and other ways to minimize the risk of crude oil interaction.

A human health risk could result from the inhalation of elevated levels of H_2S emitted into the air in the vicinity of the oil spill. Human health effects of exposure to H_2S, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of H_2S in urban areas reportedly range from 0.11 to 0.33 parts per billion (ppb), while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb (Skrtic 2006). Olfactory perception of H_2S occurs for most people at concentrations in the air of approximately 0.2 parts per million (ppm) or 200 ppb.

In a risk assessment of first responders (local emergency services, emergency response contractors, spill management team) at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of H_2S from crude oil spills using three different crude oil H_2S

concentrations (1 ppm, 20 ppm, and 350 ppm), calm wind speeds, and temperatures typical of the southern United States. The results of their analysis indicate that H_2S levels in the immediate aftermath of a crude oil spill at the two higher levels of H_2S concentration (20 ppm and 350 ppm) could pose short-term health risks (shortness of breath) to first responders or others at the spill site. Model results indicate that even under worst-case conditions (no wind), modeled concentrations drop to non-toxic levels in less than 4 minutes after oil leaves the pipeline and is exposed to air, assuming no further release of oil. H_2S exposure is expected to be highest where oil has been spreading for the first 4 minutes immediately after discharge from the pipeline (adjacent to the pipeline and within the right-of-way). The Thayer and Tell (1999) modeling effort suggests that exposure to H_2S concentrations could pose health risks in the immediate area of the release of an ongoing release or source.

In the event of a pipeline spill, Keystone has identified and prepared written procedures to address a response action. These activities are provided in Keystone's Draft ERP (see Appendix I, SPCC and ERP). More information describing spill response, including notification procedures, response actions, response teams, and spill impact considerations is discussed in Section 4.13.5.2, Safety and Spill Response.

Unusually Sensitive Areas

Unusually Sensitive Areas include drinking water or ecological resource areas that are especially sensitive to environmental damage from a hazardous liquid pipeline release. These areas have been defined by the USDOT. Unusually Sensitive Areas are separated from other water resources due to their increased potential of direct impact to human health or particularly sensitive wildlife. Other water or ecological resources, not captured by the USDOT-designated areas, are addressed below in the Other Resources discussion.

Drinking Water Resource

PHMSA identifies certain surface water and groundwater resources as drinking water Unusually Sensitive Areas (49 CFR 195.6 and 195.450). An example of a drinking water Unusually Sensitive Area is the water intake for a Community Water System or a Non-Transient Non-Community Water System that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source. The USEPA defines a Non-Transient Non-Community Water System as a public water system that regularly supplies water (but not year-round) to at least 25 of the same people for at least 6 months per year. A drinking water Unusually Sensitive Area could also include a Source Water Protection Area for a Community Water Source or a Non-Transient Non-Community Water System if the water supply is obtained from a USDOT Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has yet to identify a Source Water Protection Area, a Wellhead Protection Area is used.

Some segments of the proposed Project route would cross areas that are considered HCAs due to potential risks to sensitive drinking water resources (see Table 4-12 in the *Pipeline Risk Assessment and Environmental Consequence Analysis* in Appendix P, Risk Assessment).

Ecological Resource

An Ecological Resource Unusually Sensitive Area is an area containing a critically imperiled species or ecological community, a multi-species assemblage area, or a migratory water bird concentration area. An Ecological Resource is an area containing an imperiled species; federal threatened, endangered, proposed and candidate species; Bureau of Land Management sensitive species; state threatened and endangered species; species of conservation concern; depleted marine mammal species; or an imperiled ecological community where the species is considered to be one of the most viable, of the highest-quality, or in the best condition. Ecological Resources and special ecological considerations are further discussed in Section 4.13.4.1, High Consequence Areas, and Section 5.4 of E^{x}ponent's Environmental Review (E^{x}ponent 2013).

Commercially Navigable Waterways

CNWs are waterways where a substantial likelihood of commercial navigation exists (PHMSA Section 195.452). These areas are included as HCAs because these waterways are a major means of commercial transportation and critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of a national defense system.

3.13.4.2 Other Resources

Other resources that could be affected by a pipeline release include:

- Soils and sediments;
- Terrestrial vegetation;
- Wildlife;
- Water resources (including groundwater, flowing surface waters, aquatic organisms, and wetlands/reservoirs/lakes);
- Cultural resources; and
- Socioeconomic resources.

Potential impacts to these resources are described in Section 4.13, Potential Releases.

3.13.5 Spill Magnitudes

For the purpose of assessing potential spill impacts for this Final Supplemental EIS, the spill volumes defined and discussed in the Final EIS were simplified from five to three representative spill volumes: small, medium, and large. The entire range of mainline pipe spills in the PHMSA database is addressed by these three spill sizes. These have been reduced from the original five categories to provide a comparison analysis to earlier work done for the State of Nebraska; simplify the range of reported spill volumes in the database, including data under the revised reporting requirements; and facilitate assessment of the spill impact along the proposed Project route. The historic incident frequencies of these three representative spill volumes are detailed using PHMSA data in Appendix K, Historical Pipeline Incident Analysis.

3.13.5.1 Small Spills

Small spills defined herein are less than 50 bbl (2,100 gallons). This spill category represents approximately 79 percent of 1,692 crude oil spills evaluated. Based on the database, this volume of release is typically the result of a pinhole-sized, underground leak. A small volume surface release may also develop from corrosion leaks around valves, flanges, pumps, or other equipment. Small spills may also occur from residual oil encountered during maintenance of pipeline equipment such as valve replacement, pump service, and cleanouts.

Most small releases associated with maintenance activities are generally identified and managed in a timely fashion. Other small releases or pinhole-type releases could be identified during regular pipeline aerial inspections, ground patrols, or landowner or citizen observation. Small releases and spills can also be identified by investigating the source of petroleum odors reported by ground patrols, landowners, or citizens.

Based on a review of historical incident reports for the existing Keystone Pipeline[12] within the first year of operation, 11 of the 12 reported incidents resulted in small releases less than 15 bbl (PHMSA 2013 and National Response Center 2013). These incidents involved discrete elements of the pipeline system (i.e., pumping stations, mainline valves) and were entirely contained on the operator's property.

3.13.5.2 Medium Spills

Medium spills range from greater than 50 bbl (2,100 gallons) to 1,000 bbl (42,000 gallons). This spill category represents approximately 17 percent of 1,692 crude oil spills evaluated. Medium spills can be characterized as either underground releases or surface releases and generally are associated with physical damage to the pipeline, failure of a pipeline component, or operator error where the leak rate is more continuous than a drip. The effects of corrosion (external or internal) on the pipeline may cause a structural weakness that could lead to pipeline failure. Mechanical damage directly to the pipeline or external forces related to ground movement or flooding could cause direct damage to the pipeline. Incorrect operating procedures such as over-pressuring or mechanical vibration could exacerbate pipe weakness resulting in a release.

Historical incident reports for the existing Keystone Pipeline within the first year of operation indicate that one out of the 12 reported incidents resulted in a medium spill (PHMSA 2013 and National Responses Center 2013). The incident occurred at a pumping station and was reported as an equipment failure resulting in a surface release. An estimated 500 bbl (Final Supplemental EIS medium spill classification) of oil were released. Approximately 99 percent of the spill was contained within the pump station with an estimated 5 bbl reported on adjacent farmland. Roughly 80 percent (400 bbl) of the spill was recovered using vacuum-assisted equipment, with the remainder of the spill (an estimated 100 bbl) addressed through the excavation of approximately 300 cubic yards of soil (Crowl 2011). Cleanup activities were initiated within hours and the majority of the remediation was completed in less than a week.

3.13.5.3 Large Spills

Large spills are defined as greater than 1,000 bbl (42,000 gallons) to 31,000 bbl (1,302,000 gallons). The 31,000 bbl spill is roughly the maximum reported spill volume within the data evaluated. This spill category (greater than 1,000 to 31,000 bbl) represents approximately 4 percent of 1,692 crude oil spills evaluated. Large spills are generally characterized as a surface release. This is because the rate of the volume released usually exceeds the capacity at which soil can absorb the released oil. As a result, oil rises to the ground surface.

[12] The *Keystone Pipeline* refers to the existing operational pipeline that runs from Hardisty, Alberta, Canada to Steele City, Nebraska; Wood River, Illinois; and Pakota, Illinois.

Large spills are generally associated with severe damage to or complete failure of a major pipeline component or monitoring system.

While many of the causes listed in this section and Appendix P, Risk Assessments, apply to large spills, it is the degree of damage and the response to the spill that differentiates medium spills from large spills. Pipeline operators are typically alerted to medium and large spills through the pipeline's electronic monitoring or leak detection system (e.g., SCADA). Medium and large spills are generally the result of mechanical damage such as excavation or construction activities and are typically immediately reported and response actions are rapidly implemented.

A pinhole may create a medium to large spill due to the difficulties for SCADA or aerial surveillance to detect such a leak. The SCADA system, in conjunction with Computational Pipeline Monitoring or model-based leak detection systems, would detect leaks to a level of approximately 1.5 to 2 percent of the pipeline flow rate. Keystone has stated it could detect a leak of this size within 102 minutes. Computer-based, non-real-time, accumulated gain/loss volume-trending would be used to assist in identifying low-rate or seepage releases below the 1.5 to 2 percent by volume detection thresholds. Smaller leaks may also be identified by direct observations by Keystone or the public.

There are no large first-year spills for the existing Keystone Pipeline recorded in the historical incident reports.

3.13.6 Connected Actions[13]

There are three connected actions associated with the proposed Project:

- The Bakken Marketlink Project;
- The Big Bend to Witten 230-kV Transmission Line; and
- Electrical Distribution Lines and Substations.

The resources found along and in the proposed connected action project areas are similar to the resources described above for the proposed pipeline route itself.

Of the three connected actions, the Bakken Marketlink Project could potentially result in a spill that would affect nearby resources because of the presence of crude oil containment systems (i.e., pipeline and storage tanks). The threats of a spill are the same as for the proposed Project, as are the sources of spills during construction, operation, and maintenance. However, because of the relatively short pipeline segment length, the maximum worst-case spill size would be much less than it would be for the proposed Project.

3.13.6.1 The Bakken Marketlink Project

The Bakken Marketlink Project would be used to transport light crude oil, which is a high-quality crude oil generally characterized by a high proportion of naturally occurring light hydrocarbon fraction verses dilbit; this has the light fraction added by the introduction of a diluent. Construction and operation of the Bakken Marketlink Project would consist of a 16-inch

[13] Connected actions are those that 1) automatically trigger other actions which may require environmental impact statements, 2) cannot or will not proceed unless other actions are taken previously or simultaneously, 3) are interdependent parts of a larger action and depend on the larger action for their justification.

pipeline approximately 5 miles in length, additional piping, booster pumps, meter manifolds, and two 250,000-barrel tanks that would be used to store crude from connecting third-party pipelines and terminals. Threats of an oil release are similar to those described above for the proposed Project. The Bakken Marketlink Project facilities would be located within private land currently used as pastureland and hayfields.

3.13.6.2 The Big Bend to Witten 230-kV Transmission Line

The Big Bend to Witten 230-kV Transmission Project is located in Lyman and Tripp counties in south-central South Dakota. The project would consist of replacing the existing Big Bend-Fort Thompson No. 2 230-kV Transmission Line Turning Structure on the south side of the Big Bend Dam on Lake Sharpe; constructing a new double-circuit 230-kV transmission line for approximately 1 mile southwest of the dam; and constructing a new Lower Brule Substation south of the dam. The existing Witten Substation would be expanded immediately to the northeast to accommodate the new 230-kV connection. Potential sources for releases of oil or oil products during construction and/or operational phases of the project include fuel storage tanks, transformers, hydraulic and lubricating oil storage, and construction equipment and vehicles.

3.13.6.3 Electrical Distribution Lines and Substations

Multiple private power companies or cooperatives would construct distribution lines to deliver power to 20 pump stations located along the length of the pipeline in the United States. These distribution lines would range in length from approximately 0.1 mile to 62 miles, with the average being 13 miles long, and are estimated to extend about 377 miles, combined. The distribution lines would range in capacity from 69 kV to 240 kV, but the majority would have a capacity of 115 kV. The lines would be strung on a single pole and/or on H-frame wood poles. Potential sources for releases of oil or oil products during construction and/or operational phases of the project include fuel storage tanks, transformers, hydraulic and lubricating oil storage, and construction equipment and vehicles.

3.13.7 References

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