2.2 DESCRIPTION OF ALTERNATIVES

2.2.1 Introduction

As noted in the White House Council on Environmental Quality (CEQ) guidelines, alternatives provide decision makers and the public a range of reasonable choices in addition to the proposed action (i.e., the proposed Project), and form the *heart* of an Environmental Impact Statement (EIS) (40 Code of Federal Regulations [CFR] 1502.14). This Final Supplemental EIS considers three categories of alternatives, consistent with the National Environmental Policy Act (NEPA), including the No Action Alternative, major pipeline route alternatives, and other alternatives considered but eliminated from detailed analysis. This section describes these alternatives and the screening process to determine whether they should be carried forward for detailed analysis in this Final Supplemental EIS. This section also includes detailed discussions of major route variations and other alternatives considered.

2.2.2 Overview of Alternatives

The following section provides an overview of the alternatives considered in this Final Supplemental EIS.

2.2.2.1 No Action Alternative

The No Action Alternative includes a Status Quo Baseline and several potential scenarios that could result if the Presidential Permit is denied or the proposed Project is not otherwise implemented. Identification and analysis of these scenarios are informed by the Market Analysis in Section 1.4.

The Status Quo Baseline is included for the purposes of comparing the impacts of the proposed Project to existing conditions. Under the Status Quo Baseline, the proposed Project would not be built. Environmental conditions under the baseline would therefore be the same as those described in the respective resource sections in Chapter 3, Affected Environment.

The No Action Alternative also analyzes several scenarios of how, in the absence of the proposed Project, crude oil from the Western Canadian Sedimentary Basin (WCSB) and the Bakken would likely be shipped to markets, consistent with current market trends and the proposed Project's purpose and need (see Section 1.3, Purpose and Need). These scenarios assume that WCSB and Bakken crude oil production would expand based on industry, independent, and government projections available at the time of this Final Supplemental EIS. Under this set of scenarios, producers would increasingly rely on existing types of transportation, such as rail or a combination of rail and other intermodal methods, to ship crude oil to the U.S. Gulf Coast. The U.S. Department of State (the Department) has no authority to implement these scenarios. They are included to illustrate the likely potential impacts associated with transport of crude oil from the WCSB and the Bakken formations in the absence of the proposed Project. This section assesses three such scenarios in detail and includes a discussion of shipping costs for each method.

2.2.2.2 Major Pipeline Route Alternatives

This set of alternatives includes other potential pipeline routes for transporting WCSB and Bakken crude oil to Steele City, Nebraska, which is the northern terminus of the existing Keystone Cushing Extension. This set of alternatives considers other major route variations for the proposed TransCanada Keystone Pipeline, LP (Keystone) pipeline from the Canada-United States border to Steele City.

Consistent with NEPA, alternative routes were screened to evaluate whether an alternative would be considered in detail in this Final Supplemental EIS. Two phases of screening were conducted and are discussed in detail in Section 2.2.5.1, Screening of Major Route Alternatives. The first round of screening included the following criteria:

- Meeting the proposed Project's purpose and need, including the extent to which additional infrastructure (pipeline) is necessary to access Bakken crude oil;
- Consistency with the proposed border crossing and therefore the approved routing in Canada;
- Availability;
- Reliability;
- Length within the United States;
- Total length of the pipeline, including both the United States and Canada;
- Estimated number of aboveground facilities;
- Length co-located within an existing corridor;
- Acres of land directly affected during construction; and
- Acres of land directly affected permanently.

The following major route alternatives were evaluated in Phase I screening:

- Keystone XL 2011 Steele City Alternative (2011 Steele City Alternative);
- Western Alternative (to Cushing);
- I-90 Corridor Alternative;
- Express-Platte Alternative;
- Steele City Segment—A1A Alternative; and
- Keystone Corridor Alternative:
  - Option 1: Proposed Border Crossing (near Morgan, Montana); and
  - Option 2: Existing Keystone Pipeline Border Crossing (at Pembina, North Dakota).

A map (see Figure 2.2.5-1) showing the major route alternatives considered is found in Section 2.2.5, Major Pipeline Route Alternatives. Of these alternative routes, the following were carried forward for further screening:

- 2011 Steele City Alternative;
- I-90 Corridor Alternative; and
- Steele City Segment—A1A Alternative.

Phase II screening evaluated these three potential alternatives on the following, more specific environmental and cultural criteria:

- Total length of the pipeline, including both the United States and Canada;
- Use of the Canadian-approved Keystone XL pipeline right-of-way (ROW) outside of the United States;
- Approximate acres affected by construction of the proposed Project (based on a typical 110-foot construction ROW)
- Federal lands crossed (miles);
- Principal aquifers crossed (miles);
- American Indian lands crossed (miles);
- Total wetlands crossed (miles);
- U.S. Fish and Wildlife Service (USFWS) critical habitat for threatened and endangered species crossed (miles);
- Known cultural resource sites (listed on National Register of Historic Places) within 500 feet of proposed pipeline;
- Number of waterbodies crossed; and
- Soils designated as highly erodible by wind crossed (miles).

From this screening, the 2011 Steel City Alternative and the I-90 Corridor Alternative were identified as reasonable alternatives to the proposed Project for inclusion and evaluation in this Final Supplemental EIS.

Those major pipeline route alternatives not carried forward were eliminated from further consideration. The full discussion of the screening process and rationale for eliminating alternatives is found in Section 2.2.5.1, Screening of Major Route Alternatives.

2.2.2.3 Other Alternatives Considered but Eliminated from Detailed Analysis in this Final Supplemental EIS

This set of alternatives includes minor route variations, alternative pipeline designs, and alternative sites for aboveground facilities. These alternatives were eliminated because they did not provide a "clear basis for choice among the options for decision makers and the public," as required by the CEQ guidelines (40 CFR 1502.14), or did not meet the proposed Project's purpose and need.

2.2.3 No Action Alternative

NEPA regulations (40 CFR Part 1502.14[d]) specify that the alternatives analysis in an EIS is to include a No Action Alternative. Under this alternative, the Department would deny the Presidential Permit, the proposed Project would not be built (for that or other reasons), and the impacts relating to the proposed Project described in Chapter 4, Environmental Consequences, would not occur.

This outcome focuses only on the specific direct, indirect, or cumulative impacts in the United States associated with construction and operation of the proposed Project that would not occur, and is referred to as the Status Quo Baseline under the No Action Alternative. Analysis of this baseline serves as a benchmark against which other alternatives are evaluated.

The No Action Alternative does not consider in depth the impacts of the upstream (production of crude oil in the oil sands) or downstream (refining of crude oil and/or end-use of refined petroleum products) activities, as these are not part of the proposed Project. As discussed in Section 1.7, Environmental Review of the Canadian Portions of the Keystone XL Project, as a matter of policy, in addition to its environmental analysis of the proposed Project in the United States, the Department has included information regarding potential impacts in Canada (see Section 4.15.4, Extraterritorial Concerns). In so doing, the Department was guided by Executive Order 12114 (Environmental Effects Abroad of Major Federal Actions), which stipulates the procedures and other actions to be taken by federal agencies with respect to environmental impacts outside of the United States. The Canadian government conducted an environmental review of the portion of the proposed pipeline in Canada. As a result, and consistent with Executive Order 12114, the Department did not conduct an in-depth assessment of the potential impacts of the Canadian portion of the proposed pipeline.

To the extent that they would occur, the effects of those upstream and downstream activities that were affected by the proposed Project would be considered indirect effects, as effects that occur later in time or farther removed in distance (40 CFR 1508.8). As noted in Sections 1.4, Market Analysis, and 4.15, Cumulative Effects Assessment and Extraterritorial Concerns, because of broader market dynamics and options for crude oil transport in the North American logistics system, the upstream and downstream activities are unlikely to be substantially different whether or not the proposed Project is constructed.[1]

2.2.3.1 Market Effects that Influence the No Action Alternative

To summarize, production and disposition of crude oil in North America (and throughout the world) is driven by market forces. There exists demand for heavy crude oil in Petroleum Administration for Defense District (PADD) 3, particularly in the Gulf Coast area[2] refineries. In recent years, refiners in PADD 3 have consistently imported approximately 2.2 million barrels

[1] Section 1.4, Market Analysis, reaffirms the conclusion of the Draft Supplemental EIS that approval or denial of any one crude oil transport project, including the proposed Project, remains 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.

[2] Unless otherwise specified, in this Final Supplemental EIS the Gulf Coast area includes coastal refineries from Corpus Christi, Texas, through the New Orleans, Louisiana, region. See Section 1.4, Market Analysis, for a description of refinery regions and PADDs. For the purposes of this Final Supplemental EIS, destination terminals under two of the No Action Alternative scenarios assume delivery of crude oil to transloading facilities in the Houston/Port Arthur, Texas, area.

per day (mmbpd) of heavy crude oil (less than 25 degrees American Petroleum Institute [API] gravity). The proposed Project is supported by long-term contracts to deliver approximately 555,000 barrels per day (bpd) to the Gulf Coast area to meet part of that existing market demand. If the proposed Project is not approved, or is otherwise not constructed, the customers who signed those contracts would be expected to seek alternate transportation options to deliver the crude oil that had been committed to the proposed Project to the Gulf Coast area. Those customers would most likely seek other pipelines (if available) because they generally offer the most economic means of overland transportation of large volumes of crude oil. If other pipelines are not available, those customers would likely seek and utilize other modes of transportation if the increased cost of such transportation does not render it uneconomic to produce and transport the crude oil to market.

The analysis in the 2011 Final EIS had not carried forward other modes of transportation for full analysis as reasonable alternatives largely because of economic practicability; however, developments since then demonstrate that other modes of transportation are being economically utilized. Although the Final EIS noted the significant increase in capacity to transport crude oil using unit trains, particularly in the Bakken area, at that time the new capacity was only beginning to be developed.

As demonstrated in Section 1.4, Market Analysis, rail, although still generally more expensive than pipelines for transporting crude oil, is being used as a transport alternative, particularly where there is inadequate pipeline capacity. As noted in Section 1.4, crude loadings in Canada have been increasing from nominal amounts in early 2011, to approximately 160,000 bpd by April 2013, then declining back to around 150,000 bpd before recovering back to approximately 185,000 bpd in October. Not all of the crude oil loaded by rail in Western Canada is necessarily exported to the United States. The Canadian National Energy Board (NEB) reports exports of crude oil by rail on an annual basis, but also provides statistics by quarter for the first half of 2012 and the first half of 2013. The NEB statistics reflect a similar trend in increasing rail transport from 2011 to 2013, and indicate approximately 70 percent to 80 percent of the crude by rail loaded in western Canada is exported to the United States.[3] It is estimated that approximately 50 percent of the crude oil exported by rail to the United States was delivered to PADD 3.

Western Canada is in the midst of a significant build-out of specialized crude by rail loading facilities that would support substantial increases in shipping crude oil. At the end of 2011, crude oil loading facilities had an estimated capacity to load approximately 60,000 bpd, with most of that capacity being in the Canadian Bakken area that produces almost exclusively light crude oil. This loading capacity had grown to approximately 200,000 bpd at the end of 2012, with approximately 55 percent of the loading capacity in areas of the WCSB that produce primarily heavy crude oil and 45 percent in the Canadian Bakken. In mid-2013, crude-by-rail loading capacity began to increase substantially, particularly in the portions of the WCSB that produce primarily heavy crude oil. By the end of 2014, the total crude-by-rail loading capacity is expected to be approximately 1.1 million bpd (75 percent in the WCSB and 25 percent in the Canadian Bakken).

[3] This would mean that in 2013, 25,000 to 40,000 bpd of crude oil were being exported via rail from the WCSB to other locations in Canada. There have been media reports that refineries on the Canadian West Coast and Canadian East Coast are receiving crude oil shipments from the WCSB by rail (CBC 2013; Penty 2012).

The leading production area that has developed crude by rail is in the Bakken in North Dakota and Montana. When the 2011 Final EIS (and the EnSys Reports, see Section 1.4, Market Analysis) were prepared, rail shipments were just beginning to occur in large quantities from the Bakken. When EnSys 2010 was completed in December 2010, only approximately 50,000 bpd of crude oil were being shipped by rail; there was capacity at rail facilities to load approximately 115,000 bpd of crude oil. When the Final EIS was released in August 2011, there were approximately 80,000 bpd of crude oil being shipped by rail and capacity to load approximately 275,000 bpd of crude oil. In mid-2013, there was approximately 700,000 bpd shipped from the Bakken and a capacity to load over 900,000 bpd.

Rail offers the benefits of lower capital costs (as most of the rail infrastructure already exists), shorter time to develop, quicker transit to market, greater flexibility with market destinations, and shorter contract terms (typically 0 to 5 years). As other modes of transportation (e.g., tankers and barges) are also being economically utilized to transport such large and growing volumes of crude oil throughout North America, they are being further analyzed as alternatives to transport crude oil from the WCSB and Bakken basins to refinery markets, along with other potential proposed pipelines (e.g., Northern Gateway and Trans Mountain in British Columbia), modifications to existing pipelines (e.g., reversal of flow in the Seaway Pipeline), and construction of a new pipeline (e.g., Flanagan South). Therefore, the development of alternative methods to transport WCSB and Bakken crude to refinery markets is considered a *predictable action* (CEQ 1981). The discussion below identifies and screens other predictable actions that should be included under the Status Quo Baseline and scenarios under the No Action Alternative.

2.2.3.2 Identification and Screening of No Action Alternative Scenarios

Several technically feasible scenarios were identified for the transport of WCSB and Bakken crude oil to Gulf Coast area refineries based on existing and otherwise suggested transport measures:

- Rail to Vancouver or Kitimat, British Columbia, and tanker to the Gulf Coast area market;
- Rail to Prince Rupert, British Columbia, and tanker to the Gulf Coast area market;
- Rail directly to the Gulf Coast area market;
- Rail to the Cushing area and pipeline to the Gulf Coast area market;
- Rail to Wood River, Illinois, or other Mississippi River ports, and then barge to the Gulf Coast area market;
- Trucking;
- Existing pipeline system alternatives (i.e., use available capacity in existing pipelines); and
- Other recent crude oil transportation proposals.

In addition to these transport scenarios, other scenarios considered include:

- Use of alternative energy sources; and
- Implementation of energy conservation measures.

The screening of these scenarios took into consideration several factors including transport cost, timing (e.g., could it be implemented within the same general timeframe as the proposed Project), and whether it could transport approximately the same volume of crude oil as currently contracted to be shipped by the proposed Project, and could be scaled up to handle the maximum throughput of the proposed Project. The Status Quo Baseline and three scenarios were included for further evaluation in this Final Supplemental EIS:

- The Status Quo Baseline, under which the direct, indirect, and cumulative impacts in the United States associated with construction and operation of the proposed Project in the Project area would not occur. The Status Quo Baseline is a snapshot of the crude oil delivery systems at current levels and is used as a comparison for other alternatives and scenarios;
- The Rail/Pipeline Scenario, which could transport the equivalent capacity as the proposed Project by existing rail network and pipelines (i.e., up to 730,000 bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil [see Section 2.2.4.1, Rail/Pipeline Scenario]);
- The Rail/Tanker Scenario, which could transport the equivalent capacity as the proposed Project by existing rail network and marine vessel (i.e., up to 730,000 bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil [see Section 2.2.4.2, Rail/Tanker Scenario]); and
- The Rail Direct to Gulf Coast Scenario, which could transport the equivalent capacity of the proposed Project (i.e., up to 730,000 bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil) from producers on Class I railroads directly to the Gulf Coast (see Section 2.2.4.3, Rail Direct to Gulf Coast Scenario).

The rationale for eliminating the other scenarios is provided in Section 2.2.4.4, Scenarios Considered but Eliminated from Detailed Analysis.

Rail Transport Assumptions

For purposes of this analysis, assumptions were required regarding crude oil loading locations; whether the crude oil would be transported as dilbit, synbit, railbit, or bitumen; train sizes (e.g., 100 railcar unit trains); transportation times; rail routes; and unloading locations. The basis for the assumptions used in this analysis is described below, but it is important to note that these are simplifying assumptions. In reality, and as current trends have indicated, crude oil producers and refiners, transportation companies, and other developers are developing multiple solutions (e.g., multiple loading locations, forms of crude oil shipped, train sizes, routes, and destinations). The scenarios presented here are intended to be a reasonable representation of likely rail transport of WCSB and Bakken crude oil, but do not imply that these scenarios are the only, or necessarily the best, rail options.

Loading Locations

WCSB crude oil production for delivery by the proposed Project centers around Fort McMurray, Alberta. Currently, crude oil is shipped by pipeline from the Fort McMurray and Cold Lake area about 350 miles south to the Hardisty Hub, which is a gathering point for several large pipeline systems, including the existing Keystone pipeline system.

Both Lloydminster, Saskatchewan, and Edmonton, Alberta, have been considered for crude-by-rail hubs. They are central to the WCSB region and are served by both Canadian Class I[4] railroads. Lloydminster was selected as the representative point of origin to develop this scenario since the Canadian Pacific Railway System (CPRS) currently has a crude oil loading terminal at Lloydminster (CPRS 2012) and Canadian National (CN) also serves Lloydminster. Lloydminster is relatively close to Hardisty (about 68 miles) and is about the same rail distance to the destination markets as Hardisty.

TransCanada has recently announced that it had entered into a partnership to build the 900,000 bpd crude oil and diluent Grand Rapids pipeline system from Fort McMurray, Alberta, to the Edmonton region (TransCanada 2013a). The Heartland terminal facility north of Edmonton would have storage capacity for 1.9 million bbl of crude oil. This facility could be connected to the proposed Heartland pipeline system, which would extend 310 miles from Edmonton to Hardisty, from which it would connect to the Keystone pipeline system (TransCanada 2013b). Epping, North Dakota, was selected as a representative point of origin for transporting Bakken crude oil because it is one of the locations with an existing rail terminal already servicing that location. The construction of additional pipeline, transloading, and storage capacity in this area would enable it to serve as the major hub for the crude-by-rail scenarios. It is also possible that constraints in future pipeline capacity could make these locations more attractive to on-loading rail facility (so-called midstream) developers.

Since the publication of the Draft Supplemental EIS in March 2013, a variety of developers have either begun or have announced the construction of rail terminals capable of loading large volumes of WCSB crude oil. Similar activities have occurred with respect to the Bakken crude oil region (see Section 1.4, Market Analysis). Where appropriate, these changes have been reflected in the number of new facilities that would be required to accommodate the proposed Project's volume of crude oil if it is not built.

It is assumed that crude oil currently under contract through the proposed Project would, following needed infrastructure improvements described below, be delivered to Lloydminster and Epping through similar means as it would have been to Hardisty and Baker, Montana. As a result, delivery to the points of origin is not included in the scope of this analysis. There are no Class I rail routes that serve both Lloydminster and Epping; therefore, two separate rail scenarios have been proposed.

Form of Crude Oil Transported

As explained in Section 1.4, Market Analysis, crude oil from the WCSB can be transported by rail as dilbit, railbit, or undiluted bitumen (i.e., rawbit). Dilbit can be transported in standard rail tank cars. The railbit and rawbit require insulated rail cars with steam coils for reheating the bitumen to reduce viscosity prior to unloading at the destination terminal.

As explained in Section 1.4, Market Analysis, while it is estimated to be more expensive to ship bitumen on a per barrel basis because it requires insulated/steam coiled railcars and less bitumen could be loaded into each rail car because of weight restrictions (a result of differences in density), the ultimate delivery to the refineries is 100 percent of the bitumen produced in the

[4] A Class I railroad in the United States is a large freight railroad company, as classified based on operating revenue. The Surface Transportation Board defines a Class I railroad in the United States as "having annual carrier operating revenues of $250 million or more" (Surface Transportation Board 2012).

WCSB, rather than a blend with lighter hydrocarbon diluents (very light oil obtained from natural gas production) that the WCSB producers have to purchase to make bitumen into dilbit. Removal of the need for diluent would reduce the volume required for transport by the roughly 30 percent of volume of diluent used in the dilbit production or 15 percent of volume of diluent used in railbit production. The benefit of transporting bitumen is that fewer barrels would be handled, and there would be less need to transport diluent into Canada for blending the volume of bitumen shipped by rail into dilbit.

Even though the rail costs per barrel of bitumen may be higher, producers could receive a better netback by shipping bitumen by rail to the Gulf Coast rather than shipping it to Edmonton or Hardisty, where they are receiving significantly discounted prices. The producer could receive much higher netback prices per barrel of bitumen by accessing better prices on the U.S. Gulf Coast, backhauling diluent from the U.S. Gulf Coast, and shipping fewer total barrels of product.

While there are some logistical concerns associated with scaling up the bitumen or railbit crude-by-rail scenarios to the full capacity of the proposed Project, it has been assumed for the purposes of this analysis that all three forms of WCSB crude could be transported. This would likely result in slightly different numbers of unit trains needed per day because of different railcar load limits for the various crude oil types (see Table 2.2-1).

Table 2.2-1 Assumed Railcar Load Capacity

		Bakken General Service Tank	Dilbit General Service Tank	Railbit Insulated Tank	Bitumen Insulated Tank	Diluent Insulated Tank
Volume Capacity	gal	31,172	31,172	28,413	28,413	28,413
Tare Weight	pound	75,300	75,300	81,600	81,600	81,600
Maximum Load	pound	192,700	192,700	186,400	186,400	186,400
Total Gross Weight Limit	pound	268,000	268,000	268,000	268,000	268,000
Gallons/bbl		42	42	42	42	42
API		42	22	14.2	8.4	60
Mass per Gallon of Crude	pound/gal	6.79	7.69	8.105	8.44	6.15
Maximum	gal/car	28,380	25,059	22,998	22,085	28,413
Maximum	bbl/car	676	597	548	526	677

Rail Operations

All rail movements were assumed to occur in unit trains. A unit train transports all of its cargo from a single starting point to a single end point with no intermediate stops or storage, generally on one bill of lading (i.e., consisting of one product delivered to one point). This provides shippers with an economy of scale, minimizes delays, and increases reliability. For the purposes of the analysis in this Final Supplemental EIS, the unit trains are assumed to be 100 railcars in length.[5] The railcars remain together as one unit train and cycle back and forth between the origin and destination, loaded and empty. Unit trains are delivered empty to the rail loading terminal, and then loaded and delivered back to the rail carrier within 24 hours. At destination, the loaded trains are delivered to the terminal and unloaded; the empty trains are delivered back

[5] The number of rail cars in unit trains transporting crude oil may vary. Burlington Northern Santa Fe (BNSF) recently announced that it was considering units trains of 118 cars. Coal unit trains can be up to 150 cars long. For the purposes of analysis in this Final Supplemental EIS, unit trains consist of 100 railcars.

to the rail carrier within 24 hours. Some terminals can load or unload one 100-car unit train in 12 hours.

Number of Unit Trains

Crude oil from the Bakken formation would be shipped as a liquid with no special railcar or handling required. As described above, WCSB could be shipped in a number of forms, such as raw bitumen (rawbit), railbit, or dilbit with corresponding railcar weight limitations (Table 2.2-1). Under the rail-related scenarios, the number of unit trains per day would depend on which of these types of crude oil was being shipped. The proposed Project assumes 730,000 bpd of WCSB (shipped as dilbit) and 100,000 bpd of Bakken crude oil. Table 2.2-2 provides a daily average number of units based on the type of crude oil being shipped.

Table 2.2-2 Average Number of Unit Trains per Day for WCSB and Bakken Crude Oil

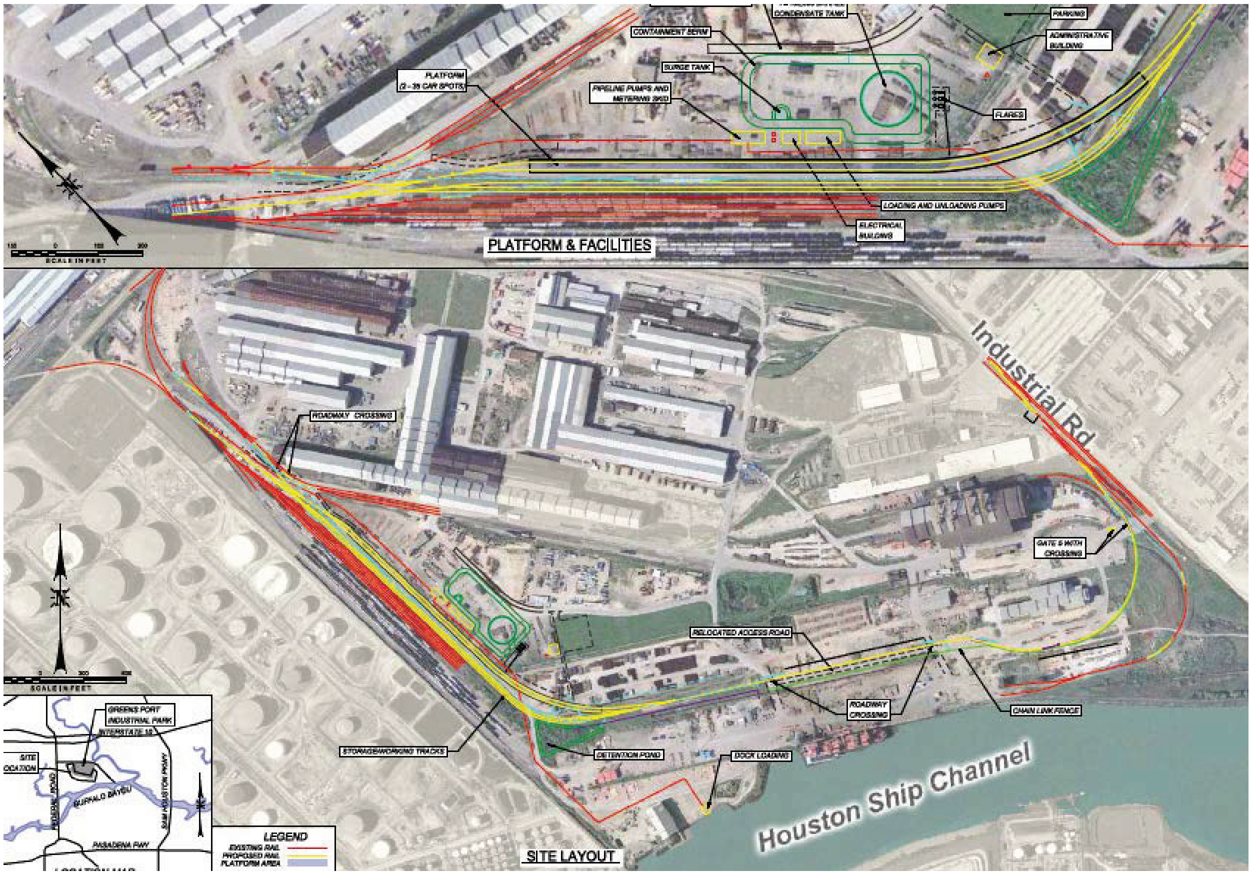
	Bakken	Dilbit	Railbit	Bitumen
Barrels/Day	100,000	730,000	620,500	584,000
Maximum Load/Car (bbl)	676	594	552	503
# Railcars/Day	148	1229	1124	1161
# Unit Trains/Day	1-2	12	11	12
Total Unit Trains/Day(Bakken + WCSB)[a]		14	13[b]	14[c]

[a] Rounded to nearest whole number average per day.
[b] Railbit would only be shipped from the WCSB.
[c] Bitumen would only be shipped from the WCSB.
Note: The total number of unit trains required could vary depending on the product shipped, and the size and number of the cars used. See Appendix C, Supplemental Information to Market Analysis, for additional information.

The number of unit trains would average 12 to 14 per day depending on the type of crude being shipped from the WCSB. These figures are used in each of the scenarios below in Sections 2.2.4.1, Rail/Pipeline Scenario; Section 2.2.4.2, Rail/Tanker Scenario; and Section 2.2.4.3, Rail Direct to Gulf Coast Scenario.

Rail Routes and Unloading Destinations

The rationale for the specific rail routes and unloading locations proposed for the Rail/Pipeline, Rail/Tanker, and Rail Direct to the Gulf Coast scenarios are described below in the description of each scenario. Given recent developments in crude-by-rail terminal construction in the WCSB region, fewer new facilities may be needed than had been previously estimated in the 2013 Draft Supplemental EIS. Some of the loading capacity may be filled by expansion of existing facilities or by building new terminals. Given the uncertainty in the amount of new construction needed, it has been assumed for analysis purposes that the equivalent of two new terminals would be needed in Lloydminster, Saskatchewan, and one new terminal in Epping, North Dakota. Facility requirements in Stroud, Oklahoma, and Prince Rupert, British Columbia, would vary depending on the scenario. Finally, no new construction would likely be needed for off-loading facilities in the Gulf Coast as the region has seen a recent rapid increase in capacity, which is expected to handle much larger amounts of crude by rail in the next 2 to 3 years. See Figure 2.2.3-1 for an example of a representative rail off-loading facility in the Gulf Coast area.



Source: Kinder Morgan 2013

Figure 2.2.3-1 Representative Crude by Rail Off-Loading Facility in the Gulf Coast Area

2.2.4 No Action Alternative Scenario Descriptions

The following is an overview of the scenarios under the No Action Alternative, including the development that would be necessary to accommodate transportation of crude oil from the WCSB and Bakken Formation to replace the proposed Project's volumes if it is not built and if other additional pipeline capacity does not become available.

As noted above, changes in the industry since the publication of the 2013 Draft Supplemental EIS have altered several assumptions regarding the amount of new development that would be needed to accommodate up to 830,000 bpd of crude oil shipments by rail and other transportation modes. While some construction assumptions have changed, most of the operational assumptions have not. These are specified under each of the detailed descriptions of the scenarios.

2.2.4.1 Rail/Pipeline Scenario

Under this scenario, the WCSB crude in the form of dilbit would be transported to Gulf Coast area refineries via the following modes and routes (see Figure 2.2.4-1):

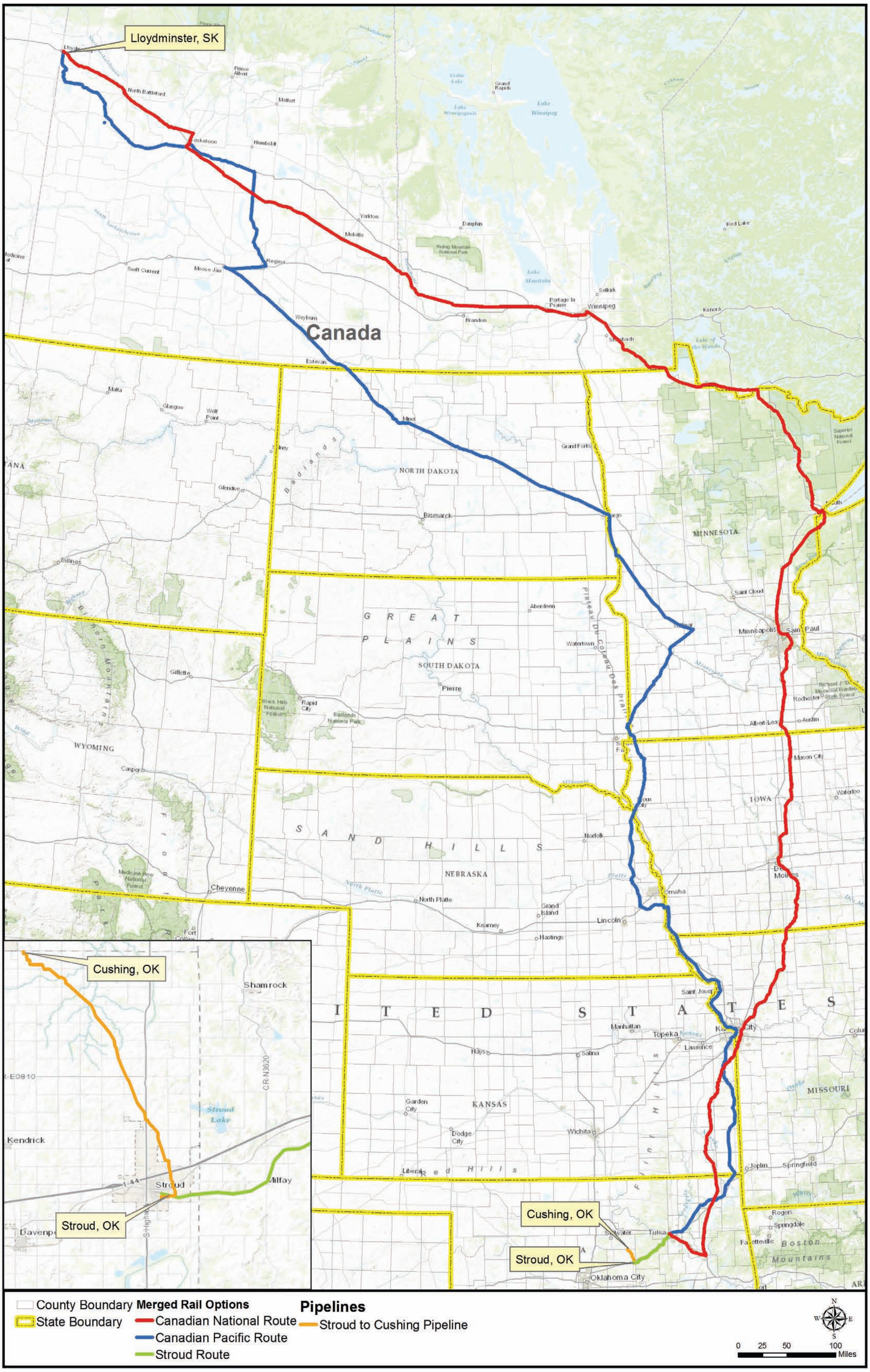
- Loaded onto rail in Lloydminster, Saskatchewan, from new, existing, and expanded rail terminals and transported approximately 1,900 miles (using CPRS and BNSF Railway Company [BNSF]) or approximately 2,000 miles (using CN and Union Pacific [UP] routing) along existing rail lines via common carrier railroads to new rail terminals at Stroud, Oklahoma. Stroud was selected as the destination rail terminal because, currently, there are no railroads that go all the way to Cushing. These representative routes are used for analysis purposes only;
- Transferred to new oil storage facilities and pipeline at Stroud, Oklahoma, and transported via a new pipeline approximately 17 miles to the existing oil terminal at Cushing, Oklahoma. Crude oil is currently being shipped by this method, but it is assumed that additional pipeline capacity would be needed to accommodate the added volume of crude oil; and
- Transferred by existing pipelines from Cushing approximately 533 miles to the Gulf Coast area for refining.

The Bakken crude would be transported via the following modes and routes (see Figure 2.2.4-2):

- Loaded onto rail from a new rail terminal in Epping, North Dakota,[6] and transported approximately 1,347 miles to new rail terminals with storage tanks at Stroud, Oklahoma, via common carrier railroad (assumed to be the same terminals identified for the WCSB crude);
- Transported from Stroud via a new pipeline approximately 17 miles to the existing oil terminal at Cushing, Oklahoma; and
- Transferred by existing pipeline approximately 533 miles from Cushing, Oklahoma, to the Gulf Coast area for refining.

These representative routes would use existing rail and pipeline infrastructure to the extent possible, but would require construction of the following new facilities, as shown in Table 2.2-3. The loading and unloading terminals would probably be sited near the railroad mainline. The terminals could be clustered near existing terminals, or spread out in the vicinity of Epping, Stroud, or Lloydminster. Representative sites were identified for these new terminals for purposes of this analysis.

[6] The Epping area currently has one operating rail on-loading facility. For the purposes of analysis, one additional terminal would be needed because of future expected expansion of exports from the Bakken field.



Source: Esri 2013

Figure 2.2.4-1 Representative Rail Routes between Canada and the United States: Rail/Pipeline Scenario

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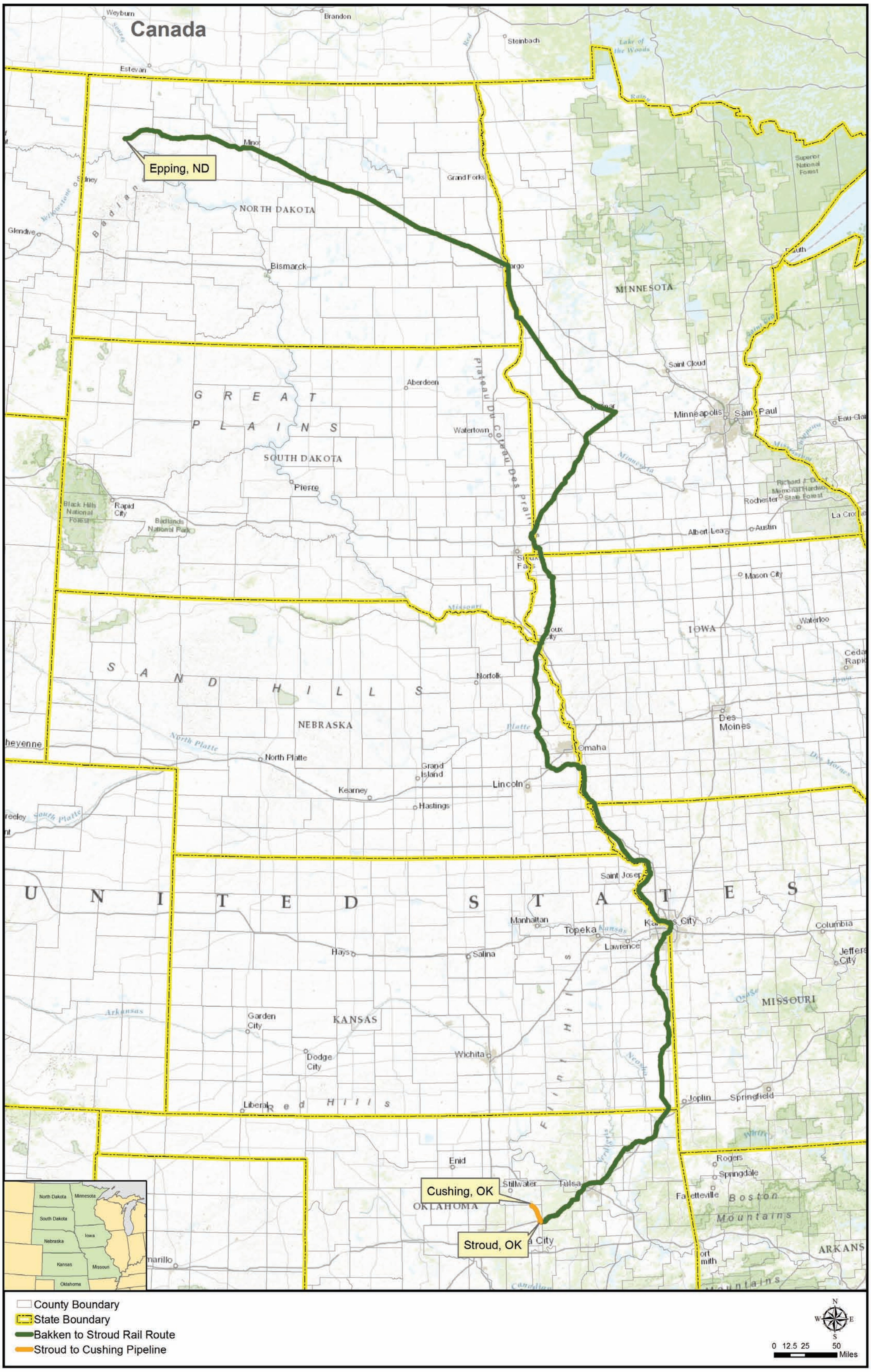

Source: Esri 2013

Figure 2.2.4-2 Representative Bakken to Cushing Rail Route

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Table 2.2-3 Crude Oil by Rail to Oklahoma/Pipeline to Gulf Coast Area Scenario: New Construction and Specifications

	Lloydminster, Saskatchewan	Epping, North Dakota	Stroud and Cushing, Oklahoma
Throughput (bpd)	up to 730,000 bpd WCSB	up to 100,000 bpd Bakken	up to 730,000 bpd WCSB; up to 100,000 bpd Bakken
New Unit Train[a] Terminal Sites Needed	2 new sites[b]; 2 unit train loadings per day/site	1 new site; 1-2 train loadings per day/site	7 new terminal sites; 2 train off-loadings per day/site for WCSB 1 off-loading/day for Bakken at existing site
Storage Needs	4 (75,000 barrel tanks per site)	4 (75,000 barrel tanks)	4 (75,000 barrel tanks per site) at Stroud 11 (75,000 barrel storage tanks) at Cushing
Number of Trains[c]	up to 12 unit trains per day	up to 2 unit trains per day	up to 14 unit trains per day (delivered WCSB + Bakken)
Total New Track (mainly within terminal)	50,000 to 60,000 feet total for 2 terminals	25,000 to 30,000 feet total	175,000 to 210,000 feet total for 7 terminals
Terminal Acreage	1,000 (500 acres per terminal site x 2)	500 acres	3,500 acres (500 acres per terminal site x 7)
New Pipeline Needed	None	None	17-mile Stroud to Cushing pipeline
Total Acreage for New Terminals and Pipeline (approximate)	**Terminals: 1,000 acres** **Total: 1,000 acres**	**Terminal: 500 acres** **Total: 500 acres**	**Terminals: 3,500 acres** **Pipeline: 103 acres (permanent)** **227 acres (temporary)** **Total: 3,603 acres (permanent)**
	Total Acres for Scenario:	**5,103 acres** (permanent disturbance) **5,227 acres** (temporary disturbance)	

[a] A *unit train* transports all of its cargo from a single starting point to a single end point with no intermediate stops or storage. This provides shippers with an economy of scale. For the purposes of the analysis in this Final Supplemental EIS, the unit trains would be 100 railcars in length.
[b] The number of new sites assumes a combination of new construction and expansion at existing facilities.
[c] The number of trains per day includes those originating from other, existing terminals to transport a total of 730,000 bpd of WCSB crude. See Table 2.2-2.

Lloydminster Loading Terminals

Depending on the type of crude oil shipped from the WCSB, up to 12 unit trains would be needed to transport 730,000 bpd of dilbit equivalent from Lloydminster to Stroud. A new rail terminal located near the mainline would have the capacity to load two 100-car unit trains per day. Based on the proposed throughput and the terminal capability, two new terminal sites would need to be constructed at Lloydminster to load up to 730,000 bpd. Each terminal would occupy about 500 acres.[7] The terminals would include a loop track (25,000 to 30,000 feet per terminal); oil storage tanks (four 75,000 barrel tanks per site); and other infrastructure typically required for loading and unloading crude oil. Figure 2.2.4-3 shows an existing loading terminal in Canada representative of the type of facility that would be needed.

Source: Google Maps 2013

Note: Crude by rail unit train facility under construction in Alberta.

Figure 2.2.4-3 Representative Rail Loading Facility (under construction) in Canada

[7] This acreage was used for analysis purposes based on other typical facilities in the region. The exact dimensions of future facilities may differ. Crude by rail terminal developers in Canada have increasingly added double loop tracks to increase the amount of crude oil transloaded per day at existing facilities.

Loop track construction would include the following:

- Rail bed construction—a rail bed would be constructed upon which the ballast,[8] rail ties, and rail would then be laid. Rail bed construction would require clearing, excavating earth and rock on potentially previously undisturbed land, and removing and stockpiling topsoil, where needed. Construction could require both cuts and fills.
- Track construction—in-place track construction would consist of placing ties, rail, and ballast on top of the rail bed. The track could be constructed on site, or skeleton track panels could be constructed off-site and transported to the site.
- Construction staging areas—the proposed loop and terminal site could require construction staging areas to store material, weld sections of the rail line, and otherwise support construction activities. Staging areas would be identified before construction would begin.

Additional considerations for the Lloydminster Loading Terminal would include the following:

- Associated facilities—these would include buildings, maintenance equipment, security, and safety equipment.
- Associated pipelines—railcars would on-load from local storage tanks. A short pipeline from the temporary storage to the terminal would be needed at each new terminal location.
- Power requirements—it was assumed that each terminal would require 5 megawatts of electrical power. Power requirements would include new transmission lines to each new on-loading terminal.

Epping Loading Terminal

Bakken crude currently moves in unit train quantities to both the Gulf Coast area and to Stroud, Oklahoma. There are multiple terminals in North Dakota that could load unit-train quantities of Bakken crude. Rangeland Energy's terminal at Epping, North Dakota, is representative of an origination terminal. This terminal loads 100-car unit trains of Bakken crude today. It is served by BNSF, one of the two largest Class I railroads serving the western United States (Rangeland Energy 2012). Under this scenario, a new loading terminal would be constructed in the Epping vicinity to transport up to 100,000 bpd of Bakken crude oil. Also, while the existing Stroud facility has capacity to transload up to 100,000 bpd of Bakken crude oil to Cushing, it is assumed for analysis purposes that new rail facilities plus a 17-mile pipeline to Cushing would be needed to accommodate increases in crude oil deliveries.

Stroud Off-loading and Storage Terminals

Cushing, Oklahoma does not have rail service, but rail service is available in Stroud, 17 miles away. WCSB crude would need to be transported by rail to Stroud, and then from Stroud by new and existing pipelines to Cushing (from Cushing it would be transported to the Gulf Coast area via existing pipelines). An existing pipeline in Stroud operated by EOG Resources connects to the Stillwater Central Railroad (SLWC); however, its capacity is limited to 90,000 bpd. To accommodate WCSB crude, new off-loading terminals would need to be constructed in the Stroud area near the SLWC and a new pipeline would need to be built to transfer the WCSB crude from Stroud into the existing storage infrastructure in Cushing. The off-loading facilities

[8] Ballast is the rock base used for railroad beds.

would need the same basic capacity as the on-loading terminals (seven new terminals with the capacity to off-load fourteen 100-car unit trains per day) and would need the following terminal components:

- Sufficient track to hold three-plus unit trains at any time (loop track not necessary for off-loading terminals).
- Approximately 500-acres in land acquisition per terminal to handle unit trains, storage, and ancillary facilities (e.g., access roads, pump stations, and construction camps). Seven terminals would require about 3,500 acres of land.
- Four 75,000-barrel tanks at each terminal to receive the crude from the railcars and store crude for shipment into the pipeline to Cushing. For example, unit trains may be unloading WCSB into Tanks 1 and 3 while Tanks 2 and 4 are loading product into the pipeline to Cushing. The next unit trains would unload into Tanks 2 and 4 while Tanks 1 and 3 are switched to pump into the pipeline.
- Under this scenario, one new pipeline would be required from Stroud to Cushing. A number of midstream companies own storage tanks in Cushing, and they are the likely parties that may invest in rail off-loading terminals. These parties would presumably want the off-loading terminals connected to their own storage tanks in Cushing, and this could lead to more than one pipeline being built. However, for analysis purposes, only one pipeline has been considered. The pipeline would require a permanent ROW of about 103 acres, with up to 227 acres needed during construction.
- Supporting infrastructure (buildings, maintenance equipment, security, and safety equipment).
- For the purposes of this analysis, it is assumed that the power requirements would include new transmission lines to each new off-loading terminal.

Rail and Pipeline Cost Assumptions

Capital costs were estimated based on cost information for terminals recently completed or currently under construction and on assumptions regarding storage and track unit costs (Table 2.2-4). Costs for individual terminals were multiplied by the number of terminals at each; costs for transmission lines and pipelines (the latter at Stroud only) were added.

Table 2.2-4 Estimated Cost of New Facilities and Estimated Jobs Created for Crude by Rail/Pipeline Scenario

	Rail Terminals		
	Lloydminster	**Epping**	**Stroud**
Capital Costs	$185,700,000	$110,000,000	$700,000,000
Construction Jobs	NA[a]	750	4,750
Construction Period (years)	2	1	2
Operations Costs (annual)	$14,000,000	$7,000,000	$49,000,000
Operations Jobs	NA	50	400

[a] NA = not applicable; the jobs number was derived from IMPLAN® modeling system, which does not apply to Canadian operations

Operations employment were estimated using IMPLAN® (MIG, Inc. 2011), a proprietary input-output modeling system founded on data available from the U.S. Bureau of Economic Analysis, Bureau of Labor Statistics, U.S. Census Bureau, and other sources. IMPLAN® is regarded by government agencies and academic institutions as a highly credible economic modeling system. Additional information regarding the IMPLAN® modeling system and its application in the analysis in this Final Supplemental EIS is in Section 4.10, Socioeconomics.

Construction employment estimates are based on the capital cost of each terminal provided in Table 2.2-4 and were analyzed through Industry 36, *Construction of other new nonresidential structures*, which contains all using national relationships for heavy construction activity. The direct impacts from construction would be expected to be local, but would depend on the type of firm hired to complete construction activities. Operations employment estimates are based on the operations cost of each terminal provided in Table 2.2-4, and were analyzed through Industry 338, *Scenic and sightseeing transportation and support activities for transportation*, using national relationships which contains all port, rail, and airport operations.

Shipping costs for WCSB from Lloydminster and Bakken crude oil from Epping to Stroud, Oklahoma, include estimates for loading and unloading railcars, and leasing and transfer costs at destination terminals. These costs are shown on Table 2.2-5 below.

Table 2.2-5 Rail Costs from Lloydminster, Saskatchewan, to Stroud, Oklahoma, and Bakken Crude Oil from Epping, North Dakota, to Stroud, Oklahoma

	Cost $/barrel		
	CN-UP-SLWC[a]	**Canadian Pacific-BNSF-SLWC**[b]	**BNSF-SLWC**
Loading railcars	1.50	1.50	1.50
Rail Lloydminster, Saskatchewan—Stroud, Oklahoma	10.00	10.75	--
Rail Epping, North Dakota - Stroud, Oklahoma	--	--	4.75
Railcar lease	1.10	1.00	0.75
Transfer costs—railcars to storage tanks	1.50	1.50	1.50
Total	**14.10**	**14.75**	**8.50**

[a] Canadian Northern-Union Pacific-Stillwater Central Railroad
[b] Canadian Pacific-BNSF-Stillwater Central Railroad

2.2.4.2 Rail/Tanker Scenario

As noted above under the Rail/Pipeline Scenario and in Section 1.4, Market Analysis, producers in the Canadian oil sands and in the Bakken have begun to use alternative methods to transport their product to refineries. A second likely transportation method would include transporting crude oil by rail from Alberta to a western Canadian port. From there, the crude oil could be exported via tankers and delivered to various destinations. Tankers are capable of carrying heavy WCSB crudes (as well as lighter crudes) in the form of dilbit and as undiluted bitumen. Transport of dilbit on a tanker is no different from transporting any conventional heavy crude oil and does not require special equipment. Tankers generally have steam heaters so they could carry dilbit with no modifications needed, but may require upgraded heating systems and tank insulation to transport bitumen. While not on a large scale, tanker movements of up to 15,000 bpd of WCSB crude have moved in recent years from the Westridge dock (Kinder Morgan's Trans Mountain pipeline) in Vancouver via tanker to the U.S. Gulf Coast area.

If cross-border pipeline capacity into the United States was constrained, moving WCSB crudes from Pacific ports in volume to the U.S. Gulf Coast could become attractive, but would require construction of new or expansion of existing port facilities.[9] Using heavy crude as a basis, a present day movement via Trans Mountain to Vancouver and thence on a Panamax tanker via the Panama Canal to Houston would have a total freight cost (pipeline tariff plus tanker freight and Panama toll) of around $8.50 to 9.50 per barrel. Recognizing that Kinder Morgan plans to enable future shipment in larger Suezmax tankers, and that the Panama Canal Authority is expanding the Canal to take tankers of that size, the rate using a Suezmax would be approximately $1 per barrel lower. These rates compare to approximately $8-10 per barrel to move heavy crude via pipeline from Hardisty to Houston. Thus, while in normal markets a tanker movement from Western Canada would be somewhat more costly than via pipeline, in a scenario where ability to move WCSB crudes by pipeline to the U.S. Gulf Coast were constrained, refiners in the U.S. Gulf Coast could opt for tanker transport.

There are several pipelines proposed for transporting WCSB crude oil to the Pacific, including Trans Mountain to Vancouver and Northern Gateway and Northern Leg to Kitimat. These pipelines have been controversial and are encountering significant opposition. It is uncertain whether such projects ultimately would be approved. The option of transporting WCSB crude oil to the Pacific via pipeline is described in more detail in Section 2.2.4.3, Rail Direct to Gulf Coast Scenario. As discussed above, rail may offer a viable alternative for transporting crude oil to ports in Vancouver, Kitimat, and Prince Rupert in British Columbia, as all of these ports are served by Class I rail carriers.[10]

There have also been proposals for the transport of WCSB crude oil to the Canadian east coast by converting existing natural gas pipelines, such as the proposed TransCanada Energy East project, to carry crude oil, rail,[11] and/or tankers via the St. Lawrence Seaway. These options appear to be a bit more speculative and would incur logistical challenges and potentially permitting issues. For example, the option of tanker transport would be constrained to a maximum tanker size of 45,000 ton capacity by size restrictions along the St. Lawrence Seaway system. These options would clearly be more expensive, relative to the other scenarios discussed in this section, if the ultimate destination for the crude oil is the U.S. Gulf Coast.

Because of the uncertainty associated with whether these proposed pipelines would be approved and when, rail transport of crude oil to Prince Rupert and onward transport via tanker to the Gulf Coast area refineries was selected for the Rail/Tanker Scenario. WCSB would be transported as follows (see Figure 2.2.4-4):

- Loaded onto rail in Lloydminster and transported to Prince Rupert, British Columbia;
- Transferred to a new/expanded marine terminal at Prince Rupert; and
- Shipped via Suezmax vessels to the Gulf Coast area (Houston/Port Arthur) through the Panama Canal.

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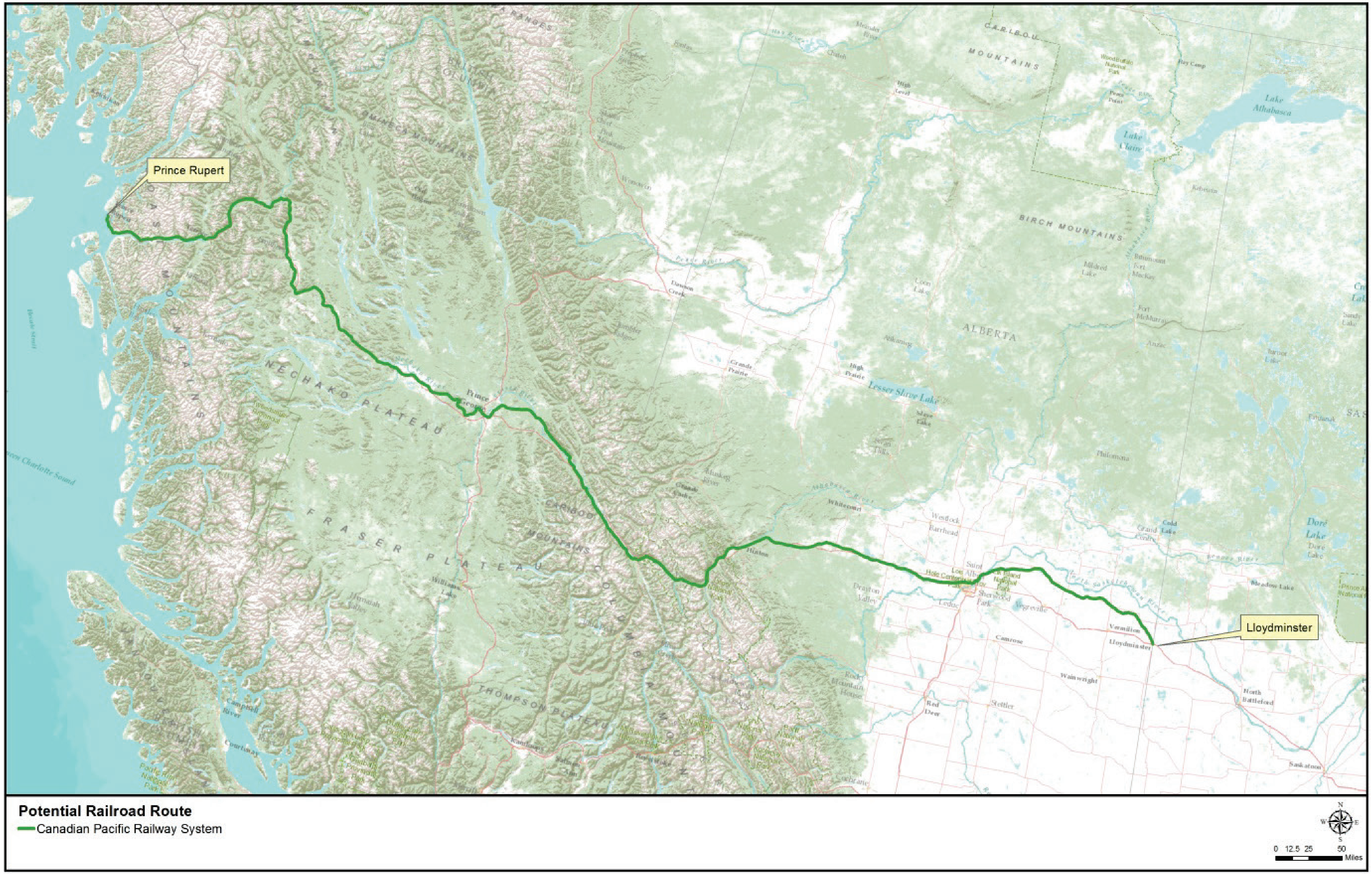
[9] Nexen Inc. is exploring moving oil by rail to Prince Rupert, British Columbia, to export crude onto tankers for delivery to Asia markets (Vanderklippe 2013).
[10] There are also rail to marine tanker transloading facilities on the U.S. West Coast that are served by Class I railroads and that could receive Canadian crudes.
[11] The Irving oil refinery in Saint John, New Brunswick, receives crude oil by rail from the Bakken and Western Canada.



Source: Esri 2013

Figure 2.2.4-4 Representative Rail Route from Lloydminster to Prince Rupert: Rail/Tanker Scenario

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However, if WCSB crude oil reaches a Pacific port, regardless of whether by rail or by pipeline, the economics for movement via tanker would favor shipping the oil to Asia rather than the Gulf Coast area. The cost of transporting crude oil via tanker from Prince Rupert to Houston and Port Arthur is estimated to be approximately $4.70 per barrel, whereas the transport cost via tanker from Prince Rupert to refinery ports in Asia (e.g., Ulsan, South Korea and Dalian, China), is estimated to be only approximately $1.70 and $2.00 per barrel, respectively. The lower transport cost to Asia versus the Gulf Coast area is attributable to shorter trip duration (30 to 37 days to Asia versus about 45 days to the Gulf Coast area), avoiding the Panama Canal toll (about $0.70 per barrel), and being able to use a larger tanker because it would not be constrained by the Panama Canal. A very large crude carrier tanker to China would have a capacity of almost 2 million bbl versus a Suezmax tanker to the Gulf Coast area with a capacity of about 884,000 bbl). The EnSys (EnSys 2010) report indicated that if the option was available to export crude from the West Coast of Canada to Asia, it would be utilized.[12] Although the main market for tanker shipments of crude oil from Pacific ports would likely be Asia, EnSys (EnSys 2011) notes that, especially if cross-border pipeline capacity into the United States were constrained, moving WCSB crudes in volume to the U.S. Gulf Coast could also become attractive. This analysis focuses on crude oil delivery via rail to Prince Rupert and tanker to the Gulf Coast area.

Crude Oil by Rail from Hardisty/Lloydminster to Prince Rupert, British Columbia

WCSB crude delivered to Lloydminster would be stored and loaded onto railcars at new and existing rail terminals and transported using the existing rail network to a new off-loading rail terminal and an expanded marine terminal in Prince Rupert, British Columbia (see Table 2.2-6 for an overview of new construction requirements for all facilities under this scenario). From there, it could be shipped by tanker and unloaded at refineries in the Gulf Coast.

Table 2.2-6 Crude Oil by Rail to Prince Rupert/Tanker to Gulf Coast Area Scenario: New Construction and Specifications

	Facility Location			
	Lloydminster, Saskatchewan	**Prince Rupert, British Columbia**	**Epping, North Dakota**	**Stroud and Cushing, Oklahoma**
Throughput	Up to 730,000 bpd WCSB	Up to 730,000 bpd WCSB	Up to 100,000 bpd Bakken	Up to 100,000 bpd Bakken
Unit Train Terminal Sites Needed	2 new sites;[a] 2 unit train loadings per day/site	1 new site (3,000 acres)	1 new site	1 new terminal site (Stroud)
Storage Needs	4 (75,000 barrel tanks per site)	Rail terminal: 4 (75,000 bbl tanks); Marine terminal: 14 (496,000 bbl tanks); Total storage: 7 million bbl	4 (75,000 bbl tanks)	2 (75,000 bbl tanks)
Number of Trains[b]	Up to 12 unit trains per day	Up to 12 unit trains per day	Up to 2 unit trains per day	Up to 2 unit trains per day

[12] Further, this report notes that it is evident that there are active efforts at the government level in Canada to access Asian markets, which are seen by the government as vital to Canada's ability to exploit its oil and gas resources.

	Facility Location			
	Lloydminster, Saskatchewan	**Prince Rupert, British Columbia**	**Epping, North Dakota**	**Stroud and Cushing, Oklahoma**
Total New Track (within terminals)	50,000 to 60,000 feet total for 2 terminals	175,000 to 210,000 feet total for 1 terminal	25,000 to 30,000 feet total	None
Pipeline Needed	None	15 miles[c]	None	17 miles[d]
Total Acreage for New Terminals and Pipelines	**Total: 1,000 acres**	**Marine: 1,200 acres** **Rail Facility: 3,000 acres** **Total: 4,200 acres**	**Terminal: 500 acres**	**Terminal: 500 acres** **Pipeline: 103 acres (permanent)** **227 acres (temporary)**
	Total Acres for Scenario:	**6,303 acres** (permanent disturbance) **6,427 acres** (temporary disturbance)		

[a] The number of new sites assumes a combination of new construction and expansion at existing facilities.
[b] The number of trains per day includes those originating from other, existing terminals. See Table 2.2-2.
[c] Pipeline connecting the off-loading rail terminal to the marine terminal
[d] The location of this pipeline cannot be determined at this time.

The new facilities in Lloydminster and Prince Rupert would include the following:

- Two new loading terminals (or equivalent of new construction and expansions at existing facilities) at Lloydminster to load up to 730,000 bpd of WCSB crude oil. The specifications of these terminals would be the same as those discussed under the Rail/Pipeline Scenario (see Section 2.2.4.1).
- One new off-loading rail terminal at Prince Rupert. This terminal would likely be a single facility capable of off-loading 12 unit trains per day of WCSB. This terminal has been estimated to be about 3,000 acres,[13] although it could be smaller. No design criteria exist for this representative facility.
- Storage tanks at Prince Rupert would total just under 7,000,000 bbl (14 tanks, each with 496,000 bbl of capacity), and would be designed to handle volumes shipped on Suezmax vessels (1 million barrel cargo). Suezmax tankers were used for the analysis because they are the largest vessels that can traverse the Panama Canal.

The proposed Northern Gateway marine terminal at Kitimat, British Columbia, was used as a surrogate to estimate the marine facilities needed at Prince Rupert. The Northern Gateway facility is designed to handle about 525,000 bpd of crude delivered by pipeline for loading on vessels to the West Coast and Asia. In addition, it is designed to receive about 193,000 bpd of diluent from cargoes arriving by water and discharging into storage at the terminal and moving back to Alberta via a parallel pipeline. The total volume of about 718,000 bpd approximates the volume of WCSB heavy crude oil that would be loaded at Prince Rupert.

[13] This number was derived by using the 500-acre per terminal used for the other crude by rail terminals in this and other scenarios. To arrive at 730,000 bpd throughput, six equivalent terminals times 500 acres was used. It is likely that an economy of scale would reduce the footprint of the actual terminal.

New facilities in Prince Rupert would consist of 1) a large rail terminal complex, most likely on the mainland or Kaien Island, where the off-loaded crude oil would be stored until it could be loaded onto tankers, and 2) an expanded port. New construction would cover 4,200 acres, including 3,000 acres for off-loading and storage facilities at the rail terminal and approximately 1,200 acres of land at the expanded Port of Prince Rupert (Table 2.2-7).

Table 2.2-7 Terminal Facility Acreage

Project Component	Estimated Area (acres)
Tank terminal	550
Security fence/windbreak area for terminal	650
Total	**1,200**

The new tank terminal construction would consist of the following:

- Fourteen petroleum storage tanks (11 oil and three condensate);
- A security fence to encompass the tank terminal;
- A 180-foot-wide firebreak area around the outside perimeter of the terminal;
- Electrical supply and distribution (this terminal would be serviced by the Texada Island Reactor substation); and
- Buildings (control center and civil infrastructure including roads).

Prince Rupert Facilities Construction and Operation

The dock portion of the facility would be expanded to accommodate two tanker berths. A utility berth would also be needed to handle large crude oil tankers. Among other things, the following facilities and equipment would be needed:

- A loading platform with gangway tower;
- Access trestles and catwalks;
- Berthing and mooring structures; and
- Spill containment equipment.

The berths would be equipped to load tankers of the size and dimensions specified in Table 2.2-8. Based on using Suezmax vessels through the Panama Canal, the Prince Rupert Marine Loading Facility would expect about 430 vessels per year loading crude oil. These tankers can hold 145,000 deadweight tonnage of heavy Canadian crude, or about 986,000 barrels. However, to transit the Panama Canal, they would need to be light-loaded to 130,000 deadweight tonnage, or about 884,000 barrels. The facility would likely be designed similarly to the proposed Northern Gateway marine terminal in Kitimat, British Columbia (in scale and general design). It may ultimately be desirable to move even greater volumes off the west coast of Canada, or there may be options to load larger or smaller vessels based on world freight market conditions, and that flexibility would likely be in the marine terminal design.

Table 2.2-8 Suezmax Tanker Dimensions and Capacities

Length (meters)	274
Beam (meters)	48
Loaded Draft (meters)	17
Deadweight Tonnage	160,000
Fuels Transport	Oil/Condensate

It was assumed that the entire Marine Loading Facility at Prince Rupert would require 5 megawatts of electric power.

When a large Suezmax vessel arrives off the coast of Houston, it must be loaded onto a smaller vessel that can navigate the Houston Ship Channel and to Port Arthur refinery docks (due to draft restrictions). This process is known in the industry as *lightering*. The charge for lightering is about $200,000. The Panama Canal and lightering charges are the primary additional charges over and above the charter cost charged by the ship owner.

Stroud Rail Terminal

Up to 100,000 bpd of crude oil by rail delivery from the Bakken region would be shipped along the same rail lines considered under the Rail/Pipeline Scenario. Fewer off-loading facilities (but the same new pipeline) would be needed in Stroud because only Bakken and not WCSB would be shipped through the nearby Cushing hub. Specifically, the following facilities and equipment would be needed:

- A new, approximately 500-acre off-loading rail terminal in Stroud;
- Two new (75,000 bbl) storage tanks in Stroud; and
- A new 17-mile pipeline from Stroud to Cushing.

Rail/Tanker Scenario Cost Assumptions

The estimated cost of the voyage from Prince Rupert to Houston and Port Arthur is estimated at $4.71 per bbl and $4.69 per bbl, respectively, for the Suezmax option (see Table 2.2-9). This analysis also examined fully loading the Suezmax vessel to 986,000 barrels and shipping through the Straits of Magellan (Cape Horn); however, this option is about 66 percent more expensive (about $7.10 per barrel) despite the absence of Panama Canal fees. This is due primarily to a much longer transit time (about 97 days versus 45).

Table 2.2-9 Rail/Tanker Costs from the Lloydminster, Saskatchewan, to the Gulf Coast Area via the Panama Canal[a]

Activity	Cost $/barrel
Loading railcars at Lloydminster, Saskatchewan	1.50
Rail: Lloydminster- Prince Rupert	7.00-9.00
Railcar lease	0.69
Transfer costs - railcars to storage tanks	1.50
Tanker Cost	4.70
Total	**15.39-17.39**[b]

[a] Does not include Panama Canal Charge or lightering costs.
[b] Does not include costs to ship Bakken crude oil, which is estimated at $7.48 per barrel. See Table 2.2-5.

This analysis excludes the costs of collecting the crude from the surrounding oil sands fields at Lloydminster to remain consistent to the proposed Project pipeline costs. Given the proximity of production operations to both the pipeline and rail origins, it is reasonable to assume that the collection costs would be similar.

2.2.4.3 Rail Direct to Gulf Coast Scenario

This scenario would involve the transport of WCSB crude oil from new terminal facilities in Lloydminster, Saskatchewan, by rail directly to the Gulf Coast area. This scenario differs from the Rail/Pipeline Scenario in that once the WCSB crude oil is on railcars, it would be transported to the Gulf Coast rather than off-loading it in Stroud and shipping by pipeline from the Cushing hub. Table 2.2-10 describes the new construction and specifications under the Rail Direct to the Gulf Coast Scenario.

Table 2.2-10 Rail Direct to the Gulf Coast Scenario: New Construction and Specifications

	Lloydminster, Saskatchewan	Epping, North Dakota
Throughput (bpd)	730,000 bpd WCSB	100,000 bpd Bakken
Unit Train Terminal Sites Needed	2 new sites (2 x 500 acres each)	1 new site
Storage Needs	4 (75,000 barrel tanks per site)	4 (75,000 barrel tanks per site)
Number of Trains[a,b]	up to 12 unit trains per day	up to 2 unit trains per day
Acreage	**1,000**	**500**
Total Acres: 1,500		

[a] Based on a representative terminal. Includes off-loading facilities, railcar storage, pipelines, barge docks, storage tanks, and administrative buildings
[b] The number of trains per day includes those originating from other, existing terminals. See Table 2.2-2.

This mode of transportation is currently used to ship some crude oil from the WCSB and Bakken regions. As noted in Section 2.2.3, No Action Alternative, independent developers have already expanded or have plans to expand capacity of crude-by-rail off-load facilities in the Gulf Coast region. Therefore, no new rail off-loading terminals are anticipated under this scenario (See Section 1.4, Market Analysis, for a list of existing and proposed off-loading facilities in the Gulf Coast).

The Lloydminster to the Gulf Coast route would transport up to 730,000 bpd to replace quantities currently planned to be shipped by the proposed Project. New or expanded rail loading facilities totaling about 1,000 acres would be built in Lloydminster (see Section 2.2.4.1, Rail/Pipeline Scenario), with existing or recently proposed loading facilities handling the remaining WCSB crude oil for shipping to the Gulf Coast area. Rail would be used to transport up to 100,000 bpd of Bakken crude oil from a new terminal in Epping, North Dakota, to refineries in the Gulf Coast area.

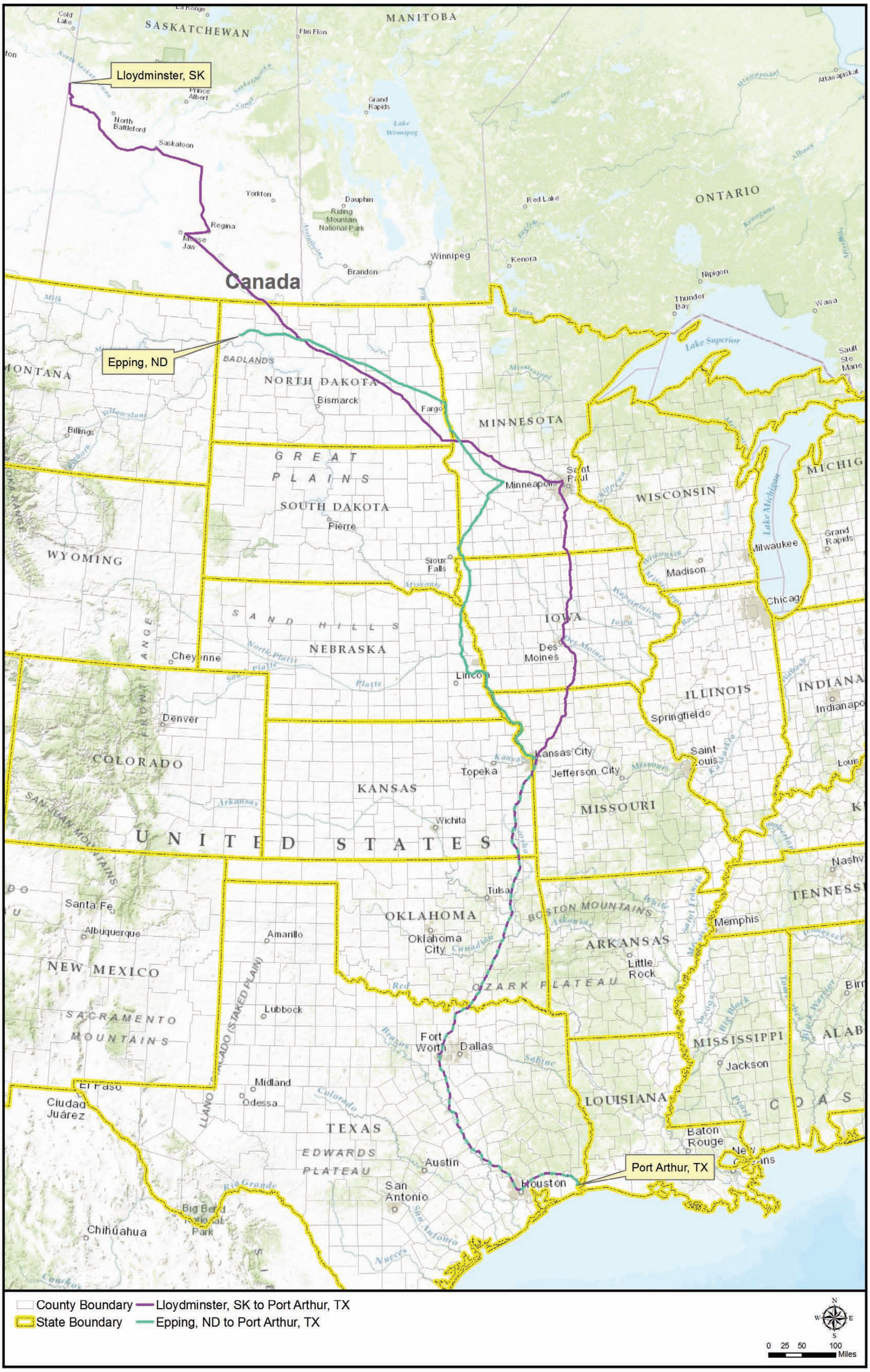
Existing infrastructure would be used; however, track improvements and new rolling stock may be needed (e.g., insulated rail cars with steam coils to transport railbit or bitumen). As noted in Section 2.2.4.1, Rail/Pipeline Scenario, producers have begun to use rail to transport crude oil to market refineries in the absence of existing pipeline capacity (see also Section 1.4, Market Analysis). Figure 2.2.4-5 shows representative rail routes from Lloydminster, Saskatchewan, and Epping, North Dakota, to the Gulf Coast. Rail distances from Lloydminster to Port Arthur, Texas, and from Epping to Port Arthur are approximately 2,485 miles and 1,916 miles, respectively.

For the purposes of the analysis in this Final Supplemental EIS, it has been assumed that dilbit would be delivered to the Gulf Coast, although it is likely that other forms of crude oil would be shipped. Once the crude oil arrives in the Gulf Coast area, it would be off-loaded and delivered to area refineries by pipeline or barge.

Estimated costs to transport crude directly to the Gulf Coast area have been developed for dilbit from Lloydminster, Saskatchewan, to Port Arthur and for Bakken crude oil from Epping, North Dakota, to Port Arthur (see Table 2.2-11).

Table 2.2-11 Rail Direct from Lloydminster, Saskatchewan, and Epping, North Dakota, to Port Arthur, Texas

Activity	Lloydminster to Port Arthur Approximate Cost $/bbl	Epping to Port Arthur Approximate Cost $/bbl
Railcar On-Loading	1.50	1.50
Rail Freight	10.88	7.58
Railcar Lease	0.89	0.73
Railcar Off-Loading	1.50	1.50
Barge to Refinery	0.52	0.52
Total	**15.29**	**11.83**



Source: Esri 2013

Figure 2.2.4-5 Representative Rail Routes between Canada and the United States: Rail Direct to Gulf Coast Scenario

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2.2.4.4 Scenarios Considered but Eliminated from Detailed Analysis

The following scenarios under the No Action Alternative were considered, but were not analyzed in detail.

Rail or Pipeline to Vancouver or Kitimat, British Columbia, and Tanker to Gulf Coast Area Scenario

Under this option, WCSB would be shipped by existing railways or new pipelines from the Hardisty region to Vancouver or Kitimat, British Columbia, for shipment by marine transport through the expanded Panama Canal and delivery to Gulf Coast area refiners. This option considers moving up to 730,000 bpd of heavy crude to the Port of Vancouver and then to the marine docks at the Westridge marine terminal in Vancouver or the port in Kitimat. Under this option, crude oil could move either via rail or by a new pipeline from the Hardisty region.

Currently, Kinder Morgan is planning an expansion of the existing Trans Mountain pipeline originating at Edmonton, increasing its capacity from 300,000 bpd (current) to up to 890,000 bpd (planned for operations in 2017). The Trans Mountain pipeline runs into Vancouver via the existing Burnaby terminal over to the Westridge dock for loading heavy crude onto vessels. The pipeline has sufficient commitment from shippers to proceed with engineering and permitting processes. Kinder Morgan indicates that the project would significantly increase tanker traffic from about 5 to 34 cargoes per month, or up to about 400 cargoes per year. The increased marine traffic is due to an increased volume to be shipped and lack of sufficient channel draft to load larger vessels.

The substantial increase in tanker traffic from the proposed Kinder Morgan expansion has raised safety and environmental concerns. Moving additional volumes of crude oil from the proposed Project into the Vancouver market by either a new pipeline or rail would result in 400 or more additional vessels loading at Vancouver each year and would require considerably more storage to be built than the current Kinder Morgan operations. The expansion of storage capacity, potential rail off-loading facilities and logistics, and increased marine traffic may make this option logistically challenging in a relatively compressed and populated geographical area. Moreover, even if a separate pipeline from Hardisty could be planned, mapped, engineered, designed, and permitted starting today, it would likely not be available as an option until well after the proposed Project’s planned start date. As a result of the logistical challenges in increasing the amounts of heavy Canadian grades of crude oil coming into the Vancouver/Burnaby region over and above the volumes from the Kinder Morgan expansion, this option was deemed to be less viable than movements from Kitimat and Prince Rupert and was eliminated from detailed analysis.

Enbridge is proposing to construct the Northern Gateway pipeline, which would transport up to 525,000 bpd of crude oil approximately 731 miles from Bruderheim, Alberta, to the Port of Kitimat, British Columbia. The port would be improved with two dedicated ship berths and 14 storage tanks for crude oil and condensate. Enbridge intends for the pipeline to be operational around 2017. A regulatory application was submitted in 2010, which is undergoing an independent review process led by the Canadian NEB and the Canadian Environmental Assessment Agency. The pipeline would traverse First Nation traditional lands and important salmon habitat. The project has been controversial and has encountered opposition from some First Nation bands and other organizations. On December 19, 2013, the joint review panel for the

Northern Gateway project recommended that the Canadian federal government approve the project subject to 209 required conditions (Enbridge Northern Gateway Project Joint Review Panel 2013). However, it remains uncertain at this time if the project would receive permits and be constructed, and therefore the option of moving additional crude to Kitimat was eliminated from detailed analysis.

Rail/Barge Scenario (Rail from Lloydminster, Saskatchewan, to Wood River, Illinois, and Barge to the Gulf Coast Area via the Mississippi River)

Under this option, WCSB crude would be shipped by rail for delivery to the Wood River, Illinois, port facility for transfer to river barges for transit down to the Gulf Coast area. Figure 2.2.4-6 shows the rail route from the Hardisty area to Wood River. There are reports of several companies pursuing rail to barge options for delivery to the U.S. Gulf Coast. This option entails rail costs that are similar to the rail costs to Cushing, but with a more expensive and logistically challenging subsequent delivery to the Gulf Coast area refiners. The costs to ship WCSB crude by barge from Wood River, Illinois, to the New Orleans market would be in the $4 to $6 per barrel range. The additional cost to move through the Intracoastal Waterway to Port Arthur and Houston could increase this by an additional $1 to $2 per barrel, making the increase $5 to $8 higher per barrel. On this basis, the cost would appear to be significantly higher relative to pipeline (the cost via pipeline from Cushing would be about $2.35 per barrel compared to much higher barging costs from Wood River, Illinois). Moreover, movement on the Mississippi River could be affected by weather and river conditions. During summer 2012, the river was too shallow due to drought conditions on the lower Mississippi, and barge traffic was held up a number of days; at other times, spring floods have affected marine movements. In addition, assuming only the heavy crude (and not the Bakken light crude) is moved by barge, the up to 730,000 bpd would require approximately thirteen 60,000-barrel barges to leave Wood River every day, along with a similar number of empty tows that would head north every day (for an estimated 12 day transit time). Table 2.2-12 shows the rail and barge-related costs of the Rail/Barge Scenario. The rail route to Wood River is shown on Figure 2.2.4-6.

Table 2.2-12 Rail/Barge Costs from Hardisty, Alberta to the Gulf Coast Area

	Approximate Cost $/barrel
Loading railcars at Lloydminster, Saskatchewan	1.50
Rail Lloydminster – Wood River, Illinois, via CPRS – St. Paul Minnesota via Union Pacific	8.50
Railcar lease	1.00
Transfer costs – railcars to barge	1.50
Barge Wood River, Illinois – Port Arthur	5.00-7.00
Total	**17.50-19.50**

Although some companies would employ this option, it was eliminated from detailed analysis discussed in Section 2.2.4.1, Rail/Pipeline Scenario, because of these increased costs and logistical challenges, because of the difficulty in scaling up to the full capacity of the proposed Project, and because it would not be an improvement over the Rail/Pipeline Scenario. Other barge options were also considered including the ports of St. Paul, Minnesota; Calumet, Illinois; and Catoosa, Oklahoma; but these all faced the same economic and logistical challenges as Wood River.

Source: Esri 2013

Figure 2.2.4-6 Representative Rail Route from Hardisty Region to Wood River, Illinois

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Trucking Scenario

The option of trucking WCSB to the Gulf Coast area was considered but eliminated from detailed analysis for a variety of reasons, including safety (trucking is 87 times more likely to cause fatal injuries than pipelines during transportation of crude oil), it would increase congestion in cities and along highways (there would need to be about 3,300 trucks per day hauling the crude oil from the WCSB), it would emit large amounts of greenhouse gases (GHGs) and other pollutants, and it would use significant amounts of fuel.

Existing Transboundary Pipeline Scenario

There are four major pipeline systems that currently transport Canadian crude oil across the U.S. border. These include the Kinder Morgan Trans Mountain system (about 300,000 bpd capacity, to both Vancouver, British Columbia, and Puget Sound refiners and some export), the Spectra Energy Express-Platte pipeline system (282,000 bpd capacity), the existing Keystone pipeline (590,000 bpd capacity), and the large Enbridge system (about 2.5 mmbpd total capacity). The status of each of these lines is described below.

- The existing Trans Mountain pipeline, which can access U.S. Puget Sound refiners in Washington State, operates fully loaded and is typically over-nominated (meaning shippers would transport more if the capacity existed).
- For the Spectra Energy Express-Platte pipeline system from Hardisty, Alberta, to Wood River, Illinois, the Express portion of the pipeline system from Hardisty to Guernsey, Wyoming, has capacity for about 282,000 bpd and is estimated to be underutilized by about 100,000 bpd. Spectra Energy announced an increase in the long-term committed volumes on the Express pipeline, and noted that some of the contracts for committed volumes have been signed by shippers intending to have the crude loaded at a rail facility in Wyoming for onward delivery.
- The existing TransCanada Keystone line (not the proposed Project) from Hardisty to Steele City, Nebraska, with pipeline interconnections to both Wood River, Illinois, and Cushing, Oklahoma, initiated operation in late 2010 with a capacity of 590,000 bpd. Data from the Canadian Association of Petroleum Producers (CAPP 2012) indicate that, as of December 2011, the existing Keystone pipeline was transporting almost 500,000 bpd.
- The Enbridge system is the largest cross-border pipeline system with a mainline capacity of 2.5 mmbpd. As noted in the Final EIS, the existing Enbridge system is near its current capacity, and has been increasing both its capacity and throughput to reach United States and Eastern Canadian markets. Enbridge's existing plans will increase utilization of its mainlines from Edmonton and Hardisty by constructing Eastern Canada pipeline expansions, reversing existing lines (moving primarily Bakken and lighter western Canadian crudes into Sarnia, Ontario, and north to Montreal, Quebec), and upgrading existing pipelines (Illinois Commerce Commission [ICC] 2012).

It was noted in the 2011 Final EIS and 2013 Draft Supplemental EIS that there was limited southbound pipeline connections to transfer crude oil from PADD 2 to PADD 3. Similar to other developments in rail transport, new pipeline capacity has been added in response to the new crude oil supplies coming from the WCSB, Bakken, and other new crude oil production areas in North America.

The final connection from Cushing, Oklahoma, to the Gulf Coast area could be made either by the recently reversed Seaway pipeline and a to-be-constructed Seaway twin pipeline, or (theoretically) by the TransCanada Gulf Coast Project. The Seaway pipeline is operated by the Seaway Crude Pipeline Company LLC, a 50/50 joint venture between Enbridge and Enterprise Product Partners L.P. It consists of an existing pipeline that had transported crude oil and petroleum products from Houston to Cushing. Because of the glut of crude oil in Cushing and the shift in North American crude oil production patterns, the pipeline was substantially underutilized. In response, the owners reversed the flow of the pipeline (its first deliveries of crude oil to Houston occurred in June 2012), and announced they would increase capacity on that existing pipeline, as well as construct another 30-inch pipeline in the same ROW. Upon completion of these projects, the Seaway pipelines would have the capacity to transport up to 850,000 bpd from Cushing to the Gulf Coast area,[14] with an expected completion date of mid-2014. Enbridge (Enbridge 2012b, 2012c, 2012d) has also stated that the Seaway twin pipeline could be expanded up to 600,000 bpd. The TransCanada Gulf Coast Project has completed construction and is expected to begin delivering crude oil in January 2014.

Additional pipeline projects include:

- Enbridge is proceeding with expansion, reversal, and upgrading projects, as well as construction of new pipelines that would provide additional capacity to deliver WCSB and Bakken crudes to the Gulf Coast area. Unlike the proposed Project, these are a series of projects on the existing Enbridge system. The status of those projects is described briefly in the following paragraphs and is based on information drawn from press releases, investor materials, and state regulatory filings.
- Currently, the Enbridge Mainline/Lakehead system has the capacity to deliver approximately 2.5 mmbpd of crude oil across the border from Canada to Superior, Wisconsin, with pipelines providing onward delivery to the Chicago area, eastward into PADD 2, and back into Eastern Canada. Enbridge is pursuing several projects that would make connections from this pipeline system to the Gulf Coast area.
- From Superior, Wisconsin, to Flanagan, Illinois, Enbridge has announced Line 61 (to be called the Southern Access project when under construction). This 42-inch-diameter pipeline has an announced capacity of 400,000 bpd; however, according to Enbridge investor materials (Enbridge 2012d), it can be expanded to transport up to 1.2 mmbpd with the addition of more pumping capacity (Enbridge is currently planning an expansion of capacity on Line 61).
- From Flanagan, Illinois, to Cushing, Oklahoma, Enbridge is seeking regulatory approval[15] to construct a new, 36-inch diameter pipeline in the same ROW as the existing Spearhead pipeline, which has a capacity of 195,000 bpd. The new pipeline would have an initial capacity of approximately 600,000 bpd, and could be expanded to approximately

[14] Enbridge has also announced it will construct a pipeline from Houston to Port Arthur, Texas. This means it would have pipeline connections to the same two main delivery areas (Houston and Port Arthur) that crude oil transported on the proposed Project would be subsequently delivered to.
[15] This proposed project is an interstate crude oil pipeline that does not cross an international border; therefore, there is no general federal permitting authority. Enbridge has applied to the ICC for a *Certificate of Good Standing*. Such a certificate is necessary for a pipeline company to make use of eminent domain proceedings in Illinois. There are no similar permitting requirements in Missouri or Oklahoma.

800,000 bpd with the addition of pumping capacity. According to regulatory filings, 70 percent of Enbridge's existing easements for the Spearhead pipeline provide rights to install additional pipelines, which means that Enbridge only needs to negotiate new easements, or seek eminent domain if necessary (and if approved by the ICC), along 30 percent of the proposed Flanagan South pipeline route. Enbridge estimates an in-service date of mid-2014.

If these various Enbridge projects and joint ventures were completed, those pipelines would have the ultimate nameplate capacity (if pumping improvements were implemented) to transport up to approximately 1 mmbpd of additional crude oil from Superior, Wisconsin, to the Gulf Coast area. The total transport distance from Hardisty to the Gulf Coast area through the Enbridge projects and joint ventures would be approximately 750 miles longer than through the proposed Project and the Gulf Coast Project.[16] However, most of the potential capacity on the Enbridge system is not available for the crude oil with long-term contracts on the proposed Project (over 500,000 bpd for delivery from the WCSB to the Gulf Coast area; 155,000 bpd from the WCSB to Cushing to be transferred from existing Keystone pipeline; and 65,000 bpd from the Bakken region) because these projects are supported by their own long-term contractual commitments.

In its regulatory filings and investor materials, Enbridge has made several statements about long-term contractual commitments from shippers for these various projects. It was reported in the media that for most of 2012, the existing Spearhead pipeline has been at capacity and/or that shippers have wanted to transport crude oil in excess of that pipeline's capacity (Clark 2012; Campbell 2012). In the ICC (2012) filings for Flanagan South, Enbridge has stated that it had commitments for "about 90 percent of the initial capacity of the Flanagan South Pipeline on terms that range from 10 to 20 years of transport." They have characterized this as fully contracted, "apart from the mandatory 10 percent minimum required by the Federal Energy Regulatory Commission" (Enbridge 2012b). This would mean that of the 600,000 bpd initial capacity, approximately 540,000 bpd is already committed. Enbridge has also stated that for the Seaway pipeline system, it has 5- and 10-year commitments to transport crude originating in Cushing, as well as 10-, 15-, and 20-year commitments for volumes originating in Flanagan, and that these commitments are for "substantially all of the initial [850,000 bpd] capacity of the Seaway System" (Enbridge 2012a).

It is likely that if the proposed Project were not constructed, the shippers that had the long-term contractual commitments would first seek other pipeline transport before resorting to other modes of transportation. Some portion of the volumes committed to the proposed Project could likely be transferred to the Enbridge system if the planned expansions occurred; however, even if the pipelines discussed installed the necessary additional pumping capacity to reach their top-line design capacity, they would not have enough spare capacity to accommodate the volume of crude oil committed under long-term contracts to the proposed Project.

As detailed above, the existing Trans Mountain, Express-Platte, and the existing Keystone pipelines have limited capacity to accept additional volumes of crude oil, certainly not in the types of volumes contractually committed to the proposed Project. Each of those three pipelines

[16] The distance estimate for the Enbridge system and joint venture (total distance approximately 2,627 miles) is based on the company's Pipeline System Configuration map and information about the Seaway pipeline project. The distance estimate for Keystone's proposed Project and Gulf Coast extension (total distance 1,960 miles) is drawn from this document and the Final EIS.

either does not deliver to Cushing or the Gulf Coast area (Trans Mountain, the Spectra Energy Express-Platte system), or does not traverse the Bakken in the area of Epping, North Dakota. Because of these capacity and geographic constraints, none are considered viable alternatives; although, as described in the EnSys report, (EnSys 2010) if there were long-term constraints on new pipeline construction, those pipelines may be able to accept some additional volumes of crude oil.

While some additional transboundary and interstate pipeline capacity is available or has recently been proposed, that capacity is being added to meet additional demand for transport, as evidenced by separate long-term contractual commitments. The capacity of those additional pipelines that is not committed under long-term contractual agreements would not accommodate all of the crude oil contracted to the proposed Project. Given these shortcomings, relying on other projects instead of the proposed Project to meet demand was not considered reasonable and was, therefore, eliminated from detailed analysis in this Final Supplemental EIS.

Other Crude Oil Transportation Proposals

During the fall 2012, industry spokespeople have announced proposals that would use other options to transport both WCSB and Bakken crude oil to refiners on the Canadian and United States East Coast (Financial Post 2012a). Another proposal would include expansion of existing rail capacity and facilities to haul WCSB to Hudson Bay for loading onto oil tankers to ship to refiners (Financial Post 2012b). This proposal, however, would only be operational between July and October due to sea ice in the Arctic Ocean, although its operations could be extended through the use of icebreakers. BNSF Railway announced plans to expand rail capacity to transport Bakken crude oil by 1 mmbpd out of the Williston Basin (Bismarck Tribune 2012). TransCanada has announced plans to convert an existing natural gas pipeline to transport up to 1 mmbpd of WCSB to refineries on Canada's East Coast (Energy East Project) (Platts 2012). Finally, BP has applied for an export license from the U.S Department of Commerce to ship Bakken crude oil from North Dakota and Montana to Canadian refiners who would use it instead of more expensive light crude from Europe (Campbell 2012). If implemented, these projects would expand takeaway capabilities of WCSB and Bakken crude while requiring little new infrastructure.

Use of Alternative Energy Sources and Energy Conservation

The 2011 Final EIS discussed and analyzed alternatives in place of crude oil from the WCSB, including different energy sources and energy conservation. These options were reconsidered in the development of this Final Supplemental EIS and are incorporated for reference.

Many commenters (on the Draft EIS and Draft Supplemental EIS) suggested that the use of alternative sources of energy and conservation of energy would either: 1) eliminate the need for the proposed Project or alternatives to the proposed Project, or 2) reduce the market need for heavy crude oil to the extent that smaller scale projects could meet short- and long-term energy needs.

The market demand for crude oil, including the market demand for heavy crude oil by refineries in PADD 3 (see Section 1.4, Market Analysis, for a discussion of the PADDs), is driven primarily by the demand for transportation fuels. Based on Energy Information Agency (EIA) statistics (EIA 2010a, 2010b), approximately 78 percent of the refined product produced by

PADD 3 refineries in 2009 was used for transportation fuel. The percentages of total production from PADD 3 refineries in 2009 for transportation uses in the EIA statistics are listed below:

- Finished motor gasoline—42.9 percent;
- Distillate fuel oil—24.9 percent (distillate production for all uses was 28 percent of total refinery production. Distillate fuel oil for transportation only was 89 percent of total distillate production, or 24.9 percent of total production);
- Kerosene-type jet fuel—9.3 percent;
- Residual fuel oil—1.0 percent (residual production for all uses was 4.1 percent of total refinery production; residual fuel oil for transportation only was approximately 25 percent of total residual fuel production, or approximately 1.0 percent of total production); and
- Finished aviation gasoline—0.1 percent.

The remaining 22 percent of PADD 3 refinery production in 2009 consisted primarily of specialized products (e.g., liquefied refinery gases, kerosene, and naphtha for feedstock).

The remainder of this section addresses 1) how the use of alternative fuels and energy conservation would affect market demand for refined products sold by PADD 3 refineries, and therefore addresses the effect on market demand for crude oil by those refineries, and 2) whether or not the use of alternative fuels and energy conservation would result in a sufficient reduction of market demand for crude oil in PADD 3 to justify selection of the No Action Alternative as the preferred alternative. Although most refined products sold by PADD 3 refineries are used in transportation, the assessment of the impact of using alternative fuels and energy conservation was also addressed for refined products that are not used for transportation. Alternative fuels and energy conservation are addressed in the following subsections:

- Use of Alternative Fuels and Energy Conservation in Transportation;
- Use of Alternative Energy Sources in Place of Distillate Fuel Oil for Non-Transportation Uses;
- Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses; and
- Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products.

Use of Alternative Fuel and Energy Conservation in Transportation

Worldwide demand for crude oil is generally projected to grow over the next 25 years unless countries, including developing economies where the majority of the growth is projected to occur, take substantial steps to address climate change. But even if there is a worldwide decline in crude oil consumption, projections indicate that there would be an increase in consumption of crude oil from unconventional sources, primarily from the Canadian oil sands, over the next several decades (EIA 2013; IEA 2013). As discussed in Section 1.4, Market Analysis, overall oil consumption in the United States is projected to remain near current levels or decline over the next 25 years (EIA 2013; IEA 2013).

Two general questions have been raised relevant to the No Action Alternative and adoption of policies that would address climate change by reducing demand for crude oil:

- Would a reduction in the U.S. demand for crude oil eliminate the need for the proposed Project?
- Would proceeding with the proposed Project alter market conditions such that there would be less rapid adoption of fuel efficiency, alternate fuels, or other measures that would reduce the demand for crude oil?

Outlooks for world and U.S. demand for crude oil indicate that even if there were a substantial reduction in U.S. consumption of crude oil (and/or relatively flat worldwide consumption), the market demand in PADD 3 that is driving the development of the proposed Project would likely remain. Also, as explained below, it does not appear that the proposed Project would have enough of an impact on refined fuel prices to alter the market incentives for more widespread adoption of fuel-efficient vehicles or deployment of alternate fuels (including vehicle electrification).

As explained in Section 1.4, Market Analysis, the updated modeling done for this Final Supplemental EIS included evaluating U.S. imports of heavy crude oil in the 2013 Annual Energy Outlook Low/No Net Imports case. In that case, U.S. consumption falls to 17.1 million bpd in 2035 versus 18.9 million bpd in the reference case (and 18.5 million bpd today). This 1.8 million bpd reduction in consumption did not result in any substantial reduction in imports of heavy crude oil in the modeling results (see Section 1.4.4, Updated Modeling, for additional details).

Additionally, the International Energy Agency's (IEA) 2012 World Energy Outlook (WEO) addresses energy demand and production in three worldwide policy scenarios.[17] Differences in oil sands production between these different scenarios give an indication of how substantial changes in worldwide policies and energy could impact oil sands production:

- The Current Policies Scenario, which assumed no change from policies in place;
- The New Policies Scenario, which assumed that countries act on their announced policy commitments and plans to address climate change; and
- The 450 Scenario, which sets out an energy pathway with the goal of limiting the global increase in temperature to 2 degrees Celsius (°C) by limiting concentration of GHGs in the atmosphere to around 450 parts per million of carbon dioxide (CO_2).

The impact of the three policy scenarios' assumptions on worldwide crude oil consumption in 2035 is substantial. Compared to the worldwide total oil production (crude oil, natural gas liquids, and unconventional oil) of 83.3 mmbpd in 2009, IEA (IEA 2012) projected the following levels of consumption in 2035:

[17] The IEA provided oil sands production projections for the 2012 WEO. The 2013 WEO does not include oil sands production numbers for the current policy scenario or the 450 scenario. Oil sands projections in the new policy scenario are similar to the 2012 WEO numbers.

- Current Policies Scenario—108.5 mmbpd;
- New Policies Scenario—99.7 mmbpd; and
- 450 Scenario—79 mmbpd.

The policy scenarios also have a substantial impact on projected consumption of oil-sands-derived crude oil in 2035:

- Current Policies Scenario—4.8 mmbpd;
- New Policies Scenario 4.3 mmbpd; and
- 450 Scenario—3.4 mmbpd.

Differing assumptions have implications for global oil demand and oil prices, which in turn affect oil sands production. While oil sands production projections differ among the three scenarios, output is expected to grow by at least 1.6 million bpd. Differences in costs attributed to GHG emissions between the scenarios also have an impact on differing production projections (IEA [2010] assumes a carbon price of $60 per ton in the New Policies Scenario and $120 per ton in the 450 Scenario and incorporates oil sands production costs).

Based on the analysis in Section 1.4, Market Analysis, it appears unlikely that the proposed Project would have enough of an impact on the prices of refined fuel to impact market drivers related to wider adoption of alternative fuels or more energy efficient vehicles. A recent report examining economic implications of different policies to reduce CO_2 emissions or petroleum imports (Morrow et al. 2010) stated:

> A fundamental insight from this study is that if one wishes to reduce U.S. CO_2 emissions or net petroleum imports from the transportation sector, the costs of driving must be significantly higher than they currently are today. Increasing the cost of driving with higher fuel costs (or other operating fees) will be required to motivate deployment of fuel economy improving technologies in conventional vehicles, accelerate penetration of high-fuel economy vehicles into the existing fleet, and reduce vehicle-miles traveled.

Two of the scenarios examined in Morrow et al. (2010) focused on policies that would directly increase the cost of transport fuels. One scenario included carbon pricing in a cap-and-trade plan, which led to a projected increase of $0.24 in the cost per gallon in 2020 and an increase of $0.46 per gallon in 2030. The second scenario included a direct fuel tax, which led to projected increases to the cost of gasoline of $1.42 per gallon in 2020 and $3.27 per gallon in 2030. The analysis considered how fuel price influenced increases in fuel efficiency (through increased purchases of more fuel efficient vehicles, hybrid vehicles, and electric vehicles) and reduced the projected increases in vehicle-miles traveled. The report concluded that the carbon tax scenario had a marginal impact on GHG emissions from transportation. Imposing the transportation tax on fuel stimulated slightly larger improvements in fuel economy of new conventional vehicles than were projected to be achieved through imposition of only Corporate Average Fuel Economy standards. Modeling and analysis in Section 1.4, Market Analysis, found that approval or denial of the proposed Project (and all future expansion of cross border pipeline capacity) had little or no impact on fuel prices. Growing evidence exists that if pipeline capacity is constrained, non-pipeline modes of transport, particularly rail, are capable of economically delivering volumes of WCSB heavy crude oils to market in excess of the capacity of the propose Project. This indicates, along with the updated analysis of supply and demand in Section 1.4, that whether the proposed Project is constructed is unlikely to have a significant long-term impact on heavy crude supplies on the U.S. Gulf Coast. Consequently, these data and analysis indicate that denial of the pipeline would not raise prices substantially. Prices would not approach the range of increases, which the Morrow et al. study (2010) indicate would prompt improved efficiency. It is reasonable to infer that based on the Market Analysis in Section 1.4, when viewed in combination with the results from the Morrow et al. study, the proposed Project's likely impact on finished transportation fuel prices would not be large enough to influence market behavior in development of more fuel efficient vehicles, development of alternative transportation fuels (including electrification of the vehicle fleet), or reduction of total vehicle-miles traveled.

The above factors also indicate that even if the United States, and/or countries around the world, adopt more aggressive policies that would reduce the consumption of crude oil (including those necessary to achieve a trajectory towards stabilizing CO_2 concentrations in the atmosphere in line with the 2 degree global goal), there is likely to be a market demand for substantial increases in the volume of crude oil such as those derived from the oil sands over the next 20 to 25 years.

As there would still be demand for oil sands-derived crude oil, use of alternative energy sources and energy conservation in meeting needs for transportation fuel have not been carried forward for further analysis as an alternative to the proposed Project.

Use of Alternative Energy Sources and Conservation in Place of Distillate Fuel Oil for Non-Transportation-Related Uses

Non-transportation uses of distillate fuel oil include space heating and electrical power generation, and represented approximately 3.1 percent of the production of PADD 3 refineries in 2009 (EIA 2010a, 2010b). The distillate fuel oil was sold for use in the following categories listed by EIA (EIA 2010b):

- Oil company
- Industrial use
- Commercial
- Electrical power
- Residential

For the *oil company* category, it is likely that the distillate fuel oil was used primarily for heating purposes. As a result, natural gas would be a likely alternative fuel in most cases, and it is possible that, in the future, many facilities could be retrofitted to accommodate natural gas as a replacement fuel. This category accounted for about 0.2 percent of the total refinery output of PADD 3 refineries. Commercial and industrial use categories were also most likely used primarily for heating purposes. These two categories combined constituted approximately 0.2 percent of the total refinery production from PADD 3. Distillate fuel oil in the residential category would likely be exclusively used for heating and represents about 0.001 percent of the total production from PADD 3 refineries.

For each of these categories, both natural gas and biofuels (e.g., fuel from municipal solid wastes, wood, and other biomass [e.g., biodiesel from cooking oil]) are potential alternative fuels for heating purposes. However, conversion of heating units to burn natural gas or biofuels would require substantial investments by the users, and it is unlikely that a majority of users would convert their heating units in the near term. In any case, the total volume of distillate fuel oil used for heating was only about 0.4 percent of the total PADD 3 refinery output in 2009. Assuming complete replacement of the distillate fuel oil used for heating by alternative fuels, there would be only a negligible reduction in the market demand for crude oil used by PADD 3 refineries. Similarly, conservation of energy for heating purposes would result in only negligible decreases in refinery output and would have very little effect on the crude oil needs of PADD 3 refineries.

The use of distillate fuel oil produced by PADD 3 refineries for the generation of electrical power represents about 0.01 percent of the total output of PADD 3 refineries. Electrical generation currently fueled by residual fuel from PADD 3 refineries could be generated in a variety of other ways, including natural gas-fired generators, wind farms, solar panels, tidal projects, hydroelectric projects, geothermal sources, nuclear power plants, and energy or fuel from municipal solid wastes, wood, and other biomass. However, use of non-transportation-related residual fuel for electrical power generation in 2009 was a negligible portion of the total output of PADD 3 refineries. With a complete replacement of this distillate fuel oil by alternative fuels to generate electrical power, there would therefore be a negligible reduction in the crude oil market demand of PADD 3 refineries, and there would be essentially no effect on the current and future crude oil needs of those refineries.

Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses

Residual fuel oil is used for the production of electric power, space heating, marine transportation, and various industrial purposes. Approximately 3.1 percent of total PADD 3 refinery production was used for electrical power generation, heating, and industrial uses (EIA 2010a, 2010b). The amount of fuel required for those uses could be reduced with conservation, and, for some uses, alternative fuels could replace the residual fuel oil. However, as for distillate fuel oil, the actual volume represents a small portion of the total production of PADD 3 refineries and the use of alternative fuels, and conservation would have a negligible effect on the market demand for crude oil in PADD 3.

Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products

As noted above, approximately 78 percent of the output of refineries in PADD 2 in 2009 was used for transportation purposes. The remaining 22 percent of PADD 3 refinery production consisted primarily of specialized products, including liquefied refinery gases, kerosene, naphtha for feedstock, other oils for feedstock, special naphtha products, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products. The three largest production streams, as a percentage of total production, were the following:

- Petroleum coke (5.9 percent)—grades of coke produced in delayed or fluid cokers that may be recovered as relatively pure carbon;
- Liquefied refinery gases (5.2 percent)—this includes ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene; and
- Still gas (4.6 percent)—still gas is used as a refinery fuel and a petrochemical feedstock.

These three categories accounted for nearly 16 percent of total PADD 3 production. For the most part, these three specialty products (as well the other specialty products produced by PADD 3 refineries) cannot be produced using alternative fuels and have not been further considered in this assessment of alternative energy sources. It is possible that conservation could reduce the need for some of these products (e.g., liquefied refinery gases) but that reduction in use would result in a negligible decrease in the market demand for crude oil in PADD 3.

2.2.5 Major Pipeline Route Alternatives

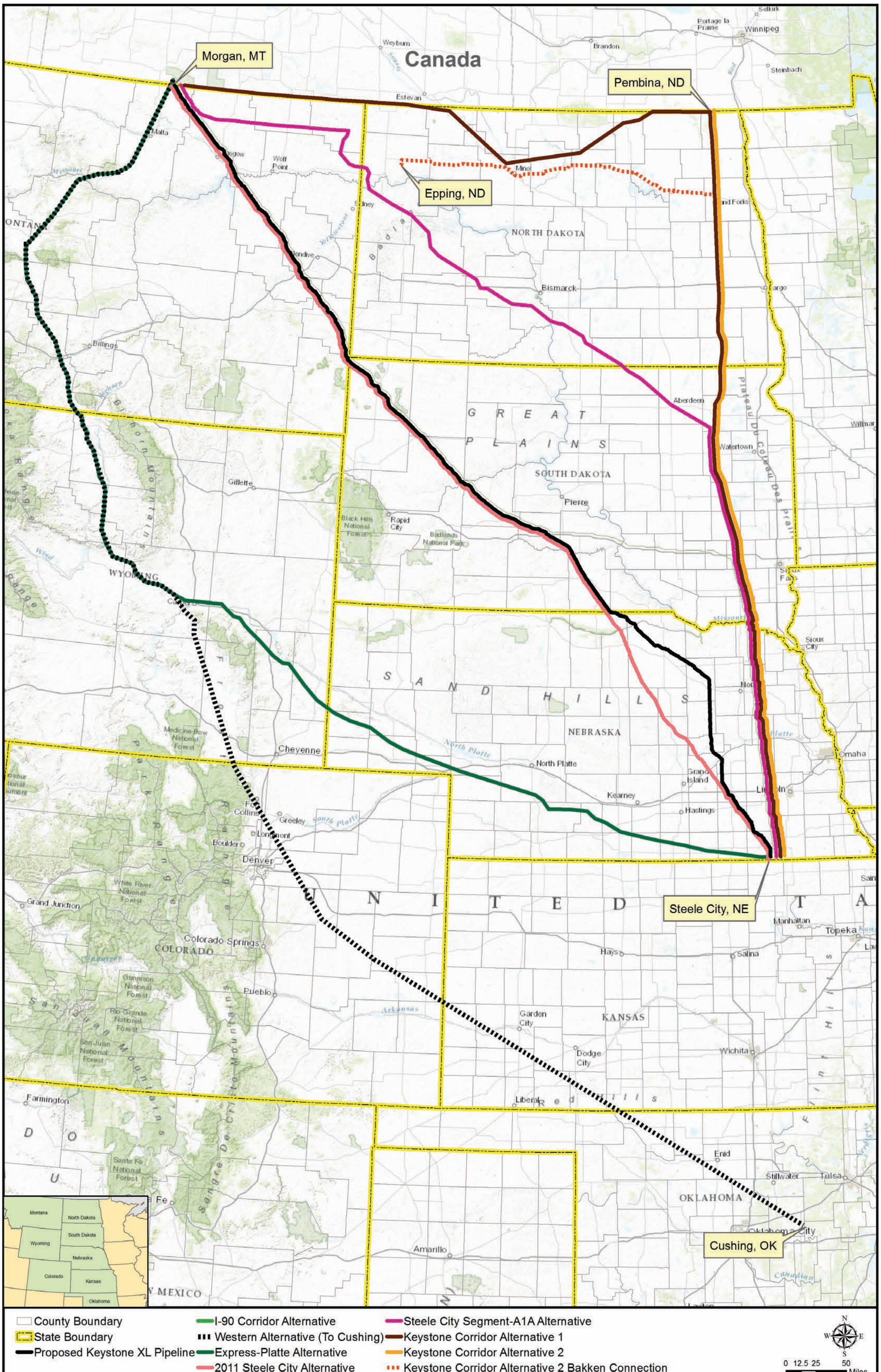
The Department considered potential alternative pipeline routes to assess whether or not there are route alternatives that would avoid or reduce impacts to environmentally sensitive resources as compared to the proposed Project, while also meeting the proposed Project purpose. Based on a review of practicable routes and comments received from agencies and the public during scoping and the previous EIS process, the route alternatives identified and considered by the Department include:

- 2011 Steele City Alternative;
- Western Alternative (To Cushing);
- I-90 Corridor Alternative;
- Express-Platte Alternative;
- Steele City Segment—A1A Alternative; and
- Keystone Corridor Alternative
  - Option 1: Proposed Border Crossing
  - Option 2: Existing Keystone Pipeline Border Crossing

A map showing the major route alternatives considered is presented in Figure 2.2.5-1. In addition to these major route alternatives, options to the proposed Project route in Nebraska have been assessed. The Nebraska Route Options analyzed by the Nebraska Department of Environmental Quality (NDEQ) are relatively short variances (between 12 and 32 miles) of Keystone's proposed route within Nebraska. The primary purpose of these route options is to identify a route that avoids the NDEQ-identified Sand Hills Region without an unacceptable increase in other environmental impacts.

These route options have specific objectives separate from the proposed Project purpose as defined in Section 1.3, Purpose and Need, and were evaluated in detail by Keystone in consultation with the NDEQ. Because the evaluation focus for these route options is somewhat different compared to the major route alternatives, the Nebraska Route Options are discussed separately at the end of the evaluation of the Major Route Alternatives section.

The major route alternatives were screened against a number of criteria to determine whether they should be analyzed in detail in this Final Supplemental EIS. A two-phase process, described below, was used to screen the route options.



Source: Esri 2013

Figure 2.2.5-1 Major Route Alternatives

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2.2.5.1 Screening of Major Route Alternatives

The subsections below describe the two-phase screening process that the Department applied to the major route alternatives considered in this Final Supplemental EIS.

Phase I Screening

The initial screening of major route alternatives considered the following criteria:

- Meeting the proposed Project's purpose and need, including whether the alternative would require additional infrastructure such as a pipeline to access Bakken crude oil;
- Availability;
- Reliability;
- Length within the United States;
- Total length of the pipeline, including both the United States and Canada;
- Estimated number of aboveground facilities;
- Length co-located within an existing corridor;
- Acres of land directly affected during construction; and
- Acres of land directly affected permanently.

Pipeline length was used as an important screening criterion because it has a relatively direct relationship with:

- System reliability, in that the longer the pipeline the greater risk that some portion may become inoperable at some point thereby delaying shipments;
- Environmental impacts, including:
  - Risk of spills and leaks, which represent the greatest potential threat to water and aquatic resources;
  - Temporary construction-related disturbance to natural habitat (e.g., wetlands, forests, native prairie); and
  - Permanent habitat fragmentation.
- Construction and operational costs, which generally increase in proportion to overall pipeline length.

All other factors being equal, longer pipelines are less desirable because they represent greater risks to system reliability, environmental impacts, and project costs.

The following major route alternatives were evaluated in Phase I screening:

- 2011 Steele City Alternative;
- Western Alternative (to Cushing);
- I-90 Corridor Alternative;
- Express-Platte Alternative;

- Steele City Segment—A1A Alternative; and
- Keystone Corridor Alternative:
  - Option 1: Proposed Border Crossing (near Morgan, Montana); and
  - Option 2: Existing Keystone Pipeline Border Crossing (at Pembina, North Dakota).

See Figure 2.2.5-1 for the major route alternatives considered. Of these routes, the following were carried forward for further screening:

- 2011 Steele City Alternative;
- I-90 Corridor Alternative; and
- Steele City Segment—A1A Alternative.

Phase I Results

Based on the Phase I screening summarized in Table 2.2-13, the following alternatives were eliminated from further consideration:

- Western Alternative (to Cushing); and
- Express-Platte Alternative; and Keystone Corridor Alternative:
  - Option 1: Proposed Border Crossing; and
  - Option 2: Existing Keystone Pipeline Border Crossing. A brief description of each alternative and the rationale for eliminating each of these alternatives is presented below.

<u>*Western Route Alternative*</u>

The Western Route Alternative would enter the United States at the proposed border crossing near Morgan, Montana, and extend through Montana, Wyoming, Colorado, Kansas, and Oklahoma, bypassing the existing Keystone Cushing Extension pipeline and connecting at the Cushing Oil Terminal in Oklahoma (Figure 2.2.5-1). The Western Route Alternative would be approximately 1,277 miles long and would parallel the existing Express-Platte System corridor for approximately 350 miles. As noted previously, it is assumed that Express-Platte would not allow Keystone to collocate within any part of its ROW due to liability, maintenance, and future expansion considerations. To satisfy the proposed Project's purpose and need as well as Keystone's current contracts for up to 100,000 bpd of crude from the Bakken, a new delivery method would need to be connected to this alternative. As summarized in Table 2.2-13, the Western route variation was removed from further consideration for the following reasons:

- It would be approximately 211 miles longer in the United States than the proposed route with associated reliability, environmental, and construction/operational cost impacts;
- It would require an additional pipeline approximately 230 miles in length to access Bakken crude at Epping, North Dakota;
- It would be 625 miles longer total in Canada and the United than the proposed Project; and
- It would require approximately 106 aboveground facilities compared to 73 for the proposed route.

Table 2.2-13 Phase I Alternatives Screening

Alternatives[a]	End point	Meets Primary P&N[b]	Meets Secondary P&N[c]	Availability	Reliability[f]	Length of Route in U.S. (Miles)	Length of Bakken Pipeline Route (Miles)	Length of Route in Canada (Miles)	Total Overall Length [g]	Estimated Number of Aboveground Facilities Required (U.S.)[h]	Length Co-located within Existing Corridor (Miles)	Affected Land Area Construction (Acres)	Affected Land Area Permanent (Acres)
Route Alternatives													
Keystone's Proposed Project Route August 2012	Steele City Nebraska	Yes	Yes	Yes	Yes	875	5	232	1,112	73	0	11,599	5,309
2011 Steele City Alternative	Steele City Nebraska	Yes	Yes	Yes	Yes	854	5	232	1,091	71	0	11,387	5,176
Western Alternative (to Cushing)	Cushing Oklahoma	Yes	No	Yes	Yes	1,277	230	232	1,739	106	0	17,027	7,739
I-90 Corridor Alternative[d]	Steele City Nebraska	Yes	Yes	Yes	Yes	927	5	232	1,164	77	254	12,360	4,818[j]
Express-Platte Alternative[e]	Steele City Nebraska	Yes	No	Yes	Yes	1,049	230	232	1,511	87	0	13,987	6,358
Steele City Segment - A1A Alternative	Steele City Nebraska	Yes	No[i]	Yes	Yes	936	30	232	1,198	78	368	12,480	4,667[j]
Keystone Corridor Option 1	Steele City Nebraska	Yes	No[i]	Yes	Yes	1,096	49	232	1,377	91	640	12,621	4,679[j]
Keystone Corridor Option 2	Steele City Nebraska	Yes	No[i]	Yes	Yes	640	273	769	1,674	53	640	6,594	1,939[j]

[a] Route alternatives from the international border between Saskatchewan, Canada, and the United States in Phillips County, Montana, near the unincorporated community of Morgan to existing Cushing Oil Terminal at Cushing Oklahoma; distribution via existing or under construction pipeline networks to customers in the Gulf Coast area
[b] Uninterrupted Transport up to 730,000 bpd of WCSB crude oil across the Canadian border to the existing Cushing Oil Terminal at Cushing, Oklahoma, through a connection to Keystone's existing Cushing extension pipeline at Steele City, Nebraska (P&N = Purpose and Need)
[c] Uninterrupted Transport up to 100,000 bpd of transport Bakken crude oil through a connection with the Bakken Marketlink Project at Baker, Montana, from the Williston Basin in North Dakota and Montana to the Cushing Oil Terminal at Cushing, Oklahoma, through a connection to Keystone's existing Cushing extension pipeline at Steele City, Nebraska; Alternatives that would not meet this component of the purpose and need included those alternative routes that were more than 20 miles from existing Williston Basin crude oil infrastructure.
[d] The pipeline for the I-90 Corridor Alternative could not be installed within the existing highway ROW because the South Dakota Department of Transportation does not allow pipelines to be installed longitudinally within the I-90 ROW, although it does allow pipelines to cross the I-90 ROW.
[e] The alternative assumes that the proposed Keystone XL pipeline would be located adjacent to but not within the existing Express-Platte pipeline easement. This corridor is controlled by a different oil transmission company, and business and engineering details of the existing corridor are not known. Transmission pipeline easement is often held by companies as potential future expansion; easement agreements as well as safety and engineering requirements may not allow co-locating an additional pipeline.
[f] As a baseline for comparison to intermodal (No Action Alternative) scenarios
[g] Includes additional Bakken pipeline route.
[h] Includes pump stations, intermediate mainline valves (IMVs), and densitometer facilities. Assumes that pig launcher and receiver facilities would be located entirely within pump station facilities. Does not include access roads or additional pump stations on the existing Cushing Extension pipeline in Kansas. The number of facilities for the 2011 Steele City Alternative, the I-90 Alternative and other alternatives is based on a ratio of 0.083 facilities per mile determined by dividing the number of aboveground facilities by the miles of new pipeline of the proposed Project.
[i] This alternative meets the purpose and need only if an additional pipeline is built between Bakken (Epping, North Dakota) to the proposed Project.
[j] For the purposes of screening it has been assumed that this alternative could be co-located within the existing Keystone pipeline corridor ROW. The permanent corridor (50 feet) ROW would occupy 25 feet of the existing Keystone pipeline ROW: (Total Miles of new ROW X 5,280 X 50)/(43,560)) + ((Total miles of co-located ROW X 5,280 X 25 feet of new permanent ROW)/(43,560).

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Express-Platte Alternative

The United States portion of the Express-Platte Alternative would be approximately 1,085 miles long from the proposed border crossing near Morgan, Montana, to Steele City, Nebraska. As shown on Figure 2.2.5-1, the Express-Platte Alternative would travel from the border crossing southwest for approximately 200 miles to the existing Express-Platte pipeline ROW. The alternative would then follow parallel and adjacent to the existing Express-Platte pipeline ROW approximately 895 miles to the proposed Project terminus at Steele City, Nebraska. It is assumed that Express-Platte would not allow Keystone to co-locate within any part of its ROW due to liability, maintenance, and future expansion considerations.

The Express-Platte Alternative would not be located near the Bakken Marketlink Project onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is a condition of Montana's current approval of Keystone's proposed route with the state. To satisfy the purpose and need as well as Keystone's current contracts for up to 100,000 bpd of crude from the Bakken, a new method for delivering this crude would need to be combined with this alternative.

As summarized in Table 2.2-13, the Express-Platte Alternative was removed from further consideration for the following reasons:

- It would be approximately 211 miles longer in the United States than the proposed route with associated reliability, environmental, and construction/operational cost impacts;
- It would require an additional new pipeline about 230 miles in length to access Bakken crude at Epping, North Dakota; and
- It would require about 87 aboveground facilities compared to 73 for the proposed route.

Keystone Corridor Alternative: Options 1 and 2

Several commenters have suggested that the proposed Project follow a route that would parallel the entire existing Keystone pipeline in the United States as a way to reduce potential impacts to groundwater (by minimizing the extent of pipeline crossing the Ogallala aquifer) and minimize habitat fragmentation (by paralleling an existing pipeline).

In response, the Department investigated two route options that would parallel the existing Keystone pipeline in the United States. The Department also assumed that the proposed pipeline construction corridor for these options would occupy up to 25 feet of the existing 50-foot Keystone pipeline ROW. New construction impacts would be limited to an area 85 feet outside of the existing ROW (i.e., 85 feet outside of the existing ROW plus 25 feet within the ROW totals to the typical 110-foot-wide pipeline construction easement). Permanent new impacts would be limited to an area 25 feet outside of the existing ROW. The combined new permanent ROW would be 75 feet wide. These two options are discussed below and shown on Figure 2.2.5-1.

A significant criterion examined as part of Phase 1 screening was the ability of the alternative to meet the purpose and need of the proposed Project. Part of that purpose and need is the ability of the proposed Project to transport 100,000 bpd of crude from the Bakken. Neither Keystone Corridor option alternatives would be located near the Bakken Marketlink onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is where this crude would be delivered into the proposed Project and is a condition to Montana's current approval of the proposed route through the state. In order for the Keystone Corridor option alternatives to meet the proposed Project's secondary purpose and need, new pipelines ranging from 49 to 273 miles in length would need to be built and connected.

Keystone Corridor Alternative Option 1 Proposed Border Crossing

The Keystone Corridor Alternative Option 1 would extend eastward approximately 463 miles across Montana and North Dakota from the proposed border crossing at Morgan, Montana, to the existing Keystone pipeline corridor near the Canadian border at Pembina, North Dakota (Figure 2.2.5-1). The eastward leg of Option 1 from Morgan, Montana, to the existing Keystone pipeline ROW would divert southeast and northeast along the route to avoid major national wildlife refuges and several smaller refuges as well as the Turtle Mountain Indian Reservation, which are present near the northern border of North Dakota. Near Pembina, Option 1 would turn southward, paralleling the existing Keystone pipeline for about 640 miles to the proposed Project terminus at Steele City, Nebraska.

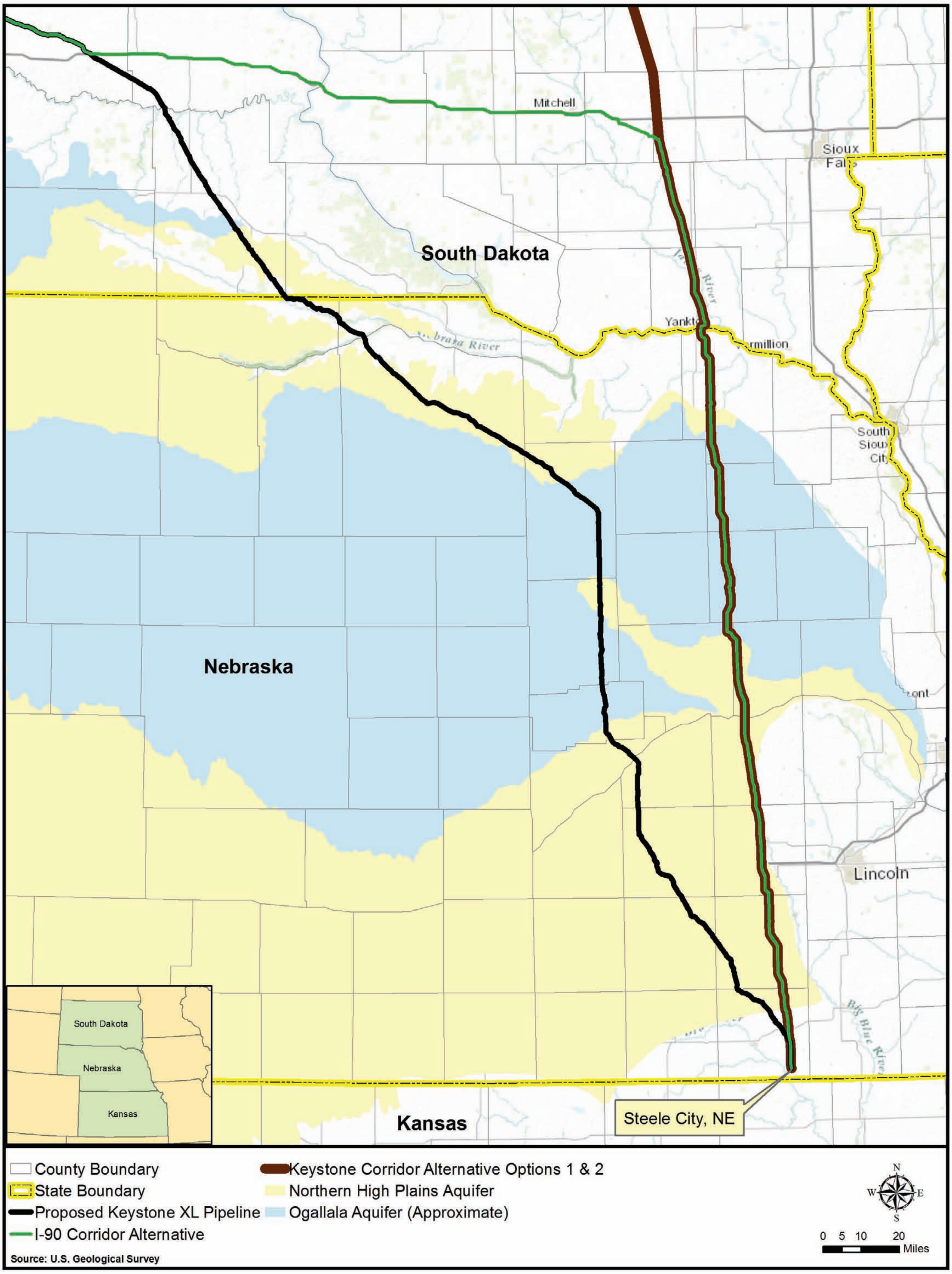
The nearest major hub for Bakken crude to Keystone Corridor Alternative Option 1 would be Epping, North Dakota, approximately 49 miles south of this alternative route. Therefore, this option requires an additional approximately 49-mile long pipeline to access Bakken crude oil in order to meet the overall proposed Project purpose.

As summarized in Table 2.2-13, the Keystone Corridor Alternative Option 1 would:

- Not meet the secondary purpose and need of the proposed Project because it does not connect to the Bakken Marketlink without requiring an additional 49-mile pipeline;
- Be approximately 260 miles longer than the proposed route in Canada and the United States with associated reliability, environmental, and construction/operational cost impacts;
- Cause additional habitat fragmentation along any new *greenfield* route between Morgan, Montana, and the existing Keystone pipeline ROW; and
- Require approximately 72 aboveground facilities compared to 59 for the proposed route.

Failure of the Keystone Option 1 to meet the proposed Project's purpose and need, without additional impacts to the environment and additional spill risk as a result of an additional 49-mile pipeline, was a significant criterion contributing toward rejection of the alternative as not reasonable.

Moreover, the Keystone Option 1 would not completely avoid the Ogallala aquifer, as the existing Keystone pipeline crosses a portion of the Ogallala aquifer in Nebraska, but it would cross less of the aquifer than the Proposed Action. Keystone Option 1, however, crosses areas of the Northern High Plains Aquifer (NHPA) where there is a correlation of 1) shallow groundwater; 2) a high number of wells within 1 mile of the pipeline; and 3) significantly higher hydraulic conductivities than areas of the aquifer crossed by the proposed route (see Figure 2.2.5-2. These areas along Keystone Option 1 are near where that route crosses the Elkhorn, Loup, and Platte Rivers in Nebraska. Keystone Option 1 would also increase the overall risk of an oil spill or leak by about 23 percent because the pipeline would be about 23 percent longer than the Proposed Action.



Source: Esri 2013

Figure 2.2.5-2 Keystone Corridor Alternative Options' Relationship to Ogallala Aquifer and Northern High Plains Aquifer

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In terms of habitat fragmentation, pipeline impacts to forested habitat are considered the most significant fragmentation because it is permanent, whereas impacts to grasslands and agricultural habitats are considered temporary because they can be restored in relatively short timeframes. Keystone Option 1 would offer negligible benefits relative to the Proposed Action in terms of habitat fragmentation because it would cross more miles of forested habitat than the proposed Project (approximately 23 miles versus 8 miles, respectively).

Further, the Keystone Option 1 offers no meaningful benefit relative to the I-90 Corridor Alternative, which is carried forward for further consideration. Both alternatives would have identical impacts to the Ogallala Aquifer, but Keystone Option 1 represents a greater overall risk to groundwater (and water resources in general) because its longer length (over 200 miles longer) increases the risk for an oil spill or leak. Both the Keystone Option 1 and the I-90 Corridor alternatives have similar lengths of new pipeline that is not co-located with an existing pipeline (513 and 516 miles, respectively), so they would be expected to have similar effects on habitat fragmentation, but the Keystone Option 1 would fragment more forest than the I-90 Corridor (7 miles versus 23 miles, respectively).

For the reasons listed above, the Keystone Option 1 was excluded from further consideration.

Keystone Corridor Option 2 Existing Keystone Pipeline Border Crossing

Keystone Corridor Alternative Option 2 would follow the existing Keystone pipeline corridor over its entire length of approximately 1,409 miles from Hardisty, Alberta, to Steele City, Nebraska (Figure 2.2.5-1). Option 2 would parallel the approximately 769-mile Canadian portion of the existing Keystone pipeline from Hardisty, Alberta, to the international border crossing near Haskett, Manitoba, and Pembina, North Dakota. A new Presidential Permit application would be required for the pipeline to cross the border at this location. This option would then parallel the existing pipeline for 640 miles through North Dakota, South Dakota, and Nebraska. The total length, including additional pipeline to access Bakken crude oil, would be 1,682 miles.

As currently proposed, the approved pipeline route in Canada from Hardisty, Alberta, to Morgan, Montana, is approximately 329 miles. Keystone Corridor Alternative Option 2 would require an additional 440 miles of new pipeline in Canada and new permits for the entire 769-mile Canadian portion of Option 2.

As summarized in Table 2.2-13, Keystone Corridor Alternative Option 2 would:

- Not meet the secondary purpose and need of the proposed Project because it does not connect to the Bakken Marketlink without requiring an additional 273-mile pipeline;
- Be approximately 570 miles longer than the total length of the proposed route in Canada and the United States (including a 273 mile long pipeline lateral to access Bakken crude at Epping, North Dakota) with associated reliability, environmental, and construction/operational cost impacts; and
- Need a re-route in Canada of about 440 miles to access the existing Keystone Pipeline border crossing and require a new permit in Canada and in the United States.

Failure of the Keystone Option 2 to meet the proposed Project's purpose and need, without additional impacts to the environment and additional spill risk as a result of an additional 273-mile pipeline, was a significant criterion contributing toward rejection of the alternative as not reasonable.

Moreover, the Keystone Option 2 would not completely avoid the Ogallala aquifer, as the existing Keystone pipeline crosses a portion of the Ogallala aquifer in Nebraska, but it would cross less of the aquifer than the proposed Project. Keystone Option 2, however, crosses areas of the NHPA where there is a correlation of 1) shallow groundwater; 2) a high number of wells within 1 mile of the pipeline; and 3) significantly higher hydraulic conductivities than areas of the aquifer crossed by the proposed route. These areas along Keystone Option 2 are near where that route crosses the Elkhorn, Loup, and Platte Rivers in Nebraska. Keystone Option 2 would also increase the overall risk of an oil spill or leak by over 50 percent because the pipeline would be over 50 percent longer than the proposed Project.

In terms of habitat fragmentation, pipeline impacts to forested habitat are considered the most significant fragmentation because such habitat is permanent, whereas impacts to grasslands and agricultural habitats are considered temporary because they can be restored in relatively short timeframes. Keystone Option 2 would offer negligible benefits relative to the proposed Project in terms of habitat fragmentation because it would cross more miles of forested habitat than the proposed Project (approximately 14 miles versus 8 miles, respectively).

Further, the Keystone Option 2 offers no meaningful benefit relative to the I-90 Corridor Alternative, which is carried forward for further consideration. Both alternatives would have identical impacts to the Ogallala Aquifer, but Keystone Option 2 represents a greater risk to groundwater (and water resources in general) because its longer length (over 500 miles longer) increases the risk for an oil spill or leak. The Keystone Option 2 would avoid new forest habitat fragmentation (whereas the I-90 Corridor would fragment about 7 miles of forest), but would widen existing fragmentation.

Additionally, the Department is responding to a Presidential Permit request from a private party, which proposes a border crossing in Morgan, Montana. The Department, in taking a hard look at alternatives, is considering alternatives that would require a different border crossing than proposed by Keystone. The Department, however, cannot propose or approve an alternative crossing location, and ultimately either has to approve or disapprove the proposed crossing in Morgan. On balance, Keystone Option 2 does not appear to offer any compelling benefits in comparison to the I-90 Corridor Alternative. Given that the proposed Project is already permitted in Canada and that other alternatives are considered in this Final Supplemental EIS that appear to offer similar if not less environmental impacts, the Keystone Option 2 was excluded from further consideration.

Phase II Screening

The three major route alternatives that remained after the Phase I screening were reviewed through a Phase II screening to identify those alternative routes that warranted consideration as reasonable alternatives as compared to the proposed route (see Table 2.2-14).

The three alternatives that were carried through to Phase II screening include:

- 2011 Steele City Alternative;
- I-90 Corridor Alternative; and
- Steele City Segment—A1A Alternative.

Phase II screening evaluated these potential alternatives on the following, more specific environmental and cultural criteria:

- Total length of the pipeline, including both the United States and Canada;
- Use of the Canadian-approved Keystone XL pipeline ROW outside of the United States;
- Approximate acres affected by construction of the proposed Project (based on a typical 110-foot construction ROW)
- Federal lands crossed (miles);
- Principal aquifers crossed (miles);
- American Indian lands crossed (miles);
- Total wetlands crossed (miles);
- USFWS critical habitat for threatened and endangered species crossed (miles);
- Known cultural resource sites (listed on National Register of Historic Places) within 500 feet of proposed pipeline;
- Number of waterbodies crossed; and
- Soils designated as highly erodible by wind crossed (miles).

In Phase II screening, route alternatives were evaluated to identify those alternatives that have a greater impact to the features identified above or those features that had a greater effect on project constructability when compared to the proposed route. If routes that had these increased impacts did not have some offsetting advantage, they were eliminated from further consideration and not carried forward in this Final Supplemental EIS.

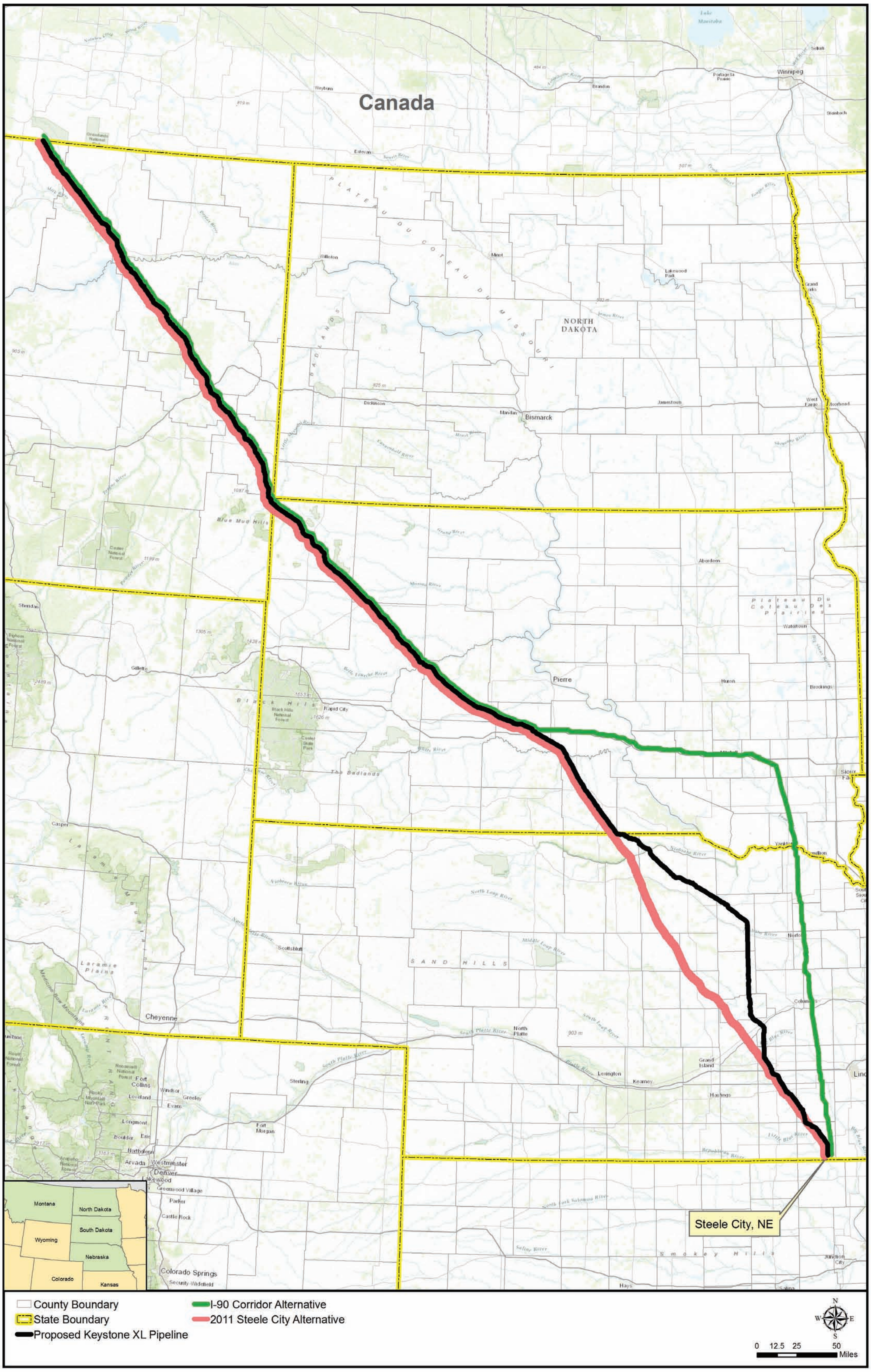
Phase II Results

Based on the results of the Phase II screening described above and summarized in Table 2.2-14, the Department selected the 2011 Steele City Alternative and I-90 Corridor Alternative to be carried forward through this Final Supplemental EIS for analysis, in addition to the proposed Project (see Figure 2.2.5-3). The Phase II screening eliminated the Steele City Segment—A1A Alternative.

Table 2.2-14 Phase II Detailed Screening

Feature	Proposed Project	2011 Steele City Alternative	I-90 Corridor Alternative	Steele City Segment – A1A Alternative
Length of route in the United States and Canada (miles) [a]	1,112	1,091	1,164	936
Approximate Acres Affected by Construction of the Pipeline Project (acres)[b]	11,599	11,387	12,360	12,480
Approximate Acres Affected by Maintenance of the Permanent Pipeline ROW (acres)[c]	5,309	5,176	4,818[l]	5,672
Federal Lands Crossed (miles)[d]	50	50	52	32
Principal Aquifers Crossed (miles) (includes glacial)[e]	597	598	565	724
American Indian Lands Crossed (miles)[f]	0	0	0	0
Total Wetlands Crossed (miles)[g]	3	8	4	20
UFWS Critical Habitat for Threatened & Endangered Species Crossed (miles)[h]	0	0	0	2
Known Cultural Resource Sites (listed on National Historic Database) within 500feet of Proposed Pipeline[i]	0	0	1	0
Number of Waterbodies Crossed[j]	62	60	61	65
Soils Designated as Highly Wind-Erodible Crossed (miles)[k]	73	115	36	4
NDEQ-Identified Sand Hills Region Crossed (miles)	0	89	0	0

[a] Miles to closest intersection with the proposed Project route, with consideration of Indian Reservations, large waterbodies, and protected lands. No other siting criteria were used.
[b] Acreage = Length of route (mi)*5280ft * 110 feet)/43,560 feet
[c] Acreage = Length of route (mi)*5280ft * 50 feet)/43,560 feet
[d] Lands owned or administered by the government of the United States.
[e] Length of route crossing principal aquifers as defined by U.S. Geological Survey.
[f] Length of route crossing areas with boundaries established by treaty, statute, and (or) executive or court order, recognized by the federal government as territory in which American Indian tribes have primary governmental authority.
[g] Length of route crossing National Wetlands Inventory classes: Freshwater Emergent Wetland, Freshwater Forested/Shrub Wetland, and Other Non-Open Water Wetlands.
[h] USFWS Critical Habitat for Threatened & Endangered Species; the Critical Habitat portal is an online service for information regarding Threatened and Endangered Species final Critical Habitat designation across the United States. Not all of the critical habitat data designated by the USFWS are available.
[i] Google Earth data provided by the National Park Service showing properties listed on the National Register of Historic Places.
[j] U.S. National Atlas Water Feature Areas (2012): aqueducts, canals, dams, intracoastal waterways, rivers, and streams
[k] Based on soil classification of Wind Erodibility Group (NRCS 2012) values of 1 to 2 being Highly Erodible (STATSGO soil characteristics for the conterminous United States)
[l] For the purpose of this screening it is assumed that this alternative could be co-located with the existing Keystone pipeline.



Source: Esri 2013

Figure 2.2.5-3 Major Route Alternatives Carried forward for Detailed Analysis

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2.2.5.2 2011 Steele City Alternative

The 2011 Steele City Alternative considered in this Final Supplemental EIS is identical to the Steele City Segment-B pipeline route that was considered as part of the overall proposed route in the Final EIS. This alternative assumes that Keystone would construct, operate, maintain, inspect, and monitor a single 36-inch pipeline system that would transport crude oil from its existing facilities in Hardisty, Alberta, Canada, and from proposed facilities in Baker, Montana, for delivery to Steele City, Nebraska.

This section provides an overview of the 2011 Steele City Alternative, associated aboveground facilities, connected actions, and a baseline impact comparison to Keystone's proposed route.

In examining the 2011 Steele City Alternative, the Department assumed that the typical engineering design specifications, construction procedures, operations, maintenance, and decommissioning would be identical to those presented in the description of the proposed Project in Section 2.1, Overview of the Proposed Project. Specific mitigation or site-specific construction and operation procedures would vary according to differences in the routes and specific conditions on those routes.

The 2011 Steele City Alternative was originally proposed by Keystone as the shortest practical route from the United States/Canada border near Morgan, Montana, to existing oil facilities at Steele City, Nebraska, with a total pipeline length of approximately 854 miles (see Table 2.2-14). The temporary construction ROW would have a nominal width of 110 feet, and the permanent operating easement would be 50 foot wide. The estimated surface impacts associated with this alternative are presented in Table 2.2-14.

As shown on Figure 2.2.5-3, this alternative would follow Keystone's current proposed Project route from the Canadian border milepost (MP 0) south to approximately MP 204 where it would connect with the Bakken Marketlink Project onramp at the same location as the proposed Project. It would then continue to approximately MP 615 in northern Nebraska near the border with South Dakota. At that location, the 2011 Steele City Alternative would divert from the current proposed Project and would continue southeasterly for another 239 miles to the southern terminus at Steele City, Nebraska. From approximately MP 635 to MP 713, the 2011 Steele City Alternative would cross the NDEQ-identified Sand Hills Region.

Aboveground Facilities

The 2011 Steele City Alternative would require approximately 155 associated aboveground facilities, including 18 pump stations, one densitometer site, 57 intermediate mainline valves (MLVs), and 80 access roads. Pig launchers and receivers, as defined in Section 2.1, Overview of the Proposed Project, would be located completely within the boundaries of the pump stations. The densitometer facility would be located just upstream (north) of the southernmost pump station near Steele City, Nebraska. A summary of these facilities by state is presented in Table 2.2-15.

Table 2.2-15 2011 Steele City Alternative Ancillary Facilities by State

State	Ancillary Facilities (e.g., access roads, pump stations, and construction camps)
Montana	6 New Pump Stations 21 IMLVs 50 Access Roads
South Dakota	7 New Pump Stations 17 IMLVs 18 Access Roads
Nebraska	5 New Pump Stations 19 IMLVs 12 Access Roads 1 Densitometer Facility

Connected Actions

The 2011 Steele City Alternative would require the same three connected actions as the proposed Project:

- Bakken Marketlink Project
- Big Bend to Witten 230-kilovolt (kV) Transmission Line
- Electrical Distribution Lines and Substations

2.2.5.3 I-90 Corridor Alternative

This section provides an overview of the I-90 Corridor Alternative pipeline route; associated aboveground facilities; connected actions; and a baseline impact comparison to Keystone's proposed route (see Figure 2.2.5-3). The I-90 Corridor Alternative assumes that Keystone would construct, operate, maintain, inspect, and monitor a single 36-inch pipeline system that would transport up to 830,000 bpd of crude oil from its existing facilities in Hardesty, Alberta, Canada and from proposed facilities in Baker, Montana for delivery to Steele City, Nebraska. In examining the I-90 Corridor Alternative, the Department assumes that the typical engineering design specifications, construction procedures, operations, maintenance, and decommissioning would be identical to those presented in the description of the proposed Project in Section 2.1, Overview of the Proposed Project.

The I-90 Corridor Alternative was identified in the Final EIS for the previous Keystone XL proposed route as an alternative that would avoid crossing the NDEQ-identified Sand Hills Region and would reduce the length of pipeline crossing the NHPA system, which includes the Ogallala formation. This alternative was developed largely in response to comments received during that EIS process, expressing concerns regarding the risk of spills to the NHPA system and suggestions that overall impacts might be reduced by avoiding this formation and using a portion of the existing Keystone pipeline ROW.

The I-90 Corridor Alternative would be approximately 927 miles in length from the United States/Canada border to Steele City, Nebraska. The temporary construction ROW would have a nominal width of 110 feet; the permanent operating easement would be 50 foot wide. As shown on Figure 2.2.5-3, the I-90 Corridor Alternative would follow Keystone's currently proposed Project route from the Canadian Border (MP 0) south through the state of Montana into South Dakota to approximately MP 516, where the proposed pipeline route intersects Interstate 90

(I-90). This alternative pipeline route would divert from the proposed Project route at this location.

In South Dakota, pipelines are allowed to cross the I-90 ROW, but are not allowed to be installed parallel to the roadway within the highway easement (South Dakota Administrative Code 70:04:05.01:01 Construction and Maintenance of Utility Facilities within Interstate Right-of-Way). As a result of this policy, this route alternative would travel eastward, adjacent and parallel to the southern side of the I-90 corridor, for approximately 144 miles (approximately 2 miles west of Alexandria, South Dakota). It is assumed that the I-90 Corridor Alternative would diverge from the I-90 ROW to avoid towns adjacent to I-90, such as Oacoma and Mitchell, South Dakota.

Near Alexandria, South Dakota, the I-90 Corridor Alternative intersects an existing corridor shared by the BNSF railroad line and State Highway 262 (BNSF/262). From this location, the I-90 Corridor Alternative would travel southeast away from I-90, parallel and adjacent to the BNSF/262 corridor for approximately 13 miles to just east of Emery, South Dakota. At this point, the I-90 Corridor Alternative would intersect the existing Keystone Oil Pipeline Project ROW. The I-90 Corridor Alternative would then parallel the west side of the existing Keystone Oil Pipeline Project ROW for approximately 254 miles to Steele City, Nebraska.

The I-90 Corridor Alternative ROW would share up to 25 feet of the existing Keystone easement where these routes are parallel and adjacent for approximately 254 miles. In this segment of the I-90 Corridor Alternative, the 110-foot-wide temporary construction corridor would impact 85 feet outside of Keystone's existing maintained pipeline easement; the new permanent easement would extend 25 feet from the edge of Keystone's existing 50-foot-wide easement.

Just south of the town of Chamberlain, South Dakota, the I-90 Corridor Alternative route crosses Lake Francis Case. This lake is a reservoir along the Missouri River formed by Fort Randall Dam located approximately 90 miles downstream of the potential crossing. The pipeline would remain parallel to the southern side of I-90 for the lake crossing. The lake is approximately 4,100 feet wide at this location. An aerial view of the lake crossing location is shown on Figure 2.2.5-4.

This would be a complex crossing and site-specific studies would be required to validate the feasibility of crossing at this location. Based on a desktop review of the crossing conditions, the proposed crossing would approach the practical limits for horizontal directional drill methods of a 36-inch pipeline (approximately 6,000 feet). As a result, for the purposes of this evaluation, it is assumed that a wet-cut crossing method using barges and bottom dredging may be the preferred method to cross Lake Francis Case at this location.

Aboveground Facilities

The I-90 Corridor Alternative would require approximately 172 aboveground facilities, including 19 pump stations, one densitometer site, 70 IMLVs, and 82 access roads. Pig launchers and receivers would be located completely within the boundaries of the pump stations or delivery facilities. The densitometer facility would be located just upstream (north) of the southernmost pump station near Steele City, Nebraska. A summary of these facilities by state is presented in Table 2.2-16.

Table 2.2-16 I-90 Corridor Alternative Estimated Aboveground Facilities by State

State	Ancillary Facilities (e.g., access roads, pump stations, and construction camps)
Montana	6 New Pump Stations 21 IMLVs 50 Access Roads
South Dakota	9 New Pump Stations 34 IMLVs 22 Access Roads
Nebraska	4 New Pump Stations 15 IMLVs 10 Access Roads 1 Densitometer Facility

Connected Actions

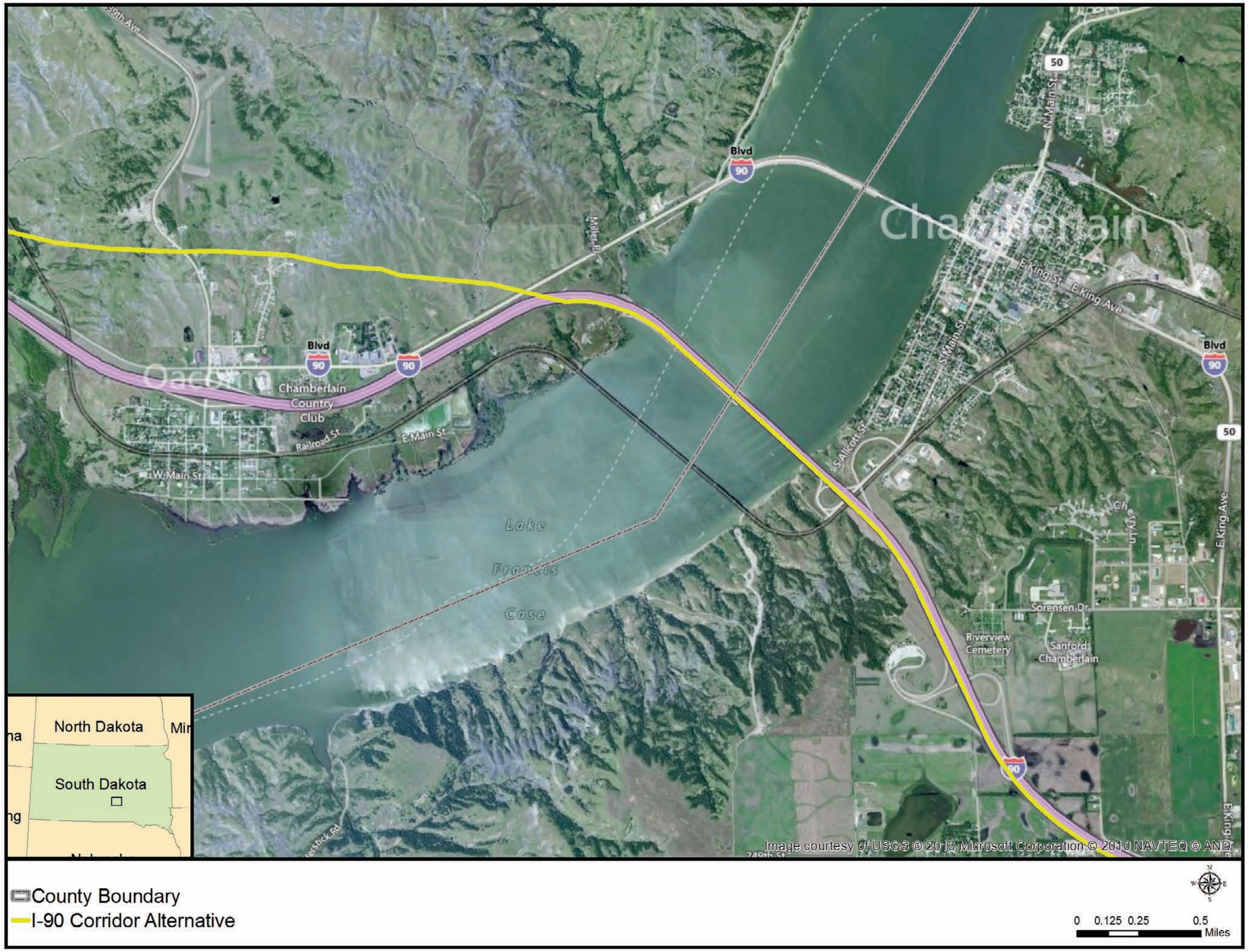
The I-90 Corridor Alternative would require the same three connected actions as the proposed Project:

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

Nebraska Route Options

On January 3, 2013, the NDEQ issued its Final Evaluation Report for the 194.5 mile proposed Nebraska Reroute of the Keystone XL Pipeline (NDEQ 2013b). Governor Heineman approved the report and proposed reroute on January 22, 2013, and requested that the Department include the new route in this Final Supplemental EIS (Appendix A, Governor Approval of the Keystone XL Project in Nebraska). The proposed reroute, shown on Figure 2.2.5-5, avoids the boundaries of the NDEQ-identified Sand Hills region of Nebraska.

In addition to the NDEQ-identified Sand Hills Region, the proposed Project route would avoid areas in Keya Paha County identified by the NDEQ that have soil and topographic characteristics similar to the NDEQ-identified Sand Hills Region, and it avoids or moves further away from wellhead protection areas for the Villages of Clarks and Western. The Nebraska reroute as currently proposed is carried forward for analysis in the Final Supplemental EIS as a component of Keystone's proposed route.



Source: Esri 2013

Figure 2.2.5-4 I-90 Corridor Alternative

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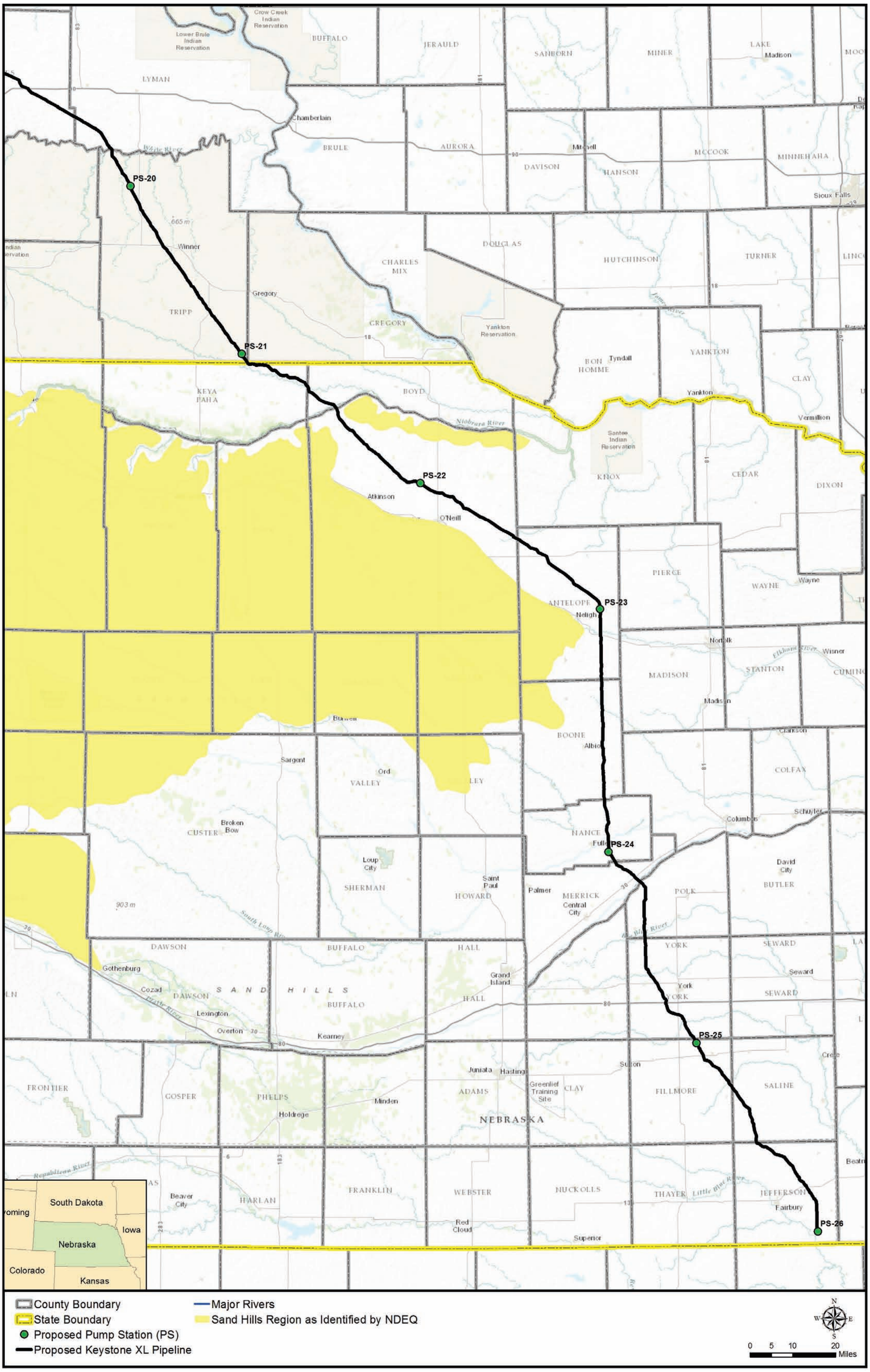

Source: Esri 2013, NDEQ 2013a

Figure 2.2.5-5 NDEQ-Identified Sand Hills Region

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2.2.5.4 Steele City Segment—A1A Alternative

The Steele City Segment—A1A Alternative is approximately 936 miles long from the border crossing near Morgan, Montana, to Steele City, Nebraska. As shown on Figure 2.2.5-1, the Steele City Alternative would be parallel and adjacent to the existing Northern Border Pipeline ROW from the border crossing for approximately 41 miles. At this point, the Steele City Alternative route would divert north away from the Northern Border Pipeline to avoid the Fort Peck Indian Reservation in Montana.

The deviation would have a total length of approximately 149 miles. Beginning in central Valley County, Montana, the route would extend to the east along a path that would be north of the Standing Rock Indian Reservation. It would then turn south to pass to the east of the Standing Rock Indian Reservation in Sheridan County until crossing into Roosevelt County, Montana, where it would extend to the southeast and cross into Williams County, North Dakota, where it would rejoin the Northern Border Pipeline ROW.

From this location, the Steele City Segment—A1A Alternative would travel parallel and adjacent to the Northern Border Pipeline ROW for approximately 365 miles to a point where the Northern Border Pipeline intersects with the existing Keystone Pipeline. The Steele City Segment—A1A Alternative would then turn south and parallel the existing Keystone Pipeline for approximately 381 miles to Steele City, Nebraska. It is assumed that the Northern Border Pipeline would not allow Keystone to collocate within any part of its ROW due to liability, maintenance, and future expansion considerations.

The Steele City Segment—A1A Alternative would not be located near the proposed Bakken Marketlink Project onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is a condition of Montana's current approval of Keystone's proposed route with the state. To satisfy the proposed Project purpose and need as well as Keystone's current contracts to transport up to 100,000 bpd of crude from the Bakken, a 30-mile pipeline connection to Epping, North Dakota, is assumed to be included in this alternative.

As summarized in Table 2.2-14, the Steele City Segment—A1A Alternative was removed from further consideration for the following reasons:

- The Steele City Segment—A1A Alternative would be approximately 90 miles (10 percent) longer than the proposed Project, taking into consideration the 30-mile pipeline that would be needed to access the Bakken crude oil at Epping, North Dakota;
- The longer Steele City Segment—A1A Alternative would also have a proportional increase in the risk for spills and leaks relative to the proposed Project;
- The Steele City Segment—A1A Alternative would cross 127 more miles of principal aquifer (724 miles versus 597 miles for the proposed Project) and 17 more miles of wetlands (20 miles versus 3 miles for the proposed Project); and
- The Steele City Segment—A1A Alternative would require two major crossings of the Missouri River, as opposed to a single crossing for the proposed Project. Further, both of the Steele City Segment—A1A Alternative crossings of the Missouri River would be farther downstream of the proposed Project crossing.

Based on this Phase II screening, the Steele City—A1A Alternative would not offer any offsetting environmental advantage relative to the proposed Project to warrant further assessment and is not carried forward for a full evaluation in this EIS.

2.2.6 Other Alternatives Considered but Eliminated from Detailed Analysis in this Final Supplemental EIS

2.2.6.1 Route Variations

In addition to major route alternatives, proposed variations to the proposed Project were also considered. Route variations are relatively short deviations from a proposed route that are developed in response to landowner requests; to avoid or minimize construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, or residences; or to minimize constructability issues such as shallow bedrock, difficult waterbody crossings, or steep terrain.

Each of the three states crossed by the proposed Project pipeline (Montana, South Dakota, and Nebraska) has incorporated minor route variations into the conditions for its approval of the proposed route. These variations were identified in the TransCanada Keystone XL Pipeline Project, Environmental Report (exp Energy Services Inc. 2012). The variations have been adopted by Keystone and are included in the detailed description of the proposed Project in Section 2.1, Overview of the Proposed Project.

2.2.6.2 Alternative Pipeline Design

In response to public comments, the Department considered two alternative pipeline designs: an aboveground pipeline and an alternative using smaller-diameter pipe. These two alternatives are addressed in the following sections.

Aboveground Pipeline

Although it is technically feasible to construct the proposed Project pipeline aboveground in most areas along the proposed Project route, there are many disadvantages to an aboveground pipeline that need to be considered. An aboveground pipeline is far more vulnerable to damage due to vandalism, sabotage, and the effects of other outside forces, such as vehicle collisions. Furthermore, there has been increased concern about homeland security over the past decade, and burying the pipeline provides a higher level of security (Government Accountability Office 2010).

In addition to safety and security issues, an aboveground pipeline would be more susceptible to the effects of ambient temperature, wind, and other storm events. Construction of an aboveground pipeline would also require exposing the pipeline above rivers (e.g., hung from a bridge or constructed as a special pipeline span) and roadways, where it would be vulnerable during bridge maintenance and accessible to those intent on damaging the pipeline.

Nearly all petroleum transmission pipelines in the United States are buried. As stated in Section 2.1.7, Pipeline System Design and Construction Procedures, the proposed Project would be constructed, operated, maintained, inspected, and monitored consistent with the Pipeline Hazardous Material Safety Administration (PHMSA) requirements presented in 49 CFR 195, relevant industry standards, applicable state standards, and a set of proposed Project-specific

Special Conditions developed by PHMSA and incorporated into the proposed Project design, operations, maintenance, and monitoring commitments.

There are examples of successful aboveground pipelines, including 466 miles of the Trans-Alaska pipeline. In addition, inspection and leak detection for aboveground pipelines could be more efficient and emergency response more rapid.

Based on review and in consultation with PHMSA, it has been determined that due to the safety and security concerns of an aboveground pipeline, it is not a reasonable alternative for the proposed Project, and it was not considered further in this Final Supplemental EIS.

Smaller-Diameter Pipe

As noted in Section 2.1, Overview of the Proposed Project, the proposed Project purpose is to transport a maximum capacity of 830,000 bpd of crude oil to satisfy existing commitments and future market demand. A pipeline system with a pipe diameter of less than the proposed Project's 36-inch-diameter would have lower throughput capacities and would not be capable of providing the volume of crude necessary to meet the proposed Project purpose.

The recommended work safety and construction requirements, including the construction ROW width for a small 30-inch diameter, long-distance transportation pipeline are the same as those of the proposed 36-inch-diameter pipe (INGAA 1999). The working ROW dimensions of pipeline construction are primarily related to the size of construction vehicles and the need for working space near the pipeline trench.

The proposed pipeline is sized to efficiently meet the contracted volume of crude oil of 500,000 bpd with a maximum capacity of 830,000 bpd with increased pumping capacity. While there are limitations to the ultimate capacity of throughput based on pipeline diameter, the operational throughput is a combined function of pipeline diameter, pipeline operating pressure, and crude oil flow velocity. Therefore, to achieve a throughput that would meet the purpose of the proposed Project, a smaller-diameter pipeline would have to operate at higher pressures and flow velocities, and, for the delivery capacity proposed, the pressures and velocities required for a smaller diameter would not be consistent with PHMSA safety regulations, which limit maximum pipeline pressure.

Even if a special exception would be approved by PHMSA to increase pressure and velocity, it is unlikely that a 30-inch-diameter pipeline would be capable of transporting the volumes proposed for transport in the proposed Project. As of February 2011, Keystone had firm contract commitments to transport 500,000 bpd of crude oil to the oil terminal at Cushing, Oklahoma. If a smaller-diameter pipeline were installed, it would likely be necessary to install an additional pipeline to meet those initial commitments.

As a result of these findings, the Department has determined that the use of a smaller-diameter pipe for the proposed Project is not a reasonable alternative, and installing more than one smaller-diameter pipe to meet the purpose of and need for the proposed Project would not offer an overall environmental advantage over the proposed Project design. Therefore, this alternative was eliminated from further consideration.

2.2.7 Summary

Based on the analysis described above, the Department has identified the following as reasonable alternatives to the proposed Project for inclusion and evaluation in this Final Supplemental EIS:

- No Action Alternative, including the following:
  - Status Quo Baseline (i.e., no change in current WCSB or Bakken crude oil transport methods);
  - Rail/Pipeline Scenario:
    - WCSB Crude – Rail from Lloydminster, Saskatchewan, to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma, for onward delivery to Gulf Coast area refineries; and
    - Bakken Crude – Rail from Epping, North Dakota, to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma, for onward delivery to Gulf Coast area refineries.
  - Rail/Tanker Scenario:
    - WCSB Crude – Rail from Lloydminster, Saskatchewan, to Prince Rupert, British Columbia, then tanker through the Panama Canal to the Gulf Coast area; and
    - Bakken Crude – Rail from Epping, North Dakota, to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma, for onward delivery to the Gulf Coast area.
  - Rail Direct to Gulf Coast Scenario:
    - WCSB Crude – Rail from Lloydminster, Saskatchewan, to existing rail off-loading terminals in Houston/Port Arthur, Texas;
    - Bakken Crude Oil – Rail from Epping, North Dakota, to existing rail terminals in Houston/Port Arthur, Texas; and
    - Pipeline or barge to refineries in the Gulf Coast area.
- 2011 Steele City Alternative; and
- I-90 Corridor Alternative.

A description of the impacts associated with each of these alternatives is presented in Chapter 5, Alternatives. Section 5.3, Comparison of Alternatives, provides a summary comparison of impacts across all alternatives.

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