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Oil Sands and the Keystone XL Pipeline: Background and Selected Environmental Issues

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Summary

If constructed, the Keystone XL pipeline would transport crude oil derived from oil sands sites in Alberta, Canada, to U.S. refineries and other destinations. Because the pipeline would cross an international border, it requires a Presidential Permit.

Although some groups have opposed previous oil pipelines, opposition to the Keystone XL proposal has generated substantially more interest. Stakeholder concerns vary from local impacts, such as oil spills or extraction impacts in Canada, to potential climate change consequences.

Arguments supporting the pipeline's construction cover an analogous range. Proponents of the Keystone XL Pipeline, including high-level Canadian officials and U.S. and Canadian petroleum industry stakeholders, base their arguments supporting the pipeline primarily on increasing the security and diversity of the U.S. petroleum supply and economic benefits, especially jobs.

A number of studies have looked into the various environmental impacts of oil sands crude. This report focuses on *selected environmental* concerns raised in conjunction with the proposed pipeline and the oil sands crude it will transport.

Greenhouse Gas Emissions

Key studies indicate that the average greenhouse gas (GHG) emissions intensity—metric tons of GHG emissions per units of production (e.g., barrels)—of oil sands crude is higher than many other crude oils. However, industry stakeholders point to analyses indicating that GHG emissions from oil sands crude oil are comparable to other heavy crudes, some of which are produced and/or consumed currently in the United States.

Due to oil sands' increased emissions intensity, many stakeholders have voiced concern about potential climate change consequences associated with oil sands development. In June 2013, President Obama stated that an evaluation of the "net effects of the pipeline's impact on our climate" would factor into the Department of State's (DOS's) national interest determination in order to determine if the project would "significantly exacerbate the problem of carbon pollution." Thus, DOS's 2014 Final Environmental Impact Statement (FEIS) has received considerable attention. Among other conclusions, the FEIS estimated that the incremental (i.e., net) life-cycle GHG emissions associated with the pipeline would be 1.3 million to 27.4 million metric tons of carbon dioxide per year (0.02%-0.4% of U.S. annual GHG emissions). In addition, the FEIS stated that the "approval or denial of any one crude oil transport project, including the proposed project, is unlikely to significantly impact the rate of extraction in the oil sands or the continued demand for heavy crude oil at refineries in the United States based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios."

Some stakeholders have questioned these conclusions, arguing (1) that the project may have greater climate change impacts than projected by DOS, and (2) that there is nothing presumed or inevitable about the rate of expansion for the Canadian oil sands. Other stakeholders support the FEIS analysis, arguing that as long as there is strong global demand for petroleum products, resources such as the Canadian oil sands will be produced and shipped to markets using whatever route necessary.

Oil Spills and Other Local Impacts

Some groups have argued that both the pipeline's operating parameters and the material being transported through it impose an increased spill risk. The National Academy of Sciences National Research Council examined this issue in a 2013 report, stating that it did not "find any causes of pipeline failure unique to the transportation of diluted bitumen [oil sands crude]." However, according to the Environmental Protection Agency (EPA), spills of oil sands crude may result in different impacts than spills of other crude oils.

Other environmental concerns pertain to the region in which the oil sands resources are extracted. Potential impacts include, among others, wildlife and ecosystem disturbance and water resource issues. In general, these local/regional impacts from Canadian oil sands development are unlikely to directly affect public health or the environment in the United States. Within the context of a Presidential Permit, the mechanism to consider local Canadian impacts is unclear.

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Introduction

The proposed Keystone XL pipeline has received considerable attention in recent months. If constructed, the pipeline would transport crude oil (e.g., synthetic crude oil or diluted bitumen) derived from oil sands resources in Alberta, Canada, to refineries and other destinations in the United States. Policy makers continue to debate various issues associated with the proposed pipeline. Although some groups have raised concerns over previous oil pipelines—Alberta Clipper and the Keystone mainline pipelines, both of which are operating—the Keystone XL proposal has generated substantially more interest among environmental stakeholders.

"Oil Sands" vs. "Tar Sands"

The terms "oil sands" and "tar sands" are often used interchangeably to describe a particular type of nonconventional oil deposit that is found throughout the world in varying quantities. Opponents of the resource's development often use the term tar sands, which arguably carries a negative connotation; proponents typically refer to the material as oil sands. Some federal government resources refer to the deposits as tar sands, some oil sands, and some have used both terms. In its documents evaluating the Keystone XL pipeline, the Department of State (DOS) refers to the material as oil sands. The Environmental Protection Agency (EPA) has followed suit in its letters to DOS concerning the pipeline's environmental impacts. In general, this report uses the term oil sands to describe the deposits in the ground and oil sands-derived crude oil to describe the material imported into the United States. The use of this term is not intended to reflect a point of view, but to adopt the term most commonly used by the primary executive agencies involved in recent oil sands policy issues.

Before the Keystone XL pipeline can be constructed, its owner/operator, TransCanada,[1] must receive a Presidential Permit, which is issued by the State Department. The decision of whether to issue this permit has provided (and continues to provide) a rallying point for environmental groups who have voiced various concerns over the construction of the pipeline and/or further development of the oil sands.

The Presidential Permit application—submitted by TransCanada—for the pipeline's construction represents a singular decision made by the Administration about whether or not the pipeline would serve the national interest. Such a decision requires the identification of factors that would inform that determination, as well as an assessment of the resulting impacts of both building and not building the pipeline.

Stakeholders who raise concerns with the pipeline project are not a monolithic group. Some raise concerns about potential local impacts, such as oil spills. Some highlight the oil extraction impacts in Canada. Some argue the pipeline would have national energy and climate change policy implications. For these stakeholders, the Presidential Permit decision has been seen as a gauge of the Administration's support for reducing domestic fossil fuel use and greenhouse gas emissions. Thus, the pipeline proposal has provided a vehicle to galvanize advocates interested in climate change mitigation, particularly the reduction or replacement of fossil fuel use.

Arguments supporting the pipeline's construction also cover a range of issues. Proponents of the Keystone XL Pipeline, including high-level Canadian officials and U.S. and Canadian petroleum

[1] TransCanada is a public energy company, based in Canada, that owns oil and natural gas pipelines and power plants, among other assets, in Canada, the United States, and Mexico. See http://www.transcanada.com.

industry stakeholders, base their arguments supporting the pipeline primarily on increasing the security and diversity of the U.S. petroleum supply and economic benefits, especially jobs. An analysis of these issues is beyond the scope of this report. For more discussion of these and other issues, see CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted) et al.

This report focuses on *selected environmental* concerns raised in conjunction with the proposed pipeline and the oil sands crude it will transport. As such, the environmental issues discussed in this report do not represent an exhaustive list of concerns and issues. Moreover, many of the environmental concerns are not unique to oil sands. One could compose analogous lists for all forms of energy: coal, natural gas, nuclear, biofuels, conventional crude oil. Therefore, the oil sands/pipeline issues discussed in this report, when practicable, will be compared to other energy sources, particularly conventional crude oil development.

- **Section One** provides an overview of oil sands by addressing the following questions: what are oil sands; how are they extracted; how do oil sands crude oils compare to other crude oils?
- **Section Two** provides an overview of the Keystone XL pipeline, including a project description; a discussion of the federal requirements to consider environmental impacts from the pipeline, including the Department of State's national interest determination, obligations pursuant to the National Environmental Policy Act, and a list of recent milestones in the national interest determination process; and information about other international oil pipelines.
- **Section Three** discusses selected environmental issues, including greenhouse gas emissions intensity, related climate change concerns, pipeline oil spill risks, and two oil sands extraction concerns: land disturbance and water resources.
- An **Appendix** provides a list of agencies with jurisdiction or expertise relevant to pipeline impacts.

This report is intended to complement other CRS reports that address different aspects of the Keystone XL proposal, including the following:

- CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name re dacted) et al.
- CRS Report R42124, *Proposed Keystone XL Pipeline: Legal Issues*, by (name redacted), (name redacted), and (name redacted).
- CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).
- CRS Report R43415, *Keystone XL: Greenhouse Gas Emissions Assessments in the Final Environmental Impact Statement*, by (name redacted).

Section 1: Oil Sands—Overview

The term oil sands generally refers to a mixture of sand, clay and other minerals, water, and a very dense[2] and highly viscous (i.e., resistant to flow) form of petroleum called "bitumen." At room temperature, oil sands bitumen has the consistency of cold molasses. This property makes it difficult to transport.[3]

Bitumen can also be processed into a fuel, because it is a form of crude oil that has undergone degradation over geologic time. At some point, the bitumen may have been lighter crude oil that lost its lighter, more volatile components due to natural processes.

Companies developing oil sands reserves currently must process or dilute the bitumen before it can be transported. This processed/diluted bitumen falls into three general categories:

- **Upgraded bitumen, or synthetic crude oil (SCO).** SCO is produced from bitumen at a refinery that turns the very heavy hydrocarbons into a lighter material.
- **Diluted Bitumen (DilBit).** DilBit is bitumen that is blended with lighter hydrocarbons, typically natural gas condensates, to create a lighter, less viscous, and more easily transportable material. DilBit may be blended as 25% to 30% condensate and 70% to 75% bitumen.
- **Synthetic bitumen (Synbit).** Synbit is typically a combination of bitumen and SCO. Blending the lighter SCO with the heavier bitumen results in a product that more closely resembles conventional crude oil. Typically the ratio is 50% synthetic crude and 50% bitumen, but blends, and their resulting properties, may vary significantly.

Figure 1 illustrates the proportions of crude oil types that Canada has exported to the United States in recent years. The figure indicates that "blended bitumen" exports, which include both DilBit and Synbit, have nearly tripled in the past six years. They are also expected to constitute most of the growth in oil sands production in the foreseeable future.[4] Canadian crude oil imports accounted for approximately 33% of U.S. crude oil imports in 2013, up from 28% in 2012.[5]

[2] Oil sands bitumen contains up to 50% (by weight) asphaltenes, a class of hydrocarbon of high molecular weight.

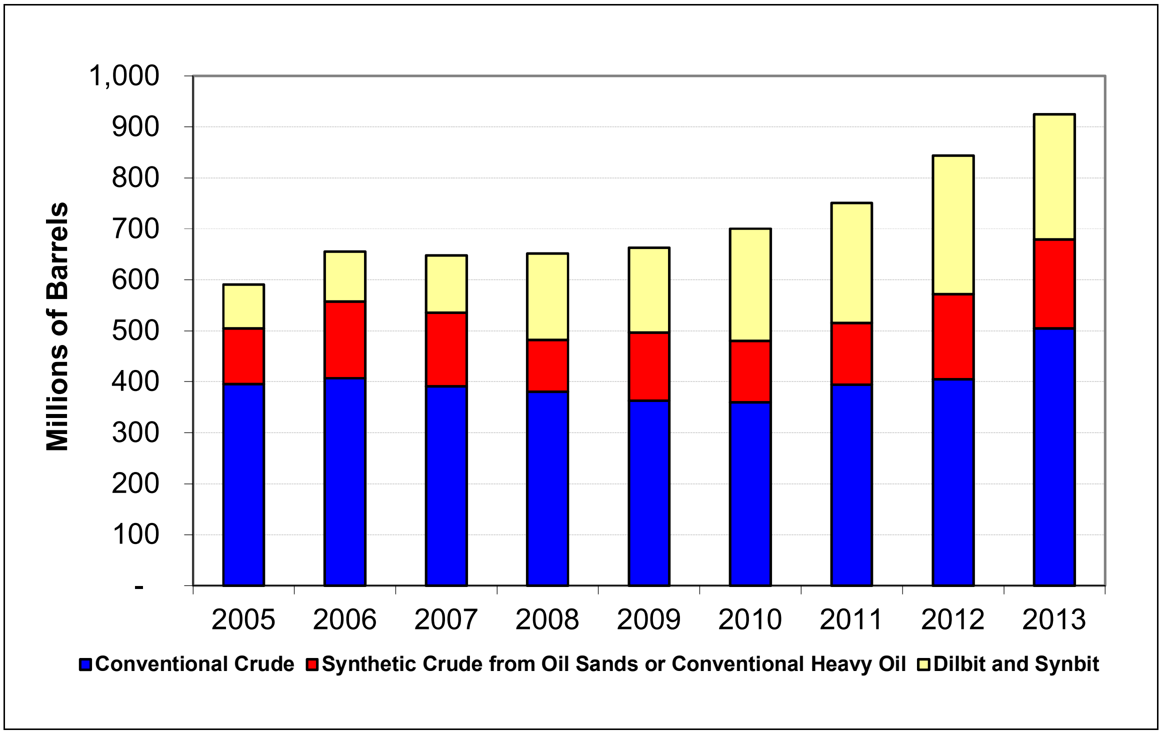
[3] This same property lends itself well to making asphalt—a mixture of asphaltenes and petrolenes—useful for road paving.

[4] Canadian Association of Petroleum Producers, *Crude Oil: Forecast, Markets & Transportation*, June 2013.

[5] Energy Information Administration, "U.S. Imports by Country of Origin," at http://www.eia.gov.

Figure 1. U.S. Imports of Canadian Crude Oil by Type

2005-2013



Source: Prepared by CRS; data from Canada's National Energy Board: 2005-2008 data provided in personal communication; 2009-2013 data are available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/stmtdcndncrdlxprttpdstn-eng.html.

Notes: Conventional crude includes conventional light, medium, and heavy crude oil. Synthetic Crude Oil includes crude oil produced from both oil sands and conventional heavy oil. According to Canada's National Energy Board, approximately 90% of the synthetic crude oil comes from oil sands (personal communication June 14, 2013).

Oil Sands Estimates and Locations

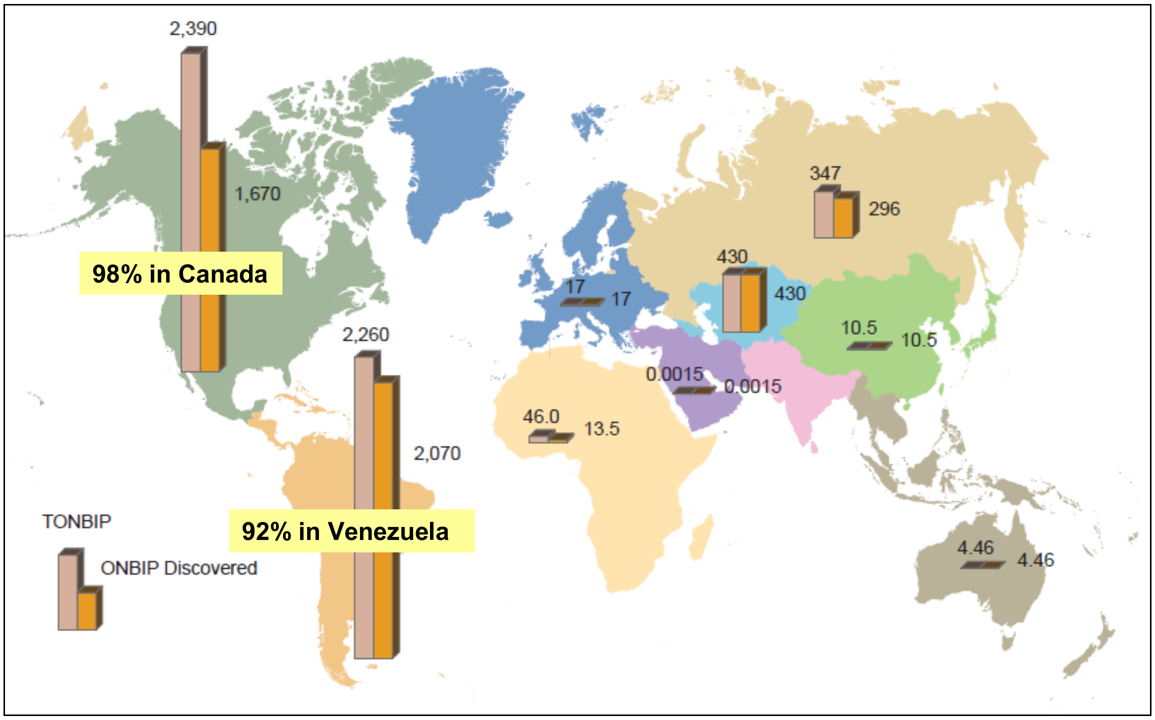
Resource estimates indicate that oil sands deposits are located throughout the world in varying amounts (**Figure 2**). By far, the two largest estimated deposits of oil sands are in Canada, particularly the Province of Alberta, and in Venezuela's Orinoco Oil Belt (**Figure 2**). As stated by the U.S. Geological Survey, the "resource quantities reported here … are intended to suggest, rather than define the resource volumes that could someday be of commercial interest."[6] For a variety of reasons (e.g., technology and economics), less than 0.4%—based on information in 2007—of the estimated oil sands resources are currently being produced.[7]

[6] U.S. Geological Survey (USGS), *Heavy Oil and Natural Bitumen Resources in Geological Basins of the World*, 2007.

[7] Ibid.

Figure 2. Estimated In-Place Natural Bitumen (Oil Sands) Resources by Region

Billion Barrels



Source: Prepared by CRS; original figure and data from U.S. Geological Survey (USGS), *Heavy Oil and Natural Bitumen Resources in Geological Basins of the World*, 2007. CRS added the notes regarding percentages in Canada and Venezuela, based on the USGS report data.

Notes: Column bars represent "original natural bitumen in place-discovered" (ONBIP Discovered) and "total original natural bitumen in place" (TONBIP). The latter includes ONBIP-discovered plus "prospective additional oil," which is "the amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study." These estimates are substantially higher than "proven reserve" estimates, discussed below. The different regions in the figure include North America, South America, Europe, Africa, Transcaucasia, Middle East, Russia, South Asia, East Asia, Southeast Asia, and Oceania.

Perhaps a more useful estimate of oil resources is "proven reserves." According to the Energy Information Administration (EIA), proven energy reserves are "estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions."[8] The Government of Alberta estimates that its proven oil sands reserves are approximately 170 billion barrels,[9] which accounts for 97% of Canada's total proven oil reserves, 7%-10% of the total estimated resource in Canada's geologic basin (**Figure 2**).

[8] See EIA Glossary at http://www.eia.gov/.

[9] Government of Alberta, "About the Resource," at http://oilsands.alberta.ca/resource.html (accessed April 6, 2012).

U.S. Oil Sands: Resource Estimates and Extraction Efforts

Estimates of U.S. oil sands deposits vary. According to a "measured-in-place" estimate from the U.S. Geological Survey (USGS), deposits of oil sands in the United States may contain approximately 36 billion barrels.[10] This is not a proven reserve estimate, but an estimate comparable to the "original natural bitumen" estimates in **Figure 2**. As that figure illustrates, the estimated resource of oil sands in the United States accounts for approximately 2% of the total North American oil sands resource.

The estimated resource of U.S. oil sands is located in several states in varying amounts: Alaska (41%), Utah (33%), Texas (11%), Alabama (5%), California (5%), and Kentucky (5%).[11] The deposits are not uniform. For instance, some deposits (estimated at less than 15%)[12] in Utah may be amenable to surface mining techniques. In contrast, the Alaska deposits are buried below several thousand feet of permafrost.[13] In addition, the physical/chemical properties of oil sands can differ by location. The U.S. Bureau of Land Management (BLM) states that "Canadian tar sands are different than U.S. tar sands in that Canadian tar sands are water wetted, while U.S tar sands are hydrocarbon wetted." Such differences may influence whether extraction of particular deposits is economically and technologically viable.

According to BLM, oil from oil sands deposits is not produced on a significant commercial level in the United States.[14] Although prior attempts, dating back decades, have been made in several locations, various challenges hindered commercial development.[15]

A comprehensive assessment of oil sands-related activities in the United States is beyond the scope of this report. Efforts to extract U.S. oil sands continue at several locations, particularly in Utah. A Canadian company, U.S. Oil Sands, owns leases in Utah that cover over 32,000 acres.[16] As of the date of this report, the company has received a permit to begin relatively small-scale oil sands mining operations on approximately 200 acres of state-owned lands.[17] According to the company, it plans to begin operations in 2015,[18] achieving an initial output of approximately 2,000 barrels per day.[19] This project has been opposed by environmental groups, some of which are appealing the permit decision in the court system.[20]

Figure 3 illustrates the estimated proven oil reserves for the top 15 nations in 2012. Canada ranks third behind Venezuela and Saudi Arabia, due to its supply of oil sands in Alberta.[21] Note that proven reserve estimates can change dramatically over a relatively short time (**Figure 3**). EIA

[10] See USGS, *Natural Bitumen Resources of the United States*, 2006, at http://pubs.usgs.gov/fs/2006/3133/pdf/FS2006-3133_508.pdf. The USGS estimates are largely based on studies from 1984 and 1995.

[11] The USGS assessment identifies additional states—Oklahoma, New Mexico, and Wyoming—with potential oil sands deposits, but these would each account for less than 1% of the total U.S. estimate.

[12] See Bureau of Land Management, *Draft Programmatic Environmental Impact Statement and Possible Land Use Plan Amendments for Allocation of Oil Shale and Tar Sands Resources on Lands Administered by the Bureau of Land Management in Colorado, Utah, and Wyoming*, Appendix B, January 2012.

[13] V.A. Kamath et al., "Assessment of Resource and Recovery Potential of Ugnu Tar Sands, North Slope Alaska," in Meyer, R.F., ed., Heavy crude and tar sands—Fueling for a clean and safe environment: Sixth United Nations Institute for Training and Research (UNITAR) Conference on Heavy Crude and Tar Sands, Houston, Texas, February 12-17, 1995, pp. 141-157.

[14] Bureau of Land Management, Oil Shale and Tar Sands Programmatic EIS Information Center, at http://ostseis.anl.gov.

[15] An archived CRS report includes a history of oil sands activities in the United States. See CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by (name redacted).

[16] See U.S. Oil Sands website, at http://www.usoilsandsinc.com.

[17] See U.S. Oil Sands, Notice of Intention to Commence Large Mining Operations, 2009; Utah Department of Environmental Quality, Administrative Hearings conducted May 2012, both available at http://www.deq.utah.gov/locations/prsprings/index.htm.

[18] U.S. Oil Sands, "US Oil Sands Inc. Awards Utah Project and Construction Management Contract," January 20, 2014, at http://www.usoilsandsinc.com.

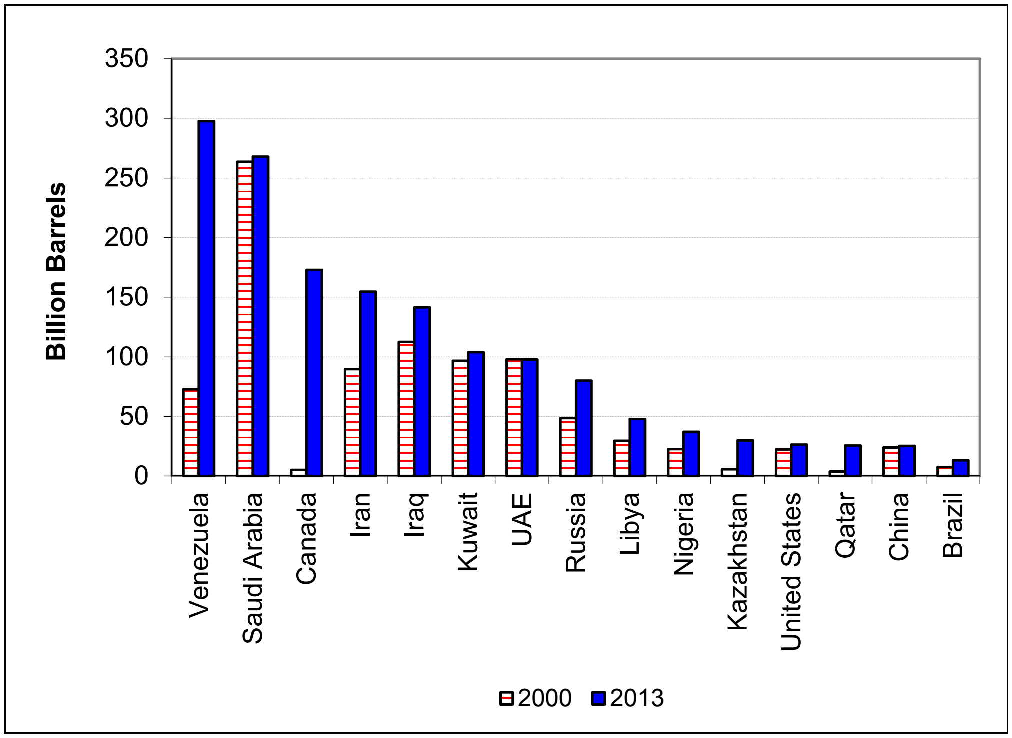
[19] U.S. Oil Sands, Notice of Intention to Commence Large Mining Operations, 2009.

[20] See, e.g., Utah Tar Sands Resistance, at http://tarsandsutah.blueskyinstitute.org.

data indicate that Canada's proven reserve estimate increased from approximately 5 billion barrels of oil (BBO) in 2002 to 175 BBO in 2003. Similarly, Venezuela's estimated proven reserves increased from 73 BBO in 2000 to 298 BBO in 2013.[22] The increases resulted from the addition of oil sands in Canada and extra-heavy oil in Venezuela to the total estimated proven reserves for each country.

Figure 3. EIA Estimated Proven Oil Reserves

Top 15 Nations in 2013—Compared to 2000 Estimates



Source: Prepared by CRS; data from EIA, "International Energy Statistics," at http://www.eia.gov/.

Notes: The 2013 estimate for the United States is based on the 2012 estimate because the 2013 estimate was not available.

Oil Sands Extraction Processes

Oil sands extraction processes are generally divided into two categories: mining and in situ operations, which are described below. **Figure 4** identifies the locations of areas accessible to mining and in situ sites of oil sands in Alberta. According to the Government of Alberta, 80% of the Canadian oil sands are accessible by in situ methods only.[23]

(...continued)

[21] EIA "International Energy Statistics," at http://www.eia.gov/.

[22] Ibid.

[23] Government of Alberta website, at http://oilsands.alberta.ca/reclamation.html#JM-OilSandsArea.

Figure 4. Alberta Oil Sands

Potential Mining and In Situ Sites

Source: Government of Alberta, at http://oilsands.alberta.ca/reclamation.html#JM-OilSandsArea.

Note: According to the Canadian Association of Petroleum Producers, smaller oil sands deposits are in northwest Saskatchewan next to the Alberta deposit, but the resource base has not been officially determined (*Crude Oil: Forecast, Markets & Pipelines*, June 2011).

The year 2012 was the first year in which in situ operations accounted for a larger percentage (55%) of oil sands production than mining. The Canadian Association of Petroleum Producers (CAPP) projects in situ production to increase its share of production in coming years, accounting for approximately 62% of total production by 2020.[24] Both processes are briefly discussed below.

Mining

Oil sands deposits that are less than about 250 feet below the surface can be removed using conventional strip-mining methods. The strip-mining process includes removal of the overburden

[24] Canadian Association of Petroleum Producers (CAPP), *Crude Oil: Forecast, Markets & Transportation*, June 2013.

(i.e., primary soils and vegetation), excavation of the resource, and transportation to a processing facility. Nearly all mined bitumen is currently upgraded to synthetic crude oil.[25]

In Situ

Oil sands deposits that are deeper than approximately 225 feet are recovered using one of three in situ methods: primary production,[26] cyclic steam stimulation (CSS), and steam-assisted gravity drainage (SAGD). CSS and SAGD, which accounted for approximately 75% of Alberta's in situ recovery in 2012, involve injecting steam into an oil sands reservoir.[27] The steam heats the bitumen, decreasing its viscosity and enabling its collection. Based on 2012 data, SAGD accounts for the greatest percentage of in situ recovery and is the preferred method of recovery for most new projects.[28] SADG involves a top well for steam injection and a bottom well for bitumen production.[29] **Figure 5** provides an illustration of this process.

In contrast to bitumen from mining operations, which generally produce synthetic crude oil, the vast majority of bitumen from in situ operations becomes DilBit.[30]

[25] National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 2013.

[26] According to the Energy Resource Conservation Board (ERCB), "Primary production includes those schemes that use water and polymer injection as a recovery method." *Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013-2022*, 2013.

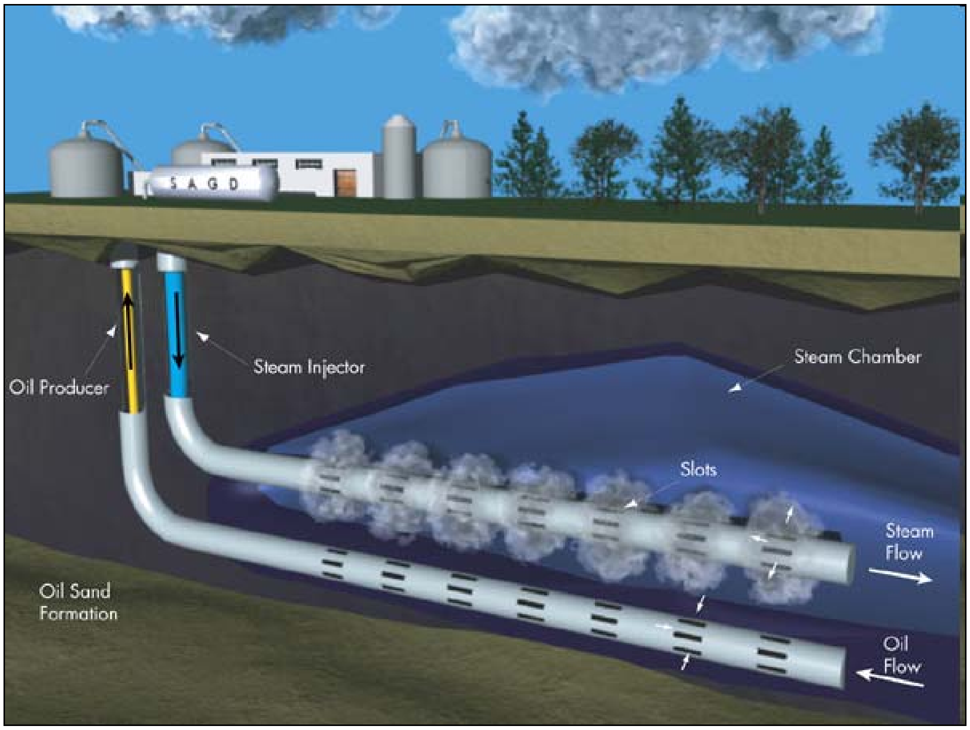
[27] ERCB, 2013.

[28] ERCB, 2013.

[29] In contrast, CSS uses a vertical well to liquefy the bitumen, which is then pumped to the surface using the same well.

[30] National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 2013.

Figure 5. Illustration of Steam-Assisted Gravity Drainage (SAGD)



Source: Pembina Institute, at http://www.pembina.org.

Properties of Oil Sands-Derived Crudes Compared to Other Crudes

Crude oil is a complex mix of hydrocarbons, ranging from simple compounds with small molecules and low densities to very dense compounds with extremely large molecules. Three key properties of crude oils include the following:

- **API Gravity.**[31] API gravity measures the weight of a crude oil compared to water. It is reported in degrees (º) by convention. API gravities above 10º indicate crude oils lighter than water (they float); API gravities below 10º indicate crude oils heavier than water (they sink). Although the definition of "heavy" crude oil may vary, it is generally defined by refiners as being at or below 22º API gravity.[32]
- **Sulfur Content.** Sulfur content in crude oil is an indication of potential corrosiveness due to the presence of acidic sulfur compounds. Sulfur content is measured as an overall percentage of free sulfur and sulfur compounds in a crude oil by weight. Total sulfur content in crude oils generally ranges from below 0.05% to 5.0%. Crudes with more than 1.0% free sulfur or other sulfur-

[31] American Petroleum Institute.

[32] U.S. Energy Information Administration, Crude Oil Input Qualities, "Definitions, Sources and Explanatory Notes," at http://www.eia.gov/dnav/pet/TblDefs/pet_pnp_crq_tbldef2.asp. In the marine tanker industry, heavy grade crudes are defined as crudes with an API below 25.7º, as bitumen emulsions, or as certain viscous fuel oils. See McQuilling Services, LLC, "Carriage of Heavy Grade Oil," Garden City, NY, 2011, http://www.meglobaloil.com/MARPOL.pdf.

containing compounds are typically referred to as "sour," below 0.5% sulfur as "sweet."[33]

- **Total Acid Number.** Total Acid Number (TAN) measures the composition of acids in a crude which can gauge its potential for corrosion, particularly in a refinery. TAN value is measured as the number of milligrams (mg) of potassium hydroxide (KOH) needed to neutralize the acids in one gram of oil. As a rule-of-thumb, crude oils with a TAN greater than 0.5 are considered to be potentially corrosive due to the presence of naphthenic acids.[34]

Table 1 compares Alberta's different oil sands crudes with other crude oils extracted in the United States and around the world. The data indicate that all oil sands crudes would be considered heavy crudes. Heavy crudes are found throughout the world, including the United States. The data indicate that oil sands crudes resemble other heavy crudes in terms of sulfur content and TAN.

[33] JDL Oil and Gas Exploration, Inc., "Crude Oil Basics," web page, July 28, 2011, http://www.jdloil.com/oil_basics.htm.

[34] R.D. Kane and M.S. Cayard, "A Comprehensive Study of Naphthenic Acid Corrosion," Paper No. 02555, Corrosion 2002, http://www.icorr.net/wp-content/uploads/2011/01/napthenic_corrosion.pdf.

Table 1. Selected Global Crude Oil Specifications

Source	Crude Oil Name	°API Gravity	Sulfur (Weight %)	TAN (mgKOH/g)
	Alberta Oil Sands Crude Oils			
DilBits	Access Western Blend	21.9	3.94	1.70
	Cold Lake	20.9	3.78	0.97
	Peace River Heavy	20.8	4.97	2.49
	Seal Heavy	20.5	4.64	1.86
	Smiley Coleville	20.0	2.98	0.97
	Wabasca Heavy	20.3	4.10	1.03
	Western Canadian Select	20.6	3.46	0.92
DilSynBit	Albian Heavy	19.1	2.42	0.51
	Selected Heavy Crude Oils			
Western Canada	Western Canadian Blend	20.7	3.16	0.71
U.S. (California)	Hondo Monterey	19.4	4.70	0.43
	Kern River	13.4	1.10	2.36
Venezuela	Pilon	16.2	2.47	1.60
	Boscan	10.1	5.40	0.91
Mexico	Maya	21.5	3.31	0.43
Italy	Tempa Rossa	20.4	5.44	0.05
United Kingdom	Captain	19.2	0.70	2.40
Indonesia	Duri (Sumatran Heavy)	20.8	0.20	1.27
	Selected Medium and Light Crude Oils (> 22.3° API)			
U.S. (Alaska)	Alaskan North Slope	32.1	0.93	0.12
U.S. (Texas)	West Texas Intermediate	40.8	0.34	0.10
U.S. (Gulf of Mexico)	Hoops Blend	31.6	1.15	1.07
	Southern Green Canyon Heavy-Sour	28.4	2.48	0.17
Nigeria	Bonga	30.2	0.25	0.55
Norway	Statfjord	28.3	0.64	0.47
Dubai	Dubai Fateh Heavy	30.8	2.07	0.05
Saudi Arabia	Arabian Heavy	27.5	2.95	0.40
	Arabian Light	33.7	1.96	0.05

Sources: Canadian crude data from Crude Quality Inc., Canadian Crude Quick Reference Guide; other crude oil data from Capline, Crude Oil Assays; BP Crude Assays; ExxonMobil Assays; "Benchmark West Texas Intermediate Crude Assayed," *Oil and Gas Journal*, 1994; McQuilling Services, LLC, "Carriage of Heavy Grade Oil," Garden City, NY, 2011; Hydrocarbon Publishing Co., *Opportunity Crudes Report II*, Southeastern, PA, 2011.

Notes: The crude oils listed above are not an exhaustive list, nor do they represent a specific percentage of global consumption. Multiple crude oils from certain locations are included to indicate the range of parameters.

API gravity—measured in degrees—is typically used to compare the weight of crude oils to water. An API gravity greater than 10° indicates that the crude oil is lighter than water (i.e., it floats); an API gravity less than 10° indicates that the crude oil is heavier than water (i.e., it sinks). The average API gravity for natural bitumen deposits is 5.4° (U.S. Geological Survey, *Heavy Oil and Natural Bitumen Resources in Geological Basins of the World*, 2007).

TAN (or total acid number) is the amount of potassium hydroxide (in milligrams) needed to neutralize the acid in one gram of oil.

Section 2: Keystone XL Pipeline—Overview

As originally proposed by TransCanada in September 2008,[35] the Keystone XL pipeline would have involved two major segments (**Figure 6**). The first segment—approximately 875 pipeline miles in the United States—would cross the U.S.-Canadian border into Montana, pass through South Dakota, and terminate in Steele City, NE. The second segment—approximately 485 miles and labeled as the "Gulf Coast Project" in **Figure 6**—would connect an existing pipeline in Cushing, OK, with locations in southern Texas.

Following action from Congress, DOS, and state governments (see **Table 2** for details), DOS ultimately denied TransCanada's initial permit application in January 2012.[36] TransCanada then proceeded with construction of the Gulf Coast Pipeline. That segment did not require a permit from DOS because it does not cross a U.S. border. (See "Presidential Permit Requirements for Cross-Border Pipelines," below.) The Gulf Coast Pipeline Project became operational on January 22, 2014.

In May 2012, TransCanada submitted a new permit application to DOS for the proposed Keystone XL Pipeline. That application is for only the 875-mile northern pipeline segment.

Once complete, the entire Keystone XL pipeline system would have the capacity to deliver 830,000 barrels per day (bpd), a substantial flow rate compared to other U.S.-Canada import pipelines (**Table 3** in the section below, "Other Oil Pipelines from Canada"). Assuming the pipeline were to deliver this maximum capacity each day of the year, it would transport approximately 300 million barrels per year, a considerable volume when compared to the 420 million barrels of DilBit and synthetic crude oil Canada exported to the United States in 2013 (**Figure 1**).

The 36-inch-diameter pipeline would require a 50-foot-wide permanent right-of-way along the route.[37] Approximately 88% of the pipeline right-of-way would be on privately owned land; the remaining 12% is owned by local, state, or federal governments. Rangeland and agricultural land comprise most of the land crossed by the proposed pipeline. Additional facilities associated with the pipeline system include pump stations (with associated electric transmission interconnection facilities), mainline valves, and delivery metering facilities.[38]

The Keystone XL pipeline and the Gulf Coast Project would combine with two existing pipeline segments to complete TransCanada's Keystone Pipeline System. This system is depicted in **Figure 6**. These existing segments include the following:

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[35] The original application and related documents are available at the Department of State Keystone XL website, at http://keystonepipeline-xl.state.gov/archive/index.htm.

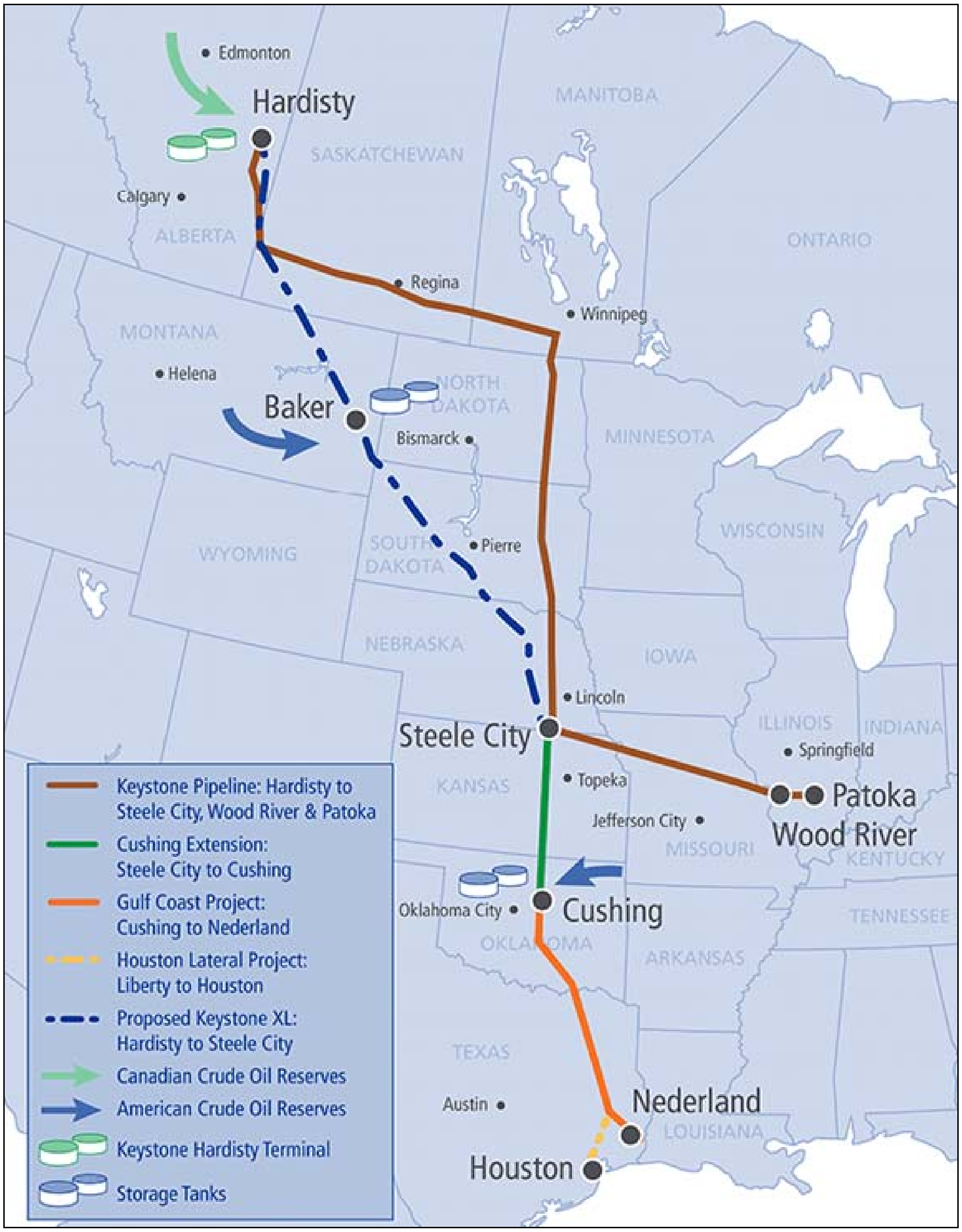
[36] A more detailed timeline of events is available in CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted) et al.

[37] According to a Pipeline and Hazardous Materials Safety Administration online glossary, a "pipeline right-of-way is a strip of land over and around pipelines where some of the property owner's legal rights have been granted to a pipeline company.... generally, the pipeline company's right-of-ways extend 25 feet from each side of a pipeline unless special conditions exist" (see http://www.phmsa.dot.gov/resources/glossary#R).

[38] U.S. State Department, *Final Supplemental Environmental Impact Statement for the Keystone XL Project*, Section, 3.9, "Land Use, Recreation, and Visual Resources," p. 3.9-1, January 2014, available at http://keystonepipeline-xl.state.gov/documents/organization/221168.pdf

- The Keystone Mainline: A 30-inch pipeline with a capacity of nearly 600,000 bpd that connects Alberta oil sands to U.S. refineries in Illinois. The U.S. portion runs 1,086 miles and begins at the international border in North Dakota. The Keystone Mainline began operating in June 2010.
- The Keystone Cushing Extension: A 36-inch pipeline that runs 298 miles from Steele City, NE, to existing crude oil terminals and tank farms in Cushing, OK. The Cushing Extension began operating February 2011.

Figure 6. Existing and Proposed Segments of Keystone Pipeline System



Source: TransCanada, at http://keystone-xl.com/keystone-xl-pipeline-overall-route-map/.

Federal Requirements to Consider the Pipeline's Environmental Impacts

The DOS decision-making process related to a Presidential Permit application is subject to environmental review requirements established pursuant to the National Environmental Policy Act (NEPA, 42 U.S.C. §4321 et seq.). Compliance with NEPA is intended, in part, to assure that DOS fully identifies and considers any significant environmental impacts associated with the issuance or denial of a permit to construct, operate, and maintain the pipeline system and associated facilities. The analysis of impacts prepared during the NEPA process is intended to inform the federal decision-making process. As a result, compliance with NEPA must be documented and demonstrated before DOS can make a final decision on the Presidential Permit.

Issues that arose and environmental impacts identified during DOS efforts to process TransCanada's application for a Presidential Permit ultimately resulted in the denial of its 2008 permit application. With TransCanada's 2012 reapplication for a permit to construct the newly configured Keystone XL pipeline project, the Presidential Permit process and NEPA compliance process began anew.

Generally, federal agencies have no authority to control siting of oil pipelines, even interstate pipelines.[39] Instead, the primary siting authority for oil pipelines generally would be established under applicable state law (which may vary considerably from state to state).[40] However, in accordance with Executive Order 13337, a facility connecting the United States with a foreign country, including a pipeline, requires a Presidential Permit from DOS before it can proceed.[41]

Key elements of the Presidential Permit process, including DOS efforts to identify environmental impacts associated with the TransCanada's 2008 and 2012 permit applications are discussed below (and summarized in **Table 2**). Included in that discussion are relevant activities and requirements associated with DOS compliance with NEPA and its obligation to determine whether the proposed pipeline would serve the national interest.

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[39] This is in contrast to interstate natural gas pipelines, which, under Section 7(c) (15 USC §717f(c)) of the Natural Gas Act, must obtain a "certificate of public convenience and necessity" from the Federal Energy Regulatory Commission.

[40] Federal laws and regulations address other matters, including worker safety and environmental concerns. See CRS Report R41536, *Keeping America's Pipelines Safe and Secure: Key Issues for Congress*, by (name redacted) and CRS Report RL33705, *Oil Spills in U.S. Coastal Waters: Background and Governance*, by (name redacted).

[41] This authority was originally vested in the U.S. State Department with the promulgation of Executive Order 11423, "Providing for the performance of certain functions heretofore performed by the President with respect to certain facilities constructed and maintained on the borders of the United States," in 1968. Executive Order 13337, "Issuance of Permits With Respect to Certain Energy-Related Facilities and Land Transportation Crossings on the International Boundaries of the United States," of April 30, 2004, amended this authority and the procedures associated with permit review for energy-related projects, but did not substantially alter the exercise of authority or the delegation to the Secretary of State in E.O. 11423. Due to the particular significance to Presidential Permit issuance for pipelines, provisions in E.O 13337 will be cited in this report. For further information on the Executive Order authority and related issues, see CRS Report R42124, *Proposed Keystone XL Pipeline: Legal Issues*, by (name redacted), (name red acted), and (name redacted).

Presidential Permit Requirements for Cross-Border Pipelines

A decision to issue or deny a Presidential Permit application is based on a determination that the proposed project would serve the "national interest." This term is not defined in applicable Executive Orders. However, when discussing the 2008 permit application, DOS stated, "Consistent with the President's broad discretion in the conduct of foreign affairs, DOS has significant discretion in the factors it examines in making a National Interest Determination. The factors examined and the approaches to their examination are not necessarily the same from project to project."[42]

More recently, DOS stated that its national interest determination will involve "consideration of many factors including: energy security; environmental, cultural, and economic impacts; foreign policy; and compliance with relevant federal regulations and issues."[43]

In addition, DOS stated that some of the key factors it considered in past decisions include the following:

- environmental impacts of the proposed projects;
- impacts of the proposed projects on the diversity of supply to meet U.S. crude oil demand and energy needs;
- the security of transport pathways for crude oil supplies to the United States through import facilities constructed at the border relative to other modes of transport;
- stability of trading partners from whom the United States obtains crude oil;
- relationship between the United States and various foreign suppliers of crude oil and the ability of the United States to work with those countries to meet overall environmental and energy security goals;
- impact of proposed projects on broader foreign policy objectives, including a comprehensive strategy to address climate change;
- economic benefits to the United States of constructing and operating proposed projects; and
- relationships between proposed projects and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources.[44]

DOS may consider additional factors to inform its national interest determination for a given project. However, pursuant to E.O. 13337, for each permit application it receives for an energy-related project, DOS must request the views of the Attorney General, Administrator of the Environmental Protection Agency (EPA), and Secretaries of Defense, the Interior, Commerce, Transportation, Energy, and Homeland Security (or the heads of those departments or agencies

[42] The U.S. State Department, *Final Environmental Impact Statement for the Keystone XL Project*, August 2011, "Introduction: 1.3 Presidential Permit Process" (as amended September 22, 2011), p. 1-4, available at http://keystonepipeline-xl.state.gov/archive/dos_docs/feis/index.htm#.

[43] See the U.S. State Department press release, "Keystone XL Final Supplemental Environmental Impact Statement Released," January 31, 2014, available at http://www.state.gov/r/pa/prs/ps/2014/01/221112.htm.

[44] 2011 final EIS.

with relevant authority or responsibility over relevant elements of the proposed project). DOS may request the views of additional federal department and agency heads, as well as additional local, state, or tribal agencies, as it deems appropriate for a given project. DOS must also invite public comment on the proposed project.

If, after considering the views and assistance of various agencies and the comments from the public, DOS finds that the proposed project would serve the national interest, then a Presidential Permit must be issued. Specific to the Keystone XL pipeline, in its 2012 Presidential Permit application, TransCanada states the following:

> The project will serve the national interest of the United States by providing a secure and reliable source of Canadian crude oil to meet the demand from refineries and markets in the United States, by providing critically important market access to developing domestic oil supplies in the Bakken formation in Montana and North Dakota, and by reducing U.S. reliance on crude oil supplies from Venezuela, Mexico, the Middle East, and Africa. The project will also provide significant economic and employment benefits to the United States, with minimal impacts on the environment.[45]

To ensure that environmental impacts are considered before final agency decisions are made, NEPA requires an environmental impact statement (EIS) must be prepared for every major federal action that may have a "significant" impact upon the environment.[46] With respect to the Presidential Permit applications submitted by TransCanada for Keystone XL, the State Department concluded that approval of a permit did require the preparation of an EIS.[47] Analysis included in the EIS is intended to identify any significant impact of the proposed pipeline, including anticipated impacts of taking no action (e.g., denying the permit) and potential mitigation measures or protections necessary to reduce the potential for adverse environmental impacts. DOS uses that assessment of environmental impacts, with other factors, to determine if the project does, in fact, serve the national interest.

Identification of Environmental Impacts During the NEPA Process[48]

The DOS review of a Presidential Permit application explicitly requires compliance with multiple federal environmental statutes.[49] Environmental requirements identified within the context of the NEPA process have drawn considerable attention.

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[45] TransCanada Keystone Pipeline, L.P., "Application of TransCanada Keystone Pipeline L.P. for a Presidential Permit Authorizing the Construction, Operation, and Maintenance of Pipeline Facilities for the Importation of Crude Oil to be Located at the United States-Canada Border," U.S. Dept. of State, May 4, 2012, pp. 1-2, available at http://www.keystonepipeline-xl.state.gov/.

[46] 42 U.S.C. §4332(2)(C).

[47] U.S. Department of State, "Notice of Intent to Prepare a Supplemental Environmental Impact Statement (SEIS) and To Conduct Scoping and To Initiate Consultation Under Section 106 of the National Historic Preservation Act for the Proposed TransCanada Keystone XL Pipeline Proposed To Extend From Phillips, MT (the Border Crossing) to Steele City, NE," 77 *Federal Register* 36032, June 15, 2012.

[48] For more detailed NEPA information, see CRS Report RL33152, *The National Environmental Policy Act (NEPA): Background and Implementation*, by (name redacted).

[49] DOS is explicitly directed to review the project's compliance with the National Historic Preservation Act (16 U.S.C. §470f), the Endangered Species Act (16 U.S.C. §1531 et seq.), and Executive Order 12898 of February 11, 1994 (59 *Federal Register* 7629), concerning environmental justice.

Pursuant to NEPA, when considering an application for a Presidential Permit, DOS must take into account environmental impacts of a proposed facility and directly related construction. The EIS for the proposed Keystone XL Pipeline project identifies significant impacts associated with the construction, connection, operation, and maintenance of the pipeline and its associated facilities. In August 2011, DOS issued a final EIS that identified reasonably foreseeable impacts associated with approving or denying a permit for the Keystone XL pipeline, as proposed in 2008.[50] On January 31, 2014, DOS released the final EIS prepared for the 2012 permit application.

EIS preparation is done in two stages, resulting in a draft and final EIS. NEPA regulations require the draft EIS to be circulated for public and agency comment, followed by a final EIS that incorporates those comments.[51] The agency responsible for preparing the EIS, in this case DOS, is designated the "lead agency." In developing the EIS, DOS must rely on information provided by TransCanada. For example, TransCanada's original permit application included an Environmental Report which was intended to provide the State Department with sufficient information to understand the scope of potential environmental impacts of the project.[52]

In preparing the draft EIS, the lead agency must request input from "cooperating agencies," which include any agency with jurisdiction by law or with special expertise regarding any environmental impact associated with the project.[53] The original Keystone XL permit process involved 11 federal cooperating agencies, including the Environmental Protection Agency (EPA), as well as state agencies. **Table A-1** (in the **Appendix**) provides a list of various agencies and their roles in the pipeline permitting process.

In addition to its role as a cooperating agency, EPA is also required to review and comment publicly on the EIS and rate both the adequacy of the EIS itself and the level of environmental impact of the proposed project.[54] EPA's role in rating draft EISs for the Keystone XL pipeline project had a significant impact on the NEPA process for TransCanada's 2008 Presidential Permit application.[55]

[50] In preparing an EIS associated with a Presidential Permit application, NEPA regulations promulgated by both the Council of Environmental Quality (CEQ) and the State Department would apply to the proposed project. CEQ regulations implementing NEPA (under 40 C.F.R. §§1500-1508) apply to all federal agencies. NEPA regulations applicable to State Department actions, which supplement the CEQ regulations, are found at 22 C.F.R. §161.

[51] For information regarding NEPA requirements, see CRS Report RL33152, *The National Environmental Policy Act (NEPA): Background and Implementation*, by (name redacted).

[52] Documents submitted by TransCanada for its initial 2008 Presidential Permit application, now archived by DOS, are available at http://keystonepipeline-xl.state.gov/archive/proj_docs/index.htm.

[53] 40 C.F.R. §1508.5. Also, Executive Order 13337 directs the Secretary of State to refer an application for a Presidential Permit to other specifically identified federal departments and agencies on whether granting the application would be in the national interest.

[54] Rating the EIS takes place after the draft is issued. The EIS could be rated either "Adequate," "Insufficient Information," or "Inadequate." EPA's rating of a project's environmental impacts may range from "Lack of Objections" to "Environmentally Unsatisfactory." In rating the impact of the action itself, EPA would specify one of the following: "Lack of Objections," "Environmental Concerns," "Environmental Objections," or "Environmentally Unsatisfactory." The federal agency would then be required to respond to EPA's rating, as appropriate. For more information, see the U.S. Environmental Protection Agency's "Environmental Impact Statement (EIS) Rating System Criteria" at http://www.epa.gov/compliance/nepa/comments/ratings.html.

[55] Issues associated with the NEPA process for the 2008 permit application are detailed in CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted) et al.

On March 1, 2013, the State Department released the draft EIS for the 2012-proposed Keystone XL Pipeline project as a supplement to the final EIS prepared for the 2008 Presidential Permit application (released in August 2011).[56] In contrast to EISs prepared for the 2008 permit application, EISs prepared for the 2012 permit application evaluated potential impacts associated with a pipeline route from Montana to Steele City, NE, that avoids the Nebraska Sand Hills and excludes the proposed Gulf Coast Project. The EISs expand upon and update information included in the 2011 final EIS prepared for the 2008 permit application.

EPA provided comments on the draft EIS for the 2012 permit application.[57] It rated the draft EIS as "EO-2" (Environmental Objections—Inadequate Information). EPA stated that, while the agency believes the draft EIS strengthens the analysis presented to date in the NEPA process, it recommended several improvements to the analysis of the proposed project's impacts and to mitigate certain impacts. The recommendations for improvements to the EIS fell broadly into categories regarding the analyses of GHGs, pipeline safety, alternative pipeline routes, and community and environmental justice impacts.

On January 31, 2014, the State Department released the final EIS for the 2012 permit application. Any additional or revised analysis included in the final EIS reflects DOS's response to comments from the public, EPA, and any federal, state, tribal, or local agency. With the release of the final EIS, DOS begins the process to determine whether the project will serve the national interest.

Identification of Environmental Impacts During the National Interest Determination

Generally, the NEPA process is considered complete when (or if) the federal agency issues a final Record of Decision (ROD), formalizing the selection of a project alternative. However, for a project subject to a Presidential Permit, issuance of a final EIS marks the beginning of the DOS process to make its national interest determination. For previous Presidential Permits, a ROD and National Interest Determination (NID) were issued as the same document.[58]

With the publication of the final EIS, the process to make the NID begins. As required in Executive Order 13337, DOS will seek input from selected federal agencies to determine whether issuance of a Presidential Permit for the pipeline would serve the national interest. Those agencies have 90 days to submit relevant information to DOS. DOS also provided a 30-day public comment period, ending on March 7, 2014.

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[56] See U.S. Department of State, "New Keystone XL Pipeline Application" webpage at http://www.keystonepipeline-xl.state.gov/. On March 8, 2013, EPA listed the draft EIS in its weekly "Environmental Impacts Statements; Notice of Availability," in the *Federal Register,* see 78 *Federal Register* 15012. DOS refers to the EIS released in March 2013 as a "Draft Supplemental" EIS. This reference apparently reflects the fact that the 2013 draft EIS draws largely from (or supplements) documentation and analysis included in the final EIS issued in 2011 for the project proposed in the 2008 Presidential Permit application. However, for purposes of NEPA compliance, the submission of a new permit application in May 2012 started the NEPA process anew. While it may draw from the 2011 final EIS, the 2013 draft EIS is a new NEPA document—not a supplement to an EIS prepared for a different, albeit similar, Presidential Permit application.

[57] Letter from the U.S. Environmental Protection Agency's Cynthia Giles, Assistant Administrator for Enforcement and Compliance Assurance to Jose Fernandez and Kerri-Ann Jones, Assistant Secretaries, U.S. Department of State, available online at http://epa.gov/compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf.

[58] U.S. Department of State, *Department of State Record of Decision and National Interest Determination, TransCanada Keystone Pipeline, LP Application for Presidential Permit*, February 25, 2008.

Issuance of the ROD and NID involve distinctly different, but interrelated requirements. Under NEPA, DOS must fully assess the environmental consequences of an action and potential project alternatives *before* making a final decision. NEPA does not prohibit a federal action that has adverse environment impacts; it requires only that a federal agency be fully *aware of* and *consider* those adverse impacts before selecting a final project alternative. That is, NEPA is intended to be part of the decision-making process, not dictate a particular outcome.

The NID, however, does dictate a particular outcome—approval or denial of a Presidential Permit. Issuance of a Presidential Permit is predicated on the finding that the proposed project would serve the national interest. While NEPA does not prohibit federal actions with adverse environmental impacts, a project's adverse environmental impacts may lead the DOS to determine that the project is not in the national interest. To illustrate the relationship between the NEPA process and NID process, **Table 2** summarizes milestones in the Presidential Permit process for TransCanada's 2008 and 2012 permit application.[59]

[59] A more comprehensive timeline is provided in CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted) et al.

Table 2. National Interest Determination Milestones for the Keystone XL Pipeline

Administrative, Congressional, State, and Company Actions

Date	Description
2011	
August 26	DOS issues its FEIS for the 2008 permit application, starting the NID 90-day public review period.
October 24	The governor of Nebraska calls the state legislature into a special session to determine if siting legislation can be crafted and passed for pipeline routing in Nebraska.
November 10	DOS announces that additional information will be needed regarding alternative pipeline routes that would avoid the Nebraska Sand Hills before National Interest Determination can be made.
November 14	TransCanada announces that it will work with the Nebraska Department of Environmental Quality (DEQ) to identify a potential pipeline route that would avoid the Nebraska Sand Hills.
November 22	The governor of Nebraska signs legislation passed during the special session directing the Nebraska DEQ to work collaboratively with the State Department to gather information necessary for a supplemental EIS.
December 23	The Temporary Payroll Tax Cut Continuation Act of 2011 (P.L. 112-78) is enacted, including provisions requiring the Secretary of State to issue a permit for the project within 60 days, unless the President determines the project is not in the national interest.
2012	
January18	DOS announces, with the President's consent, that it will deny the Keystone XL permit. It states that its decision was predicated on the fact that the 60-day deadline under P.L. 112-78 did not provide sufficient time to obtain information necessary to assess the current project's national interest.
February 3	DOS issues the formal permit denial in the *Federal Register* (Vol. 77, p. 5614), which included a Memorandum from the President stating that the project would, "at this time … not serve the national interest."
February 27	TransCanada announces that it will proceed with development of the southern pipeline segment as a separate proposal.
May 4	TransCanada submits a new Presidential Permit application to DOS, reflecting new information regarding alternative pipeline routes through Nebraska. The NEPA process for the new project begins, potentially drawing upon relevant documents from the 2011 final EIS.
June 15	DOS announces its plan to prepare an EIS for the 2012 Presidential Permit application, that will supplement information included in the 2011 final EIS (77 *Federal Register* 36032).
September 5	TransCanada submits a Supplemental Environmental Report to Nebraska DEQ with a preferred route alternative.
2013	
March 1	DOS releases draft EIS for the 2012 Keystone XL Pipeline project.
April 22	EPA submits its comments, rating the proposed project and draft EIS as "EO-2," meaning EPA has "Environmental Objections" to certain adverse project's impacts and that the draft EIS includes "Insufficient Information." EPA recommends action that could be taken to reduce certain adverse project impacts and additional analysis that should be included in the final EIS.
2014	
January 31	DOS releases the final EIS for the 2012 Keystone XL Pipeline project; DOS begins NID process, starting the 90-day time period for federal agencies to provide DOS with information to make its determination begins.
February 5	30-day public comment period begins, ending March 7th.

Source: Prepared by the Congressional Research Service. Permit-related documents available at, http://www.keystonepipeline-xl.state.gov/ and Nebraska DEQ website, at http://www.deq.state.ne.us/.

Consideration of Environmental Impacts Outside of the United States

NEPA does not require DOS to identify or analyze environmental impacts that occur within another sovereign nation that result from actions approved by that sovereign nation. However, to further the purpose of the NEPA, Executive Order 12114 "Environmental Effects Abroad of Major Federal Actions," requires federal agencies to prepare an analysis of significant impacts from a federal action abroad. This order does not, however, require federal agencies to evaluate the impacts of projects outside the United States when that project is undertaken with the involvement or participation of the foreign nation in which the project is undertaken—as is the case with Canada's participation in the Keystone XL pipeline project. While it is not subject to it, as a matter of policy, DOS uses the order as guidance and includes information in the final EIS regarding the environmental analysis conducted by the Canadian government.

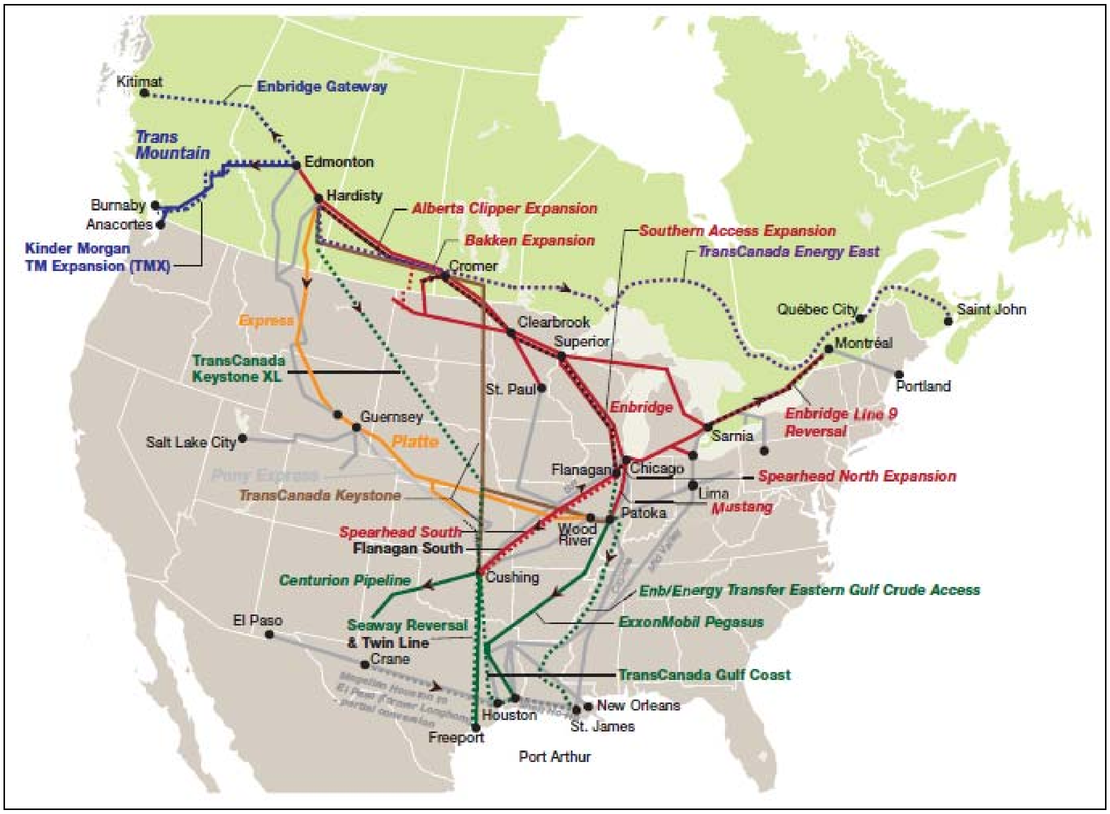
Apart from any obligation under NEPA, however, DOS may take into consideration extraterritorial project impacts, as it deems necessary, as part of its national interest determination. For example, as noted above, factors DOS considered in making its determination for past pipeline projects included the proposed project's impact on broader policy objectives, including a comprehensive strategy to address climate change, and the relationships between the proposed project and U.S. goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources. In its January 2012 denial of TransCanada's initial Presidential Permit application, DOS did not specifically cite these issues as playing a role in its determination. However, these issues continued to generate concern among some stakeholders. It is uncertain whether or the degree to which environmental impacts abroad will affect DOS's determination that the proposal will serve the national (i.e., U.S.) interest.

Other Oil Pipelines from Canada

As illustrated in **Figure 7**, multiple pipelines connect Canadian oil resources with the United States. Several of these pipelines have been constructed in recent years.

Figure 7. Oil Pipelines between Canada and the United States

Existing (Solid Lines) and Proposed (Dashed Lines)



Source: Canadian Association of Petroleum Producers, *Crude Oil: Forecast, Markets & Transportation*, June 2013.

Table 3 identifies pipelines that have applied for a Presidential Permit in the past six years. The table indicates that the Keystone XL permit process timetable, which is ongoing, has substantially exceeded prior permit process timetables.

Table 3. Major U.S.-Canadian Petroleum Import Pipelines

Presidential Permit Activity (2006-Present)

Pipeline	Operator	Permit Submitted	EIS Prepared?	Permit Issued	First Year of Operation	Capacity (bpd)
Southern Lights (LSr)[a]	Southern Lights	April 2007	No	June 2008	2009	186,000
Keystone[b]	TransCanada	April 2006	Yes	March 2008	2010	591,000
Alberta Clipper[c]	Enbridge	May 2007	Yes	August 2009	2010	450,000
Keystone XL[d]	TransCanada	September 2008	Yes	Denied January 2012	NA	830,000
Keystone XL[d]	TransCanada	May 2012	Final EIS issued January 2014		NA	830,000

Source: Prepared by CRS; pipeline status and capacity information from CAPP, 2011. More specific sources identified below.

a. 72 *Federal Register* 41383, July 27, 2007; 73 *Federal Register* 32620, June 9, 2008.

b. DOS website, at http://www.keystonepipeline.state.gov.

c. DOS website, at http://www.albertaclipper.state.gov.

d. DOS website, at http://www.keystonepipeline-xl.state.gov.

When DOS issued the Presidential Permit for the first Keystone pipeline project in 2008, DOS concluded that the project "would result in limited adverse environmental impacts" and would serve the national interests of the United States for the following reasons:

> It increases the diversity of available supplies among the United States' worldwide crude oil sources. Increased output from the [Western Canada Sedimentary Basin] can be utilized by a growing number of refineries in the United States that have access and means of transport for these increased supplies.
>
> It shortens the transportation pathway for a portion of United States crude oil imports. Crude oil supplies in Western Canada represent the largest and closest foreign supply source to domestic refineries that do not require marine transportation.
>
> It increases crude oil supplies from a source region that has been a stable and reliable trading partner of the United States and does not require exposure of crude oil in high seas transport and railway routes that may be affected by heightened security and environmental concerns.

> It provides additional supplies of crude oil to make up for the continued decline in imports from several other major U.S. suppliers.[60]

Some stakeholders may point to these statements as reasons to issue a Presidential Permit to the XL proposal.

Section 3: Selected Environmental Issues

Environmental issues related to the Keystone XL pipeline and the oil sands crude oil it would carry cover a wide spectrum. These issues involve both local/regional concerns—some in the United States, some in Canada—and national/global concerns. This section does not provide an exhaustive list of environmental issues. Instead, this section discusses several key issues, including the following:

- greenhouse gas emissions intensity;
- climate change policy;
- oil spill risk; and
- oil sands extraction impacts.

GHG Emissions Intensity of Oil Sands Crude Oils[61]

Greenhouse gas (GHG) emissions, primarily carbon dioxide (CO_2) and methane, are emitted during a variety of stages in oil sands production. Although all fossil fuel development activities—and other forms of energy to varying degrees—emit GHG emissions, some have raised concern that oil sands have a higher emissions intensity than other forms of crude oil.[62] In this context, emissions intensity means GHG emissions per units of production (e.g., barrels).

Other stakeholders, including the Alberta government and industry associations, argue that this conclusion is overstated, asserting that GHG emissions from oil sands crude oil are comparable to some other global crudes, some of which are produced and/or consumed in the United States.[63] The issue has generated considerable debate, attention, and analyses from multiple parties.

This section (1) describes the tool—life-cycle assessments—used for comparisons; (2) discusses the oil sands life-cycle assessment results; and (3) compares oil sands emissions intensities with other crude oils.

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[60] DOS, *Record of Decision and National Interest Determination, Keystone Pipeline*, 2008, at http://www.cardnoentrix.com/keystone/project/SignedROD.pdf.

[61] This section is an abridged version of CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).

[62] See, e.g., NRDC, *Setting the Record Straight: Lifecycle Emissions of Tar Sands*, November 2010.

[63] See e.g., Alberta Government "Oil Sands" website, at http://oilsands.alberta.ca/ghg.html; and Canadian Association of Petroleum Producers, *The Facts on Oil Sands*, April 2012, at http://www.capp.ca.

Life-Cycle Assessments

A life-cycle assessment (LCA) is an analytic method used for evaluating and comparing the environmental impacts of various products.[64] LCAs can be used to identify, quantify, and track emissions of CO_2 and other GHG emissions arising from the development of hydrocarbon resources, and to express them in a single, universal metric: carbon dioxide equivalent (CO_2e) per unit of fuel or fuel use.[65] The results of an LCA can be used to evaluate the GHG emissions intensity of various stages of the fuel's life cycle, as well as to compare the emissions intensity of one type of fuel or method of production to another.

GHG emissions profiles modeled by most LCAs are based on a set of boundaries commonly referred to as "cradle-to-grave," or, in the case of transportation fuels such as petroleum, "Well-to-Wheel" (WTW). WTW assessments for petroleum-based transportation fuels focus on the emissions associated with the entire life cycle of the fuel. This includes

- extraction;
- transportation;
- upgrading and/or refining;
- distribution of refined product (e.g., gasoline, diesel, jet fuel); and
- combustion of the fuel.

Inclusion of the final combustion phase allows for the most complete picture of crude oil's impact on GHG emissions, as this phase can contribute up to 70%-80% of WTW emissions. However, other LCAs, such as well-to-tank (WTT) assessments, may focus solely on production and/or extraction.

Both study types are valid, but they tell different stories. Focusing on the WTT assessment would show oil sands crudes' emissions intensities to be considerably higher than conventional oils, because the assessment is weighted more proportionally to the production phase. Focusing on the WTW assessments returns values for the emission intensity differences which are less pronounced due to the inclusion of the combustion phase.

GHG Life-Cycle Assessments of Canadian Oil Sands

A number of published and publicly available studies have attempted to assess the life-cycle GHG emissions data for Canadian oil sands crudes. The studies examined in this report include the LCAs analyzed by DOS in its 2014 FEIS. A CRS survey of these studies reveals the following:

1. Canadian oil sands crudes are generally more GHG emission-intensive than other crudes they may displace in U.S. refineries, emitting an estimated 17% more

[64] For a discussion of LCAs and biofuels, see (archived) CRS Report R40460, *Calculation of Lifecycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)*, by (name redacted) and (name redacted).

[65] Greenhouse gases include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), among many others. In order to compare and aggregate different greenhouse gases, various techniques have been developed to index the effect each greenhouse gas has to that of carbon dioxide, where the effect of CO_2 equals one. When the various gases are indexed and aggregated, their combined quantity is described as the CO_2-equivalent.

GHGs on a life-cycle basis than the average barrel of crude oil refined in the United States;

2. compared to selected crude oil imports, Canadian oil sands crudes emit an estimated 2%-19% more GHGs on a life-cycle basis (well-to-wheels (WTW)); and
3. they emit an estimated 9%-102% more GHGs on a well-to-tank (WTT) basis, which omits the combustion phase.

These dramatically different ranges highlight the importance of LCA boundaries and data presentation. When a comparison is expressed on a WTT basis rather than on a WTW basis, GHG emissions from Canadian oil sands crudes show values that are significantly higher than reference crudes. This difference is due to the omission of the combustion phase, which generates the vast majority of GHG emissions and generally yields minimal variance among different crude oils.

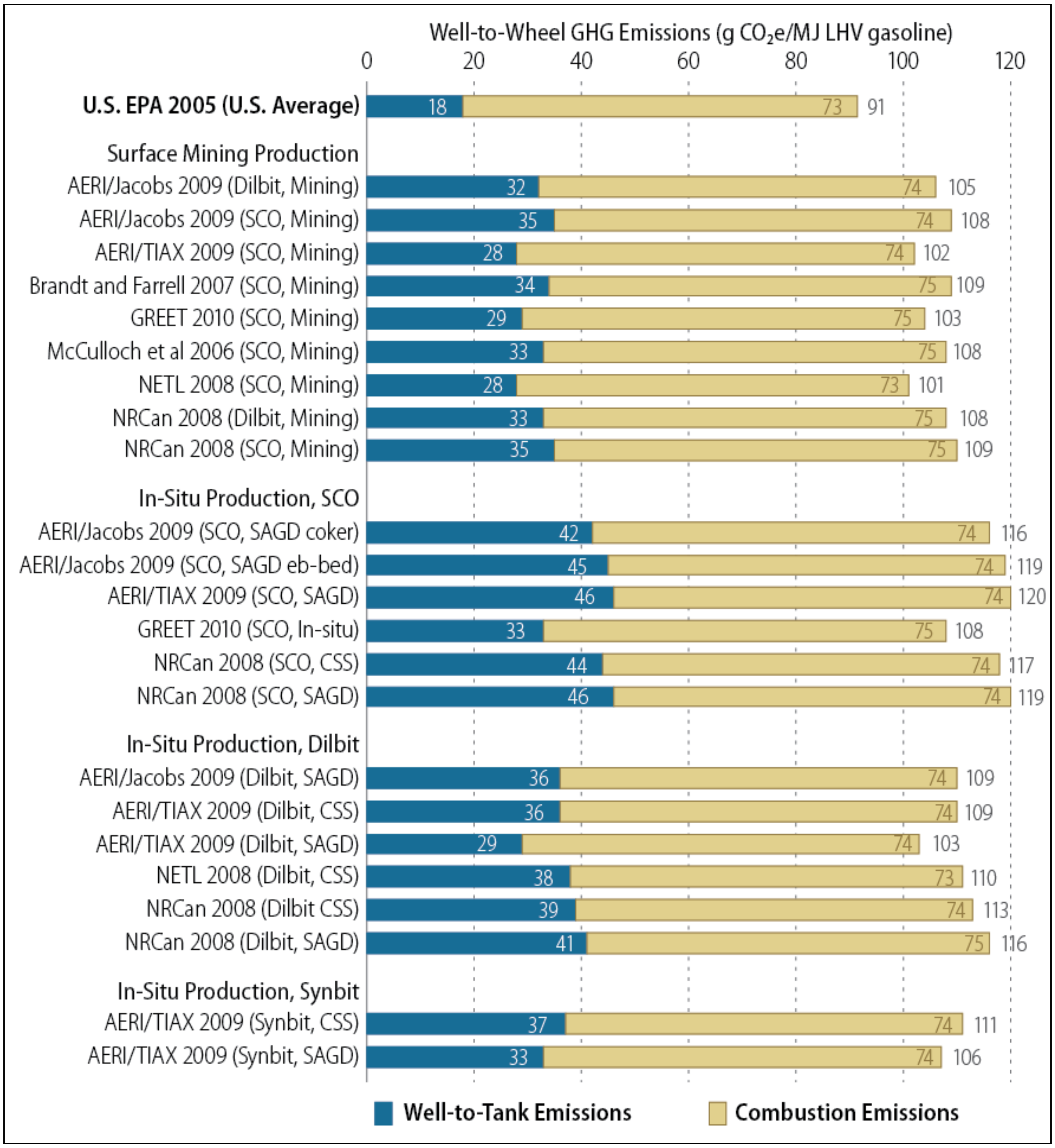
The studies identify two main reasons for the range of increases in GHG emissions intensity:

- oil sands are heavier and more viscous than lighter crude oil types on average, and thus require more energy- and resource-intensive activities to extract; and
- oil sands are compositionally deficient in hydrogen, and have a higher carbon, sulfur, and heavy metal content than lighter crude oil types on average, and thus require more processing to yield consumable fuels by U.S. standards.

Figure 8 presents a summary of the WTW GHG emissions estimates for various Canadian oil sands crude types and production processes as reported by several studies. Variability among the estimates is the result of each study's design and input assumptions.[66]

[66] Discussed in detail in CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).

Figure 8. Well-to-Wheel GHG Emissions Estimates for Canadian Oil Sands Crudes



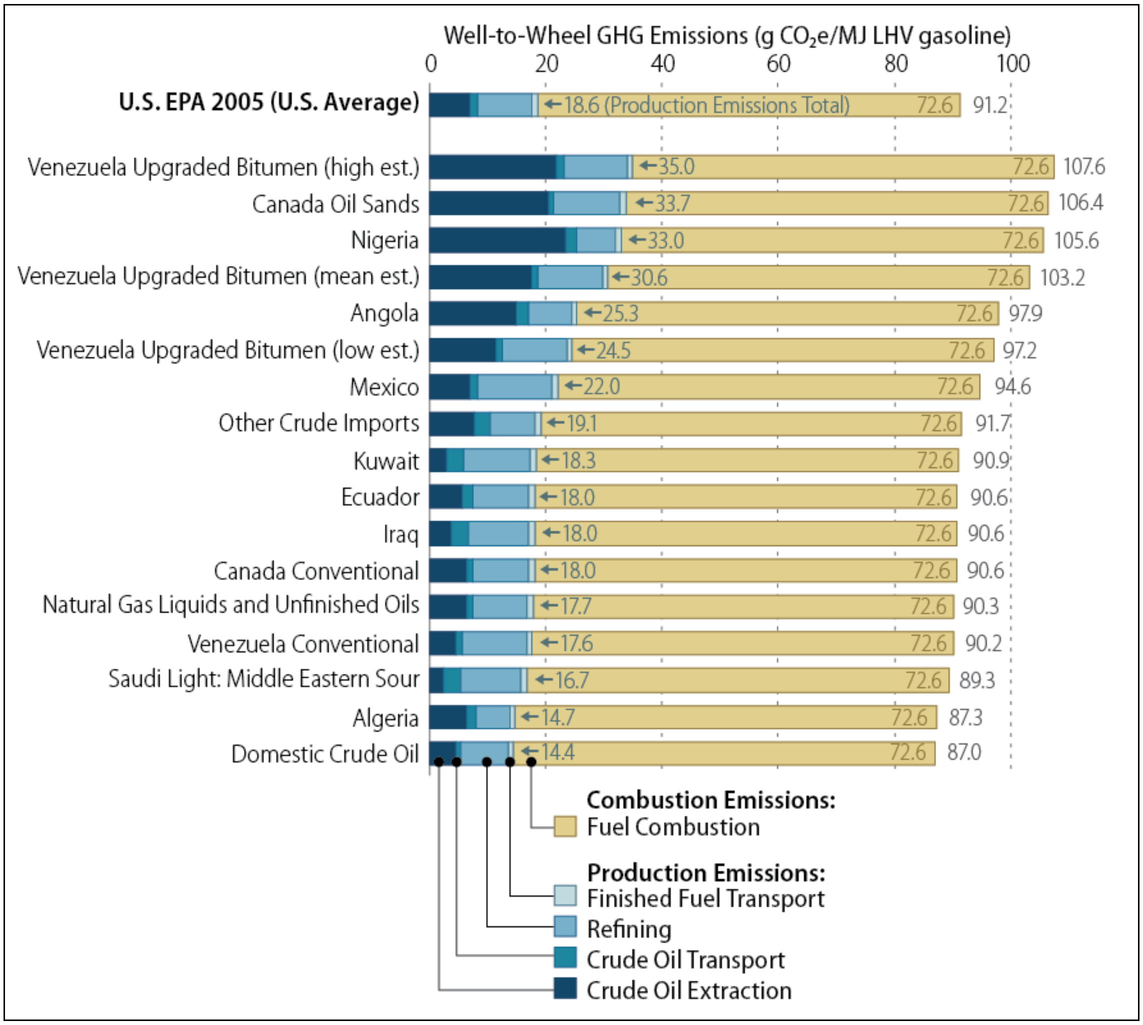
Source: CRS, from studies cited in CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted). Average U.S. petroleum baseline for 2005 provided by U.S. Environmental Protection Agency (U.S. EPA), *Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis*, February 2010, EPA-420-R-10-006, with data sourced from DOE/NETL, *Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels*, November 2008.

Notes: Emission intensity measured in grams of carbon dioxide-equivalent per megajoule of lower heating value gasoline (gCO2e/MJ LHV). U.S. EPA 2005 (U.S. Average) assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). This baseline includes Canadian oil sands, but does not include emissions from some of the most carbon-intensive imported crude oils (e.g., Venezuelan Heavy) due to modeling uncertainties (NETL 2008, p. ES-7; NETL 2009, p. ES-2). For information on crude oil types and production processes, see CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).

Canadian Oil Sands Compared to Other Crude Oils

Many of the LCA studies examined by DOS compared the GHG emission intensity of Canadian oil sands crude oil to other crude oils. **Figure 9** presents the results of one of the more comprehensive studies, which was prepared by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) in 2009. NETL compared WTW GHG emissions of reformulated gasoline across various crude oil feedstocks. NETL concluded that WTW GHG emissions from gasoline produced from a weighted average of Canadian oil sands crudes are approximately 17% higher than that from gasoline derived from the average mix of crudes sold or distributed in the United States in 2005 (**Figure 9**). This corresponds to an increase in WTT (i.e., "production") GHG emissions of 80% over the 2005 average production emissions for imported transportation fuels to the United States (18 gCO_2e/MJ).

Figure 9. Well-to-Wheel GHG Emissions Estimates for Global Crude Resources



Source: CRS, from NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions*, National Energy Technology Laboratory, March 27, 2009.

Note: For further details concerning this figure and the NETL study, see CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).

Similar to the LCAs of Canadian oil sands crudes, assessments of other global crude oil resources are bounded by specific design factors and input assumptions that can affect the results.[67]

Parties from both sides of the issue may be able to use results from one or more of the above studies to advance their positions. For example, some stakeholders often use WTT comparisons to highlight the GHG emissions intensity of the oil sands extraction process. On the other hand, other groups often point out that the GHG emissions intensity of oil sands is comparable to other heavy crudes that are used and/or produced in the United States. Both assertions are supported by the analyses, but the above results suggest that these assertions may not tell the complete story.

The data underlying the assertions are generated by conducting LCAs. Although LCAs have emerged as an important analytical tool for comparing the GHG emissions of various hydrocarbon resources, LCAs retain many variables and uncertainties. The life-cycle of hydrocarbon fuels is complex and differs by fuel. LCAs rely on a large number of analytical design features that are needed to model their emissions. As noted above, certain factors that could alter the results (e.g., land use changes and combustion of co-products) may be omitted, due, in part, to their additional complexity. Therefore, comparing results across resources or production methods may be problematic.

GHG Emissions Intensities of Fossil Fuels

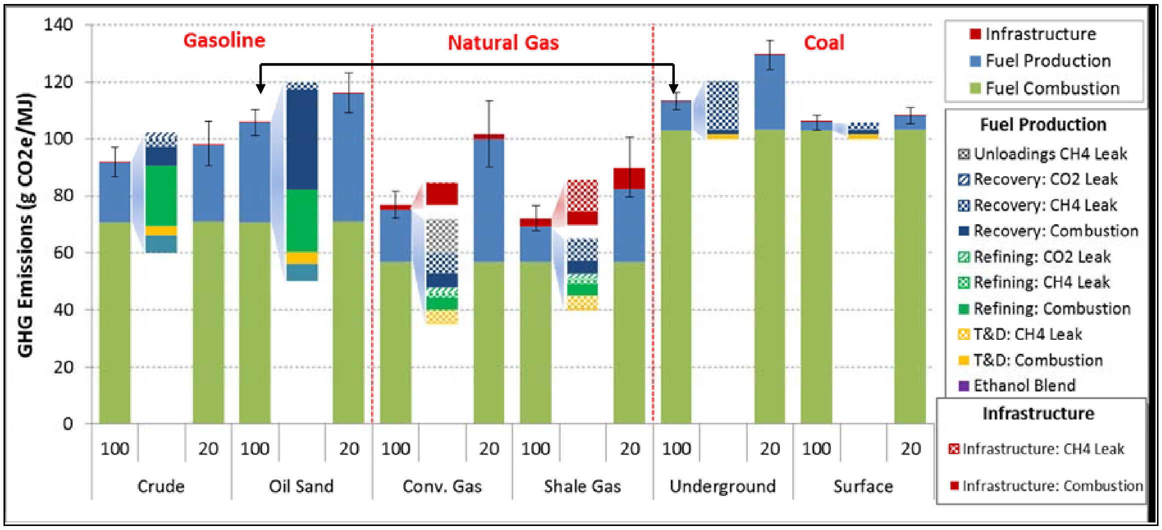
How does the GHG emissions intensity of oil sands compare to other fossil fuels, particularly coal? Authoritative analyses that provide such comparisons are sparse. One study from a peer-review journal compares the GHG emissions intensity of oil sands with other fossil fuels. The study found that oil sands crude oil emissions intensity is slightly less than emissions intensity from underground coal mining, but surpasses the life-cycle emissions intensity from surface coal mining. **Figure 10** illustrates this result. CRS added the line with the arrows to focus one's attention on the comparison described above.

One must be cautious when singling out oil sands crudes, because other heavy crude oils would also be comparable to coal's emissions intensity, as indicated in **Figure 9**. Regardless, the relative comparison in **Figure 10** may draw the attention of certain stakeholders. If heavier crudes, such as those derived from oil sands, were to replace crude oils in the United States with less GHG emissions intensity, the emissions intensity of the U.S. energy portfolio would—all things being equal—increase. Such a result would make GHG emissions reductions more difficult.

[67] These are discussed in detail in CRS Report R42537, *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions*, by (name redacted).

Figure 10. Life-Cycle GHG Emissions Estimates for Gasoline, Natural Gas, and Coal

GHG Emissions for Global Warming Potentials of 20 and 100 years



Source: Prepared by CRS from Burnham, A., et al, "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum," *Environmental Science and Technology*, Vol. 46, 2012, pp. 619-627.

Note: The source article included both the 20 and 100 year time horizons for comparison purposes. The effects of short-lived GHGs, such as methane, are more pronounced in the 20-year time horizon. Most researchers use the 100-year horizon and the Intergovernmental Panel on Climate Change recommends using the longer time horizon. CRS added the line with the two arrows that connects the oil sands emission intensity with the underground coal mining emission intensity.

Climate Change Concerns

During a June 2013 speech, President Obama stated that an evaluation of the "net effects of the pipeline's impact on our climate" would factor into the State Department's national interest determination in order to determine if the project would "significantly exacerbate the problem of carbon pollution."[68] Therefore, the 2014 FEIS GHG emission and climate change discussion has generated considerable debate among stakeholders. The first section below discusses the DOS analysis in its 2014 FEIS of GHG emissions related to the proposed pipeline and potential climate change impacts.

The second section discusses oil sands development and its potential impact on the so-called "global carbon budget." Many stakeholders have raised concerns that the pipeline's approval would facilitate further development of oil sands, a potential outcome, they argue, that runs counter to maintaining a specific carbon budget.

The 2014 FEIS GHG and Climate Change Analysis

Among the various impacts identified in the project's environmental impact statement are those involving GHG emissions. As required under NEPA, the 2014 FEIS identifies anticipated direct and indirect impacts of the project as proposed by TransCanada as well as various project

[68] White House, "Remarks by the President on Climate Change," Georgetown University, Washington, DC, June 25, 2013, http://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change.

alternatives, including analysis of the "no action alternative" (i.e., an assessment of the impacts associated with denying TransCanada's permit application). The 2014 FEIS finds the following:[69]

- the GHG emissions released during the construction period for the project would be approximately 0.24 million metric tons of carbon dioxide equivalents ($MMTCO_2e$)[70] due to land use changes, electricity use, and fuels for construction vehicles (equivalent to 0.004% of U.S. annual GHG emissions);[71]
- the GHG emissions released during normal operations would be approximately 1.44 $MMTCO_2e$/year due to electricity use for pumping stations, fuels for maintenance and inspection vehicles, and fugitive emissions (equivalent to 0.02% of U.S. annual GHG emissions);
- the total, or gross, life-cycle GHG emissions (i.e., the aggregate GHG emissions released by all activities from the extraction of the resource to the refining, transportation, and end-use combustion of refined fuels) attributable to the oil sands crude transported through the proposed pipeline would be approximately 147 to 168 $MMTCO_2e$ per year (equivalent to 2.2%-2.6% of U.S. annual GHG emissions);
- the incremental, or net, life-cycle GHG emissions (i.e., GHG emissions over-and-above those from the crude oils expected to be displaced in U.S. refineries) is estimated to be 1.3 to 27.4 $MMTCO_2e$ per year (equivalent to 0.02%-0.4% of U.S. annual GHG emissions); but
- according to the State Department's market analysis, "approval or denial of any one crude oil transport project, including the proposed project, is unlikely to significantly impact the rate of extraction in the oil sands or the continued demand for heavy crude oil at refineries in the United States based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios."[72]

The 2014 FEIS presents the crude oil market analysis separately from the GHG emissions assessment. By determining that the most likely scenario is one in which oil sands production would be unaffected by expected market conditions, the Final EIS implies that the "incremental" life-cycle GHG emissions attributable to the oil sands crudes transported through the proposed pipeline are negligible. With this determination, the only difference in estimates between competing scenarios would be attributable to the operational GHG emissions of the alternative modes of transportation (e.g., GHG emissions from rail cars, trucks, or tankers versus the pipeline). The FEIS reports that the annual operational emissions attributed to the "no action"

[69] 2014 FEIS, pp. ES-15, ES-16, 4.14-39.

[70] "Carbon dioxide equivalent" is a metric used to compare emissions of various greenhouse gases based upon their global warming potential as indexed against one unit of carbon dioxide.

[71] EPA reports that total domestic GHG emissions for all sectors in 2012 to be 6,502 $MMTCO_2e$. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2012,* http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[72] Final EIS, p. ES-16. The State Department bases its analysis primarily on three market projections: (1) the crude oil input mix at Gulf Coast refineries remains constant, (2) rail and other non-pipeline transport options would fully accommodate all projected growth in oil sands production, and (3) at no point would the global price of oil fall—or the marginal cost of production increase—far enough that investment in new oil sands projects would be deemed uneconomical (i.e., below the breakeven cost of production).

alternatives range from 4.0 to 4.4 $MMTCO_2e$ per year (an increase of 29%-42% over the 3.1 $MMTCO_2e$ per year in operational emissions for the proposed project inclusive of the existing southern leg).

Some stakeholders have questioned many of the conclusions in the 2014 FEIS and argue that the project may have greater climate change impacts than the DOS projects. They contend that there is nothing presumed or inevitable about the rate of expansion for the Canadian oil sands.[73] Current oil sands projects face a challenging financial environment, and up-front production costs and price differentials are comparatively higher for oil sands crudes, making new investment sensitive to changes in supply costs and global prices. Commentators have highlighted the many reported instances where current price discounts for oil sands crudes have dampened investment and project development, including questions about whether rail transport will be used if the pipeline is not built.[74] They stress that oil market projections and transportation options are rife with uncertainty, and that the proposed Keystone XL Pipeline could have a much more significant impact on expansion if a number of key variables differ from the DOS assumptions. These variables include lower global oil prices than projected; higher rail costs than projected; higher new project costs than expected; greater competition from shale oil and tight oil plays; and future carbon pricing or procurement policies in the United States or Canada. Any decrease or delay in oil sands development could have significant impacts on the rate of growth in global GHG emissions both directly (by curtailing production)[75] and indirectly (by allowing more time for the development of energy-efficiency strategies, the promulgation of climate policies, and the deployment of lower-carbon energy technologies).

On the other hand, other stakeholders agree with a market analysis similar to the one outlined in the 2014 FEIS. They argue that as long as there is strong global demand for petroleum products, resources such as the Canadian oil sands will be produced and shipped to markets using whatever route necessary. They see future investment affected only in scenarios where the global price of oil falls below supply costs for an extended period of time. They see current production affected only in scenarios that assume all pipeline transport capacity is frozen and no other transport capacity (such as rail or tanker) is available.[76] They contend that incentives are too great for oil sands producers and the Canadian and Albertan governments to leave the oil in the ground; and that once the oil is extracted, the market would likely respond by adding adequate transport capacity over time. They contend that scaling up transport is logistically and economically feasible, based on past and present evidence in the Powder River Basin and the Bakken, as well

[73] See, for example, Natural Resources Defense Council et al., "Request for Supplemental Environmental Impact Statement for the TransCanada Keystone XL Pipeline Based on Significant New Information," Submitted to the U.S. Department of State, June 24, 2013; Oil Change International, "Cooking the Books: How The State Department Analysis Ignores the True Climate Impact of the Keystone XL Pipeline," April 2013; and Rep. Henry Waxman et al., "Letter to the Hon. Kerry-Ann Jones," Submitted to the U.S. Department of State, July 10, 2013.

[74] See for example, Canadian Imperial Bank of Commerce, "Too Much of A Good Thing: A Deep Dive Into The North American Energy Renaissance," Institutional Equity Research Industry Update, August 15, 2012; TD Economics, "Pipeline Expansion is a National Priority," Special Report, December 17, 2012; Goldman Sachs, "Getting the Oil Out of Canada: Heavy Oil Diffs Expected to Stay Wide and Volatile," June 2, 2013.

[75] As an example, the non-governmental organization Carbon Tracker Initiative has conducted a market analysis of forecasted supply costs and breakeven prices for Canadian oil sands projects. They estimate the cumulative GHG emissions from KXL-enabled "incremental production" through 2050 would be 5,145 to 5,880 MMTCO2e, http://www.carbontracker.org/kxl.

[76] Scenario results as indicated by the State Department's modeling in Ensys 2010 WORLD Model in the market analysis for the 2011 Final EIS as updated in the 2014 Final EIS.

as the oil sands region itself.[77] Furthermore, they estimate that GHG emissions intensities for the Canadian oil sands are currently within the range of many other heavy crude oils, and that in the future Canadian oil sands emissions intensities will only decrease (due to efficiency improvement and technological advances), while those of other crudes around the world will likely increase (due to a heavier resource base). They note also that the government of Alberta has implemented policies to help mitigate and reduce the GHG emissions associated with oil sands production. These include (1) a mandatory GHG intensity reduction program for large industrial emitters,[78] (2) a fund for clean energy investment that is capitalized by the reduction program, and (3) dedicated funding for the construction of large-scale carbon capture and sequestration (CCS) facilities.[79]

Keystone XL and the Global Carbon Budget

Some stakeholders are concerned with the effect that Canadian oil sands development would have on what is referred to as the "global carbon budget." The global carbon budget is a scientifically estimated maximum amount of net worldwide GHG that could be emitted without exceeding a proposed temperature target of 3.6°F above pre-industrial levels (a 2°C target). Some consider that such a temperature target would avoid the worst effects of greenhouse-gas induced climate change, and it has been agreed as a political consideration in international negotiations to address climate change under the United Nations Framework Convention on Climate Change. If this estimation is correct, all countries' emissions (net of any sequestration or "sinks") would have to stay within a given carbon budget to avoid exceeding the 2°C temperature cap. Based on studies published during the past several years, the International Energy Agency (IEA)[80] and the U.N. Intergovernmental Panel on Climate Change (IPCC),[81] among others, have estimated carbon budget scenarios. The IPCC finds that in order to have at least a 66% chance of limiting global warming to, or below, 2°C above pre-industrial levels, no more than 1 trillion tons of carbon can be released into the atmosphere from the beginning of the industrial era through the end of this century. The report estimates that 531 billion tons of that budget have been emitted as of 2011 and that current global GHG emissions are on track to reach the threshold in 2040. Similarly, the IEA estimates that "no more than one-third of proven reserves of fossil fuels can be consumed prior to 2050 if the world is to achieve the 2°C goal."

Some have argued that the DOS Final EIS does not properly consider the potential impact of using up the shared global carbon budget, estimating that the capacity of the proposed Keystone XL project is equivalent to the net oil production growth budgeted by the IEA for the entire

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[77] Reports by the two major rail operators in Canada, Canadian National (CN) and Canadian Pacific Railway System (CPRS), indicate crude and fuel oil car-loadings in Western Canada increased from nominal amounts in early 2011 to approximately 160,000 bpd by April 2013 (however, "not all of the crude oil loaded by rail in western Canada is necessarily exported to the United States," and "approximately half of the crude oil hauled by rail in western Canada was light, and half was heavy." Final EIS, pp. 1.4-52-56. Further, crude-by-rail loading facilities have expanded considerably in the past several years, with capacity expected to reach 720,000 bpd in WCSB by the end of 2014. Final EIS, p. 1.4-61. The analysis also determines that the expansion of rail network capacity and rail tank car fleets could be accommodated without encountering capacity issues. Final EIS, pp. 1.4-74, 1.4-80.

[78] See Government of Alberta, Climate Change and Emissions Management Amendment Act, http://www.qp.alberta.ca/574.cfm?page=2007_139.cfm&leg_type=Regs&isbncln=9780779738151.

[79] Government of Alberta, *Alberta's Oil Sands Fact Sheet: Carbon Capture and Storage*, http://www.oilsands.alberta.ca/FactSheets/Carbon_Capture_FSht_June_2012_Online.pdf.

[80] IEA, "World Energy Outlook," 2012, http://www.worldenergyoutlook.org/publications/weo-2012/.

[81] IPCC, Fifth Assessment Report (AR5), 2013, http://www.ipcc.ch/report/ar5/.

OECD Americas region.[82] Others have calculated that the GHG emissions from oil sands projects currently producing or under construction would themselves reach the 2°C threshold if all the oil sands resources were consumed.[83]

As with the assessment of incremental life-cycle GHG emissions, an understanding of the "incremental carbon budget" that can be attributable to the proposed Keystone XL pipeline would be dependent upon a market analysis that examines whether approval or denial of any one crude oil transport project, including the proposed project, would significantly impact the rate of extraction in the oil sands.[84] For example, if extraction is likely to occur regardless of whether the pipeline is built, then the approval or denial of the pipeline may have little effect on total net carbon emissions. Conversely, if oil sands extraction is dependent on the pipeline, then incremental carbon emissions could be high.

There is no political agreement in the United States on a domestic carbon budget, on the appropriateness of the global 2°C target, or on the validity of any target. Some stakeholders may contend that the project is such a large increment of emissions that it should be "the line in the sand" for making a climate-protective decision.[85] Conversely, others may argue that the project's share of incremental emissions is small and therefore not a significant addition of risk. Some policy makers may not be sure of where any lines should be drawn or whether the project is the "right" place to draw one, especially one drawn unilaterally by the United States.

Oil Spills

A primary environmental concern of any oil pipeline is the risk of a spill. Based on experience with pipelines historically, the Keystone XL pipeline will likely lead to some number of oil spills over the course of its operating life, regardless of design, construction, and safety measures. However, the frequency, volume, and location of spills are unknown. Some contend that oil spill risks are understated; others contend that pipeline risks are overstated.

Pipeline integrity concerns—whether real or perceived—were magnified by a 2010 pipeline spill in Michigan and a 2013 pipeline spill in Arkansas, both of which involved oil sands crude oil.[86] A

[82] Carbon Tracker Initiative, "KXL: The Significance Trap," March 2014, http://www.carbontracker.org/kxl.

[83] See Oil Change International, "Petroleum Coke," The Coal Hiding in the Tar Sands, January 2013, http://priceofoil.org/content/uploads/2013/01/OCI.Petcoke.FINALSCREEN.pdf; and James Hansen, "Game Over for the Climate," New York Times, May 9, 2012, http://www.nytimes.com/2012/05/10/opinion/game-over-for-the-climate.html?_r=0, who estimates that "Canada's tar sands … contain twice the amount of carbon dioxide emitted by global oil use in our entire history," and that "the concentration of carbon dioxide in the atmosphere has risen from 280 parts per million to 393 p.p.m. over the last 150 years. The tar sands contain enough carbon—240 gigatons—to add 120 p.p.m. ... If we turn to these dirtiest of fuels, instead of finding ways to phase out our addiction to fossil fuels, there is no hope of keeping carbon concentrations below 500 p.p.m.—a level that would, as earth's history shows, leave our children a climate system that is out of their control."

[84] If the project is considered in the context of this "global carbon budget," then it requires a close examination of the energy produced per ton of GHG emitted. The question that would be important to address in this context is whether the same investment can be made in another energy source (e.g., efficiency or domestic oil production) that results in less net GHG emissions per unit of energy delivered. Fundamentally the consideration of the project is being done in the context of an economic system that places no price on carbon.

[85] For example, see non-governmental advocacy organizational initiatives such as "Draw the Line," http://www.drawthelineattarsands.com/.

[86] A 2011 pipeline spill into the Yellowstone River in Montana also received attention, but that spill did not involve oil sands crude oil. On July 1, 2011, an ExxonMobil pipeline spilled approximately 63,000 gallons of crude oil into the

(continued...)

key question for policy makers is whether the Keystone XL would impose a greater or lesser risk of an oil spill than another oil pipeline. In particular, do the properties of oil sands crude oil entail a greater risk of a pipeline spill than other crude oils? If an oil spill occurs, how would an oil sands crude oil spill differ from other crude oil spills? In addition, how do the oil spill risks from a pipeline compare to other modes of oil transportation. These issues and other spill-related topics are discussed below.

Oil Sands Crudes and Pipeline Spills

Some environmental groups have argued that the pipeline would pose additional oil spill risks due to the material being transported. One vehicle for these arguments was a 2011 report from several environmental groups.[87] In that report, the authors asserted that certain characteristics of DilBit may pose greater risks of a spill than other crude oils. Other organizations, including Canadian agencies, questioned these conclusions.[88] To examine these issues, Congress enacted P.L. 112-90, which, among other provisions, directed the Secretary of Transportation to:

> complete a comprehensive review of hazardous liquid pipeline facility regulations to determine whether the regulations are sufficient to regulate pipeline facilities used for the transportation of diluted bitumen. In conducting the review, the Secretary shall conduct an analysis of whether any increase in the risk of a release exists for pipeline facilities transporting diluted bitumen.

Pursuant to that act, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) contracted with the National Academy of Sciences' National Research Council (NRC)[89] to conduct a study. In June 2013, the NRC issued a report (hereinafter, NRC report) that analyzed whether transportation of DilBit by pipelines poses an increased likelihood of release compared to other crude oils.[90] The central findings of the report included the following:

> The committee does not find any causes of pipeline failure unique to the transportation of diluted bitumen. Furthermore, the committee does not find evidence of chemical or physical

(...continued)

Yellowstone River. In an October 2012 report, PHMSA stated: "The cause of the release was determined to be a severed pipeline near the south shore of the Yellowstone River that occurred after a prolonged period of high runoff and flooding. Debris caught on the pipe over time increased the stresses until ultimately the critical stress of the pipe was exceeded." PHMSA Report available at http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Other%20files/ExxonMobil_HL_MT_10-2012.pdf.

[87] Anthony Swift et al., *Tar Sands Pipelines Safety Risks*, Joint Report by Natural Resources Defense Council, National Wildlife Federation, Pipeline Safety Trust, and Sierra Club, February 2011 (hereafter Swift et al., *Tar Sands Pipelines Safety Risks,* 2011); see also Anthony Swift et al., *Pipeline and Tanker Trouble: The Impact to British Columbia's Communities, Rivers, and Pacific Coastline from Tar Sands Oil Transport*, Joint Report by Natural Resources Defense Council, Pembina Institute, and Living Oceans Society, November 2011 (hereafter *Pipeline and Tanker Trouble*).

[88] See e.g., Energy Resources Conservation Board, Press Release, "ERCB Addresses Statements in Natural Resources Defense Council Pipeline Safety Report," February 2011; and Crude Quality Inc., *Report regarding the U.S. Department of State Supplementary Draft Environmental Impact Statement*, May 2011.

[89] Organized by the National Academy of Sciences in 1916, the National Research Council has become the principal operating agency of both the National Academy of Sciences and the National Academy of Engineering in providing services to the government, the public, and the scientific and engineering communities.

[90] National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 2013 (hereinafter, NRC report).

> properties of diluted bitumen that are outside the range of other crude oils or any other aspect of its transportation by transmission pipeline that would make diluted bitumen more likely than other crude oils to cause releases.[91]

The following sections discuss these and related issues in greater detail.

Corrosion

The 2013 NRC report describes internal pipeline corrosion as an electrochemical process that typically causes damage to the bottom of the pipeline when water is present. Some have argued that DilBit pipelines may be more likely to fail than other crude oil pipelines because the bitumen mixtures they carry are "significantly more corrosive to pipeline systems than conventional crude."[92] Crude oil properties of particular interest are acidity and sulfur content, which are discussed below.

Acidity

Crude oil acidity is generally measured by total acid number (TAN).[93] As indicated in **Table 1** (above) Canadian DilBit TANs range between 0.92 to 2.49. This range is generally higher than lighter crude oils, but comparable with other heavy oils.

It is well-established that the presence of naphthenic acids in high TAN crudes can considerably increase corrosion potential in the parts of refinery distillation units operating at high temperature—above 570ºF.[94] However, pipeline transportation of DilBit is expected to occur at much lower temperatures: the operating temperature for Keystone XL is expected to be between 42ºF and 135ºF.[95] Moreover, DilBit pipeline corrosion rates may not have a direct correlation with TAN values. There is evidence of more than 1,000 napthenic acid varieties with varying corrosivity, which may comprise a single TAN number.[96] TAN values depend upon the specific content and types of compounds in specific crudes—which may vary significantly from crude to crude.[97] Some testing of pipeline steels has shown that Canadian oil sands crudes exhibit "very low corrosion rates" despite high TAN numbers, in part because they contain other "inhibitor" compounds that reduce the corrosivity of the bitumen.[98] Therefore, it is uncertain whether refiners' experiences with corrosion from high TAN crudes can be directly extended to DilBit transmission pipelines.

Sulfur Content

[91] NRC report, p. 2.

[92] Swift et al., *Tar Sands Pipelines Safety Risks,* 2011

[93] TAN is the amount of potassium hydroxide (in milligrams) needed to neutralize the acid in one gram of oil.

[94] NRC report, 2013.

[95] 2014 FEIS, p. 3.13-15.

[96] See Anne Shafizadeh et al., "High Acid Crudes," Presentation to the Crude Oil Quality Group New Orleans Meeting, January 30, 2003, http://www.coqa-inc.org/20030130High%20Acid%20Crudes.pdf.

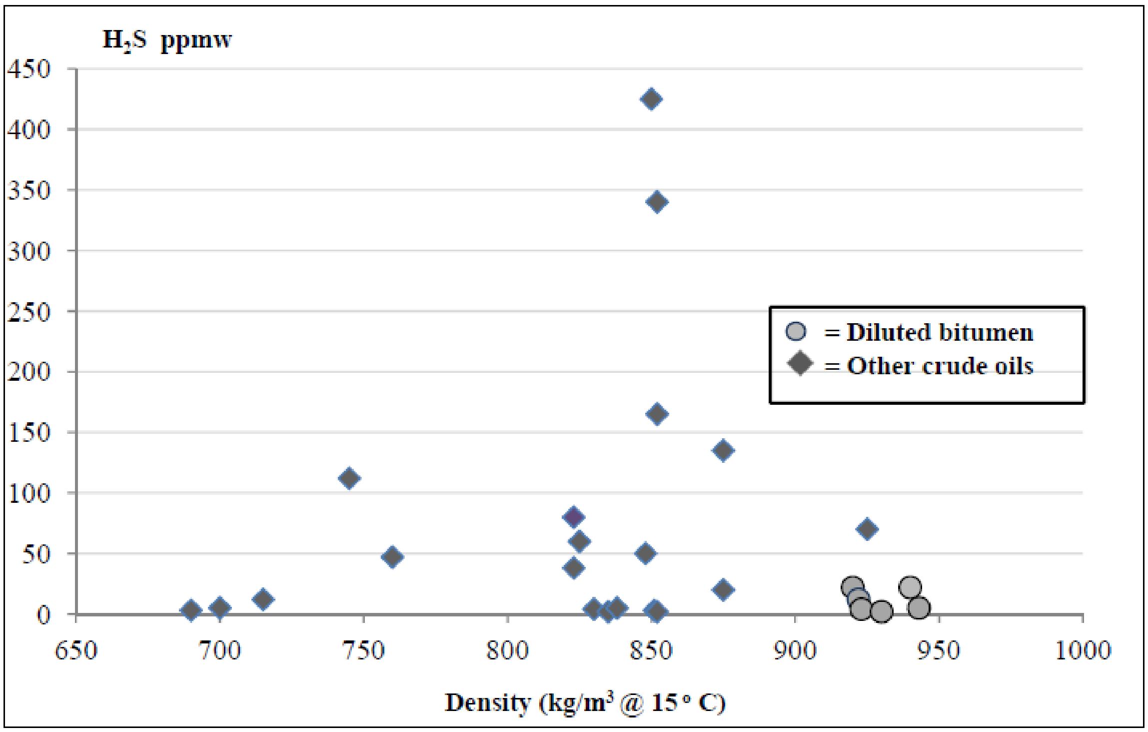
[97] Canadian Crude Quality Technical Association, TAN Phase III Project, Meeting Minutes of June 23, 2009, http://www.ccqta.com/docs/documents/Projects/TAN_Phase_III/TAN%20Phase%20III%20March%202009%20Minutes.pdf.

[98] Rena Liviniuk et al., "Organic Acid Structure—A Correlation With Corrosivity," AM-09-20, Presented to the National Petrochemical and Refiners Association, Annual Meeting, March 22-24, 2009, San Antonio, TX, p. 9.

Sulfur content may be another indicator of crude oil corrosivity. Crude oils sent to U.S. refineries typically contain 0.5% to 2.5% sulfur.[99] As indicated in **Table 1**, DilBits have sulfur contents substantially above this range—between 3% and 5%—as do other heavy crude oils. In some sour crudes (> 1% sulfur content), sulfur content may indicate hydrogen sulfide (H_2S),[100] which acts as a corrosive acid when dissolved in water.

However, the NRC report states that most of the sulfur in bitumen is contained in stable compounds, instead of the corrosive H_2S. **Figure 11** provides a comparison of H_2S content in selected DilBits with other crude oils. The figure indicates that (based on the samples tested) the DilBit samples contained relatively lower concentrations of H_2S than the other tested crude oils.

Figure 11. Content of Hydrogen Sulfide (H2S) in DilBits and Selected Crude Oils



Source: Reproduced from Reproduced by CRS from National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 201, Figure 3-9.

Notes: Data provided to the NRC by the Canadian Crude Quality Technical Association.

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[99] U.S. Energy Information Administration, "Crude Oil Input Qualities: Sulfur Content, Annual," Internet table, June 29, 2011, http://www.eia.gov/dnav/pet/pet_pnp_crq_a_EPC0_YCS_pct_a.htm.

[100] H_2S is generated at temperatures greater than 392°F (200°C) through a reaction between carbon-containing and sulfur-containing compounds in the crude. Thus, H_2S can be generated during the oil sands thermal extraction process. See G.G. Hoffmann et al., "Thermal Recovery Processes and Hydrogen Sulfide Formation," Presented at the Society of Petroleum Engineers International Symposium on Oilfield Chemistry, San Antonio, Texas, February 14-17, 1995.

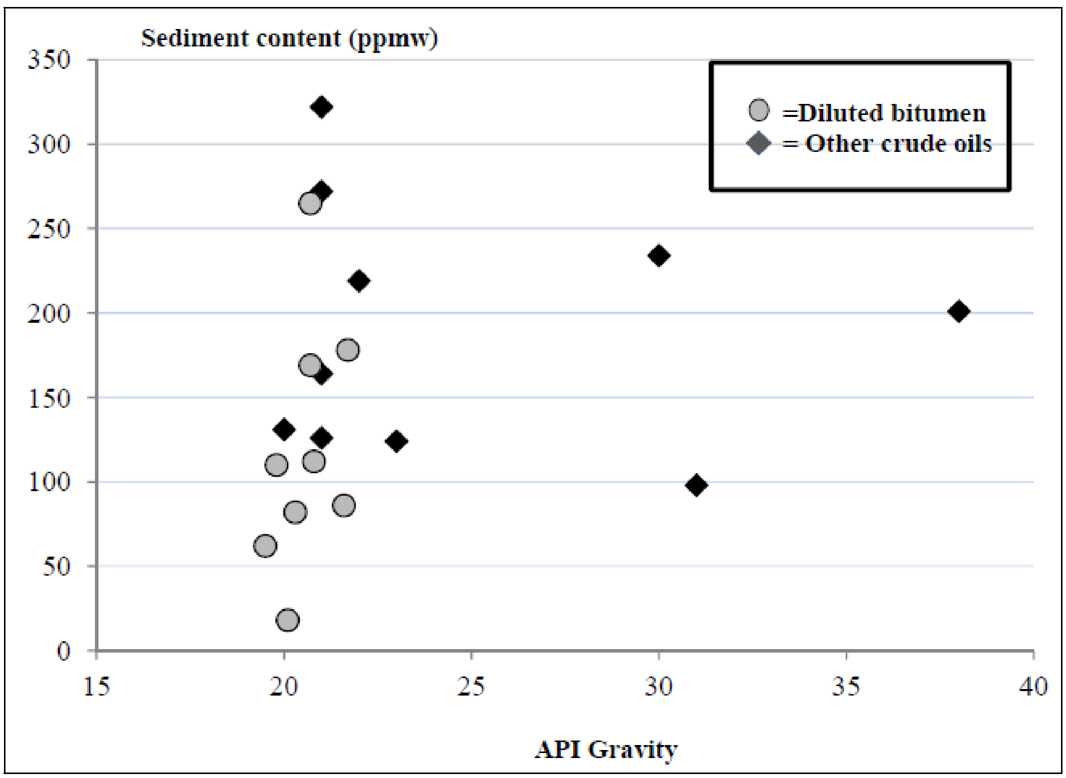
Erosion

In the context of pipeline transport, erosion is a mechanical process in which solid particles in the crude oil damage pipeline walls. Some have raised this process as a particular concern for DilBit pipelines.[101]

The 2013 NRC report compared the sediment contents in various DilBit blends with light, medium, and heavy Canadian crude oils. **Figure 12** illustrates the results of this comparison. As the figure indicates, the sediment contents in DilBit blends are similar to those in other Canadian crude oils.

Moreover, crude oils with high solids content are also generally filtered to meet the quality specifications set by pipelines and refiners. The 2013 NRC report points out that Canadian pipeline regulations require that sediment and water content in crude oil not exceed 0.5% by volume, while U.S. regulations allow ratios up to 1% by volume. Crude oil pipeline imports from Canada would be meeting the more stringent standards of Canada during their transit within the United States.

Figure 12. Sediment Content in DilBit Blends and Other Canadian Crude Oils



Source: Reproduced by CRS from National Research Council, *Effects of Diluted Bitumen on Crude Oil Transmission Pipelines*, 201, Figure 3-7.

Notes: Data in NRC figure obtained from CrudeMonitor, at http://www.crudemonitor.ca.

[101] Swift et al., *Tar Sands Pipelines Safety Risks,* 2011.

Volatility

According to the NRC report, a liquid that has a relatively high fraction of hydrocarbons with high vapor pressure can theoretically increase the potential for a process known as column separation—the transformation of the liquid into a vapor phase. Such an event can create a pressure surge, which can increase the potential for pipeline damage, if a pipeline is already weakened by corrosion, cracking, or deformities from earlier mechanical damage.[102]

During the 2011 EIS process, some contended that the "instability of DilBit can render pipelines particularly susceptible to ruptures caused by pressure spikes."[103] However, the NRC report stated that DilBit does not contain a high percentage of light (high vapor pressure) hydrocarbons and thus the potential for column separation "should be indistinguishable from that of other crude oils."[104]

Keystone XL Pipeline Operating Parameters

Some parties have expressed concern about the Keystone XL pipeline operating parameters, particularly the operating temperature and pipeline pressure.[105] In general, parties contended that the Keystone XL pipeline would be operating at temperatures and pressures well above conventional crude oil pipelines.

In the 2014 FEIS, DOS states that the operating temperature is "expected to be approximately between 42°F and 135°F."[106] However, one of the parameters unique to Keystone XL ("Special Condition 15," discussed below) appears to allow for temperatures higher than 150°F, subject to specific testing results and PHMSA approval.[107] Although the FEIS does not discuss whether or not operating temperatures will approach or breach 150°F during the pipeline's operation, Special Condition 15 appears to allow that possibility.

As to the operating pressure, DOS states the following: "the design of the proposed Project pipeline system is based on a maximum 1,308 pounds per square inch gauge (psig) discharge pressure at each pump station.... There would be situations where, due to elevation changes, the hydraulic head created would result in a maximum operating pressure of up to and including 1,600 psig."[108]

How do the Keystone XL operating parameters compare to other DilBit pipelines? The NRC collected operating parameter data from five Canadian pipeline operators transporting DilBit. The

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[102] NRC report, p. 63.

[103] Swift at al., *Tar Sands Pipelines Safety Risks,* 2011.

[104] NRC report, p. 65.

[105] See 2014 FEIS, Volume V, "Comments and Responses;" see also 2011 final EIS, "Appendix A, Responses to Comments and Scoping Summary Report," available at http://keystonepipeline-xl.state.gov/archive/dos_docs/feis/vol3and4/appendixa/index.htm; and Swift et al., *Tar Sands Pipelines Safety Risks,* 2011.

[106] 2014 FEIS, p. 3.13-15.

[107] Special Condition 15 states: "under no circumstances may the pump station discharge temperatures exceed 150°F without sufficient justification that Keystone's long-term operating tests show that the pipe coating will withstand the higher operating temperature for long-term operations, and approval from the appropriate PHMSA region(s)" (2014 FEIS, Appendix B, "Potential Releases and Pipeline Safety").

[108] 2014 FEIS, p. 2.1-40.

highest reported operating temperature was 122°F and the highest reported operating pressure was 1,440 psig. Thus, both the "expected" maximum temperature (135°F) and the potential maximum operating pressure (1,600 psig)[109] of the Keystone XL pipeline would exceed operating parameter data presented in the NRC report. It is uncertain whether or not these *potential* temperature and pressure differences are a cause for concern.

DOS states that the proposed pipeline would satisfy the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations (49 CFR Part 195) that apply to hazardous liquid pipelines. In addition, Keystone agreed to implement 57 additional measures ("Special Conditions") developed by PHMSA. In consultation with PHMSA, DOS determined that incorporation of those conditions "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 [High Consequence Areas (HCAs)] as defined in 49 Code of Federal Regulations (CFR) 195.450."[110]

DOS compares the Special Conditions with existing regulatory requirements in Appendix B to the 2014 FEIS. The *degree* of safety provided by the additional 57 measures has been a subject of debate. The primary author of the 2011 environmental groups' report argued that only 12 of these conditions actually differ in some way from minimum requirements.[111]

Keystone XL Spill Frequency and Volume Estimates

Oil spill frequency and volume estimates for the Keystone XL project have been a subject of debate during the permit process. Comparing various estimates is difficult, because the estimates may or may not

1. include different years of underlying data;
2. apply to different pipeline segments (e.g., the 875-mile northern U.S. portion or the entire 1,938-mile pipeline from Canada to the Gulf Coast);
3. apply to different components of the pipeline (e.g., the mainline or the mainline and supporting equipment, such as tanks and valves); and
4. include additional assumptions or adjustments.

In the 2014 FEIS, DOS used PHMSA data to analyze crude oil pipeline spill incidents that occurred between 2002 and 2012. DOS stated that "Although the results were not a direct indicator of the nature of possible incidents that could occur in association with the proposed [Keystone XL pipeline], they could be used to provide insight into what could potentially occur with respect to spill volume, incident cause, and incident frequency."[112]

Based on the PHMSA data, DOS calculated spill frequency rates and average volumes for crude oil. The PHMSA records do not differentiate between types of crude oil: heavy, light, etc. **Table 4**

[109] It is uncertain whether those surveyed in the NRC report accounted for pressure changes that might result from elevation changes as was done in the DOS FEIS.

[110] 2014 FEIS, "Potential Releases," p. 3.13-4.

[111] Anthony Swift, "Clinton's Tar Sands Pipeline 'Safety Conditions' are Smoke and Mirrors," August 19, 2011, at http://switchboard.nrdc.org.

[112] 2014 FEIS, "Potential Releases," p. 4.13-8.

provides the spill frequency and volume estimates for individual components of the pipeline system: mainline pipeline, tanks, mainline valves, and other components, such as pump station equipment. For example, the table indicates that mainline pipelines and tanks have a lower frequency of spills than valves and other components, but a higher average spill volume.

Table 4. Estimates of Oil Spill Frequency and Volume

Based on DOS Analysis of PHMSA Data (January 2002-July 2012)

Pipeline Component	Oil Spills Per Mile-Year	Average Volume Per Spill in Barrels (Gallons)	Estimated Number of Spills Per Year for 875-Mile Proposed KXL [a]	Estimated Spill Volume Per Year for 875-Mile Proposed KXL in Barrels (Gallons)
Mainline Pipe (>16")	0.00025	1,116 (46,872)	0.22	246 (10,332)
Tanks	0.00017	1,720 (77,240)	0.15	258 (10,836)
Mainline Valves	0.00005	34 (1,428)	0.04	1 (42)
Other components[b]	0.00168	173 (7,266)	1.47	254 (10,668)
Total	0.00215	362[c] (15,204)	1.88	681 (28,602)

Source: Prepared by CRS; Incident rate per mile-year from 2014 FEIS, Table 4.13-1; average volume per pipeline component from Tables 6-9 in Appendix K to the 2014 FEIS.

Notes:

a. The estimated number of spills per year calculated by multiplying incident rates (per mile-year) by number of miles in the proposed Keystone XL pipeline (875 miles from the Canadian border to Steele City, NE).

b. According to the 2014 FEIS, other components "include pump station equipment, but exclude tanks, valves, and mainline pipe" (Appendix K, p. 18).

c. The total average volume does not equate to the sum of the average volume from each component. This approach would overstate the total average volume, because it would give the same weight to the infrequent, large volume spills as the more frequent, lower volume spills.

CRS used Tables 6-9 in Appendix K to the 2014 FEIS to calculate the total volume average by dividing the total number of incidents from the four pipeline component categories (1,098 incidents between 2002 and 2012) by the total volume from these incidents (397,303 barrels).

Using the frequency rates and average volumes listed in **Table 4**, DOS estimated the annual spill frequency (0.46 releases per year) and volume (518 barrels per year) that would result from the *entire* Keystone XL pipeline project—1,938 miles from its origin in Canada to the Gulf Coast.[113] This estimate only includes the spill frequency and volume estimate for mainline pipelines greater than 16" in diameter. By comparison, **Table 4** provides the estimated number of spills and spill volume that would occur along the 875-mile northern segment of the Keystone XL pipeline (the segment under consideration for a Presidential permit). The table lists the individual component estimates as well as an estimate for the entire system. For instance, *based on PHMSA data*, a spill from the KXL mainline would occur 0.22 times per year (or once about every five years); a spill from any of the components, including the mainline, would occur 1.88 times per year.

[113] See Table ES-7 in the Executive Summary and Table 5.3-3 in the 2014 FEIS.

Some would argue that using the PHMSA data as a guidepost for Keystone XL incidents would overestimate spill frequency, because the data include older pipelines that may have been built to less stringent standards. Moreover, pipeline proponents contend the Special Condition would provide additional protection from incidents.[114] In the 2014 FEIS, DOS states that "the application of the Special Conditions and various studies that indicate more modern pipelines are less likely to leak, it is reasonable to expect a sizable reduction in spills when compared to the historic spill record."[115]

On the other hand, the spill frequency for the existing Keystone pipeline,[116] which began transporting approximately 590,000 bpd of oil sands crudes in 2010, has exceeded the historical spill frequency estimate. Based on DOS analysis in the 2014 FEIS, Keystone operators reported 12 incidents during the first year of operation. Although the vast majority of the incidents were minor, one incident resulted in a spill of approximately 400 barrels (16,800 gallons). According to DOS, "11 of the 12 reported incidents resulted in a small spill, eight of which were less than 1 bbl.... all reported first-year incidents for the existing Keystone pipeline system involved discrete elements of the pipeline system (i.e., pumping stations, mainline valves); none involved mainline pipe or tanks."[117]

U.S. and Alberta Pipeline Spill Data

Some stakeholders have argued that a comparison of oil spill data from Alberta and the United States indicates that internal corrosion has led to substantially more oil spills in the Alberta pipeline system than the U.S. system.[118] They reason that this difference is likely related to high proportion of oil sands crudes, which have been in the Alberta system since the 1980s. In contrast, the first dedicated oil sands crudes pipeline in the United States, the Alberta Clipper, began operating in 2010.[119]

Both the NRC report and DOS[120] have pointed out that existing pipeline spill data are limited in their ability to analyze potential risks associated with the transportation of oil sands crude oils compared to other crude oils. The NRC report stated the following:

> The information contained in the U.S. and Canadian incident records is insufficient to draw definitive conclusions. One reason is that the causal categories in the databases lack the specificity needed to assess the particular ways in which transporting diluted bitumen can affect the susceptibility of pipelines to failure. Another reason is that incident records do not contain information on the types of crude oil transported and the properties of past shipments

[114] When TransCanada submitted a spill frequency estimate in 2009, the company derived its estimate by using historical databases from PHMSA and then applying project-specific factors, such as regulatory requirements, material strength, and technological advances. TransCanada, *Keystone XL Project Pipeline Risk Assessment and Environmental Consequence Analysis*, 2009 (Appendix P of the 2014 FEIS).

[115] 2014 FEIS, p. 4.13-30.

[116] The existing Keystone pipeline system analyzed by DOS includes the Keystone pipeline extending from Hardisty, Alberta, to Patoka, IL, and the Cushing Extension extending from Steele City, NE, to Cushing, OK.

[117] 2014 FEIS, p. 4.13-31.

[118] 2011 FEIS, Appendix A.

[119] Swift et al., *Tar Sands Pipelines Safety Risks,* 2011.

[120] The 2014 FEIS states "given how incident data are reported, it is not possible to distinguish dilbit, SCO, and Bakken oil spills from the general population of crude oil spills, nor is it possible to distinguish pipelines carrying dilbit, SCO, or Bakken oil from other crude oil pipelines" (p. 4.13-29).

> in the affected pipeline. Because many pipeline releases involve cumulative and time-dependent damage, there is no practical way to trace the transportation history of a damaged pipeline to assess the role played by each type of crude oil and its properties in transport.[121]

DOS pointed out that a comparison of U.S. and Alberta oil spill data is problematic for various reasons. In particular, the scopes of the data collected in each nation are different. Canadian data includes smaller spills and spills from certain pipelines not covered by PHMSA regulations.[122] To address these discrepancies in data collection, PHMSA prepared a comparison of pipeline incidents of similar scopes between the two databases for the 2011 FEIS. The comparison indicated that internal corrosion failures (per 1,000 miles of pipeline) were approximately 30% higher in the U.S. system (0.42 vs. 0.32). Regardless, such comparisons are challenging, if not impossible, considering the range of potential factors—pipeline age, enforcement, etc.—that may affect the underlying data. For this reason, the above comparison might be described as preliminary. DOS did not include this table in its 2014 FEIS, but states that "incident statistics from Alberta show that incident frequencies and corrosion-based incidents are similar for pipelines in the United States and Alberta."[123]

Impacts of Spills of Oil Sands Crude

If an oil spill occurs, its impacts would depend on multiple factors, including the type of oil spilled, the volume of oil spilled, and the location of the spill.[124] Although location is generally considered the most important factor, EPA stated (in comments during the EIS process) that spills of oil sands crude (e.g., DilBit) may result in different impacts than spills of other crude oils.[125]

The 2013 NRC report did not examine this particular issue and CRS is not aware of an authoritative study that has assessed this topic. Although parallels may be drawn between the possible behavior of conventional crudes and DilBit, studies are scarce regarding spills of heavy crudes with the specific composition of Canadian heavy crudes.

Spill Behavior

The behavior of crude oil spills and the fate of crude oil in the subsurface have been studied extensively around the world for a wide range of conventional crudes and other petrochemicals in both experimental settings and actual spills (e.g., Bemidji, MN, in 1979).[126] These include studies

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[121] NRC report, p.47.

[122] For similar reasons, the 2013 NRC report stated (p. 45) that the Alberta data were not useful in its study.

[123] 2014 FEIS, p. 4.13-29.

[124] See CRS Report RL33705, *Oil Spills in U.S. Coastal Waters: Background and Governance*, by (name redact ed).

[125] See comments from EPA on the DOS draft Supplemental Environmental Impact Statement, submitted in a letter from Cynthia Giles to Jose Fernandez and Kerri-Ann Jones, April 22, 2013.

[126] See, for example, work compiled by the U.S. Geological Survey about the 1979 crude oil spill near Bemidji, MN, which contaminated a shallow aquifer: U.S. Geological Survey, "Crude Oil Contamination in the Shallow Subsurface: Bemidji, Minnesota," Internet page, July 20, 2011, http://toxics.usgs.gov/sites/bemidji_page.html. See also: M. Whittaker, S.J.T. Pollard, and T.E. Fallick, "Characterisation of Refractory Wastes at Heavy Oil-Contaminated Sites: A Review of Conventional and Novel Analytical Methods," *Environmental Technology*, Vol. 16, No. 11, November 1, 1995, pp. 1009-1033; S Khaitan et al., "Remediation of Sites Contaminated by Oil Refinery Operations," *Environmental Progress*, Vol. 25, No. 1, April 2006, pp. 20-31.

of specific chemical components that may be present in DilBit (e.g., benzene).[127] Based on extensive experience with other crudes and DilBit constituents, analysts may claim considerable confidence in models of DilBit behavior around groundwater. For example, the Canadian Energy Resources Conservation Board has stated that "DilBit should behave in much the same manner as other crude oils of similar characteristics."[128]

All spilled oil begins to "weather" or separate into different components over time. For a land spill, the heavier and more viscous components (i.e., the asphaltenes) would likely remain trapped in soil pores above the water table. It is also likely that the lighter constituents would partly evaporate and not be transported down through the soil with the heavier components.

However, if an oil spill reached the water table, some of the more soluble portions would likely dissolve into the groundwater and be transported in the direction of regional groundwater flow. The ultimate extent, shape, and composition of a groundwater contaminant plume resulting from a DilBit spill would depend on the specific characteristics of the soil, aquifer, and the amount and duration of the accidental release.

Cleanup Issues

The heavier components of a DilBit spill would be difficult to remove from the soil during cleanup operations, and may require wholesale soil removal instead of other remediation techniques.[129] The 2014 FEIS states

> DilBit intermixed with sediment and trapped in the river bed and shoreline results in a persistent source of oil and has the potential to present additional response and recovery challenges.[130]

These challenges may come at a higher cost. In an oil spill model prepared for EPA, the model estimates that spills of heavy oil will cost nearly twice as much to clean up as comparable spills of conventional crude oil.[131]

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[127] See, for example: Lisa M. Geig et al., "Intrinsic Bioremediation of Petroleum Hydrocarbons in a Gas Condensate-Contaminated Aquifer," *Environmental Science and Technology*, vol. 33, no. 15 (1999), pp. 2550-2560; Paul E. Hardisty et al., "Characterization of LNAPL in Fractured Rock," *Quarterly Journal of Engineering Geology & Hydrogeology*, Vol. 36, No. 4, November 2003, p. 343-354; J.L. Busch-Harris et al., "In Situ Assessment of Benzene Biodegradation Potential in a Gas Condensate Contaminated Aquifer," Proceedings of 11th Annual International Petroleum Environmental Conference, Albuquerque, NM, October 12-15, 2004; John A. Connor et al., "Nature, Frequency, and Cost of Environmental Remediation at Onshore Oil and Gas Exploration and Production Sites," *Remediation*, Vol. 21, No. 3, Summer 2011, pp. 121-144; Bruce E Rittmann et al., *Natural Attenuation for Groundwater Remediation*, National Academy Press, 2000.

[128] Canadian Energy Resources Conservation Board (ERCB), "ERCB Addresses Statements in Natural Resources Defense Council Pipeline Safety Report," Press release, Calgary, Alberta, February 16, 2011.

[129] One such other method is "pump and treat," which involves cleaning soil and groundwater contamination by pumping and capturing the contaminated groundwater, then treating it at the surface to remove the contaminants. The same technique may be used to extract soil gas vapor from contaminated soil above the water table. For more information, see Environmental Protection Agency, *Basics of Pump-and-Treat Ground-Water Remediation Technology*, EPA/800/8-90003, March 1990.

[130] 2014 FEIS, p. 4.13-88.

[131] Dagmar Etkin, *Modeling Oil Spill Response and Damages Costs*, Proceedings of the 5th Biennial Freshwater Spills Symposium, 2004, at http://www.environmental-research.com.

Recent pipeline oil spills have generated interest among policy makers and stakeholders. For example, a 2010 Enbridge pipeline spill released approximately 850,000 gallons of oil sands crude oil into Talmadge Creek, a waterway that flows into the Kalamazoo River (Michigan).[132] The spill demonstrates particular challenges associated with heavier crude oil spills, like oil sands crude oils. As of the date of this report, response activities continue,[133] because, according to EPA, the oils sands crude "will not appreciably biodegrade."[134] The oil sands crude oil is submerged at the river bottom, mixed with sediment, and EPA has ordered Enbridge to dredge the river to remove the oiled sediment.[135] As a result of this order, Enbridge estimated in December 2013 its response costs would be approximately $1.122 billion.[136]

Toxicity

Crude oils may contain multiple compounds that present toxicity concerns. DOS stated that "based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills."[137] Benzene and other BTEX compounds (benzene, toluene, ethyl benzene, and xylene) are generally in greater proportions in the lighter crude oils and particularly in refined products like gasoline.[138] In its 2011 FEIS, DOS compared the BTEX content of crude oil derived from oil sands (DilBit and DilSynBit) with conventional crude oils from Canada. The BTEX content of oil sands crudes ranged from 5,800 parts per million (ppm) to 9,100 ppm. The BTEX contents of conventional crude oils ranged from 5,800 ppm to 29,100 ppm.[139]

Other toxic compounds of concern in crude oils are polycyclic aromatic hydrocarbons (PAHs). Generally, PAHs are more toxic than BTEX and evaporate at a slower rate, but they are less soluble in water. The National Research Council's *Oil in the Sea* report stated that with weathering/evaporation and the resulting loss of BTEX, PAHs become more important contributors to the remaining oil's toxicity.[140]

Unlike BTEX, the 2011 and 2014 FEIS documents do not include a comparison of PAH concentrations across different crude oils. DOS states that PAH concentrations of crude oils that would be transported in the Keystone XL pipeline are unknown, because this information is

[132] National Transportation Safety Board, *Accident Report: Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release - Marshall, Michigan, July 25, 2010*, July 2012, at http://www.ntsb.gov/.

[133] For more up-to-date information, see EPA's Enbridge oil spill website at http://www.epa.gov/enbridgespill/index.html.

[134] Letter from Cynthia Giles (EPA) to DOS, commenting on the draft SEIS, April 22, 2013.

[135] EPA Removal Order, March 14, 2013, at http://www.epa.gov/enbridgespill/ar/enbridge-AR-1720.pdf.

[136] See Enbridge Inc., Management's Discussion and Analysis, February 2014, at http://enbridge.com/InvestorRelations/FinancialInformation/InvestorDocumentsandFilings.aspx.

[137] 2014 FEIS, p. 4.13-46.

[138] For a comprehensive discussion, see National Research Council, *Oil in the Sea III: Inputs, Fates, and Effects*, National Academies of Science, February 2003.

[139] 2011 FEIS, "Potential Releases," Table 3.13.5-6, p. 3.13-45.

[140] National Research Council, 2003, p. 126.

proprietary.[141] Some commenters, including EPA, took issue with this during the 2011 EIS review process.[142]

Heavy metals may also be a concern. A 2011 NRDC report states that DilBit contains quantities of heavy metals, particularly vanadium and nickel, that are "significantly larger" than conventional crude oil.[143] Assuming conventional oil means lighter crudes, this statement is largely correct.[144] However, the heavy metal concentrations in DilBit are similar to some other heavy crude oils, such as Mexican and Venezuela crudes that are processed in Gulf Coast refineries.[145] Most, if not all, of this crude oil arrives in the United States via vessel.[146]

Other Modes of Oil Transportation

Although pipelines and oil tankers transport the vast majority of oil within the United States, other modes of transportation have increased in recent years (**Figure 13**). As **Figure 13** illustrates, the volume of crude oil carried by rail increased by 423% between 2011 and 2012; the volume moving by barge, on inland waterways as well as along intracoastal routes, increased by 53%; and the volume of crude oil shipped by truck rose 38% between 2011 and 2012. Some portion of these recent increases is likely related to the status of proposed Keystone XL pipeline.

[141] 2011 FEIS, "Potential Releases," p. 3.13-31.

[142] U.S. Environmental Protection Agency's July 16, 2010, letter to the U.S. Department of State commenting on the 2010 draft EIS.

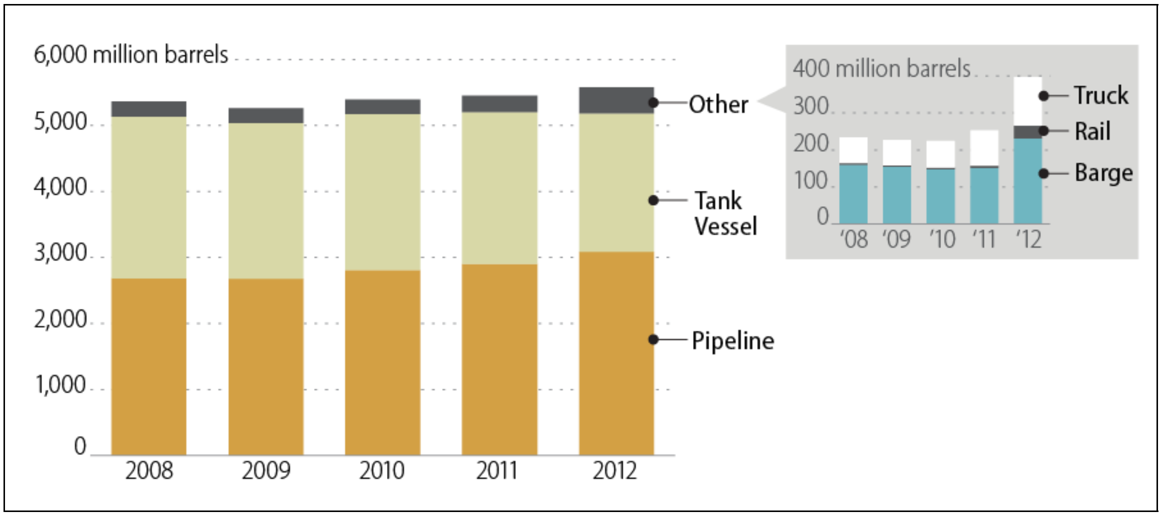
[143] Swift et al., *Tar Sands Pipelines Safety Risks*, 2011.

[144] Based on a comparison of crude oil assays from sources listed in **Table 1**.

[145] 2011 FEIS, "Potential Releases," Table 3.13.5-7.

[146] Although a considerable percentage of oil imports come from Mexico (e.g., approximately 12% of crude oil imports in 2010), the EIA states that "Mexico does not have any international pipeline connections, with most exports leaving the country via tanker from three export terminals in the southern part of the country." EIA, Country Analysis Briefs, at http://www.eia.gov/cabs/Mexico/Full.html.

Figure 13. U.S. Refinery Receipts of Crude Oil by Mode of Transportation



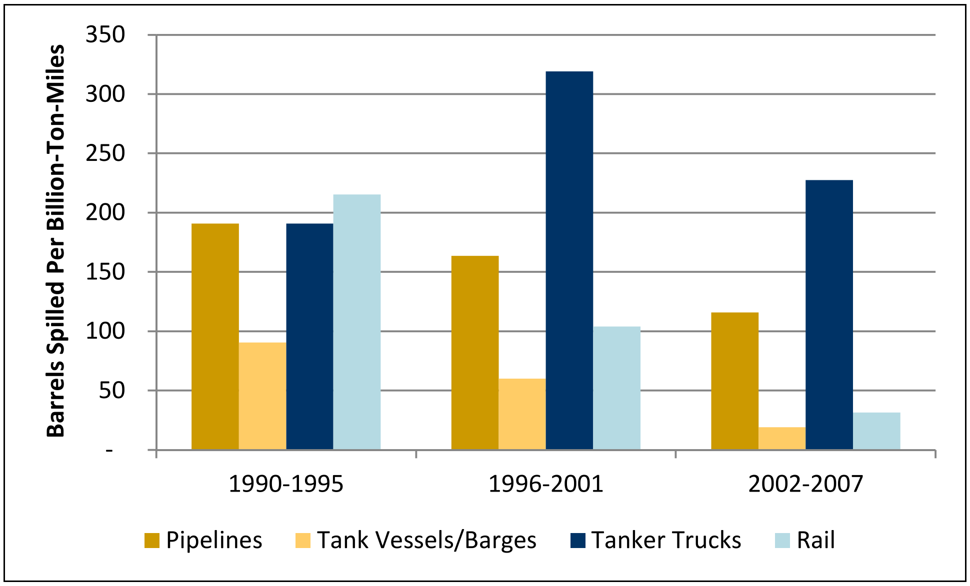
Source: Prepared by CRS; data from EIA, *Refinery Capacity Report*, Table 9, June 2013.

Notes: EIA collects annual data from petroleum refineries, including their receipts of crude oil by different modes of transportation. Although this information does not precisely measure crude oil transportation within the United States, the data provide an approximate comparison of crude oil transportation by different modes. The data only capture the method by which the crude oil is ultimately delivered to the refinery. For example, if a producer shipped crude via pipeline to an intermediate destination (e.g., tank farm), and then shipped the oil to a refinery via barge, the pipeline transport leg would not be captured in this dataset. CRS is not aware of a more comprehensive, and up-to-date, source of crude oil transportation data.

Each mode of oil transportation involves some risk, and each has historically resulted in oil spills. **Figure 14** illustrates the relative risk of oil spills by mode of transportation, comparing spill volume to the volume/distance transported. Over the period 1996-2007, railroads consistently spilled less crude oil per ton-mile than trucks or pipelines; barges and domestic tanker ships have much lower spillage rates than trains. However, the data in the figure precede the recent dramatic increase in oil by rail transportation.

Figure 14. Oil Spill Volume Per Billion-Ton Miles

Crude Oil and Petroleum Products in Domestic Transportation



Source: Prepared by CRS; oil spill volume data from Dagmar Etkin, *Analysis of U.S. Oil Spillage*, API Publication 356, August 2009; ton-mile data from Association of Oil Pipelines, Report on Shifts in Petroleum Transportation: 1990-2009, February 2012.

Notes: Pipelines include onshore and offshore pipelines. The time periods were chosen based on the available annual data for both spill volume and ton-miles. The values for each time period are averages of annual data for each six-year period.

In addition, in its 2014 FEIS the State Department used PHMSA and Coast Guard data to compare oil spill frequency and volume by mode of transportation. Between 2002 and 2009, DOS found that

1. pipeline transport has the highest number of barrels released per ton-mile compared to rail and marine transport; and
2. rail transport has the highest number of reported releases per ton-mile compared to pipeline and marine transport.[147]

Oil Sands Extraction Concerns

Although local/regional impacts from Canadian oil sands development may not directly affect public health or the environment in the United States, stakeholders often highlight the environmental impacts that pertain to the region in which the oil sands resources are extracted. DOS points out that, pursuant to NEPA or applicable Executive Orders, DOS NEPA analysis need not include the environment or activities outside of the United States (see "Consideration of Environmental Impacts Outside of the United States"). However, DOS included—"as a matter of policy"—a summary of information regarding environmental analyses and regulations related to

[147] 2014 FEIS, p. 5.3-9 and Figures 5.3.3-1 and 5.3.3-2.

the Canadian portion of the proposed Keystone XL Project and Canadian oil sands production.[148] This inclusion reflects the level of interest these issues have received in recent years.

The scope and degree of the extraction-related impacts is a subject of some debate. A comprehensive assessment of extraction-related concerns is beyond the scope of this report.[149] The following sections include discussions of two selected topics: land disturbance and water resource issues.

Land Disturbances

Both oil sands mining and in situ operations can disturb the land to varying degrees. For example, land disturbances from mining operations include

- clearance and excavation of a relatively large surface area,
- storage of removed overburden (e.g., vegetation soil), and
- construction of tailings ponds to contain extraction process wastestreams.

In contrast, many stakeholders associate in situ operations with "minimal land disturbances."[150] For example, the 2014 FEIS states that "in situ recovery is less disturbing to the land surface than surface mining and does not require tailings ponds."[151] However, some research suggests the comparison between the two processes is more complicated. A 2009 study described the different impacts from the two processes in the following manner:

> Surface mining and in situ recovery affect the landscape in different ways. Land use of surface mining is comprised largely of polygonal features (mine sites, overburden storage, tailing ponds and end pit lakes); whereas in situ development is mostly defined by linear features that extend across the lease area (networks of seismic lines, access roads, pipelines and well sites).[152]

Although the actual extraction site at in situ operations impacts substantially less land than at mining sites, some contend that in situ processes may ultimately create a larger disturbance, because the dispersed nature of in situ operations increases landscape fragmentation.[153] In addition, one study finds that in situ operations disturb more land (per unit of oil) than mining, when natural gas requirements are considered.[154] As noted above, in situ operations require

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[148] 2014 FEIS, Section 4.15.4 ("Extraterritorial Concerns").

[149] Perhaps the most comprehensive assessment of potential environmental concerns was prepared by the Royal Society of Canada. See P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010.

[150] P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010.

[151] 2014 FEIS, p. 4.15-107.

[152] Sarah M Jordaan et al., "Quantifying Land Use of Oil Sands Production: a Life Cycle Perspective," *Environmental Research Letters*, 2009.

[153] See, e.g., Dan Woynillowicz et al., *Oil Sands Fever,* Pembina Institute, 2005; Pembina Institute, Mining vs. In Situ: Factsheet, 2012; Sarah M Jordaan et al., "Quantifying Land Use of Oil Sands Production: a Life Cycle Perspective," *Environmental Research Letters*, 2009.

[154] Sarah M Jordaan et al., "Quantifying Land Use of Oil Sands Production: a Life Cycle Perspective," *Environmental Research Letters*, 2009.

energy (i.e., natural gas) to generate the steam needed to extract the underlying resource. According to the study, the land disturbances from the natural gas development contribute a major portion of in situ's total land disturbance.

How does land disturbance from oil sands operations compare to conventional oil development? Almost all forms of energy production disturb the land to some degree. A 2010 study compared land disturbances from Alberta oil sands operations with conventional oil development in Alberta and California.[155] **Figure 15** illustrates the results. The figure indicates that in situ oil sands operations have a substantially higher energy yield—energy produced per disturbed land (measured in petajoules per hectare)—than other sources. However, when natural gas use is included in the estimate, in situ operations' energy yield decreases substantially, making its energy yield equivalent to conventional oil development from California, but still greater than oil sands mining operations in Canada.[156] The Alberta Chamber of Resources estimates that in situ production requires approximately four times the quantity of natural gas used for surface mining on a production volume basis.[157] Therefore, the factor of natural gas plays an important role in energy yield estimates.

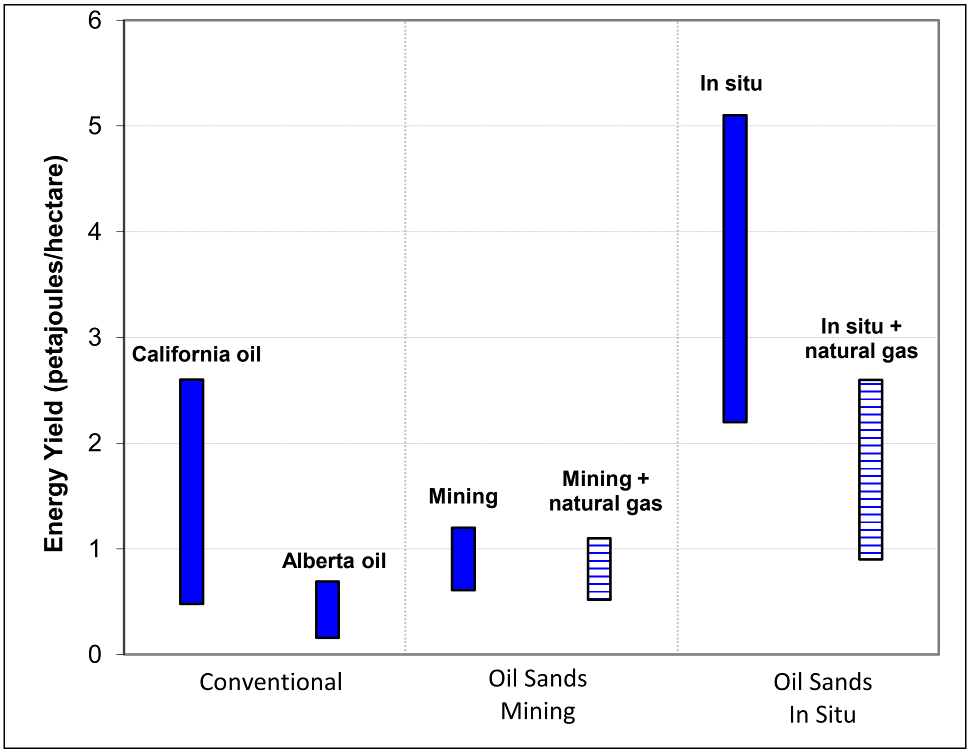
[155] Sonia Yeh et al., "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," *Environmental Science and Technology*, 44(22): 8766-8722, 2010.

[156] In the main text of the 2010 study (Yeh et al.), the authors exclude the natural gas components of oil sands mining and in situ operations (represented above by the striped columns), but provide the data in supplementary information.

[157] Alberta Chamber of Resources, *Oil Sands Technology Roadmap*, 2004.

Figure 15. Illustrative Comparison of Energy Yields by Selected Sources

Energy Produced Per Amount of Disturbed Land (Range of Low to High)



Source: Prepared by CRS; data from Sonia Yeh et al, "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," *Environmental Science and Technology*, 44(22): 8766-8722, 2010.

Notes: Columns reflect the *range of values* reported by Yeh, 2010. In the main text of the 2010 study, the authors exclude the natural gas components of oil sands mining and in situ operations (represented above by the blue columns), but provide data that include natural gas components in supplementary information (represented above by the striped columns). Including the natural gas component lowers the energy yield. Such a component was not part of the conventional California and Alberta oil data.

Another factor in land disturbance assessments is the type of land disturbed. The Alberta oil sands are located within Canada's boreal forest, a large ecosystem that supports a wide range of biodiversity and provides key ecological services. For example, the boreal forest has been described as the "world's largest and most important carbon storehouse."[158] The 2010 study that provided data for **Figure 15** also estimated the carbon storage in the lands overlying the various resources (e.g., California oil, Alberta oil sands). The study estimated that the soil carbon ratio (tons of carbon per hectare) and biomass carbon ratio was approximately five and four times greater, respectively, in oil sands areas than in California oil sites.[159]

[158] Rebecca Rooney et al., "Oil Sands Mining and Reclamation Cause Massive Loss of Peatland and Stored Carbon," *Proceedings of the National Academy of Sciences*, 109: 4933-4937, 2012.

[159] Sonia Yeh et al., "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," *Environmental Science and Technology*, 44(22): 8766-8722, 2010.

A further consideration is the fate of the land after the resources are extracted. In Alberta, an environmental law requires an oil sands development company to demonstrate that it has reclaimed the land to an "equivalent capability."[160] Subsequent regulations have expanded on the meaning of this phrase: "The ability of the land to support various land uses after conservation and reclamation is similar to the ability that existed prior to an activity being conducted on the land, but that the individual land uses will not necessarily be identical."[161]

The Alberta reclamation requirement is not unique. The United States has similar requirements that may apply in certain instances. For example, the Bureau of Land Management (BLM) has reclamation regulations that apply to oil and gas operations on federal lands.[162] BLM guidance states:

> The long-term objective of final reclamation is to set the course for eventual ecosystem restoration, including the restoration of the natural vegetation community, hydrology, and wildlife habitats. In most cases, this means returning the land to a condition approximating or equal to that which existed prior to the disturbance. The operator is generally not responsible for achieving full ecological restoration of the site.[163]

A comparison between the U.S. and Canadian reclamation requirements and their applications is beyond the scope of this report. However, data from Alberta indicate that reclamation has not kept pace with land disturbance. Data from 2012 indicate that approximately 7% of the total disturbed area has been permanently reclaimed.[164] Of the permanently reclaimed land, 2% has been certified per Alberta requirements (equating with 0.14% of the total disturbed area). The 2010 Royal Society of Canada report stated, "Because of the very small amount of land certified to date relative to the large area that has been disturbed in the oil sands region, there is major skepticism as to whether reclamation to an equivalent land capability can be achieved in a reasonable time frame."[165]

Subsequent to that report, a 2012 study from the Proceedings of the National Academy of Sciences assessed pre- and post-reclamation data at several oil sands mining sites. The study found that lost wetlands were not being replaced, resulting in a "dramatic loss of carbon storage and sequestration potential."[166]

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[160] Alberta Environmental Protection and Enhancement Act, Section 146 (as of December 2013), at http://www.qp.alberta.ca/documents/Acts/E12.pdf.

[161] Alberta Conservation and Reclamation Regulation, AR 115/93. For a discussion of this regulation and its applications, see P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010.

[162] See, e.g., 43 CFR Section 3101.1-2 and BLM Onshore Oil and Gas Lease Form (Form 3100-11), Section 12.

[163] United States Department of the Interior and Department of Agriculture, *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development*, ("Gold Book"), 2007, p. 43.

[164] The total disturbed area includes cleared areas, disturbed areas, and areas ready for reclamation. These categories are defined by the following source: Alberta Government, Oil Sands Mine Regional Totals for Reclamation and Disturbance Tracking by Year, at http://environment.alberta.ca.

[165] P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010, p. 194.

[166] Rebecca Rooney et al., "Oil Sands Mining and Reclamation Cause Massive Loss of Peatland and Stored Carbon," *Proceedings of the National Academy of Sciences*, 109: 4933-4937, 2012.

Water Resources and Quality Issues

While the water resource impacts from oil sands development are generally considered a Canadian domestic issue, other stakeholders view the environmental consequences of oil sands development as part of the global discussion about the long-term implications of unconventional oil and gas. At issue is whether oil sands development may harm the water resources and aquatic ecosystems and species of the northern Alberta and the northern territories.

Both oil sands in situ and surface mining techniques have water resource impacts. In situ processes use groundwater that is brought to the surface and heated, then reinjected for the underground steam-based separation of the oil from the sand. Freshwater use in in situ extraction has declined due to increased recycling and use of treated brackish water. Surface mining operations withdraw water from the north-flowing Athabasca River. This water is heated for use in a complex process that separates the oil from the sands. Process waste streams are collected in tailings ponds or lakes, which can cover a substantial area. Following extraction through in situ or surface mining, the bitumen recovered must be treated, typically upgraded to synthetic crude oil. This treatment requires both cooling water and process water.

Mining also results in significant land disturbance. As discussed earlier, remediation of the disturbed land is addressed in Alberta statute and regulations. The extent and effectiveness of remediation in terms of long-term restoration and protection of water resources is a subject of on-going debate.[167] Additionally, ongoing mine site maintenance during extraction operations requires capturing and disposing of surface water and groundwater entering the site. The potential wetlands and associated migratory bird impacts from changes in surface water and groundwater regimes that result both from direct water use in-situ and mining operations and indirectly through long-term changes to the landscape also are concerns.

On a direct water use per unit of energy basis, the oil sands production and upgrading processes appear to be more water intense than most conventional oil production and oil and gas from shale and tight formations, below the water intensity of U.S. oil shale, and considerably below the (rainfall or irrigation) water intensity of biofuels from corn, sugarcane, soybean, and switchgrass feedstocks.[168] The freshwater intensity of in situ oil sands production is generally lower than oil sands mining; however, while more water efficient, in situ production leaves in place (i.e., unrecovered) a considerable portion of the petroleum resources. The current direct water efficiency of oil sands production may improve as new technologies are employed.

Much of the concern with oil sands development (and other types of unconventional oil and gas development) is the concentration of water use and impacts within a limited geographic area. One

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[167] See P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010.

[168] Currently there is no authoritative source comparing the water intensities of a wide range of fuels on an energy basis. Water intensity data for shale oil and life-cycle water use for gas-to-liquids are particularly scarce. Existing data sources all have shortcomings; therefore, this paragraph is based on information compiled from a number of different sources, including E. D. Williams and J.R. Simmons, *Water in the energy industry. An introduction.*, BP, 2013; C. King and M. Webber, "Water Intensity of Transportation," *Environmental Science & Technology*, vol. 42, no. 21 (2009), available at http://pubs.acs.org/doi/pdf/10.1021/es800367m; P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010, p. 51. http://www.rsc.ca/documents/expert/RSC%20report%20complete%20secured%209Mb.pdf; DOE, *Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water*, December 2006; Canadian Association of Petroleum Producers, *Water Use in Canada's Oil Sands*, July 2011.

concern is that water use for oil sands mining reduces river flows, particularly during low flow periods. To manage these concerns, oil sands operators are required to obtain water withdrawal licenses, and a water management framework was developed to protect in-stream flows in the Athabasca River. The framework identifies how water withdrawals are to be reduced during low flow periods. A report by an expert panel of the Royal Society of Canada concluded that "water use at current levels does not threaten viability of the Athabasca River system if the Water Management Framework … is fully implemented and enforced."[169] Another concern is groundwater depletion. The expert panel report found that "there needs to be greater attention directed to regional groundwater resources" which currently are not well characterized, and that there was no evidence of a framework to limit groundwater extraction.[170]

In addition, the issue of water quality has generated considerable debate. Results from the Regional Aquatic Monitoring Program (RAMP) are often highlighted as evidence of the minimal impacts to water resources due to oil sands development.[171] RAMP describes itself as "an industry-funded, multi-stakeholder environmental monitoring program" that began in 1997.[172] A 2011 RAMP Technical Report stated that "differences in water quality measured in fall 2011 between all test and one of the upper baseline stations in the Athabasca River were classified as Negligible-Low compared to the regional baseline conditions."[173]

However, results from several peer-reviewed studies contradict the RAMP conclusions.[174] For example, a 2012 study found that the oil sands operations "substantially increase[] the loadings of toxic PPE [priority pollutant elements] to the Athabasca River and its tributaries."[175] Moreover, seven PPE—cadmium, copper, lead, mercury, nickel, silver, and zinc—exceeded Canada or Alberta guidelines for aquatic life protection. In addition, another 2012 study concluded that the "lake sediments in the Athabasca oil sands region register a clear PAH legacy with the pace and scale of industrial development of the region's tremendous bitumen [oil sands] deposits."[176]

Some of these contradictory findings may be addressed by the Joint Implementation Plan for Oil Sands Monitoring, established by the Canadian and Albertan governments in October 2012.[177] According to the plan, it "builds on a foundation of monitoring that is already in place, and is intended to enhance existing monitoring activities." Among other objectives, the plan seeks to "improve analysis of existing monitoring data to develop a better understanding of historical baselines and changes."

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[169] P. Gosselin et al., *Environmental and Health Impacts of Canada's Oil Sands Industry*, The Royal Society of Canada, Expert Panel Report, Ottawa, Ontario, December 15, 2010, p. 284.

[170] Ibid., p. 285.

[171] See, e.g., Government of Alberta, Oil Sands Factsheet: Protecting the Environment, at http://www.oilsands.alberta.ca/FactSheets/Protecting_the_Environment%283%29.pdf.

[172] RAMP website, at http://www.ramp-alberta.org/RAMP.aspx.

[173] RAMP, 2011 Technical Report, Executive Summary, at http://www.ramp-alberta.org/UserFiles/File/RAMP_2011_Final_Executive_Summary.pdf.

[174] See annual Technical Reports and Community Reports, at http://www.ramp-alberta.org.

[175] Erin Kelly et al., "Oil Sands Development Contributes Elements Toxic at Low Concentrations to the Athabasca River and Its Tributaries," *Proceedings of the National Academy of Sciences*, 107: 16178-16183, 2010.

[176] Joshua Kurek et al., "Legacy of a Half Century of Athabasca Oil Sands Development Recorded by Lake Ecosystems," *Proceedings of the National Academy of Sciences*, Early Edition October 2012.

[177] The plan is available at http://environment.gov.ab.ca/info/library/8704.pdf.

Appendix. Additional Information

Table A-1. Agencies With Jurisdiction or Expertise Relevant to Pipeline Impacts

Not Including Department of State

Agency	Role/Responsibilities in the Keystone XL Pipeline
EPA	Oversees state-implemented permit programs administered pursuant to the Section 402 of the Clean Water Act (CWA) regarding National Pollutant Discharge Elimination System (NPDES). The NPDES program covers point-source discharges of pollutants into U.S. waters. In addition, EPA reviews and comments on U.S. Army Corps of Engineers permit applications (per CWA Section 404).
U.S. Army Corps of Engineers (Corps)	Issues permits for sections of the pipeline that require placement of dredge and fill material in waters of the United States, including wetlands (pursuant CWA Section 404), or for pipeline crossings of navigable waters (pursuant to Section 10 of the Rivers and Harbors Act);
Department of the Interior (DOI)	The Bureau of Land Management (BLM) is authorized to grant temporary use permits for portions of the project that would encroach on federal lands.
	The National Park Service (NPS) is responsible for providing technical review of the proposal in the vicinity of NPS-administered lands affected by the proposed Project.
	The U.S. Fish and Wildlife Service is responsible for ensuring project compliance with the Endangered Species Act and would provide a Biological Opinion if the project is likely to adversely affect federally listed species.
U.S. Department of Agriculture (USDA)	The Natural Resources Conservation Service (NRCS) administers the Wetlands Reserve Program under which it purchases conservation easements and provides cost share to landowners for the purposes of restoring and protecting wetlands.
Department of Transportation (DOT)	The Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) has the safety-related authority for the nation's natural gas and hazardous liquid pipelines. PHMSA evaluates risks; develops and enforces standards for design, construction, operations and maintenance of pipelines; responds to accidents/incidents; conducts research on promising technologies; provides grants to states to support their pipeline safety programs; and reviews oil spill response plans.
U.S. Department of Energy (DOE)	The Office of Policy and International Affairs (PI) provides advice to DOE on existing and prospective energy-related policies. At the request of DOS, PI provided assistance in the analysis of the proposed project in light of world crude oil market demand, and domestic and global energy challenges ranging from energy price and market volatility to the long-term technology transitions related to greenhouse gas emissions reduction, energy efficiency, and the use of renewable resources.
	The Western Area Power Administration (Western) is a federal power-marketing agency that sells and delivers federal electric power to municipalities, public utilities, federal and state agencies, and Native American tribes in 15 western and central states. Western consulted with DOS to ensure cultural resources potentially affected by any Western transmission lines are taken into account.
Various state/county agencies	Various agencies must consult on and/or consider issuing permits for projects that cross navigable waters or state highways, or involve work potentially affecting state streams, cultural resources, or natural resources.

Source: CRS, based on a review of the U.S. Department of State's, *Final Environmental Impact Statement for the Proposed Keystone XL Project: Introduction*, amended September 2011, p. 1-12 to p.1-17.

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