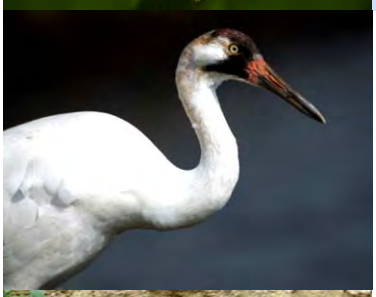

Final
Environmental Impact Statement
Keystone XL Project

Applicant for Presidential Permit:
TransCanada Keystone Pipeline, LP

August 26, 2011

United States Department of State
Bureau of Oceans and International
Environmental and Scientific Affairs

VOLUME 2
Sections 3.9 – 4.6

3.9 LAND USE, RECREATION, AND VISUAL RESOURCES

The proposed Project would affect land use on or near the pipeline right-of-way (ROW) and in the locations of appurtenant facilities (e.g., power lines, access roads, and construction camps). This section describes the potential impacts of the proposed Project on land use, recreation, and visual resources. For each element of the environment, information is provided on the environmental setting, construction impacts, operational impacts, and mitigation.

3.9.1 Land Ownership and Use

3.9.1.1 Environmental Setting

Land Ownership along Proposed Pipeline Corridor

Construction of the proposed pipeline would occur across 1,384 miles of land (see Table 3.9.1-1). Approximately 1,286 miles of the proposed pipeline would cross private land, approximately 44 miles would cross federal land, and approximately 54 miles would cross state-owned land.

TABLE 3.9.1-1
Land Ownership Crossed by the Proposed Project Pipeline (Miles)

State	Federal	State	Private	Total	Percent of Total
Steele City Segment					
Montana	43.8	20.0	218.9	**282.7**	**33.2%**
South Dakota	0.0	25.9	288.3	**314.2**	**36.9%**
Nebraska	0.0	5.8	248.9	**254.7**	**29.9%**
Segment Total	*43.8*	*51.7*	*756.1*	***851.6***	***100.0%***
Cushing Extension					
Kansas[a]					
Gulf Coast Segment					
Oklahoma	0.0	2.1	153.7	**155.7**	**32.2%**
Texas	0.0	0.0	328.0	**328.1**	**67.8%**
Segment Total	*0.0*	*2.1*	*481.7*	***483.8***	***100.0%***
Houston Lateral					
Texas	0.0	0.0	48.6	**48.6**	**100.0%**
Project Total	**43.8**	**53.8**	**1,286.4**	**1,384.0**	**100.0%**

[a] No new pipeline mileage would be constructed in Kansas.

Steele City Segment

The proposed pipeline of the Steele City Segment would cross about 282.7 miles of Montana, 314.2 miles of South Dakota, and 254.7 miles of Nebraska. Land ownership along the proposed pipeline is summarized in Table 3.9.1-1. Of the 851.6 miles of land that would be crossed by the proposed pipeline, about 756.1 miles would be private land, 51.7 miles would be state land, and 43.8 miles would be federal land.

Cushing Extension

Two new pump stations would be constructed on privately owned land in Kansas along the Cushing Extension of the Keystone Pipeline system to accommodate increased crude oil volumes associated with the proposed Project.

Gulf Coast Segment

The proposed Gulf Coast Segment pipeline would cross 155.7 miles in Oklahoma and 328.1 miles in Texas, of which 481.7 miles would occur on private land and the remaining 2.1 miles would occur on state land in Oklahoma.

Houston Lateral

The proposed Houston Lateral pipeline would cross 48.6 miles of privately-owned land in Texas.

Land Use along Proposed Pipeline Corridor

The proposed Project would cross 754.4 miles of rangeland, 329.2 miles of agricultural lands, 175.5 miles of forest land, 64.6 miles of developed lands, and 60.1 miles of water and wetlands (Table 3.9.1-2).

TABLE 3.9.1-2
Current Land Uses That Would be Affected by the Proposed Project Pipeline (Miles)

State	Developed	Agriculture	Rangeland	Forest[a]	Water/Wetland	Total[b]
Steele City Segment						
Montana	2.8	70.2	204.4	0.6	4.7	**282.7**
South Dakota	3.0	80.9	223.7	0.9	5.5	**314.0**
Nebraska	3.9	112.8	126.1	4.5	7.4	**254.7**
Segment Total	*9.7*	*263.9*	*554.2*	*6.0*	*17.6*	**851.4**
Cushing Extension						
Kansas	0.0	0.0	0.0	0.0	0.0	**0.0**
Gulf Coast Segment						
Oklahoma	17.3	11.7	83.4	40.3	3.2	**155.9**
Texas	35.9	50.4	97.7	111.5	32.4	**327.9**
Segment Total	*53.2*	*62.1*	*181.1*	*151.8*	*35.6*	**483.8**
Houston Lateral						
Texas	1.7	3.2	19.1	17.7	6.9	**48.6**
Project Total	64.6	329.2	754.4	175.5	60.1	**1,383.8**

[a] No groves or nurseries are crossed by the proposed Project. Locations of forest land are identified by milepost in Appendix O.
[b] Discrepancies in totals are due to rounding.

Steele City Segment

Land uses along the proposed pipeline of the Steele City Segment include 554.2 miles of rangeland, 263.9 miles of agricultural land, 17.6 miles of water/wetlands, 9.7 miles of developed land, and 6 miles of forest land (Table 3.9.1-2).

Cushing Extension

No new pipeline would be constructed along the existing Cushing Extension. However, two new pump stations would be constructed in rangeland and forest land. Acreages that would be impacted by construction and operation of the two new proposed pump stations are addressed under subsections for construction and operational impacts.

Gulf Coast Segment

The Gulf Coast Segment would cross 181.1 miles of rangelands, 151.8 miles of forest land, 62.1 miles of agricultural land, 53.2 miles of developed land, and 35.6 miles of water/wetlands (Table 3.9.1-2). Developed land would comprise sparsely populated areas located outside of communities, most of which are concentrated in central Texas and south to the proposed Project terminus. Forest land in Oklahoma and Texas would primarily be located in the South Central Plains Ecoregion (see Table 3.5-1), which is locally called "piney woods." Wetland crossings would largely be concentrated in the Texas portion of the Gulf Coast Segment.

Houston Lateral

The proposed pipeline for the Houston Lateral would cross 19.1 miles of rangeland, 17.7 miles of forest land, 6.9 miles of water/wetlands, 3.2 miles of agricultural land, and 1.7 miles of developed land (Table 3.9.1-3). Water and wetlands would be affected near the Trinity River and San Jacinto River, and developed land would be crossed near the proposed Project terminus in the East Houston area.

3.9.1.2 Potential Impacts

This section describes the potential impacts of constructing and operating the proposed Project on each type of land use. For a detailed discussion about impacts to waterbodies and wetlands, please refer to Sections 3.3 and 3.4, respectively.

Easement Acquisition for Right-of-Way (ROW) and Ancillary Facilities

The proposed Project would require the acquisition of temporary and permanent easements with landowners and land managers along the pipeline ROW and at the locations of proposed ancillary facilities. Land ownership that would be affected by proposed Project construction, operation, and maintenance is shown in Table 3.9.1-3.

TABLE 3.9.1-3
Land Ownership Affected by Construction and/or Operation of the Proposed Project (Acres)[a]

State	Federal	State	Private	Total	Percent of Total
Steele City Segment					
Montana	654.5	303.5	3,721.9	**4,679.9**	**33%**
South Dakota	0.2	380.1	4,808.6	**5,188.9**	**37%**
Nebraska	0.3	116.9	4,114.9	**4,232.1**	**30%**
Segment Total	*655.0*	*800.5*	*12,645.4*	***14,100.9***	***100%***
Cushing Extension					
Kansas	0.0	0.0	*15.2*	***15.2***	**100%**
Gulf Coast Segment					
Oklahoma	0.0	40.8	3,065.8	**3,106.6**	**36%**
Texas	0.0	0.0	5,435.8	**5,435.8**	**64%**
Segment Total	*0.0*	*40.8*	*8,501.6*	***8,542.4***	***100%***
Houston Lateral					
Texas	0.0	0.0	652.0	**652.0**	**100%**
Project Total	**655.0**	**841.3**	**21,814.2**	**23,310.5**	**100%**

[a] All acreages assume a 110-foot-wide construction ROW and do not include: the tank farm, access roads and rail sidings on the Steele City Segment; and permanent easements on federal- or state-owned road ROW.

Temporary workspace areas (TWAs) would necessitate the negotiation of temporary ROW easements. Operation and maintenance of the pipeline and ancillary facilities would require permanent ROW easements for the proposed Project lifetime. Easements would typically cover monetary compensation to landowners for long term land use losses (e.g., property use during construction, operation and maintenance), and for temporary land use losses (e.g., crop production impairment, private road damage or obstruction etc). Easements would also address restoration of land or compensation to landowners for any unavoidable construction-related damage to property. For some areas such as water crossings, road/railroad crossings, and steep or rocky slopes, additional TWAs may be needed. In some cases, land would likely be purchased rather than controlled through easements.

Temporary and Permanent Access Roads

The construction ROW would be accessed by public and existing private roads. State transportation agencies would be consulted prior to construction to assess road infrastructure (e.g., bridges) to determine if it is suitable for potential construction loads. If infrastructure is insufficient to transport the projected Project loads, a plan would be developed to avoid or reinforce the infrastructure. No improvement or maintenance is likely to be required for paved roads before or during construction, although gravel and dirt roads may require maintenance during that time. Private roads and temporary access roads would only be used with the permission of the affected landowner or land management agency. In the event that oversized or overweight loads would be needed to transport construction materials to the proposed Project work spreads, separate permit applications would be submitted to the appropriate state regulatory agencies.

Construction of the proposed Project would require the use of 978.8 acres for access roads, including 464.6 acres in the Steele City Segment, 452.2 acres in the Gulf Coast Segment, and 62.0 acres in the

Houston Lateral (Table 3.9.1-4). Proposed Project operations would require 113.0 acres for permanent access roads, including 30.8 acres in the Steele City Segment, 63.2 acres in the Gulf Coast Segment, and 19.0 acres in the Houston Lateral (Table 3.9.1-4).

TABLE 3.9.1-4
Land Affected by Access Roads (Acres)

State	Construction (Temporary)	Operation (Permanent)
Steele City Segment		
Montana	266.5	21.7
South Dakota	144.8	9.1
Nebraska	53.3	0.0
Steele City Subtotal	*464.6*	*30.8*
Cushing Extension		
Kansas	0.0	0.0
Gulf Coast Segment		
Oklahoma	118.6	15.1
Texas	333.6	48.1
Gulf Coast Subtotal	*452.2*	*63.2*
Houston Lateral		
Texas	62.0	19.0
Project Total[a]	**978.8**	**113.0**

[a] Acres of disturbances from temporary and permanent access roads are calculated based upon a 30-foot width.

Pipeline Construction

Construction of the pipeline would involve several key land use issues and impacts, including:

- Lease or acquisition and development of the pipeline ROW and land for appurtenant facilities;
- Possible damage to agricultural features such as irrigation systems or drain tiles;
- Temporary loss of the agricultural productivity of the land;
- Potential visual impacts attributable to removal of existing vegetation and visibility of exposed soil; and
- Increased dust and noise to neighboring residential and commercial areas.

The duration of the construction phase would affect the degree of land use impact. The pipeline would be constructed in 17 separate spreads under the currently proposed Project schedule. It is anticipated that each spread would require from six to eight months for construction and that all pump stations would be completed in 18 to 24 months.

A 110-foot-wide construction ROW would be required for installation of the 36-inch-diameter pipeline, including a 60-foot-wide temporary easement/temporary use permit and a 50-foot-wide permanent easement/right-of-way. The construction ROW width could be reduced to 85 feet to avoid or reduce impacts in some areas, including wetlands, cultural sites, and residential and commercial/industrial areas. Table 3.9.1-5 provides estimates of the acreages of land impacted by each proposed Project element

during construction. The proposed Project would require a total of approximately 24,134 acres[1] during construction.

TABLE 3.9.1-5
Summary of Land Affected During Constructiona,b (Acres)

State	Pipeline ROW	Lateral ROW	Additional Temporary Workspace Areas[c]	Pipe Storage Sites, Rail Sidings, and Contractor Yards	Construction Camps	Pump Stations/ Delivery Facilities	Access Roads[d]	Tank Farm	*Total*
Steele City Segment									
Montana	3,758.6	-	327.8	460.7	182.5	50.1	266.5	-	**5,046.2**
South Dakota	4,178.9	-	309.3	581.2	160.2	59.4	144.8	-	**5,433.8**
Nebraska	3,384.8	-	349.5	515.6	-	42.2	53.3	-	**4,345.4**
Segment Subtotal[e,f]	11,322.3	-	986.6	1,557.5	342.7	151.7	464.6	-	**14,825.4**
Cushing Extension[f]									
Kansas[e,g,f]	-	-	-	-	-	15.2	-	-	**15.2**
Gulf Coast Segment									
Oklahoma	2,033.5	-	179.1	701.3	-	0.0	118.6	74.1	**3,106.6**
Texas	4,198.8	-	332.6	519.6	-	51.1	333.6	-	**5,435.7**
Segment Subtotal[e]	*6,232.3*	-	*511.7*	*1,220.9*	-	*51.1*	*452.2*	74.1	***8,542.3***
Houston Lateral									
Texas	-	652	32	5	-	-	62	-	**751**

[a] Disturbance is based on a total of 110-foot-wide construction ROW for a 36-inch-diameter pipe, except in certain wetlands, cultural sites, shelterbelts, residential areas, and commercial/industrial areas where an 85-foot-wide construction ROW would be used, or in areas requiring extra width for workspace necessitated by site conditions. Disturbance also includes pipe stock piles, contractor yards, and construction camps.

[b] Operational acreage was estimated based on a 50-foot-wide permanent ROW in all areas. All pigging facilities would be located within either pump stations or delivery facility sites. Intermediate mainline valves and densitometers would be constructed within the construction easement and operated within a 50-foot by 50-foot area or 50-foot by 66-foot area within the permanently maintained 50-foot-wide ROW. Other mainline valves, check valves and block valves, and meters would be located within the area associated with a pump station, delivery site or permanent ROW. Consequently, the acres of disturbance for these aboveground facilities are captured within the pipeline ROW and ump station/delivery facilities categories within the table.

[c] Includes staging areas of approximately 5 acres. Does not include the potential for extended additional TWAs necessary for construction in rough terrain or in unstable soils. These locations are currently undergoing identification and analysis. Potential disturbance associated with these areas would be included in supplemental filings when these additional temporary work spaces are identified.

[d] Access roads temporary and permanent disturbances are based on a 30-foot width; all non-public roads are conservatively estimated to require upgrades and maintenance during construction.

[e] Discrepancies in total acreages are due to rounding.

[f] Includes disturbances associated with construction of the Steele City Segment, the Gulf Coast Segment, and the Houston Lateral. This total includes 15 acres associated with construction and operation of new pump stations along the Keystone Cushing Extension.

[g] Disturbance associated with the Keystone Cushing Extension in this table is for the two new pump stations to be constructed for this proposed Project.

Changes in land use due to construction would for the most part be temporary. Temporary impacts to land use include loss of agricultural productivity, potential damage to drain tiles or other irrigation systems, visual impacts from the removal of vegetation within the ROW, and increased noise and dust.

[1] This total number of acres varies from the total provided in Table 3.9.1-3 since it includes: pipe storage, rail, and contractor yards; access roads; construction camps; and the tank farm whereas the Table 3.9.1-5 does not.

Existing commercial or industrial sites with public or private road access would be used when practical and temporary workspaces would be restored to preconstruction levels.

Temporary and permanent changes in vegetation due to the clearing of trees and shrubs, pipeline excavation, and general construction activity are expected within the ROW. It is estimated that disturbed pastures, croplands, and grassy rangelands may take one to five years to recover to preconstruction levels. Herbaceous vegetation, low shrubs, and forest lands are estimated to take from one to 20 or more years to recover depending upon the species. The permanent pipeline ROW would require occasional trimming to remove woody vegetation and trees from the permanent easement/ROW to facilitate aerial inspection. Landowners would be permitted to cultivate crops in the permanent easement.

Impacts to each type of land uses are described in greater detail in the following sections.

Agricultural Land, Rangeland and Prime Farmland

As shown in Table 3.9.1-6, agricultural land and rangeland would comprise 79 percent of the land affected by proposed Project construction, including 4,656 acres of agricultural land and 11,122 acres of rangeland.

TABLE 3.9.1-6
Current Land Uses That Would be Affected by Construction (Acres)

State	Developed	Agriculture[a]	Rangeland	Forest[b]	Water/Wetland	Total[c]
Steele City Segment						
Montana	41	1,005	3,010	8	64	**4,128**
South Dakota	48	1,152	3,255	15	69	**4,539**
Nebraska	60	1,578	1,955	67	110	**3,770**
Segment Total	*149*	*3,735*	*8,220*	*90*	*243*	***12,437***
Cushing Extension						
Kansas	0	0	14	1	0	**15**
Gulf Coast Segment						
Oklahoma	220	166	1,224	607	38	**2,255**
Texas	483	712	1,397	1,604	367	**4,563**
Segment Total	*703*	*878*	*2,621*	*2,211*	*405*	***6,818***
Houston Lateral						
Texas	23	43	267	236	83	**652**
Project Total	**875**	**4,656**	**11,122**	**2,538**	**731**	**19,922**

[a] Agriculture includes land listed by the NRCS (2007) as potential prime farmland, if adequate protections from flooding and adequate drainage are provided.

[b] No groves or nurseries are crossed by the proposed Project. Locations of forest land are identified by milepost in Appendix O.

[c] The acreage includes disturbance associated with centerline easements, ATWs, and pump stations. Discrepancies in totals are due to rounding.

The USDA defines prime farmland as, "land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, and oilseed crops and is available for these uses." Prime farmland includes cultivated land, pastures, or forest that is not located on developed land or in water and wetlands (Table 3.9.1-6). Not all prime farmland soils are used for agricultural purposes.

Acreages of prime farmland that would be affected by proposed Project construction within each segment and within each state are shown in Table 3.9.1-7. For the entire proposed Project corridor, construction would affect 7,157 acres of prime farmland.

TABLE 3.9.1-7
Prime Farmlanda That Would be Affected by the Proposed Project (Acres)

State	Construction[b]
Steele City Segment	
Montana	961
South Dakota	1,490
Nebraska	1,389
Segment Total	*3,840*
Cushing Extension	
Kansas	14
Gulf Coast Segment	
Oklahoma	985
Texas	1,872
Segment Total	*2,857*
Houston Lateral	
Texas	446
Project Total	**7,157**

[a] Includes land listed by the NRCS (2007) as potential prime farmland, if adequate protection from flooding and adequate drainage is provided.

[b] Acreage does not include land disturbance associated with pipe storage/contractor yards or that associated with power lines.

Potential Crop Types in Affected Areas

Crop production along the proposed Project corridor is estimated using statewide statistics. As shown in Table 3.9.1-8, the principal crops include wheat (27.260 million acres), hay (18.910 million acres), grain corn (16.900 million acres), and soybeans (12.530 million acres), with significantly less acreage in sorghum (5.800 million acres), cotton (3.400 million acres), and barley (0.740 million acres).

TABLE 3.9.1-8
Total State Acreages of Largest Crops Grown, 2008

State	Crop	State Harvested Acres (in 1,000)
Steele City Segment		
Montana	Wheat, All	5,470
	Hay, All	2,400
	Barley, All	740
	Total Principal Crops	*8,610*
South Dakota	Corn for Grain	4,400
	Soybeans	4,060
	Hay, All	3,850
	Wheat All	3,420
	Total Principal Crops	*15,730*
Nebraska	Corn for Grain	8,550
	Soybeans	4,860
	Hay, All	2,570
	Wheat, All	1,670
	Total Principal Crops	*17,650*
Gulf Coast Segment and Houston Lateral (Texas Only)		
Kansas	Wheat, All	8,900
	Corn for Grain	3,630
	Soybeans	3,250
	Hay, All	2,750
	Sorghum for Grain	2,750
	Total Principal Crops	*21,280*
Oklahoma	Wheat, All	4,500
	Hay, All	2,910
	Soybeans	360
	Corn for Grain	320
	Total Principal Crops	*8,090*
Texas	Hay, All	4,430
	Cotton, Upland	3,400
	Wheat, All	3,300
	Sorghum for Grain	3,050
	Total Principal Crops	*14,180*

Source: USDA National Agricultural Statistics Service (NASS) Quick Stats, accessed June 22, 2009.

Prior to construction, agricultural land (where crops are present) would be disked or mowed to ground level to provide clear, safe, and efficient access for construction. Timber shelterbelts within the proposed construction ROW would be removed to the minimum extent practicable for proposed pipeline construction. Additional construction impacts could include:

- Soil profile disturbance;
- Irrigation system damage; and
- Drainage system damage.

Impacts to soil profiles could include topsoil degradation, soil compaction, and rock introduction or redistribution. According to the proposed Project CMR plan (Appendix B), pipeline construction would not stop or obstruct active irrigation ditches except during the short (typically one day or less) time period needed to install the pipeline beneath the ditch. Additionally, drain tiles and fences would be repaired or restored using either original material or high quality new material, and farm terraces would be restored to their preconstruction functions. Construction could also cause temporary loss of crops and/or forage on affected lands.

Conservation Programs

Conservation easements crossed by the proposed Project (Table 3.9.1-9) are managed by either the United States Department of Agriculture (USDA) or the U.S. Fish and Wildlife Service (USFWS).

USDA Programs

The Farm Service Agency (FSA) and the Natural Resources Conservation Service (NRCS), both part of the USDA, manage various types of government land conservation, cost-sharing, and financial programs. FSA programs include the Conservation Reserve Program (CRP) and the Farmable Wetlands Program (FWP). The CRP is one of the largest conservation programs in the country. Eligible FWP land can be enrolled through the CRP. Landowners with CRP contracts are provided rental payments and cost sharing to develop long-term conservation vegetative covers on eligible farmland. The program goals are the reduction of erosion, improvement of water quality, enhancement of forest and wetlands resources, and establishment of wildlife habitat. Landowners are encouraged to plant grasses, trees, and other vegetation on highly-erodible cropland. The full listing of affected CRP tracts in the Steele City Segment may be found in Appendix K, Conservation Reserve Program Facilities. There are no CRP tracts in either the Gulf Coast Segment or the Houston Lateral. The NRCS Wetland Reserve Program (WRP) provides long-term or permanent protection for areas the landowner has restored with NRCS funding assistance. A WRP contract land would be crossed in Texas on the Gulf Coast Segment.

Pipeline construction should have no effect on landowners' participation in CRP. Affected landowners would be required to contact their local FSA offices as part of their contractual agreement for participation in the program. FSA would require that landowners, prior to pipeline construction, notify the FSA of the planned construction activities (Braun, pers. comm. 2009). Assuming the land would be restored to its pre-construction condition, landowners would not lose their eligibility for participation in the CRP.

USFWS Programs

A USFWS wetland easement is a legal agreement that provides landowners compensation to permanently protect wetlands. Wetlands covered by an easement cannot be drained, filled, leveled, or burned. When these wetlands dry up naturally, they can be farmed, grazed, or hayed. The easements typically allow localized, low-intensity, or broad extraction of natural resources (e.g., logging or mining). A wetland easement in Phillips County would be crossed by the proposed Project. The Rainwater Basin, which is managed by the USFWS, is a wetland area south of the Platte River in Nebraska used by many migratory birds in the spring and fall.

TABLE 3.9.1-9
USFWS, NRCS, and Other Easements Crossed by the Proposed Project

Easements	Approximate Mileposts	Miles Crossed
Montana		
Cornwell Ranch Conservation Easement (FWP)	49.4 and 70.9	3.1
Philips County USFWS Wetland Easement	4.3 - 5.1	0.8
CRP Contract Land (consists of 39 easements)	Multiple	9.2
South Dakota		
CRP Contract Land (consists of 39 easements)	Multiple	7.6
Nebraska		
CRP Contract Land (consists of 27 easements)	Multiple	5.2
Rainwater Basin Wetlands (UFWS)	758.0 - 847.4	89.4
Texas		
WRP Contract Land (consists of 1 easement)	Near 162	0.7

Forest Land

The entire proposed Project would cross 202.8 miles (2,537 acres) of forest land (Table 3.9.1-10). The majority of this forest land occurs within the "piney woods" area of the Gulf Coast Segment. During construction, trees would be removed from the ROW. Landowners would be consulted to determine if timber within the ROW has a commercial or salvage value, and landowners at their discretion could contract with Keystone to clear and harvest trees prior to removal. Tree removal and disposal would be accomplished consistent with all local, state, and federal permit requirements. Trees would be allowed to regrow only in the temporary ROW after construction, consistent with DOT pipeline safety standards and Keystone requirements for aerial pipeline safety inspections.

TABLE 3.9.1-10 Forest Land That Would be Affected by the Proposed Project (Miles and Acreage)			
State	**Miles Crossed[a]**	**Acreage[b]**	**Mileposts**
Steele City Segment			
Montana	0.6	8	36.1 to 196.1
South Dakota	0.9	15	409 to 595.9
Nebraska	4.6	67	599.9 to 850.6
Segment Total	*6.1*	*90*	
Cushing Extension			
Kansas	0.0	-	-
Gulf Coast Segment			
Oklahoma	41.6	607	1.2 to 155.8
Texas	152.2	1,604	155.8 to 482.7
Segment Total	*193.8*	*2,211*	
Houston Lateral			
Texas	2.95	236	0.0 to 40.8
Project Total	**202.85**	**2,537**	**-**

[a] Distances crossed reflect the sum of the actual distance within the referenced mileposts. Totals were rounded to the nearest 0.1 mile. Values less than 0.1 a mile, but greater than zero, were rounded to 0.05 mile.

[b] Acreage includes disturbance associated with centerline easements, ATWs, and pump stations. Acreage does not include acres of disturbance associated with pipe storage/contractor yards or disturbance. Discrepancies in totals are due to rounding.

Developed Land – Residential/Commercial/Industrial

Construction of the proposed Project would affect a total of 875 acres of developed land (see Table 3.9.1-6). The proposed Project area was surveyed in the spring of 2009 to determine the number of inhabited or abandoned buildings within 25 feet and within 500 feet of the construction ROW, and to develop site-specific crossing plans and procedures for residences in close proximity to the ROW (Table 3.9.1-11). Approximately 170 structures would be located within 25 feet of the proposed construction ROW and 2,325 structures would be located within 500 feet of the ROW. At the new pump station locations in Kansas, no structures are located within 500 feet of the proposed construction ROW.

TABLE 3.9.1-11 Number of Structures Within 25 and 500 Feet of Construction ROW		
State	**Within 25 feet of the ROW**	**Within 500 feet of the ROW**
Steele City Segment		
Montana	9	117
South Dakota	15	96
Nebraska	17	150
Segment Total	*41*	*363*
Cushing Extension		
Kansas	0	0
Gulf Coast Segment		
Oklahoma	28	448
Texas	91	1,410
Segment Total	*119*	*1,858*
Houston Lateral		
Texas	10	104
Project Total	**170**	**2,325**

Note: Excludes swimming pools, power poles, groundwater wells, and baseball fields.

More than one-third of the structures within 500 feet of the proposed ROW are homes or residences, almost 20 percent are out-buildings, and almost 12 percent are barns (see Table 3.9.1-12). Less than 17 percent of structures within 25 feet of the ROW are homes or residences.

TABLE 3.9.1-12
Types of Structures Within 25 and 500 Feet of the Construction ROW

Type of Structure	Within 25 feet of the ROW	Percent of Total	Within 500 feet of the ROW	Percent of Total
Barn	21	**12.35%**	275	**11.83%**
Building	49	**28.82%**	228	**9.81%**
Cabin	1	**0.59%**	5	**0.22%**
Commercial Building	0	**0.00%**	138	**5.94%**
Commercial Structure	1	**0.59%**	14	**0.60%**
Garage	2	**1.18%**	40	**1.72%**
Home/Residence	28	**16.47%**	783	**33.68%**
Industrial	1	**0.59%**	4	**0.17%**
Other	31	**18.24%**	153	**6.58%**
Out-Building	32	**18.82%**	458	**19.70%**
Public Assembly	0	**0.00%**	14	**0.60%**
School	0	**0.00%**	1	**0.04%**
Storage Building	4	**2.35%**	212	**9.12%**
Project Total	**170**	**100.0%**	**2,325**	**100.0%**

Homes and residences within 25 feet of the ROW would likely experience many temporary inconveniences during the construction period (typically 7 to 30 days) including disruptions to privacy and property ingress or egress. Homes within 500 feet of the ROW could experience temporary inconveniences such as construction dust and noise during the construction period. However, local noise restrictions would apply and the CMR plan (Appendix B) includes best management practices (BMPs) to address dust suppression.

Pipeline Operation

Estimates of the total acreage of land impacted during operation of the proposed Project are provided for various Project elements (e.g., pipeline ROW and pump stations) in Table 3.9.1-13. Land committed for operations and maintenance activities of the proposed Project would amount to approximately 8,793 acres[2].

[2] This total number of acres varies from the total provided in Table 3.9.1-14 since it includes: pipe storage, rail, and contractor yards; access roads; construction camps; and the tank farm whereas Table 3.9.1-13 does not.

TABLE 3.9.1-13
Summary of Land Affected During Operation[a,b] (Acres)

State	Pipeline ROW	Lateral ROW	Pump Stations/ Delivery Facilities	Access Roads[c]	Tank Farm[d]	*Total*
Steele City Segment						
Montana	1,713.2	-	50.1	21.7	-	**1,785.0**
South Dakota	1,904.0	-	59.4	9.1	-	**1,972.5**
Nebraska	1,543.8	-	42.2	0.0	-	**1,586.0**
Steele City Subtotal[e,f]	*5,161.0*	*-*	*151.7*	*30.8*	*0.0*	***5,343.5***
Cushing Extension[f]						
Kansas[e,g,f]	-	-	15.2	-	-	**15.2**
Gulf Coast Segment						
Oklahoma	943.8	-	0.0	15.1	74.1	**1,033.0**
Texas	1,988.9	-	51.1	48.1	-	**2,088.1**
Gulf Coast Subtotal[e]	*2,932.7*	*-*	*51.1*	*63.2*	*74.1*	***3,121.1***
Houston Lateral						
Texas	-	294.0	-	19.0	-	***313.0***
Project Total[e,g,f,h]	**8,093.7**	**294.0**	**218.0**	**112.9**	**74.1**	**8,792.8**

[a] Disturbance is based on a total of 110-foot-wide construction ROW for a 36-inch-diameter pipe, except in certain wetlands, cultural sites, shelterbelts, residential areas, and commercial/industrial areas where an 85-foot-wide construction ROW would be used, or in areas requiring extra width for workspace necessitated by site conditions. Disturbance also includes pipe stock piles, contractor yards, and construction camps.

[b] Operational acreage was estimated based on a 50-foot-wide permanent ROW in all areas. All pigging facilities would be located within either pump stations or delivery facility sites. Intermediate mainline valves (MLVs) and densitometers would be constructed within the construction easement and operated within a 50-foot by 50-foot area or 50-foot by 66-foot area within the permanently maintained 50-foot-wide ROW. Other MLVs, check valves, and block valves, and meters would be located within the area associated with a pump station, delivery site or permanent ROW. Consequently, the acres of disturbance for these aboveground facilities are captured within the pipeline ROW and pump station/delivery facilities categories within the table.

[c] Access roads temporary and permanent disturbances are based on a 30-foot width; all non-public roads are conservatively estimated to require upgrades and maintenance during construction.

[d] The tank farm includes PS-32 acreage.

[e] Discrepancies in total acreages are due to rounding.

[f] Includes disturbances associated with construction of the Steele City Segment, the Gulf Coast Segment, and the Houston Lateral. This total includes 12 acres associated with construction and operation of new pump stations along the Keystone Cushing Extension.

[g] Disturbance associated with the Keystone Cushing Extension in this table is for the two new pump stations to be constructed for this proposed Project.

[h] Includes staging areas of approximately 5 acres. Does not include the potential for extended additional TWAs necessary for construction in rough terrain or in unstable soils. These locations are currently undergoing identification and analysis. Potential disturbance associated with these areas would be included in supplemental filings when these additional temporary work spaces are identified.

Approximately 8,625 acres of land would be affected during proposed Project operations (Table 3.9.1-14). The proposed Project would affect approximately 4,702 acres of rangeland, 2,046 acres of agricultural lands, 1,067 acres of forest land, 437 acres of developed lands, and 373 acres of water and wetlands (Table 3.9.1-14).

TABLE 3.9.1-14
Current Land Uses That Would be Affected by Operation (Acres)

State	Developed	Agriculture[a]	Rangeland	Forest[b]	Water/Wetland	Total
Steele City Segment						
Montana	19	448	1,261	4	28	**1,760**
South Dakota	20	511	1,389	6	33	**1,959**
Nebraska	26	693	780	29	55	**1,583**
Segment Total	*65*	*1,652*	*3,430*	*39*	*116*	***5,302***
Cushing Extension						
Kansas	0	0	14	1	0	**15**
Gulf Coast Segment						
Oklahoma	113	71	539	245	19	**987**
Texas	247	304	603	677	196	**2,027**
Segment Total	*360*	*375*	*1,142*	*922*	*215*	***3,014***
Houston Lateral						
Texas	12	19	116	105	42	**294**
Project Total	**437**	**2,046**	**4,702**	**1,067**	**373**	**8,625**

[a] No groves or nurseries are crossed by the proposed Project. Locations of forest land are identified by milepost in Appendix O.
[b] Acreage does not include acres of disturbance associated with electrical distribution lines. Discrepancies in totals are due to rounding.

Agricultural Land, Rangeland and Prime Farmland

Agricultural land and rangeland together would amount to 78 percent of the land that would be affected by proposed Project operation (Table 3.9.1-14). Additionally, proposed Project operation would affect approximately 3,126 acres of prime farmland (Table 3.9.1-15).

TABLE 3.9.1-15
Prime Farmland[a] That Would be Affected by Operation (Acres)

State	Operation[b]
Steele City Segment	
Montana	410
South Dakota	645
Nebraska	604
Segment Total	*1,659*
Cushing Extension	
Kansas	14
Gulf Coast Segment	
Oklahoma	423
Texas	831
Segment Total	*1,254*
Houston Lateral	
Texas	199
Project Total	**3,126**

[a] Prime farmlands include lands listed by the NRCS (2007) as potential prime farmland, if adequate protection from flooding and adequate drainage is provided.
[b] Acreage does not include land disturbance associated with pipe storage/contractor yards or that associated with power lines.

Potential Crop Types in Affected Areas

Impacts to crops from operation of the proposed Project would be less than for construction because the ROW width would be reduced from 110 feet to 50 feet for the permanent ROW. Since the proposed pipeline would be buried to a nominal depth of 4 feet and maintained at a depth of 4 feet in cultivated agricultural areas pursuant to Special Condition 19 (the Special Conditions are presented in Appendix U), agricultural land use would continue for the most part across the permanent ROW.

Conservation Programs

Impacts to conservation lands from operation of the proposed Project would be less than for construction because the ROW width would be reduced from 110 feet to 50 feet for the permanent ROW. Low level grasses and plants would be allowed to regrow on the ROW, however moderate to large vegetation would continue to be cleared from the permanent ROW and would not be allowed to re-establish.

Forest Land

Operation of the proposed Project would affect approximately 1,067 acres of forest land (Table 3.9.3-14). Trees would be allowed to regrow only in the temporary ROW after construction, consistent with DOT pipeline safety standards and Keystone requirements for aerial pipeline safety inspections.

Developed Land – Residential/Commercial/Industrial

Operation of the proposed Project would affect approximately 437 acres of developed land along the proposed Project ROW, including 65 acres within the Steele City Segment, 360 acres within the Gulf Coast Segment, and 12 acres within the Houston Lateral (Table 3.9.3-14). Some current land uses would be converted to long-term utility use for the life of the proposed Project. The long-term conversion would put constraints on development of private land. To facilitate maintenance or emergency access, improvements including landscaping, catch basins, leaching fields, garages, guy wires, houses, utility poles, septic tanks, sheds, swimming pools, or any other structures that are not easily removed would be prohibited from the permanent ROW.

3.9.1.3 Potential Mitigation

The proposed Project would incorporate the procedures presented in the Project CMR plan (Appendix B) to reduce potential Project construction and operation impacts. The CMR plan includes general BMP measures, including worksite appearance maintenance and noise and dust control. The CMR plan includes specific conditions that would be followed during construction within agricultural, forest, pasture, rangeland, grasslands, wetland crossings, waterbodies, and riparian lands. The CMR plan also includes measures to avoid or minimize potential damage to drain tile systems. As noted in the CMR plan, specific landowner requirements could occasionally supersede the procedures in the CMR plan. However, the conditions of applicable federal, state, and local permits would apply in all cases.

Agricultural Land, Rangeland and Prime Farmland

Construction could cause the temporary loss of crop production or forage on affected lands. According to the CMR plan (Appendix B), landowners would be compensated for any construction-related crop or forage loss. To minimize potential impacts to agricultural lands (including prime farmland), the CMR plan commits Keystone to measures that would protect the soil profile, including:

- Segregating the upper 12 inches of topsoil during construction and replacing it during site restoration (Section 2.3.2.3 describes the topsoil separation methods that would be used);
- Utilizing soil ripping or chiseling to alleviate soil compaction and to return the soil to pre-construction conditions;
- Plowing wood chips, manure, or other organic matter into the soil to further enhance soil aeration, if required; and
- Removing excess rock that is greater than 3 inches in diameter from the top 12 inches of soil in all active agricultural fields, pastures, and hayfields.

If pipeline construction crosses active irrigation ditches, the ditches would not be stopped or obstructed except during the typical one day or less time period needed to install the pipeline beneath the ditch. Drain tiles and fences would be repaired or restored using either original material or high quality new material, and farm terraces would be restored to their preconstruction functions.

To minimize potential impacts to rangelands, the CMR plan (Appendix B) includes measures that would reduce impacts, including:

- Restoring disturbed areas with custom seed mixes (approved by landowners and land managers) to match the native foliage;
- Providing access to rangeland during construction when practicable;
- Installing temporary fences with gates around construction areas to prevent injury to livestock or workers;
- Leaving hard plugs (short lengths of unexcavated trench) or installing soft plugs (areas where the trench is excavated and replaced with minimally compacted material) to allow livestock and wildlife to cross the trench safely;
- Removing litter, garbage, and any pipeline shavings at the end of each construction day, to protect livestock and wildlife from accidental ingestion;
- Prohibiting construction personnel from feeding or harassing livestock or wildlife;
- Prohibiting construction personnel from carrying firearms or pets into the construction area;
- Securing rangeland fences to prevent drooping;
- Closing any openings in the fence at the end of each day to prevent livestock from escaping;
- Maintaining all existing improvements such as fences, gates, irrigation ditches, cattle guards, and reservoirs to the degree practicable; and
- Returning any damaged improvements to at least their condition prior to construction.

Compensation

Disturbed agricultural land and rangeland would be returned to approximate pre-construction use and capability. For agricultural land and rangeland requiring reseeding, an inspection after the first growing season would determine if additional revegetation would be required. If the landowner performs the required reseeding, monetary compensation would be provided. Revegetation would be considered successful when crop yields or vegetation are similar to adjacent undisturbed portions of the same field. Landowners would be compensated for any decreases in land productivity that are demonstrated to result from proposed Project-related activities. Landowners would also be compensated for yields less than those on unaffected lands where lesser yields would result from proposed Project impacts. Crop values would be assessed based upon the values of those crops in the specific area, as well as local crop prices at grain elevators. Landowners would be compensated for crop loss effects over three years. During the year of construction, 100 percent of calculated losses would be compensated. In the second year 75 percent of calculated losses would be compensated and during the third year 50 percent of calculated losses would be compensated. If landowners demonstrate that crop losses persist beyond three years, additional compensation would be negotiated.

Conservation Programs

Should CRP participants be required to leave the program because of the proposed Project, they would be compensated. Compensation would be for any lost CRP payments, including retroactive forfeit payments.

Forest Land

Potential adverse impacts to forest land would be reduced through protection, reclamation, and remediation measures committed to in the CMR plan (Appendix B). Examples of protective or restorative measures on forest lands would include:

- Routing the proposed Project along existing ROW areas in forest lands, when practical;
- Felling trees toward the pipeline centerline to minimize additional tree disturbance;
- Recovering all trees and slash that fall outside of the ROW;
- Depositing all tree materials according to specific protection measures and in accordance with landowner, land manager, or permit requirements;
- Removing stumps using equipment that helps to preserve organic matter; and
- Reversing effects on windbreaks, shelterbelts, and living snow fences to the degree practicable.

Developed Land – Residential/Commercial/Industrial

To minimize potential impacts to developed lands, the CMR plan (Appendix B) includes measures that would be implemented, including:

- Prior to construction, surveys would be conducted to confirm the location of buildings relative to the pipeline and to ascertain whether the buildings are occupied residences or businesses;
- Site-specific protective constructions plans would be developed for residential and commercial/industrial structures within 25 feet of the construction ROW;

- Noise levels would be controlled during non-daylight hours consistent with any applicable noise regulations around residential and commercial/industrial areas;
- If noise levels are expected to exceed regulations, advance notice would be provided to all residences within 500 feet of the construction ROW;
- High noise level activities would be limited in duration and coordinated to expedite the construction work through the area;
- Written permission would be required for certain objects related to current land uses to remain in the permanent ROW;
- Consideration would be given in some cases to provide construction shielding for certain land improvements (e.g., fences and sheds) and to preserve landscaping and mature trees;
- Workspaces would be fenced from residential areas where appropriate;
- Vehicle access and traffic control would be provided in construction areas;
- Trash and debris would be removed and disposed from the construction site each day;
- Plating would be used to cover open trenches during non-construction times in developed areas;
- For areas in which the pipeline is within 25 feet of a residential structure, excavation of the pipeline trench would be delayed until the pipe was ready to be installed, then the trench would be quickly backfilled after installation;
- Following installation of the pipeline and backfilling, all fences, landscaping improvements, shrubs, lawn areas, and other structures would be restored to pre-construction conditions (or as directed by the landowner); and
- Knowledgeable individuals would be retained to assist in landscape restoration.

Compensation

Commercial and industrial landowners would be compensated for any construction-related impacts based upon land values determined by local professional appraisers. Any damaged infrastructure would be repaired or replaced or the owner would be compensated for the damage.

3.9.2 Recreation and Special Interest Areas

3.9.2.1 Environmental Setting

The proposed Project would cross approximately 90.5 miles of recreation and special interest areas in Montana, South Dakota, Nebraska, Oklahoma, and Texas on the Steele City Segment and Gulf Coast Segment (Table 3.9.2-1). These areas would include state or federal public lands, recreational waterbodies, state parks and forests, national historic trails, wildlife management areas, and wildlife refuges. No national parks or national forests would be affected by the proposed Project, but six national historic trails would be crossed.

BLM field offices are required to manage public lands crossed by the proposed Project according to the following resource management plans: the Big Dry (April 1996); the Powder River (March 1985); and the Judith Valley Phillips. BLM lands are primarily composed of grasslands leased to farmers with livestock. Construction and operation of the proposed Project would be consistent with existing leases, management plans, and current land uses.

TABLE 3.9.2-1
Recreation and Special Interest Areas Crossed by the Proposed Project

State	Name / Ownership	Miles Crossed
Steele City Segment		
Montana	Montana State Trust Lands (consists of 25 parcels)	19.2
	BLM (consists of 50 parcels)	42.0
	Missouri River (MP 88.9); Yellowstone River (MP 196.0)	0.2
	U.S. Department of Defense	0.4
	Lewis and Clark National Historic Trail	<1
South Dakota	Spring Creek (MP 346.8); Cheyenne River (MP 425.6); Sarah Laribee Creek (MP 464.8)	0.3
	State School Land	21.3
Nebraska	Bureau of Reclamation – canal	0.1
	Nebraska Board of Education	5.80
	Mormon Pioneer National Historic Trail	<1
	Pony Express National Historic Trail	<1
	California National Historic Trail	<1
	Oregon National Historic Trail	<1
Segment Total		*89.3*
Cushing Extension		
Kansas	-	-
Gulf Coast Segment		
Oklahoma	Deep Fork Wildlife Management Area - Oklahoma Department of Wildlife Conservation	1.2
Texas	El Camino Real de los Tejas National Historic Trail	<1
Segment Total		*1.2*
Houston Lateral		
Texas	-	-
Segment Total		*0.0*
Project Total		**90.5**

A total of 1,748 waterbodies would be crossed by the proposed Project (Table 3.9.2-2). The Steele City Segment would cross 792 waterbodies, with 432 ephemeral streams and 261 intermittent streams. The Gulf Coast Segment would cross 936 waterbodies, with 334 ephemeral streams, 297 intermittent streams, and 238 perennial rivers or streams. The Houston Lateral would cross 20 waterbodies, with eight ephemeral streams and five perennial rivers or streams. Recreational use would likely be centered on or near the 309 total perennial rivers and streams crossed by the proposed Project, including 66 in the Steele City Segment, 238 crossed in the Gulf Coast Segment, and five crossed in the Houston Lateral.

TABLE 3.9.2-2 Waterbody Crossings								
State	Perennial Rivers or Streams	Intermittent Streams	Ephemeral Streams	Natural Ponds	Canals	Man-made pond	Other[a]	Total
Steele City Segment								
Montana	19	111	197	--	15	1	-	**343**
South Dakota	20	97	169	2		5	-	**293**
Nebraska	27	53	66	1	8	1	-	**156**
Segment Total	*66*	*261*	*432*	*3*	*23*	*7*	*0*	***792***
Cushing Extension								
Kansas	-	-	-	-	-	-	-	-
Gulf Coast Segment								
Oklahoma	67	113	112	-	-	-	23	**315**
Texas	171	184	222	-	-	-	44	**621**
Segment Total	*238*	*297*	*334*	*0*	*-*	*0*	*67*	***936***
Houston Lateral								
Texas	5	2	8		3	-	2	**20**
Total	**309**	**560**	**774**	**3**	**26**	**7**	**69**	**1,748**

[a] "Other" includes artificial water paths, seasonal water, and unclassified waterbodies.

3.9.2.2 Potential Impacts

Construction activities would temporarily affect recreational traffic and use patterns in special management and recreational areas. Sightseers, hikers, wildlife viewers, fishers and hunters, and other recreationists would be temporarily dislocated. In some cases, construction of the pipeline could cause disrupted or delayed recreational usage of private lands. Compensation for damages associated with these disruptions would be negotiated with affected landowners. Construction scheduling would be coordinated with local, state, and federal agencies to reduce the conflicts with recreational users. Impacts are expected to be short term. Noise impacts from pump stations are expected to be minor and would be within appropriate regulatory levels. Recreational use access would not be affected by proposed Project operations within special management areas.

The proposed Project would not cross rivers within any reaches that have been designated by federal, state or local authorities as wild and/or scenic. Waterbodies with recreationally and/or commercially valuable fish species would be crossed using site specific waterbody crossing plans designed to reduce impacts to these important resources.

3.9.3 Visual Resources

Visual resources are landscape characteristics that have an aesthetic value to residents and visitors from sensitive viewpoints such as residences, recreation areas, rivers, and highways. All land has inherent visual values that warrant different levels of management. Aesthetic judgment, especially related to landscape views, is often considered subjective.

As a Federal land-management agency, BLM is charged with managing the scenic resources of public lands through the Federal Land Policy and Management Act of 1976 as amended (FLPMA). As a result of that responsibility, the Visual Resource Management (VRM) methodology has been developed to identify and evaluate scenic resources under its jurisdiction and to develop management objectives for those resources. The system classifies resources based on scenic quality, viewer sensitivity to visual change, and viewing distance (USDI BLM 1980, 1984, and 1986).

For the proposed Project, only Montana contains lands managed by the BLM and thus is subject to Visual Resource Class Objectives. The system includes four visual inventory classes: Classes I and II are the most valued, Class III represents a moderate value, and Class IV is of least value. Management objectives for each class are tailored to the inherent visual value of the respective landscape. The Class I objective is to preserve the existing character of the landscape, including the natural ecological qualities, although some very limited management activity is permitted. The Class II objective is to preserve the existing character of the landscape while keeping landscape changes to a minimum. Whatever landscape changes occur should reflect the ambient colors, textures, and form of the surrounding features. The Class III objective is to keep landscape changes moderate while retaining some portion of the existing character of the landscape. Landscape changes should reflect the basic features found in the landscape character and should not attract much attention or dominate the view. The Class IV objective allows management activities that require major alterations to the existing character of the landscape that may dominate the view, although the location, disturbance, and blending with the surrounding landscape should be minimized.

For the purposes of this proposed Project, visual resource analysts for the Malta and Miles City BLM Field Offices conducted land inventories within their respective jurisdictions in Montana. Both offices recognize that even though BLM lands are intermingled among private lands along the proposed route, the quality of the landscape is not limited by ownership. As a result, the VRM classifications were applied to both public and private lands within the proposed Project in Montana. It should be noted that BLM does not retain the jurisdiction, however, to apply Visual Resource Class Objectives to non-BLM managed lands. Additional information pertaining to VRM classifications on BLM lands in Montana are included in the following resource management plans (RMPs); the Big Dry (1995), Powder River (1985), Judith-Valley-Phillips (1992), (USDI BLM 1995, 1985 and 1992).

South Dakota, Nebraska, Kansas, Oklahoma, and Texas do not have formal guidelines for managing visual resources for private or state-owned lands. For these states, the prevailing landscape characteristics within the proposed Project area are identified and project effects to those characteristics are analyzed.

3.9.3.1 Environmental Setting

The proposed Project area crosses a variety of landscapes consisting of wetlands, waterways, floodplains, grassland/rangeland, and upland forest. The most common landscapes temporarily affected during proposed Project construction would consist of grasslands and rangelands (11,533 acres) and upland forest (2,523). Once constructed, the permanent ROW would impact 749.1 acres of grassland/rangeland and 175.6 acres of upland forest. Some of the proposed Project would follow existing utility right-of-ways and roads, while other segments would exist within a new right-of-way.

Two scenic byways are crossed by the proposed Project: The Big Sky Back Country Byway (Montana) and Historic Route 66 (Oklahoma). The Big Sky Back Country Byway was designated by the BLM in 2000. The BLM's Byways Program is a component of the National Scenic Byways Program. BLM Byways Handbook (8357-1) provides specific direction for BLM's Byways program. The proposed Project also crosses Historic Route 66 in Oklahoma. This historic route in Oklahoma has not been nominated to the Federal Highway Administration's National Scenic Byways program and the actual

roadway in the vicinity of the proposed Project has been abandoned and replaced by parallel roadways. During construction, some activity may be seen from these roadways (or parallel roads), but this would be temporary, occurring only during construction.

All federal lands that would be crossed by the proposed Project occur within the Steele City Segment and are under the management of BLM and the Department of Defense. The VRM classifications of federal lands that would be crossed include Class II (approximately 8.44 miles), Class III (approximately 5.79 miles), and Class IV areas (approximately 29.83 miles) (Table 3.9.3-1). Non-federally managed lands with BLM classifications include 28.04 acres of Class II, 42.54 acres of Class III, and 168.34 acres of Class IV lands.

TABLE 3.9.3-1
BLM's Visual Resource Management Classifications of Land Crossed by the Proposed Project in Montana (Miles)

Type of Federal Land Crossed	Class I	Class II	Class III	Class IV	Total
BLM	-	8.08	5.79	29.83	**43.39**
BLM and Department of Defense	-	0.36	-	-	**0.36**
State, Municipal, or Privately Ownership	-	28.04	42.54	168.34	**238.91**
Total	**-**	**36.48**	**48.33**	**198.17**	**282.66**

3.9.3.2 Potential Impacts

Construction and operation of the proposed Project would have some visual impacts, although most would be temporary. Such impacts would be associated with the construction ROW; additional temporary workspace; clearing and removal of existing vegetation; exposure of bare soils; earthwork and grading scars; trenching; rock formation alteration; machinery and pipe storage; new aboveground structures such as pump stations; pipeline markers, and various landform changes. Most visual effects resulting from ROW disturbance in agricultural areas would likely be substantially reduced with the first crop growth. Perceptible changes resulting from construction and operation would largely be visible to travelers along the major transportation corridors in the vicinity of the proposed Project. Their views would typically be limited to short periods of time and small portions of the ROW. Although recreational travelers are generally more sensitive to changes in scenic quality, there are no major recreation areas in the vicinity of the proposed route and few recreationists would be affected. During the final stages of construction, backfilling and grading would restore the construction ROW to its approximate previous contours and reclamation and revegetation would ultimately return the ROW to its approximate previous condition except in currently forested areas. In addition, vegetative buffers would be planted around the pump stations to reduce the visual impacts of the facilities. No pump stations would be situated on federal lands or in visually sensitive lands.

Most of the landscape changes caused by the proposed Project would be visible as linear changes to vegetation patterns. The proposed pipeline route was adjusted to reduce adverse aesthetic impacts, where possible, and measures to reduce long term visual impacts to insignificant levels would be implemented as described in the proposed Project CMR plan (Appendix B). Aboveground facilities would be painted in accordance with standard industry painting practices to further reduce visual impacts. Landowners would be consulted to address visual aesthetic issues that arise as a result of construction activities. Where reclamation and revegetation result in returning the ROW to visual conditions similar to existing conditions, there would be either no impact or only minor impacts to visual resources during operation.

For those segments of the proposed Project on BLM managed lands in Montana, consistency with the CMR plan (Appendix B) would require that the proposed Project remains consistent with the respective Visual Resource Class Objectives and the respective BLM RMPs.

3.9.4 Connected Actions

3.9.4.1 Power Distribution Lines and Substations

The proposed Project would require electrical service from local power providers (see Section 2.5.1). This section provides a preliminary assessment of impacts to land use, recreation, and visual resources from the proposed power distribution lines.

Environmental Setting

Land Ownership

Proposed power distribution lines would cross approximately 342.7 miles of privately-owned land, approximately 44.7 miles of federal land, and approximately 19.8 miles of state land would be located on privately-owned land (Table 3.9.4-1).

TABLE 3.9.4-1
Land Ownership Crossed by Power Distribution Lines (Miles)

State	Federal	State	Private	Total	Percent of Total
Steele City Segment					
Montana	39.1	7.7	88.9	**135.7**	**33.4%**
South Dakota	5.6	12.1	141.5	**159.2**	**39.1%**
Nebraska	0.0	0.0	68.1	**68.1**	**16.7%**
Segment Total	*44.7*	*19.8*	*298.5*	***363.0***	***89.2%***
Cushing Extension					
Kansas	0.0	0.0	13.6	**13.6**	**3.3%**
Gulf Coast Segment					
Oklahoma	0.0	0.0	12.7	**12.7**	**3.1%**
Texas	0.0	0.0	17.9	**17.9**	**4.4%**
Segment Total	*0.0*	*0.0*	*30.6*	***30.6***	***7.5%***
Houston Lateral					
Texas	-	-	-	-	-
Project Total	**44.7**	**19.8**	**342.7**	**407.2**	**100.0%**
Total Percent	**11.0%**	**4.8%**	**84.2%**	**100.0%**	

Land Use

Land uses categories along the proposed power distribution line ROWs include developed land, agricultural land, rangeland, forest land, and waterbodies and wetlands (Tables 3.9.4-3 and 3.9.4-4).

Potential Impacts

Construction Impacts

Areas of land disturbance have been estimated based upon the number and type of proposed distribution line support structures. Assumptions used to calculate temporary impacts from ground disturbances during power distribution line construction are displayed in Table 3.9.4-2. As shown, a 69-kV structure with a maximum height of 40 to 60 feet, spaced 350 feet apart and spanning 300 to 400 feet, would disturb a 60-foot radius, on average. Structures supporting 115-kV and 138-kV lines would disturb, on average, a 70-foot and 80-foot radius, respectively. An H-frame power line of any voltage would disturb, on average, a 90-foot radius.

TABLE 3.9.4-2
Power Distribution Line Construction Impact Assumptions

Transmission Structure	Maximum Structure Height (feet)	Spacing Between Structures (feet)	Average Structure Span (feet)	Average Disturbance Radius (feet)
69-kV	40-60	350	300-400	60
115-kV	50-70	550	500-600	70
138-kV	60-80	650	600-700	80
H-frame	70-90	800	700-900	90

The ROW area would be cleared to prepare for construction. Limited clearing would be required along existing roads in native and improved rangelands and agricultural lands. Some trees could require removal to provide adequate clearance between conductors and underlying vegetation. Where possible, trees would be trimmed to avoid removal.

Power distribution line construction would also require the development of temporary access roads, which would occupy a 20-foot-wide area within the ROW for all of the power poles. Pulling and tensioning areas would require one acre per change in direction. Turnaround areas would require a 30-foot radius at each structure. Construction staging areas would require one acre every 25 miles.

Total land area affected by construction of the power distribution lines would be approximately 1,333 acres (Table 3.9.4-3). Of this total, about 1,187 acres would be in the Steele City Segment, 44 acres would be in the Cushing Extension, and 100 acres would be in the Gulf Coast Segment.

TABLE 3.9.4-3 Existing Land Uses Temporarily Affected by Construction of Power Distribution Lines (Acres)						
State	**Developed**	**Agriculture**	**Rangeland**	**Forest**	**Water/Wetland**	**Total**
Steele City Segment						
Montana	8.8	81.7	343.0	1.1	8.5	**443.1**
South Dakota	53.9	137.4	314.8	1.0	13.7	**520.8**
Nebraska	14.5	106.1	90.5	5.6	6.1	**222.8**
Segment Total	*77.2*	*325.2*	*748.3*	*7.7*	*28.3*	***1,186.7***
Cushing Extension						
Kansas	1.3	19.1	21.6	1.8	0.6	**44.4**
Gulf Coast Segment						
Oklahoma[a]	4.5	1.5	26.2	8.8	0.5	**41.6**
Texas	4.5	26.6	11.2	15.0	1.2	**58.5**
Segment Total	*9.0*	*28.1*	*37.4*	*23.8*	*1.7*	***100.1***
Houston Lateral						
Texas	-	-	-	-	-	-
Project Total	**87.6**	**372.3**	**809.1**	**33.2**	**30.6**	**1,332.9**

[a] Includes power to Cushing tank farm.

Aerial interpretation56 and field surveys were used to discern the number of buildings within 50 feet of the proposed power distribution lines (Table 3.9.4-4). An estimated 78 structures would be located within 50 feet of the proposed power distribution lines, including 74 in the Steele City Segment and four in the Gulf Coast Segment.

TABLE 3.9.4-4 Number of Buildings Within 50 Feet of a Power Distribution Line	
State	**Number of Structures within 50 Feet**
Steele City Segment	
Montana	13
South Dakota	48
Nebraska	13
Segment Total	*74*
Cushing Extension	
Kansas	0
Gulf Coast Segment	
Oklahoma	2
Texas	2
Segment Total	*4*
Houston Lateral	
Texas	-
Project Total	**78**

Most construction impacts on land use would be temporary and may include short term disruptions to local traffic, land access, and agricultural practices. A small amount of land clearing would likely be required at support structure locations and other construction staging areas described previously. Short term noise and dust impacts may occur at one or more of the 78 structures identified within 50 feet of the construction ROWs (Table 3.9.4-4).

Operation Impacts

In forest lands, during power distribution line operations, each power provider would maintain a ROW free of woody vegetation. All operations-related impacts on land use would likely last through the useful lifetime of the power distribution lines. Impacts associated with permanent access roads for use during power distribution line operations are not estimated since the number and location of these roads are not currently known.

Assumptions used to calculate impacts from power distribution line operational structures are provided in Tables 3.9.4-5. As shown, a 69-kV, 115-kV, and 138-kV structure would each affect, on average, a 12 square-foot area. An H-frame power line structure of any voltage would affect approximately 24 square feet.

TABLE 3.9.4-5
Power Distribution Line Operation Impact Assumptions

Structure	Maximum Structure Height (feet)	Spacing Between Structures (feet)	Average Structure Span (feet)	Average Disturbance (square feet)
69-kV	40-60	350	300-400	12
115-kV	50-70	550	500-600	12
138-kV	60-80	650	600-700	12
H-frame	70-90	800	700-900	24

Due to the need for a cleared power distribution line ROW, operational impacts in forested lands are greater than for other land uses. ROW widths in forest lands for various types of power distribution line structures are provided in Table 3.9.4-6.

TABLE 3.9.4-6
Power Distribution Line Operation Impact Assumptions in Forest land

Structure	ROW (feet)	Average Disturbance (square feet)
69-kV	60-80	80
115-kV	60-80	80
138-kV	60-80	80
H-frame	100-150	150

Estimates of the acreage of land affected for each land use type during operation of the proposed power distribution lines are provided in Table 3.9.4-7. Total acreage of land affected during power distribution line operations would be approximately 1,090 acres. Actual impacted acreage may vary from the estimates based upon actual power distribution line designs to be developed by each power provider.

TABLE 3.9.4-7 Existing Land Uses Affected by Power Distribution Line Operations (Acres)						
State	**Developed**	**Agriculture[a]**	**Rangeland**	**Forest**	**Water/Wetland**	**Total**
Steele City Segment						
Montana	6.5	60.5	253.4	4.1	6.6	**331.1**
South Dakota	40.0	101.8	233.2	3.6	10.7	**389.3**
Nebraska	10.7	78.6	67.0	20.6	9.3	**186.2**
Segment Total	*57.2*	*240.9*	*553.6*	*28.3*	*26.6*	***906.6***
Cushing Extension						
Kansas	1.0	14.1	16.0	6.5	0.4	**38.0**
Gulf Coast Segment						
Oklahoma[a]	3.3	1.1	19.4	32.7	0.4	**56.9**
Texas	3.4	19.7	8.3	55.4	1.2	**88.0**
Segment Total	*6.7*	*20.8*	*27.7*	*88.1*	*1.6*	***144.9***
Houston Lateral						
Texas	-	-	-	-	-	-
Project Total	**64.9**	**275.8**	**597.3**	**122.9**	**28.6**	**1,089.5**

[a] Includes power to Cushing tank farm.

Operation of the power distribution lines could lead to some impacts to vegetation external to the construction ROW due to the need for tree trimming to reduce hazards to power line operations. The locations of actual power distribution line structures could lead to long term operational impacts to farming and other land uses. Impacts to land use are primarily based on surface disturbance areas. Impacts associated with service drops (electrical lines running from a utility pole to a pump station) from adjacent distribution lines are expected to be minimal and comparable to those associated with supplying electricity to the average home or farm.

Potential Mitigation

Once the power distribution poles are in place and the conductor wires are strung between poles, the construction ROW would be restored pursuant to each power provider's requirements as specified in easement agreements with landowners. This may include soil reshaping and contouring, and reseeding as specified by landowners. All remaining materials and litter would be removed from the construction area and properly disposed.

Preliminary power line locations have been identified in consultation with each utility company. Where feasible, the entire length of each of these preliminary power line routes would be placed along existing county roads, section lines, or field edges to minimize interference with adjacent land uses. Upon completion, power providers would restore the work area around each new service drop as specified by applicable permit conditions.

Recreation and Special Interest Areas

Environmental Setting

The proposed power distribution lines would likely cross recreation and special interest areas (Table 3.9.4-8). In Montana, the power distribution lines would likely cross Montana State Trust Lands, BLM land, Bureau of Reclamation land, and U.S. Department of Defense land. South Dakota power distribution lines would cross South Dakota Game, Fish, and Park land; BLM land; U.S. Forest Service land; and State School land. No special interest areas would be crossed in Nebraska, Kansas, Oklahoma, or Texas.

TABLE 3.9.4-8
Recreation and Special Interest Areas Crossed by Power Distribution Lines

State	Name / Ownership
Steele City Segment	
Montana	Montana State Trust Lands
	BLM
	Bureau of Reclamation
	U.S. Department of Defense
	U.S. Fish and Wildlife Service
South Dakota	BLM
	South Dakota Game, Fish, and Park Lands
	State School Land
	U.S. Forest Service
	State of South Dakota Lands
Nebraska	None
Cushing Extension	
Kansas	None
Gulf Coast Segment	
Oklahoma	None
Texas	None
Houston Lateral	
Texas	None

Potential Impacts

Power distribution line impacts on recreation and special interest areas are unknown. To the extent that the power distribution lines would change the character, general use, and/or recreation opportunities provided on special interest lands, there would be an adverse impact.

Potential Mitigation

Final design of the power distribution lines would likely include locational criteria to reduce potential impacts on recreation and special interest areas.

Visual Resources

Visual resources are natural or developed landscape characteristics that have an aesthetic value to residents and visitors from sensitive viewpoints such as residences, recreation areas, rivers, and highways. The Visual Resource Management (VRM) system was developed by BLM to assist in the identification and protection of scenic lands in a systematic and interdisciplinary manner. See Section 3.9.3.1 for a description of the VRM classification system.

Environmental Setting

The VRM classes for federal lands crossed by proposed power distribution lines, which include lands managed by BLM, the Bureau of Reclamation, and the Department of Defense along the Steele City Segment are displayed in Table 3.9.4-9. The proposed power distribution lines would be located on BLM-managed lands designated as Class III (28.2 miles) and Class IV (6.5 miles).

TABLE 3.9.4-9
BLM's Visual Resource Management Classifications in the Power Distribution Line Corridor I Montana (Miles)

Type of Federal Land Crossed	Class I	Class II	Class III	Class IV	Unclassified	Total
BLM	-	0.0	28.2	6.5	0.0	**34.7**
Bureau of Reclamation	-	-	0.4	-	-	**0.4**
Department of Defense	-	0.0	-	2.0	-	**2.0**
U.S. Fish and Wildlife Service	-	0.6	-	-	1.5	**2.1**
Total	**-**	**0.6**	**28.6**	**8.5**	**1.5**	**39.2**

Potential Impacts

Outside of Montana, there are no formal guidelines for managing visual resources on private or state-owned lands. BLM is responsible for identifying and protecting scenic values on public lands under several provisions of FLPMA and NEPA. It is plausible that the proposed power distribution lines may not be consistent with BLM's Visual Resource Class Objectives and could generate adverse impacts to visual resources due to their high visibility, although other power distribution lines are assumed to be present in the general area of the distribution lines. The assessment of visual impacts of the proposed power distribution lines would be included in the analysis conducted by BLM as part of the review of the electrical power providers BLM ROW grant applications.

Potential Mitigation

Because potential impacts from the proposed power distribution lines have not been identified for visual resources, no mitigation measures are proposed at this time. Determination of any necessary mitigation measures for power distribution lines would be part of the environmental reviews required by applicable federal, state, and local regulations.

3.9.4.2 Big Bend to Witten 230-kV Transmission Line

The Western Area Power Administration (Western) determined that a 230-kV transmission line would be required to ensure system reliability within the Western power grid given the power requirements for pump stations 20 and 21 in the Witten, South Dakota area. To meet these requirements, the existing Big

Bend-Fort Thompson No. 2 230-kV line turning structure would be converted to a double circuit structure. Western would construct 2.1 miles of new double-circuit transmission line south to the new Big Bend Substation and would construct the Big Bend Substation. Western would own and operate the 2.1-mile-long line. Ownership of the Big Bend Substation would be transferred to the Basin Electric Power Cooperative (BEPC).

BEPC has proposed construction and operation of a new 230-kV transmission line from the new Big Bend Substation to the existing Witten Substation, the latter owned by Rosebud Electric Cooperative. The approximately 70-mile-long transmission line would be built, owned, and operated by BEPC. The proposed line would be built within a 125-foot-wide ROW, although the specific type of structure to be used has not yet been determined. All substation and switchyard work would be within secured areas. The Big Bend substation site and the Witten area expansion site would be cleared and leveled. Topsoil would be separated from underlying soils and placed on disturbed areas located outside of security fences. Substation components would be transported to the site on local highways and roads.

As described in Section 2.2, Western and BEPC have identified two alternative corridors (A and B) for the proposed Big Bend to Witten 230-kV transmission line project, and there are several route options within each corridor. For Corridor A, the Western Alternative would be 67.2 miles long and BEPC Alternatives A through D would be 69.7 to 72.0 miles long, respectively. For Corridor B, the BEPC Alternatives E through H would be 73.9 to 75.2 miles long, respectively.

Environmental Setting

Land Ownership

Ownership of lands that would be crossed by the Big Bend to Witten transmission line alternatives is summarized in Tables 3.9.4-10 and 3.9.4-11. All affected land would be in South Dakota. For Corridor A, route options would cross between 60.1 and 65.0 miles of private land, and between 6.8 and 7.0 miles of the Lower Brule Reservation (Table 3.9.4-10). Corridor B route options would cross between 65.1 and 66.2 miles of private land, and between 8.7 and 9.0 miles of the Lower Brule Reservation (Table 3.9.4-11). Three potential route options (the Western option, BEPC-C, and BEPC-G) would cross approximately 0.3 acre of state lands.

TABLE 3.9.4-10
Land Ownership Crossed by the Big Bend to Witten 230-kV Transmission Line
Corridor A Alternatives (Miles)

	Western	BEPC-A	BEPC-B	BEPC-C	BEPC-D
Federal [a]					
Lower Brule Reservation	6.8	7.0	7.0	7.0	7.0
State [b]	0.3	0.0	0.0	0.3	0.0
Private [c]	60.1	62.7	63.1	64.4	65.0
Total	**67.2**	**69.7**	**70.1**	**71.7**	**72.0**

[a] The information for federal lands and the Lower Brule Reservation was obtained from ESRI.

[b] The information for state lands was obtained from the South Dakota GIS.

[c] Private lands are the difference in length from total transmission line, federal land, and state land.

TABLE 3.9.4-11
Land Ownership Crossed by the Big Bend to Witten 230-kV Transmission Line Corridor B Alternatives (Miles)

	BEPC-E	BEPC-F	BEPC-G	BEPC-H
Federal [a]				
Lower Brule Reservation	8.8	8.7	8.7	9.0
State [b]	0.0	0.0	0.3	0.0
Private [c]	65.1	65.9	65.5	66.2
Total	**73.9**	**74.6**	**74.5**	**75.2**

[a] The information for federal lands and the Lower Brule Reservation was obtained from ESRI.
[b] The information for state lands was obtained from the South Dakota GIS.
[c] Private lands are the difference in length from total transmission line, federal land, and state land.

Land Use

The acreages for each type of land use for each alternative corridor are summarized in Tables 3.9.4-12 and 3.9.4-13. Within alternative Corridor A, BEPC-D would affect more land than the other route options (approximately 1,091.6 acres) and the Western Route would affect the least amount of land among route options (approximately 1,018.5 acres). Within alternative Corridor B, BEPC-H would affect more land than the other route options (approximately 1,139.0 acres) and BEPC-E would affect the least amount of land among route options (approximately 1,119.3 acres).

TABLE 3.9.4-12
Existing Land Uses Affected by the Big Bend to Written 230-kV Transmission Line Corridor A Alternatives (Acres)[a]

Alternatives	Developed	Agriculture	Rangeland	Forest	Water/ Wetland	Total [b]
Western [c]	40.1	501.5	458.9	1.6	15.9	**1,018.5**
BEPC-A	27.4	389.5	627.0	0.7	11.8	**1,056.4**
BEPC-B	27.3	404.3	620.5	0.7	8.7	**1,061.5**
BEPC-C	69.3	427.7	576.6	0.7	12.0	**1,086.3**
BEPC-D	76.9	398.6	608.2	0.7	7.2	**1,091.6**

[a] Acres based upon square feet of affected land (125-foot ROW x lines miles x 5,280 feet) and divided by 43,560 feet/acre.
[b] Totals may not sum due to rounding.
[c] The Western route includes an additional 0.5 acre of barren land.
Source: Land use from National Land Cover Database, 2001.

TABLE 3.9.4-13
Existing Land Uses Affected by Big Bend to Witten 230-kV Transmission Line Alternatives for Corridor B (Acres)[a]

Alternatives	Developed	Agriculture	Rangeland	Forest	Water/ Wetland	Total[b]
BEPC-E	66.9	346.4	692.7	2.4	10.9	**1,119.3**
BEPC-F	61.5	348.8	712.3	0.6	7.5	**1,130.7**
BEPC-G	66.5	433.5	611.8	1.8	14.7	**1,128.3**
BEPC-H	107.1	374.7	645.8	2.6	8.8	**1,139.0**

[a] Acres based upon square feet of affected land (125-foot ROW x lines miles x 5,280 feet) and divided by 43,560 feet/acre.
[b] Totals may not sum due to rounding.
Source: Land use from National Land Cover Database, 2001.

Potential Impacts

Construction Impacts

Construction related land disturbances would be confined to a relatively small area needed for site access and equipment operations. Estimates of temporary, construction-related land disturbances for each alternative corridor and route option are provided in Tables 3.9.4-14 (Corridor A) and 3.9.4-15 (Corridor B).

Pulling and tensioning of the conductor wires would be required every 10,000 feet, resulting in approximately 35 to 40 pulling and tensioning sites, depending upon the alternative corridor and route option chosen. Each tensioning site could be located within the ROW, although angles in the route would require an additional 1.8 acres outside of the ROW.

TABLE 3.9.4-14
Estimated Big Bend to Witten 230-kV Transmission Line Construction Impacts for Corridor A (Acres)

	Western	BEPC-A	BEPC-B	BEPC-C	BEPC-D
Pre-Construction Surveys	0.001	0.001	0.001	0.001	0.001
Additional Temp Work-spaces	10	10	10	10	10
Number of Pulling Tensioning Sites	35	37	37	38	38
Temp Disturbances per Structure	0.29	0.29	0.29	0.29	0.29
Number of Structures	444	460	463	473	475
Temporary Disturbances [a]	129	133	134	137	138
Route Length (miles)	67.2	69.7	70.1	71.7	72.0
ROW	1,018.5	1,056.4	1,061.5	1,086.3	1,091.6
Estimated Total [b]	**1,157.5**	**1,199.4**	**1,205.5**	**1,233.3**	**1,239.6**

[a] Temporary Disturbances = Temporary disturbances per structure x number of structures.
[b] Totals may not sum due to rounding.
Source: BEPC 2009.

TABLE 3.9.4-15
Estimated Big Bend to Witten 230-kV Transmission Line
Construction Impacts for Corridor B (Acres)

	BEPC-E	BEPC-F	BEPC-G	BEPC-H
Pre-Construction Surveys	0.001	0.001	0.001	0.001
Additional Temp Work-spaces	10	10	10	10
Number of Pulling Tensioning Sites	39	39	39	40
Temp Disturbances per Structure	0.29	0.29	0.29	0.29
Number of Structures	488	492	492	496
Temp Disturbances [a]	142	143	143	144
Route Length (miles)	73.9	74.6	74.5	75.2
ROW	1,119.3	1,130.7	1,128.3	1,139.0
Estimated Total [b]	**1,271.3**	**1,283.7**	**1,281.3**	**1,293.0**

[a] Temporary Disturbances = Temporary disturbances per structure x number of structures.
[b] Totals may not sum due to rounding.
Source: BEPC 2009.

Within Corridor A, the Western route option would affect the fewest number of rangeland acres (approximately 458.9 acres) and route option BEPC-A would affect the greatest number of acres (approximately 627.0 acres). Within Corridor B, the BEPC-G route option would affect the fewest rangeland acres (approximately 611.8 acres) and route option BEPC-F would affect the greatest number (approximately 712.3 acres).

Within Corridor A, the Western route would affect approximately 1.6 acres of forest land while other routes would each affect approximately 0.7 acre (Table 3.9.10.12). Within Corridor B, route option BEPC-H would affect the most forest land (approximately 2.6 acres), while BEPC-F would affect the least amount of forest land (approximately 0.6 acre).

Within Corridor A, route option BEPC-D would affect the greatest area of developed lands (approximately 76.9 acres), while route options BEPC-A and BEPC-B would affect the least area (approximately 27.4 and 27.3 acres respectively). Within Corridor B, route option BEPC-H would affect the most developed land (approximately 107.1 acres) and route option BEPC-F would affect the least developed land (approximately 61.5 acres).

Within Corridor A, the Western route would impact the greatest amount of water and wetlands (approximately 15.9 acres), while route option BEPC-D would affect the least amount of water and wetlands (approximately 7.2 acres). Within Corridor B, route option BEPC-G would affect the most water and wetlands (approximately 14.7 acres), while route option BEPC-F would affect the least amount of water and wetlands (approximately 7.5 acres).

For all potential 230-kV transmission line route options, most construction impacts on land use would be temporary and may include short term disruptions to local traffic, land access, and agricultural practices. A small amount of land clearing would likely be required at support structure locations and other construction staging areas. Short term noise and dust impacts may occur at structures located within 50 feet of the construction ROW.

Operation Impacts

Operation of the transmission lines would permanently affect a relatively small amount of land. An average of 6.6 support structures per mile would be required. The average height of the structures would be 110 feet, and each would span approximately 800 feet. Permanent land disturbance would be approximately 8.7 square feet (0.0002 acre) per structure (BEPC 2009).

Operation of the 230-kV transmission line could lead to some impacts to vegetation external to the construction ROW due to the need for tree trimming to reduce hazards to power line operations. The locations of actual 230-kV transmission line structures could lead to long term operational impacts to farming and other land uses. Impacts to land use are primarily based on surface disturbance areas.

All operations-related impacts on land use would likely last through the useful lifetime of the 230-kV transmission line. Impacts associated with permanent access roads for use during transmission line operations are not estimated since the number and location of these roads are not currently known.

Each transmission line route alternative would consist largely of agricultural land and rangeland and, therefore, tree and brush removal in the ROW would likely be minimal. Trees and brush would not be removed unless they interfered with construction activities or the safe operation of the transmission line. Forested land use areas associated with drainages were avoided during the preliminary routing process.

Potential Mitigation

Mitigations for potential impacts from 230-kV transmission line construction, operation and maintenance would include BMPs appropriate for transmission line activities. Mitigations would include disturbed soil preservation and reclamation, ROW revegetation, and repair of any roads, trails, fences or other improvements associated with transmission line construction, operations and maintenance.

Recreation and Special Interest Areas

Environmental Setting

The potential alternative corridors from the proposed Big Bend Substation to the existing Fort Thompson Substation would be located in or near five identified recreation areas managed by the Lower Brule Indian Reservation in the Lake Sharpe area. The Good Soldier Creek Recreation Area and the Trailwaters Recreation Area are located on the east and west side of State Highway 47, which the proposed transmission line would parallel in this vicinity. The Counselor Creek Recreation Area would be approximately 3 miles west of the transmission line alternatives and the Fort Thompson Recreation Area and North Shore Recreation Area would be located on the north side of Lake Sharpe.

Year-around recreation opportunities in these areas include shore fishing, hiking, picnicking, camping, boating, horseback riding, ATV riding, snowmobile and dirt bike riding, cross-country skiing, wildlife viewing, and photography. Recreational access permits are required for all non-tribal members using these recreation areas and all other tribal lands.

Water-based recreational opportunities within the Big Bend to Witten Transmission line alternative corridors would occur at perennial and intermittent stream crossings. Within Corridor A, the BEPC-D route would cross the least number of streams, including four perennial and 26 intermittent streams (Table 3.9.4-16). The remaining Corridor A routes would cross between one and four perennial streams and between 33 and 36 intermittent streams. Within Corridor B, route option BEPC-E would cross the least number of streams, including three perennial and 23 intermittent streams (Table 3.9.4-17). The remaining

Corridor B routes would cross between four and seven perennial streams and 20 to 31 intermittent streams. Recreational use would likely be centered on or near the perennial rivers and streams crossed by the Big Bend to Witten Transmission line.

TABLE 3.9.4-16
Streams/River Crossings along the Big Bend to Witten 230-kV Transmission Line
Corridor A Alternatives

	Western	BEPC-A	BEPC-B	BEPC-C	BEPC-D
Perennial	1	4	4	4	4
Intermittent	33	34	36	35	26
Total	**34**	**38**	**40**	**39**	**30**

Source: Streams/Rivers from ESRI.

TABLE 3.9.4-17
Streams/River Crossings along the Big Bend to Witten 230-kV Transmission Line
Corridor B Alternatives

	BEPC-E	BEPC-F	BEPC-G	BEPC-H
Perennial	3	4	7	7
Intermittent	23	25	31	20
Total	**26**	**29**	**38**	**27**

Source: Streams/Rivers from ESRI.

Potential Impacts

Recreationists within the Lower Brule Reservation may be affected temporarily during construction activities. Impacts to recreation areas would result from both construction activities and the presence of workers, equipment, and vehicles along the construction route. However, disturbed land would be restored to pre-construction conditions to the extent possible.

Potential Mitigation

Western and BEPC would communicate with appropriate personnel from the Lower Brule Indian Reservation and relevant state and federal resource agencies to schedule construction work to reduce, to the extent practicable, disturbance to recreational uses.

Visual Resources

Environmental Setting

Visual resources are natural or developed landscape characteristics that have an aesthetic value to residents and visitors from sensitive viewpoints such as residences, recreation areas, rivers, and highways. The Big Bend to Witten 230-kV transmission line alternatives would pass through sparsely populated areas in Lyman and Tripp counties. Communities within the alternative corridors include Reliance and Hamill, with 2000 populations of 206 and 11, respectively. The Lower Brule Indian Reservation would be located at the northern terminus and contains a number of recreational opportunities for tribal members

and visitors. Major roadways would likely cross the transmission line, including State Highway 47, Interstate Highway 90, State Highway 49, and U.S. Highway 18.

Potential Impacts

The analysis of environmental effects associated with the proposed 230-kV transmission line would be handled under a separate environmental review, likely conducted by either or both of RUS and Western. Based on currently available information, it is likely that changes to visual resources would be both temporary (e.g., digging the foundations for power poles) and permanent (e.g., erection of power poles and lines). Impacts to visual resources during construction would result from both construction activities and the presence of workers, equipment, and vehicles along the construction route. Visual impacts would also result from the clearing and removal of existing vegetation, exposure of bare soils, and the presence of machinery and new aboveground structures.

The majority of viewers of the 230-kV transmission line project during construction and operation would be travelers along the transportation corridors in the vicinity of the project. Their views would typically be limited to short periods of time and small portions of the route. In addition, residents and recreationists using recreation areas within the Lower Brule Reservation could be affected by the addition of power poles and lines. Some individuals viewing the route from residences within 0.75 mile of the route might be able to observe portions of the construction activities throughout the construction period.

Potential Mitigation

Potential mitigation measures to address any environmental impacts identified for the proposed 230-kV transmission line project would be identified in a separate environmental review, likely conducted by either or both of RUS and Western.

3.9.4.3 Bakken Marketlink and Cushing Marketlink Projects

Construction and operation of the Bakken Marketlink Project would include metering systems, three new storage tanks near Baker, Montana, and two new storage tanks within the boundaries of the proposed Cushing tank farm. Keystone reported that the property proposed for the Bakken Marketlink facilities near Pump Station 14 is currently used as pastureland and hayfields and that a survey of the property indicated that there were no waterbodies or wetlands on the property. DOS reviewed aerial photographs of the area and confirmed the current use of the land and that there are no waterbodies associated with the site. A site inspection by the DOS third-party contractor confirmed these findings. As a result, the potential impacts associated with expansion of the pump station site to include the Bakken Marketlink facilities would likely be similar to those described above for the proposed Project pump station and pipeline ROW in that area.

The Cushing Marketlink project would be located within the boundaries of the proposed Cushing tank farm of the Keystone XL Project and would include metering systems and two storage tanks. As a result, the impacts of construction and operation of the Cushing Marketlink Project on land use, recreation, and visual resources would be essentially the same as potential impacts associated with construction and operation of the proposed Cushing tank farm described in this section.

Currently there is insufficient information to complete an environmental review of the Marketlink projects. The permit applications for these projects would be reviewed and acted on by other agencies. Those agencies would conduct more detailed environmental reviews of the Marketlink projects. Potential impacts to land use, recreation, or visual resources of the Marketlink projects would be evaluated and

avoided, minimized, or mitigated in accordance with applicable regulations during the environmental reviews for these projects.

3.9.5 References

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3.10 SOCIOECONOMICS

This section describes existing socioeconomic conditions and evaluates the potential socioeconomic impacts that may result from the proposed Project. The resource topics used to describe the existing socioeconomic conditions include:

- Population;
- Housing;
- Local economic activity, measured primarily by employment and income;
- Environmental justice;
- Public services, tax revenues, and property values; and
- Traffic and transportation.

The socioeconomic topics identified as potentially impacted, either positively or negatively, by the proposed Project include:

- Social benefits and costs to the United States of increased access to Canadian crude;
- Compensation to property owners for ROW easements, restrictions on land use, and damage to property;
- Creation of local area jobs;
- Economic benefits from the purchase of goods and services during construction and operations;
- Construction worker demands on local infrastructure; and
- Fiscal impacts associated with property, sales, and other tax revenues, as well as public service costs generated by the proposed Project.

The proposed Project in the United States would consist of a 1,384-mile pipeline and ancillary facilities, as described in Section 2.0. From its point of entry into the United States near Morgan, Montana the proposed pipeline would cross 58 counties in six states. From north to south the states are Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas (see Table 3.10.1-1).

TABLE 3.10-1 States and Counties within the Proposed Project Area		
Segment/State	**Number of Counties**	**Counties**
Steel City Segment		
Montana	6	Phillips, Valley, McCone, Dawson, Prairie, Fallon
South Dakota	9	Harding, Butte, Perkins, Meade, Pennington, Haakon, Jones, Lyman, Tripp
Nebraska	14	Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, Jefferson
New Cushing Extension Pump Stations		
Kansas	2	Clay, Butler
Gulf Coast Segment		
Oklahoma	8	Atoka, Bryan, Coal, Creek, Hughes, Lincoln, Okfuskee, Seminole
Texas	16	Angelina, Cherokee, Delta, Fannin, Franklin, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, Wood
Houston Lateral		
Texas	3	Liberty, Chambers, Harris

Within each county, several local communities are expected to incur most of the direct socioeconomic impacts of the proposed Project, both positive and negative. Communities located with 0.5 to 2.0 miles of the proposed pipeline are listed in Table 3.10.1-2. However, for the purposes of the analysis, information to describe the environmental setting is reported at the county versus community level. The determination to develop the analysis at the county versus community level was based on the following factors:

- The rural nature of the majority of the potentially affected environment limits the availability of consistent data below the county level;
- Proposed Project economic impacts may occur in towns further away than 2 miles from the pipeline; and
- In communities that are not predominately rural, such as Houston, located in Harris County, Texas, the economic impacts of building and operating the proposed pipeline would be relatively small.

Several types of socioeconomic effects could occur within the region of influence, as described in more detail in the impact analyses presented in Sections 3.10.1.2, 3.10.2.2, and 3.10.3.2. Temporary effects during construction of the proposed Project could include changes in population levels or local demographics, changes in the demand for housing and public services, disruption of local transportation corridors, increased employment opportunities and related labor income benefits, and increased government revenues associated with sales and payroll taxes. Isolated impacts on individual property owners and economic land use also could occur along the pipeline route. The primary socioeconomic impacts associated with long-term operation of the proposed Project likely would include employment and income benefits resulting from long-term staffing requirements and local operating expenditures, as well as an increased property tax base and associated tax revenues. On a national level, the primary benefit of the proposed Project would be for PADD III refineries (and ultimately U.S. customers) to gain access to a more reliable and steady source of crude oil supply. Long-term impacts could include impacts

to property owners if there was any decrease in land value or usefulness as a result of the pipeline. However, tilled agricultural land would still be useable after construction.

TABLE 3.10-2
Communities within 2 Miles of the Proposed Project

Community	County	Proximity to Proposed Project (miles)
Steele City Segment		
Montana		
Nashua	Valley	2
Circle	McCone	2
Baker	Fallon	2
South Dakota		
Buffalo	Harding	2
Midland	Haakon	2
Draper	Jones	2
Winner	Tripp	2
Nebraska		
Ericson	Wheeler	2
Hordville	Hamilton	2
McCool Junction	York	2
Exeter	Fillmore	2
Milligan	Fillmore	2
Western	Saline	2
Steele City	Jefferson	2
New Cushing Extension Pump Stations		
Kansas		
Towanda	Butler	0.5
Potwin	Butler	0.5
Augusta	Butler	2
Douglass	Butler	2
Wakefield	Clay	2
Green	Clay	2
Gulf Coast Segment		
Oklahoma		
Stroud	Creek	2
Paden	Okfuskee	2
Boley	Okfuskee	2
Wewoka	Seminole	2
Allen	Pontotoc	2
Allen	Hughes	2
Atoka	Atoka	2
Tushka	Atoka	2
Caney	Atoka	2
Texas		
Arp	Smith	0.5
Beaumont	Jefferson	0.5
Port Arthur	Jefferson	0.5
Central Gardens	Jefferson	0.5

TABLE 3.10-2 Communities within 2 Miles of the Proposed Project		
Community	**County**	**Proximity to Proposed Project (miles)**
Nederland	Jefferson	0.5
China	Jefferson	2
Port Neches	Jefferson	2
Tira	Hopkins	2
Winnsboro	Franklin	2
Winnsboro	Wood	2
Big Sandy	Upshur	2
Reklaw	Rusk	2
Wells	Cherokee	2
Hudson	Angelina	2
Diboll	Angelina	2
Corrigan	Polk	2
Houston Lateral		
Texas		
Hardin	Liberty	2
Liberty	Chambers	2
Ames	Harris	0.5
Mont Belvieu	Chambers	0.5
Barrett	Harris	0.5
Highlands	Harris	2
Channelview	Harris	2
Sheldon	Harris	2
Houston	Harris	0.5

Note: States and counties are listed geographically from north to south as the proposed Project crosses the area.

3.10.1 Socioeconomics and Environmental Justice

3.10.1.1 Environmental Setting

This section provides a general overview of the socioeconomic resources that could be affected by the proposed Project and represents existing (or current) socioeconomic conditions in the proposed Project area. Further, it provides context to the analysis of socioeconomic impacts and establishes baseline conditions against which the potential socioeconomic impacts of the proposed Project were evaluated. The data used to establish baseline socioeconomic conditions were derived from a variety of federal, state, and local sources. Both text and tables in this section are organized by Project area (e.g., Segment, Pump Station, or Lateral), state, and county.

Population

Population-related characteristics in the region of socioeconomic influence are summarized in Tables 3.10.1-3 and 3.10.1-4. The state populations for those states in which the proposed Project would be constructed are shown in Table 3.10.1-1. For reference the U.S. population is also included in Table 3.10.1-3. The annual average increase in population for the period 2000 to 2007 was 0.9 percent for the nation. Every state except Texas experienced an average annual population growth lower than the federal annual average – ranging from 0.5 to 0.8 percent. Texas' annual average population growth was 1.9 percent between 2000 and 2007.

TABLE 3.10.1-1 State Populations, 2000 and 2007			
Geographic Area	**Population**		**Annual Average % Change**
	2000	**2007**	
United States	282,171,936	301,290,332	0.9%
States			
Montana	903,283	956,624	0.7%
South Dakota	755,657	795,689	0.8%
Nebraska	1,713,194	1,769,473	0.5%
Kansas	2,688,418	2,777,382	0.5%
Oklahoma	3,453,861	3,608,123	0.6%
Texas	20,946,049	23,843,432	1.9%

Source: U.S. Census Population, Population change and estimated components of population change: April 1, 2000 to July 1, 2008 (NST-EST2008-alldata).

The proposed Project route is predominantly rural and sparsely populated, with the population tending to increase from north to south along the route. The total population in the counties comprising the region of influence was over 5.7 million in 2007 (see Table 3.10.1-4). Texas comprised 5.0 million, with 3.9 million of those people living in Harris County where Houston is located. The remainder of the population was distributed across counties that would be traversed by the proposed Project in the other five states as follows: 23,747 in Montana, 146,320 in South Dakota, 85,207 in Nebraska, 71,570 in Kansas, and 323,738 in Oklahoma. The population densities in these five counties ranged from less than 1 person per square mile to 99 people per square mile. Population densities in Texas were slightly greater, ranging from 10 people per square mile (Angelina County) to 1,967 people per square mile (Harris County). These population figures demonstrate the relatively rural nature of the proposed Project area.

In addition to being rural and sparsely populated, the counties within the proposed Project area have experienced relatively low to negative population growth between 2000 and 2007. Most counties located within the proposed Project area from Montana to Nebraska experienced a reduction in population ranging from 2.5 to 0.1 percent between 2000 and 2007. Some counties along the proposed Project route in Kansas, South Dakota, and Oklahoma experienced an average annual increase in population for the same time period ranging from 0.6 to 0.8 percent. The majority of the average annual population growth occurred in Texas, which experienced a 1.7 percent average annual increase in population between 2000 and 2007 (see Table 3.10.1-2).

TABLE 3.10.1-2
County Populations and Population Densities, 2000 and 2007

County	Population 2000	Population 2007	Annual Average % Change	Density (per square mile)
Steele City Segment				
Montana				
Phillips	4,601	3,934	-2.2%	<1
Valley	7,675	6,884	-1.5%	2
McCone	1,977	1,716	-2.0%	1
Dawson	9,059	8,554	-0.8%	4
Prairie	1,199	1,043	-2.0%	<1
Fallon	1,695	1,616	-0.7%	2
Subtotal Montana	*26,206*	*23,747*	*-1.4%*	
South Dakota				
Harding	1,353	1,173	-2.0%	<1
Butte	9,094	9,449	0.5%	4
Perkins	3,369	2,907	-2.1%	1
Meade	24,245	24,057	-0.1%	7
Pennington	88,573	96,230	1.2%	32
Haakon	2,196	1,842	-2.5%	1
Jones	1,193	1,047	-1.8%	1
Lyman	3,895	3,882	0.0%	2
Tripp	6,430	5,733	-1.6%	4
Subtotal South Dakota	*140,348*	*146,320*	*0.6%*	
Nebraska				
Keya Paha	983	851	-2.0%	1
Rock	1,756	1,515	-2.1%	2
Holt	11,551	10,310	-1.6%	5
Garfield	1,902	1,714	-1.5%	3
Wheeler	886	806	-1.3%	2
Greeley	2,714	2,312	-2.3%	5
Boone	6,259	5,505	-1.8%	9
Nance	4,038	3,554	-1.8%	9
Merrick	8,204	7,665	-1.0%	17
Hamilton	9,403	9,282	-0.2%	17
York	14,598	14,339	-0.3%	25
Fillmore	6,634	6,026	-1.4%	12
Saline	13,843	13,823	0.0%	24
Jefferson	8,340	7,505	-1.5%	14
Subtotal Nebraska	*91,111*	*85,207*	*-1.0%*	
New Cushing Extension Pump Stations				
Kansas				
Clay	8,822	8,691	-0.2%	14
Butler	59484	62879	0.8%	42
Subtotal Kansas	*68,306*	*71,570*	*0.7%*	
Gulf Coast Segment				
Oklahoma				
Atoka	13,879	14,479	0.6%	14
Bryan	36,534	39,298	1.0%	40
Coal	6,031	5,698	-0.8%	12

TABLE 3.10.1-2
County Populations and Population Densities, 2000 and 2007

County	Population 2000	Population 2007	Annual Average % Change	Density (per square mile)
Creek	67,369	68,940	0.3%	70
Hughes	14,154	13,576	-0.6%	18
Lincoln	32,080	32,211	0.1%	34
Okfuskee	11814	11197	-0.8%	19
Payne	68,186	77,724	1.9%	99
Seminole	24,896	24,103	-0.5%	39
Pontotoc	35,143	36,512	0.5%	49
Subtotal Oklahoma	*310,086*	*323,738*	*0.6%*	
Texas				
Angelina	80,130	82,570	0.4%	10
Cherokee	46,663	48,056	0.4%	44
Delta	5,327	5,368	0.1%	19
Fannin	31,242	32,930	0.8%	35
Franklin	9,458	11,104	2.3%	33
Hardin	48,073	51,530	1.0%	54
Hopkins	31,960	33,699	0.8%	41
Jefferson	252,051	242,372	-0.6%	279
Lamar	48,499	49,090	0.2%	53
Liberty	70,159	74,930	0.9%	60
Nacogdoches	59,203	62,221	0.7%	62
Polk	41,139	46,206	1.7%	39
Rusk	47,372	48,452	0.3%	51
Smith	174,706	197,952	1.8%	188
Upshur	35,291	37,881	1.0%	60
Wood	36,752	41,817	1.9%	56
Subtotal Texas - Gulf Coast Segment	*1,018,025*	*1,066,178*	*0.7%*	
Houston Lateral				
Texas				
Liberty (see the Gulf Coast Segment)				
Chambers	26,031	28,740	1.4%	43
Harris	3,400,590	3,912,196	2.0%	1,967
Subtotal Texas - Houston Lateral	*3,426,621*	*3,940,936*	*2.0%*	
Subtotal Texas	*4,444,646*	*5,007,114*	*1.7%*	
Total Counties	**5,080,703**	**5,657,696**	**1.5%**	

Source: U.S. Bureau of the Census. County population, population change and estimated components of population change: April 1, 2000 to July 1, 2008 (CO-EST2008-alldata).

Table 3.10.1-3 shows the communities located within a 2-mile proximity of the proposed Project. The total population of these communities was 2.467 million as of July 1, 2008. Of that 2.467 million, 2.208 million were located in Houston. The remaining 259,000 were distributed along the remainder of the proposed Project area. The total community populations by state were: 2,465 located in three communities in Montana, 3,368 located in four communities in South Dakota, 1,520 located in seven

communities in Nebraska, 13,251 located in six communities in Kansas, 12,167 located in nine communities in Oklahoma, and 214,045 in fifteen communities in Texas, excluding Houston. Many of the potentially-affected communities along the northern portions of the route have experienced an average annual reduction in population between 2000 and 2007, particularly in Montana, South Dakota, Nebraska, and Kansas. As another indication of the relatively sparsely populated nature of the proposed Project area, counties within each state that have no communities within 2 miles of the proposed Project include:

- Phillips, Dawson, and Prairie counties in Montana;
- Butte, Perkins, Meade, Pennington, and Lyman counties in South Dakota;
- Keya Paha, Rock, Holt, Garfield, Greely, Boone, Nance, and Merrick counties in Nebraska;
- Bryan, Coal, Lincoln, and Payne counties in Oklahoma; and
- Delta, Fannin, Hardin, Lamar, Liberty, and Nacogdoches counties in Texas.

Between 2000 and 2007, the highest average annual growth rate occurred along the proposed Houston Lateral in Mont Belvieu and Houston.

TABLE 3.10.1-3
Population of Communities within 2-mile Proximity of the Proposed Project

County	Communities	Population		Annual Average % Change
		2000	2007	
Steele City Segment				
Montana				
Phillips	NA	NA	NA	NA
Valley	Nashua	325	291	-1.6%
McCone	Circle	644	558	-2.0%
Dawson	NA	NA	NA	NA
Prairie	NA	NA	NA	NA
Fallon	Baker	1,695	1,616	-0.7%
Subtotal Montana		*2,664*	*2,465*	*-1.1%*
South Dakota				
Harding	Buffalo	380	330	NA
Butte	NA	NA	NA	NA
Perkins	NA	NA	NA	NA
Meade	NA	NA	NA	NA
Pennington	NA	NA	NA	NA
Haakon	Midland	179	150	-2.5%
Jones	Draper	92	83	-1.5%
Lyman	NA	NA	NA	NA
Tripp	Winner	3,137	2,805	-1.6%
Subtotal South Dakota		*3,788*	*3,368*	*-1.7%*
Nebraska				
Keya Paha	NA	NA	NA	NA
Rock	NA	NA	NA	NA
Holt	NA	NA	NA	NA
Garfield	NA	NA	NA	NA
Wheeler	Ericson	104	95	-1.3%

TABLE 3.10.1-3
Population of Communities within 2-mile Proximity of the Proposed Project

County	Communities	Population		Annual Average % Change
		2000	2007	
Greeley	NA	NA	NA	NA
Boone	NA	NA	NA	NA
Nance	NA	NA	NA	NA
Merrick	NA	NA	NA	NA
Hamilton	Hordville	150	144	-0.6%
York	McCool Junction	385	NA	NA
Fillmore	Exeter	712	647	-1.4%
-	Milligan	315	284	-1.5%
Saline	Western	287	274	-0.7%
Jefferson	Steele City	84	76	-1.4%
Subtotal Nebraska		*2,037*	*1,520*	*-4.1%*
New Cushing Extension Pump Stations				
Kansas				
Clay	Wakefield	838	854	0.3%
-	Green	147	137	-1.0%
Butler	Towanda	1,338	1,354	0.2%
-	Potwin	457	433	-0.8%
-	Douglass	1,813	1,790	-0.2%
-	Augusta	8423	8683	0.4%
Subtotal Kansas		*13,016*	*13,251*	*0.3%*
Gulf Coast Segment				
Oklahoma				
Atoka	Atoka	2,988	3,069	0.4%
-	Tushka	345	366	0.8%
-	Caney	199	210	0.8%
Bryan	NA	NA	NA	NA
Coal	NA	NA	NA	NA
Creek	Stroud	2,758	2,742	-0.1%
Hughes	Allen	2,398	NA	NA
Lincoln	NA	NA	NA	NA
Okfuskee	Paden	446	422	-0.8%
-	Boley	1,126	1,091	-0.5%
Payne	NA	NA	NA	NA
Seminole	Wewoka	3,562	3,326	-1.0%
Pontotoc	Allen	951	941	-0.2%
Subtotal Oklahoma		*14,773*	*12,167*	*-2.5%*
Texas				
Angelina	Hudson	3,792	4,231	1.6%
-	Diboll	5,470	5,541	0.2%
Cherokee	Wells	769	792	0.4%
Delta	NA	NA	NA	NA
Fannin	NA	NA	NA	NA
Franklin/Wood	Winnsboro	3,584	3,909	1.2%
Hardin	NA	NA	NA	NA

TABLE 3.10.1-3
Population of Communities within 2-mile Proximity of the Proposed Project

County	Communities	Population		Annual Average % Change
		2000	2007	
Hopkins	Tira	248	258	0.6%
Jefferson	Beaumont	113,866	109,579	-0.5%
-	Port Arthur	57,755	55,313	-0.6%
-	Central Gardens	4,106	NA	NA
-	Nederland	17,422	16,178	-1.1%
-	China	1,112	1,042	-0.9%
-	Port Neches	13,301	12,681	-0.7%
Lamar	NA	NA	NA	NA
Liberty	NA	NA	NA	NA
Nacogdoches	NA	NA	NA	NA
Polk	Corrigan	1,721	1,887	1.3%
Rusk	Reklaw	327	336	0.4%
Smith	Arp	901	952	0.8%
Upshur	Big Sandy	1,288	1,346	0.6%
Wood	See Franklin	NA	NA	NA
Subtotal Texas - Gulf Coast Segment		*225,662*	*214,045*	*-0.8%*
Houston Lateral				
Texas				
Liberty	Hardin	755	792	0.7%
Chambers	Liberty	8,033	8,033	0.0%
-	Mont Belvieu	2,324	2,637	1.8%
Harris	Ames	1,079	1,138	0.8%
-	Barrett	2,872	NA	NA
-	Highlands	7,089	NA	NA
-	Channelview	29,685	NA	NA
-	Sheldon	1,831	NA	NA
-	Houston	1,953,631	2,208,180	1.8%
Subtotal Texas - Houston Lateral		*2,007,299*	*2,220,780*	*1.5%*
Subtotal Texas		*2,232,961*	*2,434,825*	*1.2%*
Total All Communities		**2,269,239**	**2,467,596**	**1.2%**

Source: U.S. Bureau of the Census 2009. Population, Population change and estimated components of population change: April 1, 2000 to July 1, 2008 (NST-EST2008-alldata).

Housing

Available housing to serve the proposed Project is a function of the housing stock (mainly rental and short-term accommodations), recent economic and population growth, and demand for housing from other sources. The existing housing units in the proposed Project area and the existing short-term housing resources, such as rentals and hotel and motel rooms, are shown in Tables 3.10.1-4 and 3.10.1-5.

The total number of housing units in the counties that would be crossed by the proposed Project was estimated to be over 2,187,827 in 2007, with 1,557,935 (71.2 percent) of those units in counties that

would be crossed by the proposed Houston Lateral (Table 3.10.1-4). The fewest number of units were found in counties that would be crossed by the proposed Project in Montana, Kansas, and Nebraska with 14,622 units, 29,850 units, and 41,082 units, respectively. Housing stock existing in 2007 was predominantly occupied single-family residential housing that would not be available for use by proposed Project workers.

TABLE 3.10.1-4
Housing Units for Counties along the Proposed Project

County	Total Housing Units 2000	Total Housing Units 2007	Percent of Total	Building Permits
Steele City Segment				
Montana				
Phillips	2,502	2,484		0
Valley	4,847	4,807		1
McCone	1,087	1,076		0
Dawson	4,168	4,135		3
Prairie	718	711		0
Fallon	1,410	1,409		0
Subtotal Montana	*14,732*	*14,622*	*0.7%*	*4*
South Dakota				
Harding	804	804		0
Butte	4,059	4,384		91
Perkins	1,854	1,897		5
Meade	10,149	11,523		118
Pennington	37,249	42,208		838
Haakon	1,002	1,036		3
Jones	614	627		5
Lyman	1,636	1,690		6
Tripp	3,036	3,098		0
Subtotal South Dakota	*60,403*	*67,267*	*3.1%*	*1,066*
Nebraska				
Keya Paha	548	572		3
Rock	935	947		3
Holt	5,281	5,425		8
Garfield	1,021	1,028		2
Wheeler	561	573		0
Greeley	1,199	1,221		0
Boone	2,733	2,787		11
Nance	1,787	1,771		7
Merrick	3,649	3,770		30
Hamilton	3,850	3,980		28
York	6,172	6,240		22
Fillmore	2,990	2,989		6
Saline	5,611	5,788		62
Jefferson	3,942	3,991		21
Subtotal Nebraska	*40,279*	*41,082*	*1.9%*	*203*
New Cushing Extension Pump Stations				
Kansas				
Clay	4,084	4,200		20
Butler	23,176	25,650		408

TABLE 3.10.1-4
Housing Units for Counties along the Proposed Project

County	Total Housing Units 2000	Total Housing Units 2007	Percent of Total	Building Permits
Subtotal Kansas	*27,260*	*29,850*	*1.4%*	*428*
Gulf Coast Segment				
Oklahoma				
Payne	29,326	32,906		167
Lincoln	13,712	14,241		24
Creek	27,986	29,603		228
Okfuskee	5,114	5,314		5
Seminole	11,146	11,537		21
Hughes	6,237	6,368		4
Coal	2,744	2,821		1
Atoka	5,673	5,868		7
Bryan	16,715	17,998		415
Subtotal Oklahoma	*118,653*	*126,656*	*5.8%*	*872*
Texas				
Fannin	12,887	13,568		44
Lamar	21,113	22,130		81
Delta	2,410	2,489		11
Hopkins	14,020	14,651		14
Franklin	5,132	5,410		4
Wood	17,939	18,607		14
Upshur	14,930	15,593		67
Smith	71,701	77,281		679
Cherokee	19,173	19,965		33
Rusk	19,867	20,598		8
Nacogdoches	25,051	26,720		256
Angelina	32,435	34,125		185
Polk	21,177	22,636		460
Liberty	26,359	28,294		293
Hardin	19,836	20,966		129
Jefferson	102,080	104,499		1,576
Subtotal Texas – Gulf Coast Segment	*426,110*	*447,532*	*20.5%*	*3,854*
Houston Lateral				
Texas				
Chambers	10,336	13,351		368
Harris	1,298,130	1,544,584		46,455
Subtotal Texas – Houston Lateral	*1,308,466*	*1,557,935*	*71.2%*	*46,823*
Subtotal Texas	*1,734,576*	*2,005,467*	*91.7%*	*50,677*
Total All Communities	**1,908,240**	**2,187,827**	**100.0%**	

Notes:

States and counties are listed geographically from north to south as proposed Project crosses area.

Housing in counties on the Cushing Extension were analyzed as part of the Keystone Pipeline Project and are included for clarity only. Construction in these counties would be related to pump stations only except in Jefferson County, NE, and Payne County, OK, where some new pipeline construction would occur.

Source: U.S. Bureau of the Census 2000.

More pertinent to the analysis is the number of rental units and short-term accommodations, such as motel and hotel rooms and recreational vehicle (RV) sites, and related vacancy rates (Table 3.10.1-5). The total number of rental units located across all affected counties was about 757,191 in 2000, of which 592,018 (78.2 percent) were located in Chambers and Harris counties in Texas. Montana, Kansas, and Nebraska had the fewest rental units. Rental vacancy rates and available rental housing varied considerably across states and counties. The highest vacancy rates for rental units were in Montana, ranging from 7.9 to 25.8 percent in the affected counties, compared with the lowest weighted average of 8.3 percent in Nebraska. Based on these data, approximately 68,051 vacant rental units were available in the region of influence, of which 51,655 occur in the counties along the Houston Lateral. At the county level, the number of available units was smallest in Wheeler County, Nebraska, with nine units.[1] Of the 58 counties in the proposed Project area, 12 had less than 50 available units. Most of those counties are located in Montana and South Dakota.

Within the spectrum of currently available housing, alternatives to rental housing are temporary short-term accommodations in hotels/motels rooms, and RV sites. In some cases, recreational cabins and seasonal housing for migratory workers also could be available. Short-term accommodations are more flexible and likely would be the preferred form of housing for construction workers. It is estimated that approximately 23,855 hotel/motel rooms were located within a 50-mile corridor of the pipeline route. Of that number, more than half were located in the two-county Houston Lateral portion of the proposed Project. The fewest hotels/motel rooms were in Kansas (356) and Montana (761). The total number of hotels/motel rooms and RV sites by county are presented in Table 3.10.1-5. The availability of short-term accommodations varies throughout the year and depends on a number of factors, including seasonal fluctuations and timing of local events.

TABLE 3.10.1-5
Short-term Housing Assessment for Counties along the Proposed Project

	Rentals (2000)				Hotel / Motel		
County	Units	Vacancy Rate	Percent of Total	Available Units (Calculated)	Rooms	Percent of Total	RV Sites
Steele City Segment							
Montana							
Phillips	632	14.1		89	126		40
Valley	826	7.9		65	253		44
McCone	240	25.8		62	14		0
Dawson	1,076	12.5		135	277		94
Prairie	143	15.4		22	0		9
Fallon	333	22.5		75	91		18
Subtotal Montana	*3,250*	*13.8*	*0.4%*	448	*761*	*3.2%*	*205*
South Dakota							
Harding	152	8.6		13	20		0
Butte	1,119	15.9		178	222		93
Perkins	396	15.4		61	90		0
Meade	3,105	9.9		307	398		465
Pennington	12,516	6.4		801	4,045		1,895

[1] Available units are calculated by multiplying the rental units by the vacancy rate.

TABLE 3.10.1-5
Short-term Housing Assessment for Counties along the Proposed Project

	Rentals (2000)				Hotel / Motel		
County	Units	Vacancy Rate	Percent of Total	Available Units (Calculated)	Rooms	Percent of Total	RV Sites
Haakon	233	13.3		31	29		21
Jones	159	11.9		19	189		200
Lyman	477	10.1		48	390		166
Tripp	736	12.4		91	194		20
Subtotal South Dakota	*18,893*	*8.2*	*2.5%*	*1,550*	*5,577*	*23.4%*	*2,860*
Nebraska							
Keya Paha	124	8.1		10	0		20
Rock	216	4.6		10	36		0
Holt	1,376	11.6		160	198		19
Garfield	257	13.2		34	28		25
Wheeler	117	7.7		9	0		0
Greeley	244	5.3		13	0		0
Boone	676	9.8		66	34		0
Nance	440	9.3		41	16		0
Merrick	896	7.4		66	33		0
Hamilton	956	8.8		84	10		45
York	1,905	8.3		158	575		4
Fillmore	742	7.5		56	26		0
Saline	1,598	4.8		77	77		48
Jefferson	932	9.4		88	45		0
Subtotal Nebraska	*10,479*	*8.3*	*1.4%*	*871*	*1,078*	*4.5%*	*161*
New Cushing Extension Pump Stations							
Kansas							
Clay	973	13.6		132	55		0
Butler	5,327	9.8		522	301		36
Subtotal Kansas	*6,300*	*10.4*	*0.8%*	*654*	*356*	*1.5%*	*36*
Gulf Coast Segment							
Oklahoma							
Payne	12,680	7.3		926	650		0
Lincoln	2,738	10.9		298	145		29
Creek	6,182	10.1		624	142		0
Okfuskee	1,138	10.6		121	47		0
Seminole	2,991	12		359	141		0
Hughes	1,403	8.2		115	13		0
Coal	653	9.6		63	27		0
Atoka	1,354	12.9		175	54		0
Bryan	4,887	9.7		474	203		159
Subtotal Oklahoma	*34,026*	*9.3*	*4.5%*	*3,154*	*1,422*	*6.0%*	*188*

TABLE 3.10.1-5
Short-term Housing Assessment for Counties along the Proposed Project

	Rentals (2000)				Hotel / Motel		
County	Units	Vacancy Rate	Percent of Total	Available Units (Calculated)	Rooms	Percent of Total	RV Sites
Texas							
Fannin	3,167	11.5		364	53		0
Lamar	6,902	9.4		649	621		0
Delta	506	5.9		30	0		0
Hopkins	4,034	12.7		512	466		0
Franklin	907	13		118	44		0
Wood	3,003	9.7		291	61		0
Upshur	2,745	11.7		321	74		0
Smith	22,065	9.8		2,162	1,937		180
Cherokee	4,895	10		490	222		0
Rusk	3,891	10.3		401	240		0
Nacogdoches	9,334	9.4		877	106		24
Angelina	8,810	10.1		890	920		0
Polk	3,212	13.9		446	281		215
Liberty	5,405	9.6		519	168		0
Hardin	3,545	12.9		457	108		0
Jefferson	34,997	9.7		3,395	2,911		144
Subtotal Texas – Gulf Coast Segment	*117,418*	*10.2*	*15.5%*	*11,923*	*8,212*	*34.4%*	*563*
Houston Lateral							
Texas							
Chambers	1,804	17		307	202		110
Harris	590,214	8.7		51,349	12,180		501
Subtotal Texas – Houston Lateral	*592,018*	*8.7*	*78.2%*	*51,655*	*12,382*	*51.9%*	*611*
Subtotal Texas	*709,436*	*8.9*	*93.7%*	*63,140*	*20,594*	*86.3%*	*1,174*
Total All Communities	**757,191**	**9.3**	**100.0%**	**68,051**	**23,855**	**100.0%**	**1,7281,17**

Notes:

States and counties are listed geographically from north to south as proposed Project crosses area.

Housing in counties on the Cushing Extension were analyzed as part of the Keystone Pipeline Project and are included for clarity only. Construction in these counties would be related to pump stations only except in Jefferson County, NE, and Payne County, OK, where some new pipeline construction would occur.

Source: Rentals (U.S. Bureau of the Census 2000); RV sites (Delorme Gazetteers); Total hotel and motel rooms (www.travelpost.com/hotels.aspx, www.aaacolorado.com/travel/, www.tripadvisor.com/).

Local Economic Activity

Employment and income patterns provide insight into local economic conditions, including the strength of the local economy and the well-being of its residents. Statistics summarizing these economic parameters are shown in Table 3.10.1-6. The most recent per capita income, median household income, unemployment rates, and work force statistics for each county are shown in Table 3.10.1-6 along with one historical data point. For reference, data are included for each state and the U.S. In every state along the proposed Project route, both the 2007 per capita income and the 2007 median household income were less

than the U.S. levels. In nearly every county, the 2007 per capita income and median household income were less than their respective state levels. Despite the relatively lower level of income, the most recent unemployment rate (June 2009) in each state was lower than the U.S. level for the same time period. The county unemployment rates were generally less than their respective state unemployment rates, except in Oklahoma and Texas. Each statistic is discussed below in more detail.

The state with the lowest 2007 per capita income was Montana with $33,225, or $5,390 less than the national average. The state with the highest 2007 per capita income was Texas with $37,083, or $1,532 less than the national average. The county with the lowest per capita income in 2007 was Keya Paha, Nebraska with $21,254, or $15,118 less than the per capita income for Nebraska. The county with the highest per capita income was Harris, Texas (where Houston is located) with $49,634, or $12,551 greater than the state level. The range of county-level per capita incomes ($21,254 to $49,634) shows the diversity of economic conditions along the proposed Project corridor.

The state with the lowest 2007 median household income was Oklahoma with $41,551, or $9,189 less than the national level. The state with the highest 2007 median household income was Texas with $47,563, or $3,177 less than the national average. The county with the lowest median household income in 2007 was Hughes, Oklahoma with $28,689, or $12,862 less than Oklahoma's median household income. The county with the lowest median income relative to the state level was Keya Paha, Nebraska, with a difference of $16,067 from the state level. Chambers County, Texas had the highest median household income with $62,164, or $14,601 higher than Texas. This range of county-level median household income ($28,689 to $62,124) also demonstrates the diversity of economic conditions along the proposed Project corridor.

The state with the highest unemployment rate in 2008 was Texas with 4.9 percent, or 0.9 percent lower than the national level of 5.8 percent. The state with the lowest unemployment rate in 2008 was South Dakota with 3.1 percent, or 2.7 percent less than the national average. The county with the highest unemployment rate was Jefferson, Texas at 6.8 percent, or 1.0 percent higher than the state level. The lowest unemployment rates were in Fallon County, Montana and Wheeler County, Nebraska with 2.3 percent, or 3.5 percent less than the national average. The relatively lower unemployment rates along most of the proposed Project corridor shows the diversity of economic conditions and the dependence on agriculture in many of the counties, because the unemployment statistic is for non-farm payroll employment.

The number of individuals in the work force by county ranges from a low of 377 in Keya Paha, Nebraska to a high of 1,928,223 in Harris, Texas. The work force numbers represent all individuals either employed or unemployed and looking for employment.

TABLE 3.10.1-6
Per Capita Income, Median Household Income and Unemployment Rates by County (nominal dollars)

	Per Capita Income[a]			Median Household Income[b]			Unemployment Rate[c]			Labor Force
	2007	1999	2007 higher (+) lower (-) than State[d]	2007	2004	2007 higher (+) lower (-) than State[d]	Number 2008	% 2008	2008 higher (+) lower (-) than State[d]	2008[e]
Steele City Segment										
Montana										
Phillips	$26,876	$17,288	-6,349	$33,798	$31,742	-9,202	102	4.7	+0.1	2,192
Valley	$31,556	$23,247	-1,669	$37,019	$34,514	-5,981	142	3.9	-0.7	3,666
McCone	$24,857	$20,499	-8,368	$38,535	$29,746	-4,465	26	2.5	-2.1	1,036
Dawson	$29,268	$20,307	-3,957	$43,678	$35,740	678	147	3.3	-1.3	4,411
Prairie	$28,874	$21,524	-4,351	$32,857	$31,221	-10,143	23	3.9	-0.7	597
Fallon	$35,405	$20,281	2,180	$42,408	$37,822	-592	43	2.3	-2.3	1,831
State of Montana	*$33,225*	*$21,585*	*-5,390*	*$43,000*	*$35,574*	*-7,740*	*23,311*	*4.6*	*-1.2*	*510,260*
South Dakota										
Harding	$26,439	$17,807	-9,321	$34,729	$32,895	-8,778	21	2.7	-0.4	784
Butte	$29,497	$18,341	-6,263	$38,513	$33,286	-4,994	152	2.8	-0.3	5,479
Perkins	$28,636	$22,162	-7,124	$34,085	$30,730	-9,422	50	3.1	0.0	1,619
Meade	$35,599	$22,237	-161	$46,063	$44,516	2,556	386	3.1	0.0	12,373
Pennington	$36,425	$25,099	665	$44,296	$40,624	789	1,618	2.9	-0.2	55,184
Haakon	$42,511	$28,797	6,751	$40,461	$33,470	-3,046	30	2.6	-0.5	1,159
Jones	$31,324	$26,213	-4,436	$36,106	$31,281	-7,401	17	2.5	-0.6	691
Lyman	$26,024	$21,419	-9,736	$32,330	$30,035	-11,177	90	4.5	+1.4	1,985
Tripp	$30,384	$21,180	-5,376	$35,631	$32,606	-7,876	89	3.0	-0.1	2,973
State of South Dakota	*$35,760*	*$24,475*	*-2,855*	*$43,507*	*$39,265*	*-7,233*	*13,674*	*3.1*	*-2.7*	*446,351*
Nebraska										
Keya Paha	$21,254	$13,813	-15,118	$31,005	$32,279	-16,067	18	4.8	+1.5	377
Rock	$23,001	$19,493	-13,371	$32,257	$27,512	-14,815	24	2.8	-0.5	850
Holt	$31,910	$21,025	-4,462	$37,354	$35,139	-9,718	163	2.6	-0.7	6,159
Garfield	$28,712	$22,361	-7,660	$32,967	$30,568	-14,105	27	2.6	-0.7	1,058
Wheeler	$26,742	$21,715	-9,630	$34,173	$33,834	-12,899	11	2.3	-1.0	488
Greeley	$29,263	$19,654	-7,109	$34,812	$32,241	-12,260	38	2.9	-0.4	1,308
Boone	$30,930	$21,047	-5,442	$37,466	$35,655	-9,606	84	2.6	-0.7	3,267
Nance	$31,190	$20,466	-5,182	$38,372	$35,011	-8,700	60	2.9	-0.4	2,063

TABLE 3.10.1-6
Per Capita Income, Median Household Income and Unemployment Rates by County (nominal dollars)

	Per Capita Income[a]			Median Household Income[b]			Unemployment Rate[c]			Labor Force
	2007	1999	2007 higher (+) lower (-) than State[d]	2007	2004	2007 higher (+) lower (-) than State[d]	Number 2008	% 2008	2008 higher (+) lower (-) than State[d]	2008[e]
Merrick	$29,338	$21,476	-7,034	$41,711	$38,222	-5,361	130	3.1	-0.2	4,238
Hamilton	$30,294	$22,302	-6,078	$49,655	$45,934	2,583	142	2.4	-0.9	5,905
York	$32,536	$24,966	-3,836	$48,369	$41,098	1,297	259	3.7	+0.4	7,076
Fillmore	$33,949	$25,850	-2,423	$41,162	$38,911	-5,910	93	2.9	-0.4	3,192
Saline	$30,142	$21,541	-6,230	$45,645	$41,876	-1,427	284	3.4	+0.1	8,432
Jefferson	$32,691	$22,183	-3,681	$39,914	$37,559	-7,158	165	3.8	+0.5	4,336
State of Nebraska	*$36,372*	*$26,465*	*-2,243*	*$47,072*	*$42,166*	*-3,668*	*32,634*	*3.3*	*-2.5*	*993,286*
New Cushing Extension Pump Stations										
Kansas										
Clay	$34,076	$23,697	-2,449	$42,035	$37,306	-5,306	169	3.3	-1.1	5,152
Butler	$34,739	$25,351	-1,786	$56,372	$49,599	9,031	1,378	4.2	-0.2	32,614
State of Kansas	*$36,525*	*$26,195*	*-2,090*	*$47,341*	*$41,664*	*-3,399*	*65,884*	*4.4*	*-1.4*	*1,493,746*
Gulf Coast Segment										
Oklahoma										
Payne	$27,050	$19,244	-7,947	$33,840	$31,259	-7,711	1,353	3.8	+0.1	35,159
Lincoln	$26,316	$18,280	-8,681	$38,204	$33,820	-3,347	540	3.9	+0.2	13,872
Creek	$27,585	$19,779	-7,412	$41,745	$36,134	194	1,300	4.2	+0.5	31,295
Okfuskee	$22,415	$14,343	-12,582	$29,516	$26,340	-12,035	187	4.1	+0.4	4,607
Seminole	$26,460	$15,974	-8,537	$33,207	$27,124	-8,344	486	4.4	+0.7	11,061
Hughes	$22,449	$14,774	-12,548	$28,689	$25,324	-12,862	269	5.3	+1.6	5,104
Coal	$21,426	$14,230	-13,571	$30,241	$25,525	-11,310	120	4.8	+1.1	2,500
Atoka	$21,348	$14,713	-13,649	$29,810	$27,211	-11,741	274	4.5	+0.8	6,060
Bryan	$27,361	$18,106	-7,636	$33,584	$29,055	-7,967	688	3.4	-0.3	20,398
State of Oklahoma	*$34,997*	*$22,567*	*-3,618*	*$41,551*	*$37,109*	*-9,189*	*64,083*	*3.7*	*-2.1*	*1,751,090*
Texas										
Fannin	$25,258	$19,465	-11,825	$40,840	$35,434	-6,723	796	5.9	+1.0	13,406
Lamar	$27,500	$21,730	-9,583	$38,110	$32,581	-9,453	1,288	5.5	+0.6	2,434
Delta	$25,066	$18,721	-12,017	$34,975	$31,122	-12,588	126	5.5	+0.6	2,291
Hopkins	$27,843	$22,168	-9,240	$39,105	$33,267	-8,458	735	4.2	-0.7	17,490

TABLE 3.10.1-6
Per Capita Income, Median Household Income and Unemployment Rates by County (nominal dollars)

	Per Capita Income[a]			Median Household Income[b]			Unemployment Rate[c]			Labor Force
	2007	1999	2007 higher (+) lower (-) than State[d]	2007	2004	2007 higher (+) lower (-) than State[d]	Number 2008	% 2008	2008 higher (+) lower (-) than State[d]	2008[e]
Franklin	$28,517	$22,126	-8,566	$40,152	$35,830	-7,411	228	4.3	-0.6	5,287
Wood	$26,537	$19,143	-10,546	$40,592	$34,843	-6,971	932	5.2	+0.3	18,010
Upshur	$28,164	$19,918	-8,919	$40,616	$34,690	-6,947	852	4.3	-0.6	19,728
Smith	$34,713	$25,543	-2,370	$44,699	$39,665	-2,864	4,888	5.0	+0.1	98,405
Cherokee	$27,439	$21,562	-9,644	$35,413	$30,223	-12,150	1,218	6.0	+1.1	20,281
Rusk	$28,081	$19,140	-9,002	$41,906	$35,343	-5,657	1,051	4.4	-0.5	24,004
Nacogdoches	$24,491	$19,056	-12,592	$32,774	$29,952	-14,789	1,361	4.4	-0.5	30,726
Angelina	$32,627	$20,944	-4,456	$37,953	$35,749	-9,610	1,899	4.9	0.0	38,983
Polk	$31,832	$22,873	-5,251	$37,152	$36,368	-10,411	1,060	6.3	+1.4	16,732
Liberty	$30,638	$19,958	-6,445	$46,159	$39,120	-1,404	1,863	6.1	+1.2	30,773
Hardin	$32,380	$21,307	-4,703	$52,798	$41,677	5,235	1,409	5.4	+0.5	26,066
Jefferson	$33,795	$22,894	-3,288	$39,499	$35,110	-8,064	7,669	6.8	+1.9	113,554
State of Texas – Gulf Coast Segment	*$37,083*	*$26,250*	*-1,532*	*$47,563*	*$41,645*	*-3,177*	*575,797*	*4.9*	*-0.9*	*11,635,095*
Houston Lateral										
Texas										
Chambers	$38,856	$25,883	1,773	$62,164	$54,474	14,601	829	5.8	+0.9	14,238
Harris	$49,634	$32,633	12,551	$49,977	$41,922	2,414	93,142	4.8	-0.1	1,928,223
State of Texas – Houston Lateral	*$37,083*	*$26,250*	*-1,532*	*$47,563*	*$41,645*	*-3,177*	*575,797*	*4.9*	*-0.9*	*11,635,095*
United States	**$38,615**	**$27,939**	**NA**	**$50,740**	**$44,334**	**NA**	**9,055,824**	**5.8**	**NA**	**155,253,908**

[a] U.S. Bureau of Economic Analysis, Regional Economic Accounts, Local Area Personal Income, Table CA1-3: Per capita personal income, http://bea.gov/regional/reis/.

[b] U.S. Bureau of the Census, Small Area Income & Poverty Estimates, State and County Interactive Table,http://www.census.gov/did/www/saipe/data/statecounty/index.html.

[c] U.S. Bureau of Labor Statistics, Local Area Unemployment Statistics 2008, http://www.bls.gov/lau/.

[d] For each state the difference is reported as the difference between the United States and the state.

[e] U.S. Bureau of Labor Statistics, Local Area Unemployment Statistics 2008, County Data. http://www.bls.gov/lua.

Note: States and counties are listed geographically from north to south as proposed Project crosses area.

Note: Housing in counties on the Cushing Extension was analyzed as part of the Keystone Pipeline Project and is included for clarity only. Construction in these counties would be related to pump stations only except in Jefferson County, NE, and Payne County, OK, where some new pipeline construction would occur.

Environmental Justice

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* directs Federal agencies to identify and address, as appropriate, disproportionately high and adverse health or environmental effects of their programs, policies, and activities on minority populations and low-income populations. Environmental justice refers to the ~~"~~fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies" (EPA 2007). The Council on Environmental Quality (CEQ) has provided guidance for addressing environmental justice (CEQ 1997).

In the draft EIS, minority and low-income populations along the proposed Project corridor were screened at the county level for the 58 counties in six states that would be crossed by the proposed Project. Several commenters on the draft EIS requested additional detailed analyses about minority and low-income populations that could be impacted by the proposed Project. In response, DOS has evaluated census block groups within a 4-mile-wide analysis area centered on the pipeline and associated pump stations.

Methodology to Identify and Locate Minority and Low-Income Populations

Minority populations are members of one of the following racial groups: African-Americans, American Indians or Alaskan Natives, Asians, Native Hawaiians or other Pacific Islanders, ~~"~~Other" races, or multi-racial (CEQ 1997). The racial population is expressed in terms of the number and/or percentage of people that are minorities in an area. The sum of these racial minority populations is referred to as the aggregate racial minority population for counties and census block groups. Minority populations were determined using U.S. Census Summary File 1 Category P6: Race. Persons of Hispanic/Latino origin are referred to as an ethnic minority, may be of any race including the identified racial populations, and thus are identified as a separate subcategory. Hispanic or Latino population was determined using U.S. Census Summary File 1 Category P7: Hispanic or Latino by Race. Low-income populations were determined using U.S. Census Summary File 3 Category P87: Poverty Status in 1999 by Age.

Census Geographic Unit Criteria

Determination of Potentially Affected Area for Analysis

To assess the potential impacts to minority and low-income populations from construction and operation of the proposed Project as well as from potential discharge incidents, DOS considered the types of effects and the areal distribution of these effects as a function of distance from the proposed Project pipeline centerline to establish a potentially affected area for analysis. Effects considered included potential dust and noise generated by construction, disruption to traffic patterns associated with the movement of construction materials and equipment, and potential health impacts in the unlikely event of a substantial discharge from the proposed Project during operation.

The determination of the precise distance from the proposed Project centerline where these effects could impact minority or low-income populations is problematic given the length of the proposed Project, the diversity of terrain that the proposed Project would cross, and the variation in population density along the proposed Project corridor. Of particular concern would be any potential health effects to minority or low-income populations resulting from a crude oil discharge. The potential effects of a crude oil discharge are addressed in detail in Section 3.13. As discussed in Section 3.13, a 1979 pipeline crude oil release near Bemidji, Minnesota can be used as an example of possible terrestrial and subsurface crude oil distribution in the unlikely event of a substantial crude oil discharge. In that release, a substantial quantity of crude oil (approximately 10,700 bbl) was released to the environment. It affected the ground surface over an area that extended approximately 1,200 feet northwest to southeast and 900 feet northeast

to southwest. In the subsurface groundwater, the dissolved contaminant plume extended downgradient approximately 650 feet over time. Using these dimensions as a surrogate for a potential substantial discharge along the proposed Project corridor and considering that the distribution of volatile organic compounds in the air would potentially extend beyond these dimensions depending on climatic conditions at the time of the discharge, DOS defined a 4-mile-wide affected analysis area that extends a distance of 2 miles on either side of the proposed Project centerline. This conservative affected area should adequately address the uncertainty inherent in the analysis, given that actual discharge volumes and the actual release location in the unlikely event of a substantial discharge from the proposed Project are not known.

Population within County

Minority or low-income populations at the county level were assessed using an EPA Mapping Tool to identify areas of environmental justice concern within a state. The key socioeconomic demographic data pertinent for environmental justice are the racial/ethnic composition and income status of affected counties. The proposed Project corridor would cross 58 counties in six states. However, DOS analyzed county population data within a 4-mile-wide analysis area, and as a result an additional county (Payne County, Oklahoma) was added to this analysis resulting in an evaluation of 59 counties.

Population within Census Block Groups

A census block group is the smallest geographic area for which the Census Bureau provides consistent sample data and generally contains a population between 600 and 3,000 individuals. These data are summarized in Table 3.10.1-7 from north to south along the proposed alignment. The U.S. Census Bureau's 2000 census block groups were identified within the 4-mile-wide analysis area.

Geographic Information Systems (GIS) and U.S. Census Bureau's 2000 census block group data were then used to determine the minority and low-income characteristics. As indicated in Table 3.10.1-8, the 4-mile-wide analysis area for the proposed Project encompasses or intersects 287 census block groups across six states. Of the 287 census block groups identified, 63 are along the proposed Steele City Segment, five are near the proposed new pump stations on the Cushing Extension in Kansas, 180 are along the proposed Gulf Coast Segment, and 43 are along the proposed Houston Lateral. Four census block groups in Liberty County, Texas, fall within the 4-mile-wide analysis area for both the proposed Gulf Coast Segment and the proposed Houston Lateral, but are counted only once in the totals.

A census block group was included in the 4-mile-wide analysis area if its boundaries were fully contained in the area, or if any part of the census block group was contained in the area. Fully contained census block groups are shown in parentheses and with a footnote in Table 3.10.1-8. There were no fully contained census block groups in any states in the proposed Steele City Segment or pump stations in Kansas. On the proposed Gulf Coast Segment, one fully contained group was identified in Lincoln County, Oklahoma at Stroud and Angelina County, Texas at Diboll, and 14 were identified in Jefferson County, Texas at Beaumont, Port Neches, Nederland, and Central Gardens. For the proposed Houston Lateral, two fully contained groups were identified in Harris County at Channelview and Highlands. All of the remaining census block groups east of Houston on the proposed Houston Lateral are only partially within the proposed Project analysis area. As stated previously, the analysis is likely to be conservative since portions of most of the census block groups analyzed are outside of the 4-mile-wide analysis area.

Population Percentage Criteria

To assess potential environmental justice concerns related to the proposed Project in accordance with CEQ Guidance, DOS performed two separate proximity based analyses within the 4-mile-wide analysis area. These two separate analyses included:

- A *50 percent criterion* population analysis to determine those counties and census block groups along the proposed Project corridor where minority and/or low-income individuals were equal to or exceeded 50 percent of the population of the census block group.
- A *meaningfully greater criterion* population analysis in which minority and/or low-income population percentages within counties and individual census block groups were compared to state-wide reference populations. A meaningfully greater population was defined as a minority and/or low-income population within an individual county or census block group that was equal to or greater than 120 percent (1.2 times) of the state-wide reference population. This criterion level was selected based upon a suggestion from the U.S. Environmental Protection Agency and because it is commonly used for NEPA compliance by other federal agencies. DOS considers comparisons to the state-wide percentage a much more appropriate comparison than comparisons to nation-wide percentages for determining potential environmental justice concerns for linear energy projects. Comparisons to nationwide percentages are more appropriate for assessing impacts associated with facility siting where alternatives to the proposed facility are very widely dispersed geographically.

If a census block group within the proposed Project analysis area met either of these criteria, DOS assumed that there was a potential for environmental justice populations to experience disproportionate effects.

Populations within Census Block Groups, Meaningfully Greater Criterion, Proposed Project Summary

Of the 287 total census block groups occurring along the proposed Project corridor, 90 census block groups had no exceedances for any minority or low-income populations. Of the 197 census block groups that did show exceedances, 115 showed exceedances for one or more minority populations, 25 showed exceedances for only low-income populations, and 57 showed exceedances for one or more minority populations along with a low-income population.

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Steele City Segment									
Montana									
Phillips	4,601	828 (18.0%*)	4 (0.1%)	379 (8.2%*)	34 (0.7%*)	2 (0.04%)	96 (2.1%*)	515 (11.2%)	24 (0.5%)
Valley	7,675	1,026 (13.4%)	7 (0.1%)	634 (9.4%*)	11 (0.2%)	40 (0.3%)	168 (1.8%)	860 (11.2%)	118 (1.5%)
McCone	1,977	331 (16.7%)	11 (0.6%*)	27 (1.4%)	2 (0.1%)	4 (0.2%)	30 (1.5%)	74 (3.7%)	24 (1.2%)
Dawson	9,059	1,285 (14.2%)	46 (0.5%*)	87 (1.0%)	5 (0.1%)	2 (0.02%)	54 (0.6%)	194 (2.1%)	69 (0.8%)
Prairie	1,199	202 (16.8%)	0 (0.0%)	11 (0.9%)	2 (0.2%)	0 (0.0%)	4 (0.3%)	17 (1.4%)	4 (0.3%)
Fallon	2,837	349 (12.3%)	9 (0.3%)	12 (0.4%)	4 (0.1%)	0 (0.0%)	7 (0.2%)	32 (1.1%)	17 (0.6%)
Subtotal Montana	*27,348*	*4,021 (14.7%)*	*77 (0.3%)*	*1,150 (4.2%)*	*58 (0.2%)*	*48 (0.2%)*	*359 (1.3%)*	*1,692 (6.2%)*	*256 (0.9%)*
Montana Exceedance Criteria[b]	-	17.5%	0.4%	7.4%	0.7%	0.7%	2.1%	11.4%	2.4%
South Dakota									
Harding	1,353	277 (20.5%*)	7 (0.5%)	20 (1.5%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	27 (2.0%)	7 (0.5%)
Butte	9,094	1,147 (12.6%)	2 (0.02%)	86 (0.9%)	48 (0.5%)	76 (0.8%*)	127 (1.4%)	339 (3.7%)	309 (3.4%*)
Perkins	3,363	561 (16.7%*)	3 (0.1%)	70 (2.1%)	13 (0.4%)	4 (0.1%)	34 (1.0%)	124 (3.7%)	3 (0.1%)
Meade	24,253	2,195 (9.1%)	331 (1.4%*)	549 (2.3%)	178 (0.7%*)	173 (0.7%*)	573 (2.4%*)	1,804 (7.4%)	435 (1.8%*)
Pennington	88,656	9,967 (11.3%)	677 (0.8%*)	6,748 (7.6%)	954 (1.1%*)	665 (0.8%*)	2,707 (3.1%*)	11,751 (13.3%)	2,335 (2.6%*)
Haakon	2,196	298 (13.6%)	0 (0.0%)	57 (2.6%)	14 (0.6%)	0 (0.0%)	8 (0.4%)	79 (3.6%)	3 (0.1%)

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Jones	1,193	188 (15.8%*)	7 (0.6%)	18 (1.5%)	0 (0.0%)	0 (0.0%)	27 (2.3%*)	52 (4.4%)	0 (0.0%)
Lyman	3,895	941 (24.2%*)	2 (0.1%)	1,249 (32.1%*)	8 (0.2%)	0 (0.0%)	85 (2.2%*)	1,344 (34.5%*)	1 (0.03%)
Tripp	6,430	1,254 (18.4%*)	0 (0.0%)	671 (11.2%*)	19 (0.1%)	0 (0.0%)	89 (1.2%)	779 (12.1%)	46 (0.9%)
Subtotal South Dakota	*140,433*	*16,828 (12.0%)*	*1,029 (0.7%)*	*9,468 (6.7%)*	*1,234 (0.9%)*	*918 (0.7%)*	*3,650 (2.6%)*	*16,299 (11.6%)*	*3,139 (2.2%)*
South Dakota Exceedance Criteria[b]	-	15.8%	0.7%	10.0%	0.7%	0.6%	1.6%	13.6%	1.7%
Nebraska									
Keya Paha	983	264 (26.9%*)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	5 (0.5%)	5 (0.5%)	24 (2.4%)
Rock	1,756	375 (21.4%*)	0 (0.0%)	26 (1.5%*)	5 (0.3%)	0 (0.0%)	8 (0.5%)	39 (2.2%)	11 (0.6%)
Holt	11,551	1,477 (12.8%*)	2 (0.02%)	34 (0.3%)	11 (0.1%)	51 (0.4%)	19 (0.2%)	117 (1.0%)	72 (0.6%)
Garfield	1,902	232 (12.2%*)	0 (0.0%)	3 (0.1%)	2 (0.1%)	2 (0.1%)	9 (0.5%)	16 (0.8%)	20 (1.1%)
Wheeler	886	183 (20.7%*)	2 (0.2%)	5 (0.6%)	0 (0.0%)	7 (0.8%)	2 (0.2%)	16 (1.8%)	7 (0.8%)
Greeley	2,714	387 (14.3%*)	8 (0.3%)	0 (0.0%)	3 (0.1%)	14 (0.5%)	2 (0.1%)	27 (1.0%)	16 (0.6%)
Boone	6,259	638 (10.2%)	0 (0.0%)	7 (0.1%)	8 (0.1%)	19 (0.3%)	29 (0.5%)	63 (1.0%)	59 (0.9%)
Nance	4,038	518 (12.8%*)	0 (0.0%)	6 (0.1%)	8 (0.2%)	3 (0.1%)	37 (0.9%)	54 (1.3%)	49 (1.2%)
Merrick	8,204	713 (8.7%)	7 (0.1%)	6 (0.1%)	28 (0.3%)	33 (0.4%)	27 (0.3%)	101 (1.2%)	158 (1.9%)
Hamilton	9,403	690 (7.3%)	19 (0.2%)	0 (0.0%)	1 (0.01%)	27 (0.3%)	32 (0.3%)	79 (0.8%)	66 (0.7%)

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
York	14,598	1,170 (8.0%)	93 (0.6%)	30 (0.2%)	62 (0.4%)	149 (1.0%)	99 (0.7%)	433 (3.0%)	258 (1.8%)
Fillmore	6,634	498 (7.5%)	2 (0.03%)	33 (0.5%)	10 (0.2%)	63 (0.9%)	46 (0.7%)	154 (2.3%)	76 (1.1%)
Saline	13,843	1,213 (8.8%)	49 (0.4%)	120 (0.9%)	158 (1.1%)	498 (3.6%*)	89 (0.6%)	914 (6.6%)	879 (6.3%)
Jefferson	8,333	733 (8.8%)	3 (0.04%)	38 (0.5%)	8 (0.1%)	17 (0.2%)	57 (0.7%)	123 (1.5%)	74 (0.9%)
Subtotal Nebraska	*91,104*	*9,091 (10.0%)*	*185 (0.2%)*	*308 (0.3%)*	*304 (0.3%)*	*883 (1.0%)*	*461 (0.5%)*	*2,141 (2.4%)*	*1,769 (1.9%)*
Nebraska Exceedance Criteria[b]	-	11.7%	4.8%	1.1%	1.6%	3.4%	1.7%	12.5%	6.6%
New Cushing Extension Pump Stations									
Kansas									
Clay	8,822	867 (9.8%)	20 (0.2%)	16 (0.2%)	12 (0.1%)	30 (0.3%)	163 (1.8%)	241 (2.7%)	92 (1.0%)
Butler	59,482	4,187 (7.0%)	806 (1.4%)	709 (1.2%*)	212 (0.4%)	455 (0.8%)	1,031 (1.7%)	3,213 (5.4%)	1,140 (1.9%)
Subtotal Kansas	*68,304*	*5,054 (7.4%)*	*826 (1.2%)*	*725 (1.1%)*	*224 (0.3%)*	*485 (0.7%)*	*1,194 (1.7%)*	*3,454 (5.1%)*	*1,232 (1.8%)*
Kansas Exceedance Criteria[b]	-	11.9%	6.9%	1.1%	2.1%	4.2%	2.6%	16.6%	8.4%
Gulf Coast Segment									
Oklahoma									
Payne	68,186	12,431 (18.2%*)	2,550 (3.7%)	3,000 (4.4%)	1,906 (2.8%*)	629 (0.9%)	2,580 (3.8%)	10,665 (15.6%)	1,640 (2.4%)
Creek	67,367	8,924 (13.2%)	1,953 (2.9%)	5,757 (8.5%)	123 (0.2%)	462 (0.7%)	3,874 (5.8%*)	12,169 (18.1%)	1,390 (2.1%)

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Lincoln	32,080	4,591 (14.3%)	636 (2.0%)	2,086 (6.5%)	103 (0.3%)	124 (0.4%)	1,448 (4.5%)	4,397 (13.7%)	334 (1.0%)
Okfuskee	11,814	2,508 (21.2%*)	1,194 (10.1%*)	2,160 (18.3%*)	15 (0.1%)	102 (0.9%)	602 (5.1%)	4,073 (34.5%*)	215 (1.8%)
Seminole	24,894	5,055 (20.3%*)	1,454 (5.8%)	4,213 (16.9%*)	104 (0.4%)	212 (0.9%)	1,340 (5.4%*)	7,323 (29.4%*)	562 (2.3%)
Hughes	14,154	2,822 (19.9%*)	645 (4.6%)	2,230 (15.8%*)	16 (0.1%)	82 (0.6%)	851 (6.0%*)	3,824 (27.0%)	310 (2.2%)
Pontotoc	35,143	5,601 (15.9%)	835 (2.4%)	5,469 (15.6%*)	122 (0.3%)	186 (0.5%)	1,949 (5.5%*)	8,561 (24.4%)	637 (1.8%)
Coal	6,031	1,366 (22.6%*)	22 (0.4%)	1,019 (16.9%*)	18 (0.3%)	80 (1.3%)	353 (5.9%*)	1,492 (24.7%)	183 (3.0%)
Atoka	13,879	2,426 (17.5%)	813 (5.9%)	1,613 (11.6%*)	8 (0.1%)	59 (0.4%)	881 (6.3%*)	3,374 (24.3%)	139 (1.0%)
Bryan	36,534	6,529 (17.9%*)	536 (1.5%)	4,694 (12.8%*)	128 (0.4%)	399 (1.1%)	1,610 (4.4%)	7,367 (20.2%)	823 (2.3%)
Subtotal Oklahoma	*310,082*	*52,253 (16.9%)*	*10,638 (3.4%)*	*32,241 (10.4%)*	*2,543 (0.8%)*	*2,335 (0.8%)*	*15,488 (5.0%)*	*63,245 (20.4%)*	*6,233 (2.0%)*
Oklahoma Exceedance Criteria[b]	-	17.6%	9.1%	9.5%	1.6%	2.9%	5.4%	28.5%	6.2%
Texas									
Fannin	31,242	3,878 (12.4%)	2,451 (7.8%)	285 (0.9%*)	85 (0.3%)	929 (3.0%)	445 (1.4%)	4,195 (13.4%)	1,769 (5.7%)
Lamar	48,499	7,737 (16.2%)	6,257 (13.5%)	530 (1.1%*)	164 (0.4%)	689 (1.2%)	770 (1.4%)	8,410 (17.3%)	1,715 (3.3%)
Delta	5,327	911 (17.1%)	503 (9.4%)	31 (0.6%)	20 (0.4%)	4 (0.1%)	142 (2.7%)	700 (13.1%)	43 (0.8%)
Hopkins	31,960	4,580 (14.6%)	2,415 (8.0%)	233 (0.7%*)	117 (0.2%)	1,523 (4.6%)	498 (1.4%)	4,836 (15.1%)	2,960 (9.3%)

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Franklin	9,458	1,448 (15.3%)	380 (4.0%)	73 (0.8%*)	8 (0.1%)	501 (5.3%)	61 (0.6%)	1,023 (10.8%)	830 (8.8%)
Wood	36,752	5,051 (11.9%)	2,261 (6.1%)	140 (0.6%)	110 (0.2%)	963 (2.9%)	488 (1.1%)	3,962 (10.8%)	1,977 (5.7%)
Upshur	35,291	5,167 (14.6%)	3,529 (10.0%)	150 (0.4%)	104 (0.3%)	846 (2.4%)	394 (1.1%)	5,023 (14.2%)	1,336 (3.8%)
Smith	174,706	23,543 (13.5%)	33,296 (19.1%*)	726 (0.4%)	1159 (0.7%)	10,066 (5.8%)	2,288 (1.3%)	47,535 (27.2%)	19,395 (11.1%)
Rusk	47,372	6,526 (13.8%)	9,175 (19.4%*)	174 (0.4%)	130 (0.3%)	1,735 (3.7%)	476 (1.0%)	11,690 (24.7%)	3,934 (8.3%)
Cherokee	46,659	7,823 (16.8%)	7,689 (16.5%*)	126 (0.3%)	88 (0.2%)	3,493 (7.5%)	462 (1.0%)	11,858 (25.4%)	6,183 (13.3%)
Nacogdoches	59,203	12,743 (21.5%*)	9,827 (16.6%*)	249 (0.4%)	478 (0.6%)	3,174 (5.4%)	1,093 (1.8%)	14,821 (25.0%)	6,700 (11.3%)
Angelina	80,130	12,241 (15.3%)	11,851 (14.8%*)	277 (0.3%)	548 (0.7%)	5,945 (7.4%)	1,245 (1.6%)	19,866 (24.8%)	11,282 (14.1%)
Polk	41,133	6,540 (17.5%)	5,270 (13.2%)	706 (1.7%*)	253 (0.6%)	1,631 (3.7%)	609 (1.3%)	8,469 (20.6%)	3,970 (9.4%)
Liberty	70,154	9,296 (13.3%)	8,884 (12.7%)	341 (0.5%)	241 (0.3%)	4,098 (5.8%)	1,102 (1.6%)	14,666 (20.9%)	7,661 (10.9%)
Hardin	48,073	5,314 (11.1%)	3,328 (6.9%)	119 (0.2%)	278 (0.6%)	304 (0.6%)	548 (1.1%)	4,577 (9.5%)	1,176 (2.4%)
Jefferson	252,051	41,142 (16.3%)	84,970 (33.7%*)	996 (0.4%)	7,159 (2.8%)	10,648 (4.2%)	3,707 (1.5%)	107,480 (42.6%*)	26,664 (10.6%)
Subtotal Texas - Gulf Coast Segment	*1,018,010*	*153,940 (15.1%)*	*192,086 (18.9%)*	*5,206 (0.5%)*	*10,942 (1.1%)*	*46,549 (4.6%)*	*14,328 (1.4%)*	*77,025 (7.6%)*	*97,595 (9.6%)*
Texas Exceedance Criteria[b]	-	18.5%	13.8%	0.7%	3.4%	14.1%	3.0%	35.0%	38.4%

TABLE 3.10.1-7
Minority and Low-Income Populations as a Percentage of Total County Populations in Affected Counties within 4-Mile-Wide Analysis Area

County	Total Population	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Houston Lateral									
Texas									
Liberty	70,154	9,296 (13.3%)	8,884 (12.7%)	341 (0.5%)	241 (0.3%)	4,098 (5.8%)	1,102 (1.6%)	14,666 (20.9%)	7,661 (10.9%)
Chambers	26,031	2,833 (10.9%)	2,508 (9.6%)	94 (0.4%)	89 (0.3%)	1,619 (6.2%)	355 (1.4%)	4,665 (17.9%)	2,836 (10.9%)
Harris	3,400,578	503,234 (14.8%)	627,111 (18.4%*)	14,670 (0.4%)	173,491 (5.1%*)	488, 480 (14.4%*)	102,669 (3.0%*)	1,406,421 (41.4%*)	1,120,625 (32.9%)
Subtotal Texas - Houston Lateral	3,496,763	*515,363 (14.7%)*	*638,503 (18.3%)*	*15,105 (0.4%)*	*173,821 (5.0%)*	*494, 197 (14.1%)*	*104, 126 (3.0%)*	*1,425,752 (40.8%)*	*1,131,122 (32.4%)*
Texas Exceedance Criteria[b]	-	18.5%	13.8%	0.7%	3.4%	14.1%	3.0%	35.0%	38.4%
Subtotal Texas	*4,444,619*	*660,007 (14.8%)*	*821,705 (18.5%)*	*19,970 (0.4%)*	*184,522 (4.2%)*	*536,648 (12.1%)*	*117,352 (2.6%)*	*1,488,111 (33.5%)*	*1,221,056 (27.5%)*
Project Total	**5,081,890**	**747,254 (14.7%)**	**834,460 (16.4%)**	**63,862 (1.3%)**	**188,885 (3.7%)**	**541, 317 (10.7%)**	**138, 504 (2.7%)**	**1,574,942 (31.0%)**	**1,233,685 (24.3%)**

[a] The "Other" racial category accounts for those individuals who marked "Some other race", a category included in the 2000 Census for respondents who were unable to identify with the five Office of Management and Budget's race categories. Respondents who provided write-in entries such as Moroccan, South African, Belizean, or a Hispanic origin (for example, Mexican, Puerto Rican, or Cuban) are included in the "Other" race category. (http://www.census.gov/prod/2001pubs/c2kbr01-1.pdf).

[b] State-wide exceedance criteria percentages are 1.2 times the actual Environmental Justice group population percentages for each state.

* Denotes Minority populations and low-income individuals that were meaningfully greater than the corresponding minority population or low-income individual at the state level in the relevant racial/ethnic or low-income category columns.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

TABLE 3.10.1-8
Minority and Low-Income Populations as a Percentage of Census Block Group Populations within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Steele City Segment									
Montana									
Phillips	1	314 (24.4%)	0 (0%)	85 (6.6%)	5 (0.4%)	2 (0.2%)	23 (1.8%)	115 (9.0%)	10 (0.8%)
Valley	6	593 (15.3%)	7 (0.2%)	550 (14.2%)	11 (0.3%)	19 (0.5%)	74 (1.9%)	661 (17.1%)	28 (0.1%)
McCone	3	331 (16.7%)	11 (0.6%)	27 (1.4%)	2 (0.1%)	4 (0.2%)	30 (1.5%)	74 (3.7)	24 (1.2%)
Dawson	2	186 (18.0%)	0 (0%)	2 (0.2%)	0 (0%)	0 (0%)	6 (0.6%)	8 (0.8%)	2 (0.2%)
Prairie	1	152 (26.5%)	0 (0%)	3 (0.5%)	0 (0%)	0 (0%)	4 (0.7%)	7 (1.2%)	2 (0.3%)
Fallon	3	349 (12.3%)	9 (0.3%)	12 (0.4%)	4 (0.1%)	0 (0%)	7 (0.3%)	32 (1.1%)	17 (0.6%)
Carter	1	130 (14.9%)	4 (0.5%)	3 (0.3%)	0 (0%)	0 (0%)	2 (0.2%)	9 (1.0%)	0 (0%)
Subtotal Montana	*17*	*2,055 (16.5%)*	*31 (0.2%)*	*682 (5.5%)*	*22 (0.2%)*	*25 (0.2%)*	*146 (1.2%)*	*906 (7.3%)*	*83 (0.7%)*
South Dakota									
Harding	2	277 (20.5%)	7 (0.5%)	20 (1.5%)	0 (0%)	0 (0%)	0 (0%)	27 (2.0%)	7 (0.5%)
Butte	1	167 (13.9%)	0 (0%)	0 (0%)	0 (0%)	2 (0.2%)	12 (1.0%)	14 (1.2%)	10 (0.8%)
Perkins	1	239 (21.8%)	0 (0%)	6 (0.5%)	0 (0%)	0 (0%)	13 (1.2%)	19 (1.7%)	3 (0.3%)
Meade	2	261 (16.5%)	0 (0%)	56 (3.5%)	6 (0.4%)	0 (0%)	10 (0.6%)	72 (4.5%)	12 (0.8%)
Ziebach	1	392 (59.8%)	0 (0%)	591 (90.2%)	2 (0.3%)	3 (0.5%)	3 (0.5%)	599 (91.5%)	7 (1.1%)
Pennington	1	91 (17.6%)	0 (0%)	9 (1.7%)	0 (0%)	0 (0%)	9 (1.7%)	18 (3.4%)	0 (0%)
Haakon	2	202 (18.0%)	0 (0%)	20 (1.8%)	9 (0.8%)	0 (0%)	1 (0.1%)	30 (2.7%)	0 (0%)
Jones	1	188 (15.8%)	7 (0.6%)	18 (1.5%)	0 (0%)	0 (0%)	27 (2.3%)	52 (4.4%)	0 (0%)
Lyman	1	149 (14.0%)	0 (0%)	8 (0.7%)	0 (0%)	0 (0%)	23 (2.2%)	31 (2.9%)	0 (0%)
Tripp	8	1,254 (19.5%)	0 (0%)	671 (10.4%)	19 (0.3%)	0 (0%)	89 (1.4%)	779 (12.1%)	46 (0.7%)
Gregory	1	188 (25.6%)	5 (0.7%)	44 (6.0%)	0 (0%)	0 (0%)	4 (0.5%)	53 (7.2%)	3 (0.4%)

TABLE 3.10.1-8
Minority and Low-Income Populations as a Percentage of Census Block Group Populations within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Subtotal South Dakota	*21*	*3,408 (20.1%)*	*19 (0.1%)*	*1,443 (8.5%)*	*36 (0.2%)*	*5 (0.1%)*	*191 (1.1%)*	*1,694 (10.0%)*	*88 (0.5%)*
Nebraska									
Keya Paha	1	264 (26.9%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	5 (0.5%)	5 (0.5%)	24 (2.4%)
Rock	1	217 (25.8%)	0 (0%)	7 (0.8%)	0 (0%)	0 (0%)	0 (0%)	7 (0.8%)	4 (0.5%)
Holt	2	318 (15.5%)	0 (0%)	24 (1.2%)	0 (0%)	5 (0.2%)	4 (0.2%)	33 (1.6%)	7 (0.3%)
Garfield	1	67 (10.9%)	0 (0%)	0 (0%)	2 (0.3%)	0 (0%)	0 (0%)	2 (0.3%)	7 (1.1%)
Wheeler	1	183 (20.7%)	2 (0.2%)	5 (0.6%)	0 (0%)	7 (0.8%)	2 (0.2%)	16 (0.2%)	7 (0.8%)
Greeley	2	387 (14.3%)	8 (0.3%)	0 (0%)	3 (0.1%)	14 (0.5%)	2 (0.1%)	27 (1.0%)	16 (0.6%)
Boone	2	194 (13.3%)	0 (0%)	0 (0%)	4 (0.3%)	0 (0%)	4 (0.3%)	8 (0.6%)	13 (0.9%)
Nance	1	118 (17.1%)	0 (0%)	0 (0%)	4 (0.6%)	0 (0%)	5 (0.7%)	9 (1.3%)	0 (0%)
Merrick	2	145 (7.1%)	4 (0.2%)	0 (0%)	0 (0%)	8 (0.4%)	6 (0.3%)	18 (0.9%)	17 (0.8%)
Hamilton	1	46 (4.4%)	4 (0.4%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	4 (0.4%)	0 (0%)
Polk	1	28 (3.8%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
York	3	432 (9.2%)	50 (1.1%)	11 (0.2%)	0 (0%)	72 (1.5%)	21 (0.5%)	154 (3.3%)	100 (2.1%)
Fillmore	2	297 (10.8%)	0 (0%)	8 (0.3%)	7 (0.3%)	11 (0.4%)	35 (1.3%)	61 (2.3%)	15 (0.5%)
Saline	2	145 (7.9%)	2 (0.1%)	2 (0.1%)	2 (0.1%)	0 (0%)	9 (0.5%)	15 (0.8%)	4 (0.2%)
Jefferson	3	306 (8.2%)	0 (0%)	0 (0%)	8 (0.2%)	10 (0.3%)	46 (1.2%)	64 (1.7%)	25 (0.7%)
Subtotal Nebraska	*25*	*3,147 (11.6%)*	*70 (0.3%)*	*57 (0.2%)*	*30 (0.1%)*	*127 (0.5%)*	*139 (0.5%)*	*423 (1.6%)*	*239 (0.9%)*
New Cushing Extension Pump Stations									
Kansas									
Clay	4	456 (11.2%)	16 (0.4%)	7 (0.2%)	7 (0.2%)	7 (0.2%)	71 (1.7%)	108 (2.7%)	42 (1%)
Butler	1	37 (5.4%)	0 (0%)	5 (0.7%)	2 (0.3%)	0 (0%)	11 (1.6%)	18 (2.6%)	0 (0%)

TABLE 3.10.1-8
Minority and Low-Income Populations as a Percentage of Census Block Group Populations within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Subtotal Kansas	*5*	*493 (10.3%)*	*16 (0.3%)*	*12 (0.3%)*	*9 (0.2%)*	*7 (0.1%)*	*82 (1.7%)*	*126 (2.6%)*	*42 (0.9%)*
Gulf Coast Segment									
Oklahoma									
Payne	2	322 (12.2%)	423 (16.0%)	102 (3.9%)	13 (0.5%)	24 (0.9%)	107 (4.0%)	669 (25.3%)	72 (2.7%)
Creek	2	312 (14.7%)	90 (4.3%)	202 (9.5%)	3 (0.1%)	6 (0.3%)	128 (6.0%)	429 (20.2%)	17 (0.8%)
Lincoln	6 (1)[a]	1,020 (16.0%)	108 (1.7%)	533 (8.3%)	14 (0.2%)	30 (0.5%)	258 (4.0%)	943 (14.7%)	48 (0.7%)
Okfuskee	5	795 (19.9%)	962 (24.0%)	451 (11.3%)	3 (0.1%)	16 (0.4%)	176 (4.4%)	1,608 (40.2%)	33 (0.8%)
Seminole	5	778 (18.8%)	326 (7.9%)	761 (18.4%)	2 (0.1%)	15 (0.3%)	211 (5.1%)	1,315 (31.8%)	46 (1.1%)
Hughes	9	1,992 (19.3%)	597 (5.8%)	1,631 (15.8%)	5 (0.1%)	73 (0.7%)	590 (5.7%)	2,896 (28.1%)	245 (2.4%)
Pontotoc	3	440 (14.4%)	13 (0.4%)	583 (19.0%)	3 (0.1%)	11 (0.4%)	171 (5.6%)	781 (25.5%)	26 (0.8%)
Coal	3	695 (20.6%)	20 (0.6%)	559 (16.6%)	7 (0.2%)	21 (0.6%)	170 (5.1%)	777 (23.1%)	63 (1.9%)
Atoka	6	1,091 (17.1%)	203 (3.2%)	825 (12.9%)	2 (0.1%)	13 (0.2%)	237 (3.7%)	1,280 (20.1%)	30 (0.5%)
Bryan	3	735 (18.8%)	10 (0.3%)	620 (15.9%)	5 (0.1%)	103 (2.6%)	121 (3.1%)	859 (22.0%)	136 (3.5%)
Choctaw	1	112 (16.5%)	0 (0%)	164 (24.1%)	0 (0%)	5 (0.8%)	43 (6.3%)	212 (31.2%)	27 (4.0%)
Subtotal Oklahoma	*45 (1)[a]*	*8,292 (17.6%)*	*2,752 (5.8%)*	*6,431 (13.7%)*	*57 (0.1%)*	*317 (0.7%)*	*2,212 (4.7%)*	*11,769 (25%)*	*743 (1.6%)*
Texas									
Fannin	2	173 (9.7%)	1,755 (98.1%)	0 (0%)	5 (0.3%)	0 (0%)	24 (1.3%)	5 (0.3%)	42 (2.3%)
Lamar	6	987 (15.0%)	361 (5.5%)	49 (0.7%)	8 (0.1%)	101 (1.6%)	98 (1.5%)	617 (9.4%)	236 (3.6%)
Delta	1	279 (18.5%)	9 (0.6%)	18 (1.2%)	16 (1.0%)	0 (0%)	45 (3.0%)	88 (5.8%)	0 (0%)

TABLE 3.10.1-8
Minority and Low-Income Populations as a Percentage of Census Block Group Populations within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Hopkins	5	659 (13.2%)	70 (1.4%)	48 (1.0%)	0 (0%)	143 (2.9%)	47 (0.9%)	308 (6.2%)	387 (7.8%)
Franklin	3	482 (14.2%)	65 (1.9%)	20 (0.6%)	0 (0%)	204 (6.0%)	27 (0.8%)	316 (9.3%)	392 (11.5%)
Wood	8	1,374 (13.2%)	795 (7.7%)	24 (0.2%)	14 (0.1%)	89 (0.9%)	190 (1.8%)	1,112 (10.7%)	408 (4.0%)
Upshur	6	1,006 (13.9%)	550 (7.6%)	15 (0.2%)	11 (0.2%)	200 (2.7%)	61 (0.8%)	837 (11.5%)	244 (3.4%)
Smith	12	1,646 (10.3%)	3,920 (24.4%)	33 (0.2%)	9 (0.1%)	45 (0.3%)	108 (0.7%)	4,115 (25.7%)	504 (3.1%)
Rusk	4	877 (19.7%)	1,011 (22.7%)	24 (0.6%)	0 (0%)	270 (6.1%)	90 (2.0%)	1,395 (31.4%)	572 (12.9%)
Cherokee	5	1,201 (15.1%)	1,125 (14.1%)	48 (0.6%)	3 (0.1%)	506 (6.4%)	124 (1.5%)	1,806 (22.7%)	766 (9.6%)
Nacogdoches	5	972 (14.8%)	335 (5.1%)	15 (0.2%)	46 (0.7%)	381 (5.8%)	108 (1.6%)	885 (13.4%)	705 (10.7%)
Angelina	11 (1)[a]	2,986 (13.6%)	1,599 (7.3%)	59 (0.3%)	26 (0.1%)	2,032 (9.3%)	466 (2.1%)	4,182 (19.1%)	4,211 (19.2%)
Trinity	2	290 (17.4%)	263 (15.8%)	2 (0.1%)	0 (0%)	20 (1.2%)	12 (0.7%)	297 (17.8%)	27 (1.6%)
Polk	9	2,208 (15.0%)	1,025 (7.0%)	86 (0.6%)	35 (0.2%)	718 (4.9%)	227 (1.5%)	2,091 (14.2%)	1,449 (9.9%)
San Jacinto	1	393 (17.4%)	296 (13.1%)	0 (0%)	0 (0%)	45 (2.0%)	24 (1.0%)	365 (16.1%)	129 (5.7%)
Liberty	6	1,172 (20.1%)	314 (5.4%)	62 (1.0%)	27 (0.5%)	185 (3.2%)	91 (1.5%)	679 (11.6%)	363 (6.2%)
Hardin	5	852 (11.5%)	124 (1.7%)	34 (0.5%)	7 (0.1%)	85 (1.1%)	90 (1.2%)	340 (19.9%)	251 (3.4%)
Jefferson	43 (14)[a]	3,583 (5.7%)	10,697 (17%)	290 (0.5%)	1,026 (1.6%)	1,023 (1.6%)	790 (1.3%)	13,826 (22%)	5,978 (9.5%)
Orange	1	109 (4.8%)	0 (0%)	58 (2.6%)	0 (0%)	27 (1.2%)	43 (1.9%)	128 (5.7%)	84 (3.7%)
Subtotal Texas - Gulf Coast Segment	*135 (15)[a]*	*21,249 (11.2%)*	*22,559 (11.9%)*	*890 (0.5%)*	*1,228 (0.6%)*	*6,098 (3.2%)*	*2,646 (1.4%)*	*33,421 (17.6%)*	*16,748 (8.8%)*

TABLE 3.10.1-8
Minority and Low-Income Populations as a Percentage of Census Block Group Populations within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income Populations	Minority Populations						
			African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Houston Lateral									
Texas									
Liberty	17	2,700 (12.9%)	3,100 (14.8%)	60 (0.3%)	93 (0.4%)	868 (4.2%)	301 (1.4%)	4,422 (21.1%)	1,541 (7.4%)
Chambers	2	283 (6.8%)	72 (1.7%)	14 (0.4%)	0 (0%)	111 (2.7%)	38 (0.9%)	235 (5.7%)	243 (5.8%)
Harris	24	5,536 (11.0%)	11,317 (22.5%)	160 (0.3%)	1,134 (2.3%)	6,738 (13.4%)	1,326 (2.6%)	20,675 (41.1%)	13,643 (27.1%)
Subtotal Texas - Houston Lateral	*43 (2)*[a]	*8,519 (11.3%)*	*14,489 (19.2%)*	*234 (0.3%)*	*1,227 (1.7%)*	*7,717 (10.2%)*	*1,665 (2.2%)*	*25,332 (33.6%)*	*15,427 (20.5%)*
Subtotal Texas[b]	*174 (17)*[a]	*29,154 (11.2%)*	*36,770 (14.1%)*	*1,122 (0.4%)*	*2,428 (1.0%)*	*13,683 (5.2%)*	*4,238 (1.6%)*	*58,241 (22.3%)*	*31,912 (12.2%)*
Project Total	**287 (18)**	**46,549 (12.6%)**	**39,658 (10.7%)**	**9,747 (2.7%)**	**2,582 (0.7%)**	**14,164 (3.8%)**	**7,008 (1.9%)**	**73,159 (19.8%)**	**33,107 (9.0%)**

[a] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[b] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.
U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home.

Minority Populations

This section describes the minority populations along the proposed Project corridor, using the methodology previously described. Minority populations are members of one of the following racial groups: African-Americans, American Indians or Alaskan Natives, Asians, Native Hawaiians or other Pacific Islanders, "Other" races, or multi-racial (CEQ 1997).

Populations within Counties

The percent of minority populations by county within the proposed Project area are listed in Table 3.10.1-7.

50 Percent Criterion

The 2000 Census showed that no minority populations exceeded 50 percent of the total county population in any county along the proposed Project route.

Meaningfully Greater Criterion

Minority populations that were meaningfully greater than the corresponding minority population at the state level are identified with an asterisk (*) in the relevant racial/ethnic category columns in Table 3.10.1-9 and are also listed in Table 3.10.1-9. These minority populations were identified in 34 of the 59 counties in the proposed Project area.

Along the proposed Steele City Segment, 12 counties had minority populations that were meaningfully greater than their corresponding state populations. African American populations were identified in McCone and Dawson counties in Montana, and Meade and Pennington counties in South Dakota. The Native American/Alaska Native populations in Montana residing in Phillips County were partially located in the Fort Belknap Indian Reservation, while Valley County populations were partially located in the Fort Peck Indian Reservation. In South Dakota, Native American/Alaska Native populations in Lyman County were partially located in the Lower Brule Indian Reservation, while Tripp County abuts the Rosebud Indian Reservation. A Native American/Alaska Native population was also identified in Rock County, Nebraska. Phillips County, Montana and Meade and Pennington counties in South Dakota had populations of Asians or Pacific Islanders. Butte, Meade, and Pennington counties in South Dakota and Saline County in Nebraska were identified as containing populations of "Other" races. Phillips County, Montana and Meade and Jones counties in South Dakota contained multi-racial populations. South Dakota also had people identifying themselves as Hispanic or Latino in Butte, Meade, and Pennington counties; and an aggregate minority population in Lyman County, primarily comprised of Native Americans or Alaskan Natives.

In Kansas, for the two new proposed pump stations, Butler County contained a Native American/Alaska Native population that was meaningfully greater than the corresponding state population.

Along the Gulf Coast Segment, 20 counties had minority populations that were meaningfully greater than their corresponding state populations. Oklahoma had nine counties with those minority populations, which were comprised of one county with an African American population (Okfuskee County), seven counties with Native Americans or Alaska Natives (Okfuskee, Seminole, Hughes, Pontotoc, Coal, Atoka, and Bryan counties), Payne County had an Asian/Pacific Islander population, six counties with multi-racial populations (Creek, Seminole, Hughes, Pontotoc, Coal, and Atoka counties), and two aggregate minority populations (Okfuskee and Seminole counties). The remaining 11 county minority populations were in Texas, and included six counties with African American populations (Smith, Rusk, Cherokee, Nacogdoches, Angelina, and Jefferson counties), five counties with Native Americans or Alaska Natives

(Fannin, Lamar, Hopkins, Franklin, and Polk counties), and an aggregate minority population in Jefferson County.

Along the Houston Lateral, Harris County had African American, Asian or Pacific Islander, ~~"O~~ther," multi-racial, and aggregate minority populations that were meaningfully greater than the corresponding Texas population.

Populations within Census Block Groups

For each of the 287 census block groups located within the 4-mile-wide analysis area (2 miles on each side of the centerline), the percentage of each census block group's population represented by each minority classification (each race, aggregate race minority population, and Hispanic/Latino ethnic origin) was calculated and compared to the two criteria described above. Tables 3.10.1-10 and 3.10.1-11 identify the minority populations that are represented graphically in Figures 3.10.1-1 through 3.10.1-6. These figures also identify towns and cities that occur along the proposed pipeline corridor, in relation to the census block groups with minority and low-income populations meaningfully greater than state-wide averages.

50 Percent Criterion

Proposed Project Summary

Within the comparative geographic area, a total of 25 census block groups had individual racial minority populations or aggregate minority populations that exceeded the 50 percent criterion. Along the proposed Steele City Segment, one population in Valley County, Montana and another in Ziebach County, South Dakota exceeded 50 percent for Native Americans or Alaskan Natives. The Valley County population is part of the Fort Peck Indian Reservation and the Ziebach County population is part of the Cheyenne River Indian Reservation. No census block groups with minority populations exceeding 50 percent of the total population were identified in the Nebraska portion of the Steele City Segment or in Kansas for the pump stations.

The Oklahoma section of the proposed Gulf Coast Segment contained one African American population and one aggregate minority population in Okfuskee County. These populations were within Boley, a community with 1,126 (55 percent) African American residents in 2000. In Texas, along the proposed Gulf Coast Segment, there were 13 populations that met the 50 percent criterion. Of the nine African American populations, one was in Wood County near Hawkins, two were in Smith County east of Tyler, one was in Angelina County at Diboll, and five were in Jefferson County in or near Beaumont. Aggregate minority populations comprising 50 percent or more of the population included two in Jefferson County near Beaumont and one in Rusk County west of Mount Enterprise. One Hispanic population was located in Diboll in Angelina County.

For the proposed Houston Lateral, Liberty County and Harris County each had two populations that met the 50 percent criterion for African Americans. The African American populations in Liberty County were located near Liberty, Ames, and Devers and in Harris County near Barrett. Four aggregate minority populations were in Harris County, near Cloverleaf and east of Houston.

Meaningfully Greater Criterion

Proposed Project Summary

Minority populations are members of one of the following racial groups: African-Americans, American Indians or Alaskan Natives, Asians, Native Hawaiians or other Pacific Islanders, ~~"O~~ther" races, or multi-racial (CEQ 1997). There were 297 meaningfully greater minority populations that occurred within 172

individual census block groups (see Table 3.10.1-11) along the proposed Project analysis corridor. Of the 297 meaningfully greater minority populations, 36 were identified along the proposed Steele City Segment, one was found in proximity to the Kansas pump stations, 195 were identified along the proposed Gulf Coast Segment, and 69 were identified along the proposed Houston Lateral (four are common to both the Gulf Coast Segment and Houston Lateral).

Proposed Steele City Segment

For the proposed Steele City Segment, there were 15 meaningfully greater minority populations that occurred within eight individual census block groups in Montana. Four African American populations were in Montana, one each in Valley County (within St. Marie), McCone County (in Circle), Fallon County (in Baker), and Carter County. Two Native American/Alaskan Native populations and one Asian/Pacific Islander population were in Valley County on the Fort Peck Indian Reservation. Two "Other" populations also were in Valley County, one in the Fort Peck Indian Reservation and one east of Glasgow. Multi-racial populations in Montana were identified in both Valley County and McCone County. Two aggregate minority populations were also identified in Valley County, primarily comprised of Native Americans or Alaskan Natives. One Hispanic/Latino population also was located in Valley County east of Glasgow.

South Dakota had 18 meaningfully greater minority populations that occurred within 12 individual census block groups. One African American population was identified in Harding County within Buffalo. One Native American/Alaskan Native population was in Ziebach County on the Cheyenne River Indian Reservation; and three were in Tripp County within Winner and New Witten northeast of the Rosebud Indian Reservation. One Asian/Pacific Islander population was identified in both Haakon County and in Tripp County (at Winner). Multi-racial populations included one each in Pennington, Jones, and Lyman counties; and three in Tripp County. One Hispanic/Latino population also was located in each of Meade County and Tripp County, near Winner. One aggregate minority population was identified in Ziebach County and two were identified in Tripp County, primarily comprised of Native Americans or Alaskan Natives.

Nebraska contained two Native American/Alaskan Native populations in Holt County and one multi-racial population in Jefferson County.

New Cushing Extension Pump Stations

Kansas had one meaningfully greater multi-racial population in Clay County within Clay Center.

Proposed Gulf Coast Segment

For the proposed Gulf Coast Segment in Oklahoma, there were 73 meaningfully greater minority populations that occurred within 39 individual census block groups. African American populations were in Payne County (at Cushing) and Lincoln County (at Stroud). Two African American populations each were in Okfuskee County (within Boley), Seminole County (at Cromwell), Hughes County (at Holdenville), and Atoka County (at Atoka). Of the 30 Native American/Alaskan Native populations, one was in each of Creek, Lincoln, and Choctaw counties; two were in Okfuskee County; three were in each of Pontotoc, Coal, and Bryan counties; four were in Seminole County; and six populations were in each of Hughes and Atoka counties. One Asian/Pacific Islander population was in Lincoln County (near Stroud) and one "Other" population was identified in Bryan County. Individual multi-racial populations were in Atoka and Choctaw counties; two populations were in each of Creek, Okfuskee, Seminole, Pontotoc, and Coal counties; and four were identified in Hughes County. Aggregate minority populations were identified in Payne, Bryan, and Choctaw counties; three populations were in Okfuskee County; and four were each in Seminole and Hughes counties. These aggregate minority populations were primarily

comprised of African American and Native American/Alaskan Native populations. One Hispanic/Latino population was also identified in Hughes County (within Holdenville).

In Texas, there were 122 meaningfully greater minority populations that occurred within 82 individual census block groups. Of the 37 African American populations, one each was in Lamar, Angelina, Trinity, Polk, and Liberty counties; two were in Cherokee County (at Reklaw and Gallatin); three each were in Wood County (near Hawkins and Winnsboro) and Rusk County (west of Mount Enterprise and Henderson); 10 were in Smith County (east of Tyler); and 14 were in Jefferson County (near Beaumont). Native American/Alaskan Native populations included one each in Delta, Franklin, Upshur, Smith, Rusk, Nacogdoches, Angelina, and Orange counties; two were identified in each of Lamar, Cherokee, Liberty, and Hardin counties; three were in Polk County (within or near the Alabama-Coushatta Indian Reservation); four were identified in Hopkins County; and 11 populations were in Jefferson County. Six Asian/Pacific Islander populations were in Jefferson County (within Beaumont and Nederland). ~~O~~ther" populations identified included three in Angelina County (within Diboll) and one in Polk County. Seventeen multi-racial populations were identified, including one each in Lamar, Wood, Rusk, and Polk counties; two each in Liberty and Hardin counties; four were in Angelina County (at Diboll and Hudson); and five were in Jefferson County (at Port Neches and Nederland). Of the 21 aggregate minority populations, one each was identified in Wood, Trinity, Polk, and Liberty counties; two were in Rusk County (primarily African American); three each were in Smith County (primarily African American) and Angelina County (primarily Hispanic or Latino); and nine populations were indentified in Jefferson County (primarily African American). Three Hispanic/Latino populations were located in Angelina County (near Diboll).

Proposed Houston Lateral

The proposed Houston Lateral contained 69 meaningfully greater minority populations that occurred within 29 individual census block groups. Seven African American populations were identified in Liberty County (near Liberty, Dayton, Devers, and Ames) and 11 were identified in Harris County (surrounding Barrett and Channelview). Of the five Native American/Alaskan Native populations identified, two were in Liberty County and three were in Harris County (near Sheldon and Highlands). Four Asian/Pacific Islander populations were in Harris County (near Channelview and Cloverleaf). One ~~O~~ther" population was identified in Chambers County and eight populations were identified in Harris County (within Channelview). Five multi-race populations were identified in Liberty County (near Dayton and Devers), and eight were identified in Harris County (surrounding Barrett and Channelview). Of the 14 aggregate minority populations, five were in Liberty County and nine were in Harris County, primarily comprised of African American and Hispanic/Latino populations. Six Hispanic/Latino populations were along the proposed Houston Lateral in Harris County (within Channelview and Sheldon).

TABLE 3.10.1-9
County-Level Minority Populations Meaningfully Greater than Corresponding States' Minority Population

Minority Population	County	State
Steele City Segment		
African American	McCone	Montana
	Dawson	Montana
	Meade	South Dakota
	Pennington	South Dakota
Native American or Alaska Native	Phillips	Montana
	Valley	Montana
	Lyman	South Dakota
	Tripp	South Dakota
	Rock	Nebraska
Asian or Pacific Islander	Phillips	Montana
	Meade	South Dakota
	Pennington	South Dakota
Other	Butte	South Dakota
	Meade	South Dakota
	Pennington	South Dakota
	Saline	Nebraska
Two or More Races	Phillips	Montana
	Meade	South Dakota
	Pennington	South Dakota
	Jones	South Dakota
	Lyman	South Dakota
Aggregate of Racial Minorities	Lyman	South Dakota
Hispanic	Butte	South Dakota
	Meade	South Dakota
	Pennington	South Dakota
New Cushing Extension Pump Stations		
Native American or Alaska Native	Butler	Kansas
Gulf Coast Segment		
African American	Okfuskee	Oklahoma
	Smith	Texas
	Rusk	Texas
	Cherokee	Texas
	Nacogdoches	Texas
	Angelina	Texas
	Jefferson	Texas
Native American or Alaska Native	Okfuskee	Oklahoma
	Seminole	Oklahoma

TABLE 3.10.1-9
County-Level Minority Populations Meaningfully Greater than Corresponding States' Minority Population

Minority Population	County	State
	Hughes	Oklahoma
	Pontotoc	Oklahoma
	Coal	Oklahoma
	Atoka	Oklahoma
	Bryan	Oklahoma
	Fannin	Texas
	Lamar	Texas
	Hopkins	Texas
	Franklin	Texas
	Polk	Texas
Asian or Pacific Islander	Payne	Oklahoma
Two or More Races	Creek	Oklahoma
	Seminole	Oklahoma
	Hughes	Oklahoma
	Pontotoc	Oklahoma
	Coal	Oklahoma
	Atoka	Oklahoma
Aggregate of Racial Minorities	Okfuskee	Oklahoma
	Seminole	Oklahoma
	Jefferson	Texas
Houston Lateral		
African American	Harris	Texas
Asian or Pacific Islander	Harris	Texas
Other	Harris	Texas
Two or More Races	Harris	Texas
Aggregate of Racial Minorities	Harris	Texas

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 - Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

Low-Income Populations

Low-income populations in the region of influence were identified and evaluated using poverty data from the United States Census Bureau. As with minority populations, low-income populations were evaluated using the absolute 50 percent and the relative 120 percent greater criteria, first for counties and then for potentially affected census block groups within the counties. If the percentage of low-income individuals was 120 percent greater in a county than the corresponding state in which it was located, it was considered to be a low-income population. These counties are noted with an asterisk (*) in the third column of Table 3.10.1-9. Also, low-income individuals in each census block group were divided by the total individuals for that census block group to obtain the percentage of low-income individuals per census block group. If any census block group percentage exceeded the corresponding state percentage

by more than 120 percent, then the census block group was identified as containing a low-income population.

Four states, Montana (14.6 percent), South Dakota (13.2 percent), Oklahoma (14.7 percent), and Texas (15.4 percent) had greater rates of low-income residents in 1999 than the United States rate of 12.4 percent. In comparison, 9.9 percent of Kansas residents were considered low-income in 1999 and 9.7 percent of Nebraska residents were considered low-income, noticeably less than for the United States percentage. Thus, for comparative purposes, the 120-percent exceedance criterion for each state would be 17.5 percent for Montana, 15.8 percent for South Dakota, 11.7 percent for Nebraska, 11.9 percent for Kansas, 17.6 percent for Oklahoma, and 18.5 percent for Texas.

Populations within Counties

As shown in Table 3.10.1-7, no counties had 50 percent or more of low-come individuals. In total, 20 of the 59 counties that would comprise the proposed Project area met the 120 percent meaningfully greater criterion for low-income populations.

In the proposed Steele City Segment, 13 out of 29 counties had meaningfully greater low-income populations, including Phillips County in Montana; Harding, Perkins, Jones, Lyman, and Tripp counties in South Dakota; and Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, and Nance counties in Nebraska. None of the counties in Kansas were classified as low-income. Seven of the 27 counties in the proposed Gulf Coast Segment met the meaningfully greater criteria of 17.6 percent in Oklahoma or 18.5 percent in Texas. These low-income populations included Payne, Okfuskee, Seminole, Hughes, Coal, and Bryan counties in Oklahoma; and Nacogdoches County in Texas. The three counties along the proposed Houston Lateral did not have low-income populations.

Populations within Census Block Groups

Populations within census block groups meeting either of the absolute 50 percent or 120 percent meaningfully greater criteria are described in this section. Of the 287 census block groups assessed along the proposed Project analysis corridor, 82 contained low-income populations. Tables 3.10.1-10 and 3.10.1-11 and Figures 3.10.1-1 through 3.10.1-6 identify these low-income populations within census block groups.

50 Percent Criterion

Proposed Project Summary

Only one low-income population within census block groups along the 4-mile-wide analysis corridor exceeded the 50 percent criterion. This population also exceeded the 120-percent criterion, as described in the following section. The population was located in Ziebach County, South Dakota on part of the Cheyenne River Indian Reservation.

Meaningfully Greater Criterion

Proposed Project Summary

A total of 83 populations within individual census block groups along the 4-mile-wide analysis corridor had 120 percent more than the percentage of low-income individuals for each corresponding state. Table 3.10.1-11 indicates that of these 83 low-income populations, 29 were located along the Steele City Segment, one was at the pump stations in Kansas, 48 were along the Gulf Coast Segment, and five were along the Houston Lateral. One low-income population was identified in Liberty County, Texas for both the Gulf Coast Segment and the Houston Lateral.

For Montana, one low-income population was in each of Phillips, Valley, McCone, Dawson, and Prairie counties. Of the 13 low-income populations in South Dakota, one was in each of Harding, Perkins, Meade, Ziebach, Pennington, and Gregory counties; two were in Haakon County; and five were in Tripp County, surrounding Winner. Nebraska contained 11 low-income populations, one was in each of Keya Paha, Rock, Wheeler, Nance, and Fillmore counties; and two were in each of Holt, Greeley, and Boone counties.

At the proposed Pump Station 29 in Kansas, one low-income population was identified in Clay County, near Clay Center.

In the Gulf Coast Segment, of the 23 low-income populations in Oklahoma, one was in each of Payne and Pontotoc counties; two were in each of Seminole, Coal, Atoka, and Bryan counties; three were in each of Lincoln and Okfuskee counties; and seven were in Hughes County. Hughes County had the most low-income populations identified in any state affected by the proposed Project. The Gulf Coast Segment in Texas contained 25 low-income populations, one was in each of Delta, Hopkins, Upshur, Cherokee, Nacogdoches, Angelina, and Polk counties; two were in each of Lamar, Smith, and Hardin counties; and three were in each of Wood, Rusk, Liberty, and Jefferson counties.

For the Houston Lateral in Texas, four low-income populations were in Liberty County and one was in Harris County.

TABLE 3.10.1-10
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Steele City Segment											
Montana											
Phillips	1	0	0	0	0	0	0	0	0	0	0
Valley	6	0	1	0	1	0	0	0	0	0	1
McCone	3	0	0	0	0	0	0	0	0	0	0
Dawson	2	0	0	0	0	0	0	0	0	0	0
Prairie	1	0	0	0	0	0	0	0	0	0	0
Fallon	3	0	0	0	0	0	0	0	0	0	0
Carter	1	0	0	0	0	0	0	0	0	0	0
Subtotal Montana	*17*	*0*	*1*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	1
South Dakota											
Harding	2	0	0	0	0	0	0	0	0	0	0
Butte	1	0	0	0	0	0	0	0	0	0	0
Perkins	1	0	0	0	0	0	0	0	0	0	0
Meade	2	0	0	0	0	0	0	0	0	0	0
Ziebach	1	1	1	0	1	0	0	0	0	0	1
Pennington	1	0	0	0	0	0	0	0	0	0	0
Haakon	2	0	0	0	0	0	0	0	0	0	0
Jones	1	0	0	0	0	0	0	0	0	0	0
Lyman	1	0	0	0	0	0	0	0	0	0	0

TABLE 3.10.1-10
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Tripp	8	0	0	0	0	0	0	0	0	0	0
Gregory	1	0	0	0	0	0	0	0	0	0	0
Subtotal South Dakota	*21*	*1*	*1*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	1
Nebraska											
Keya Paha	1	0	0	0	0	0	0	0	0	0	0
Rock	1	0	0	0	0	0	0	0	0	0	0
Holt	2	0	0	0	0	0	0	0	0	0	0
Garfield	1	0	0	0	0	0	0	0	0	0	0
Wheeler	1	0	0	0	0	0	0	0	0	0	0
Greeley	2	0	0	0	0	0	0	0	0	0	0
Boone	2	0	0	0	0	0	0	0	0	0	0
Nance	1	0	0	0	0	0	0	0	0	0	0
Merrick	2	0	0	0	0	0	0	0	0	0	0
Hamilton	1	0	0	0	0	0	0	0	0	0	0
Polk	1	0	0	0	0	0	0	0	0	0	0
York	3	0	0	0	0	0	0	0	0	0	0
Fillmore	2	0	0	0	0	0	0	0	0	0	0
Saline	2	0	0	0	0	0	0	0	0	0	0
Jefferson	3	0	0	0	0	0	0	0	0	0	0
Subtotal Nebraska	*25*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	0

TABLE 3.10.1-10
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
New Cushing Extension Pump Stations											
Kansas											
Clay	4	0	0	0	0	0	0	0	0	0	0
Butler	1	0	0	0	0	0	0	0	0	0	0
Subtotal Kansas	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	0
Gulf Coast Segment											
Oklahoma											
Payne	2	0	0	0	0	0	0	0	0	0	0
Creek	2	0	0	0	0	0	0	0	0	0	0
Lincoln	6 (1)[a]	0	0	0	0	0	0	0	0	0	0
Okfuskee	5	0	2	1	0	0	0	0	1	0	2
Seminole	5	0	0	0	0	0	0	0	0	0	0
Hughes	9	0	0	0	0	0	0	0	0	0	0
Pontotoc	3	0	0	0	0	0	0	0	0	0	0
Coal	3	0	0	0	0	0	0	0	0	0	0
Atoka	6	0	0	0	0	0	0	0	0	0	0
Bryan	3	0	0	0	0	0	0	0	0	0	0
Choctaw	1	0	0	0	0	0	0	0	0	0	0
Subtotal Oklahoma	*45 (1)[a]*	*0*	*2*	*1*	*0*	*0*	*0*	*0*	*1*	*0*	*2*

TABLE 3.10.1-10
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Texas											
Fannin	2	0	0	0	0	0	0	0	0	0	0
Lamar	6	0	0	0	0	0	0	0	0	0	0
Delta	1	0	0	0	0	0	0	0	0	0	0
Hopkins	5	0	0	0	0	0	0	0	0	0	0
Franklin	3	0	0	0	0	0	0	0	0	0	0
Wood	8	0	1	1	0	0	0	0	0	0	1
Upshur	6	0	0	0	0	0	0	0	0	0	0
Smith	12	0	2	2	0	0	0	0	0	0	2
Rusk	4	0	1	0	0	0	0	0	1	0	1
Cherokee	5	0	0	0	0	0	0	0	0	0	0
Nacogdoches	5	0	0	0	0	0	0	0	0	0	0
Angelina	11 (1)[a]	0	2	1	0	0	0	0	0	1	2
Trinity	2	0	0	0	0	0	0	0	0	0	0
Polk	9	0	0	0	0	0	0	0	0	0	0
Hardin	5	0	0	0	0	0	0	0	0	0	0
Jefferson	43 (14)[a]	0	7	5	0	0	0	0	2	0	7
Orange	1	0	0	0	0	0	0	0	0	0	0
Subtotal Texas - Gulf Coast Segment	*135 (15)[a]*	*0*	*13*	*9*	*0*	*0*	*0*	*0*	*3*	*1*	*13*

TABLE 3.10.1-10
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Houston Lateral											
Texas											
Liberty	17	0	2	2	0	0	0	0	0	0	2
Chambers	2	0	0	0	0	0	0	0	0	0	0
Harris	24	0	6	2	0	0	0	0	4	0	6
Subtotal Texas - Houston Lateral)	*43 (2)*[a]	*0*	8	*4*	*0*	*0*	*0*	*0*	*4*	*0*	8
Subtotal Texas[b]	*174 (17)*[a]	*0*	21	*13*	*0*	*0*	*0*	*0*	*7*	*1*	*21*
Project Total	**287 (18)**[a]	**1**	**25**	**14**	**2**	**0**	**0**	**0**	**8**	**1**	**25**

[a] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[b] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Steele City Segment											
Montana											
Phillips	1	1	0	0	0	0	0	0	0	0	0
Valley	6	1	4	1	2	1	2	2	2	1	11
McCone	3	1	2	1	0	0	0	1	0	0	2
Dawson	2	1	0	0	0	0	0	0	0	0	0
Prairie	1	1	0	0	0	0	0	0	0	0	0
Fallon	3	0	1	1	0	0	0	0	0	0	1
Carter	1	0	1	1	0	0	0	0	0	0	1
Subtotal Montana	*17*	*5*	*8*	*4*	*2*	*1*	*2*	*3*	*2*	*1*	15
Montana Exceedance Criteria[a]	-	17.5%	-	0.4%	7.4%	0.7%	0.7%	2.1%	11.4%	2.4%	-
South Dakota											
Harding	2	1	1	1	0	0	0	0	0	0	1
Butte	1	0	0	0	0	0	0	0	0	0	0
Perkins	1	1	0	0	0	0	0	0	0	0	0
Meade	2	1	1	0	0	0	0	0	0	1	1
Ziebach	1	1	1	0	1	0	0	0	1	0	2
Pennington	1	1	1	0	0	0	0	1	0	0	1
Haakon	2	2	1	0	0	1	0	0	0	0	1

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Jones	1	0	1	0	0	0	0	1	0	0	1
Lyman	1	0	1	0	0	0	0	1	0	0	1
Tripp	8	5	5	0	3	1	0	3	2	1	10
Gregory	1	1	0	0	0	0	0	0	0	0	0
Subtotal South Dakota	*21*	*13*	*12*	*1*	*4*	*2*	*0*	*6*	*3*	*2*	18
South Dakota Exceedance Criteria[a]	-	15.8%	-	0.7%	10.0%	0.7%	0.6%	1.6%	13.6%	1.7%	-
Nebraska											
Keya Paha	1	1	0	0	0	0	0	0	0	0	0
Rock	1	1	0	0	0	0	0	0	0	0	0
Holt	2	2	2	0	2	0	0	0	0	0	2
Garfield	1	0	0	0	0	0	0	0	0	0	0
Wheeler	1	1	0	0	0	0	0	0	0	0	0
Greeley	2	2	0	0	0	0	0	0	0	0	0
Boone	2	2	0	0	0	0	0	0	0	0	0
Nance	1	1	0	0	0	0	0	0	0	0	0
Merrick	2	0	0	0	0	0	0	0	0	0	0
Hamilton	1	0	0	0	0	0	0	0	0	0	0
Polk	1	0	0	0	0	0	0	0	0	0	0
York	3	0	0	0	0	0	0	0	0	0	0
Fillmore	2	1	0	0	0	0	0	0	0	0	0

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Saline	2	0	0	0	0	0	0	0	0	0	0
Jefferson	3	0	1	0	0	0	0	1	0	0	1
Subtotal Nebraska	*25*	*11*	*3*	*0*	*2*	*0*	*0*	*1*	*0*	*0*	3
Nebraska Exceedance Criteria[a]	-	11.7%	-	4.8%	1.1%	1.6%	3.4%	1.7%	12.5%	6.6%	-
New Cushing Extension Pump Stations											
Kansas											
Clay	4	1	1	0	0	0	0	1	0	0	1
Butler	1	0	0	0	0	0	0	0	0	0	0
Subtotal Kansas	*5*	*1*	*1*	*0*	*0*	*0*	*0*	*1*	*0*	*0*	1
Kansas Exceedance Criteria[a]	-	11.9%	-	6.9%	1.1%	2.1%	4.2%	2.6%	16.6%	8.4%	-
Gulf Coast Segment											
Oklahoma											
Payne	2	1	1	1	0	0	0	0	1	0	2
Creek	2	0	2	0	1	0	0	2	0	0	3
Lincoln	6 (1)[b]	3(1)[b]	2	1	1	1	0	0	0	0	3
Okfuskee	5	3	4	2	2	0	0	2	3	0	9
Seminole	5	2	5	2	4	0	0	2	4	0	12
Hughes	9	7	9	2	6	0	0	4	4	1	17

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Pontotoc	3	1	3	0	3	0	0	2	0	0	5
Coal	3	2	3	0	3	0	0	2	0	0	5
Atoka	6	2	6	2	6	0	0	1	0	0	9
Bryan	3	2	3	0	3	0	1	0	1	0	5
Choctaw	1	0	1	0	1	0	0	1	1	0	3
Subtotal Oklahoma	*45 (1)*[b]	*23* (1)[b]	*39*	*10*	*30*	*1*	*1*	*16*	*14*	*1*	73
Oklahoma Exceedance Criteria[a]	-	17.6%	-	9.1%	9.5%	1.6%	2.9%	5.4%	28.5%	6.2%	-
Texas											
Fannin	2	0	0	0	0	0	0	0	0	0	0
Lamar	6	2	3	1	2	0	0	1	0	0	4
Delta	1	1	1	0	1	0	0	0	0	0	1
Hopkins	5	1	4	0	4	0	0	0	0	0	4
Franklin	3	0	1	0	1	0	0	0	0	0	1
Wood	8	3	4	3	0	0	0	1	1	0	5
Upshur	6	1	1	0	1	0	0	0	0	0	1
Smith	12	2	10	10	1	0	0	0	3	0	14
Rusk	4	3	4	3	1	0	0	1	2	0	7
Cherokee	5	1	4	2	2	0	0	0	0	0	4
Nacogdoches	5	1	1	0	1	0	0	0	0	0	1
Angelina	11 (1)[b]	1 (1)[b]	8 (1)[b]	1	1	0	3	4	3	3	15

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Trinity	2	0	1	1	0	0	0	0	1	0	2
Polk	9	1	6	1	3	0	1	1	1	0	7
San Jacinto	1	0	0	0	0	0	0	0	0	0	0
Liberty	6	3	4	1	2	0	0	2	1	0	6
Hardin	5	2	4	0	2	0	0	2	0	0	4
Jefferson	43 (14)[b]	3	25 (8)[b]	14	11	6	0	5	9	0	45
Orange	1	0	1	0	1	0	0	0	0	0	1
Subtotal Texas - Gulf Coast Segment	*135 (15)[b]*	*25* (1)[b]	*82 (9)[b]*	*37*	*34*	*6*	*4*	*17*	*21*	*3*	122
Texas Exceedance Criteria[a]	-	18.5%	-	13.8%	0.7%	3.4%	14.1%	3.0%	35.0%	38.4%	-
Houston Lateral											
Texas											
Liberty	17	4	10	7	2	0	0	5	5	0	19
Chambers	2	0	1	0	0	0	1	0	0	0	1
Harris	24	1	18 (1)[b]	11	3	4	8	8	9	6	49
Subtotal Texas - Houston Lateral)	*43 (2)[b]*	*5*	29 (1)[b]	*18*	*5*	*4*	*9*	*13*	*14*	*6*	69

TABLE 3.10.1-11
Minority and Low-Income (Environmental Justice) Populations Exceeding 120% of State Levels within Census Block Groups by County within 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Texas Exceedance Criteria[a]	-	18.5%	-	13.8%	0.7%	3.4%	14.1%	3.0%	35.0%	38.4%	-
Subtotal Texas[c]	*174 (17)*[b]	*29* (1)[b]	109 (10)[b]	*54*	*39*	*10*	*13*	*28*	*34*	*9*	*187*
Project Total	**287 (18)**[b]	**83 (2)**[b]	**172 (10)**[b]	**69**	**77**	**14**	**16**	**55**	**53**	**13**	**297**

[a] State-wide exceedance criteria percentages are 1.2 times the actual Environmental Justice group population percentages for each state.

[b] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[c] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

See http://factfinder.census.gov/home.

3.10.1.2 Potential Impacts

The socioeconomic consequences of constructing and operating the proposed Project would vary in duration and magnitude. From a temporal perspective, impacts are characterized as temporary, short-term, long-term, or permanent. Impacts are considered in the context of duration, magnitude (relative to baseline conditions), and any proposed measures or activities that would be implemented as part of the proposed Project. The following impact thresholds for potential social and economic impacts were used in the analysis:

- Changes to local social or economic activities, including changes in employment and income levels, resulting from the proposed Project construction and operations;
- Overburdening of the local housing stock because of demand generated by the temporary and permanent work force;
- Substantial burden on public service providers serving the proposed Project area, such that they would need to expand their service capacities to meet those demands;
- Substantial changes in fiscal revenues, including tax receipts, of local jurisdictions; and
- Substantial changes in private property values.

Impacts are characterized as positive (beneficial) or negative (adverse) and, where possible, are evaluated relative to regional conditions to help assess the magnitude of socioeconomic effects.

Construction Impacts

The proposed Project would require construction of approximately 1,384 miles of new pipeline, 30 pump stations, and other ancillary facilities, as listed in Table 3.10.1-12. Construction activities would involve the movement of people, equipment, and materials on roadways throughout the proposed Project area. In some cases, construction could increase the demands for permits for vehicle load and width limits. Some temporary traffic delays would be likely. However, vehicle access and assistance with traffic flows in construction areas including emergency vehicles would be provided (Appendix B, CMR Plan).

TABLE 3.10.1-12
Proposed Project Construction by State

Segment/State	New Construction Pipeline Miles	Ancillary Facilities
Steele City Segment		
Montana	282.7	6 new pump stations, 21 main line valves (MLVs), 50 access roads
South Dakota	314.2	7 new pump stations, 17 MLVs, 18 access roads
Nebraska	254.7	5 new pump stations, 19 MLVs, 12 access roads
New Cushing Extension Pump Stations		
Kansas	0	2 new pump stations, 1 access road
Gulf Coast Segment		
Oklahoma	155.7	Cushing Tank Farm, 4 new pump stations, 15 MLVs, 76 access roads
Texas	328.1	6 new pump stations, 32 MLVs, 157 access roads, 1 delivery site
Houston Lateral		
Texas	48.6	8 MLVs, 31 access roads, 1 delivery site
Total	**1,383.9**	

Construction of the pipeline is planned to occur in 17 construction spreads or completed lengths (Table 3.10.1-13). Ten spreads are planned along the proposed Steele City Segment, six spreads along the proposed Gulf Coast Segment, and one spread along the proposed Houston Lateral. Final spread configurations and construction schedules could result in shorter spreads.

Approximately 500 to 600 construction and inspection personnel would work on each spread, except for the proposed Houston Lateral which would require approximately 250 workers. Each spread would require 6 to 9 months to complete. Construction of new pump stations would require 20 to 30 additional workers at each site. Construction of all pump stations would be completed in 18 to 24 months. Tank farm construction would require approximately 30 to 40 construction personnel over a period of 15 to 18 months.

Within each state, additional jobs and income would go to workers who would leave the area upon proposed Project completion. In the long-term, a small number of people would be needed to maintain the line in each state. Unemployment rates in the proposed Project study area would probably not be affected in the long-term, although there could be a short-term lowering of unemployment during construction in the more rural areas.

Efforts would be made to hire temporary construction staff from the local population through construction contractors and subcontractors. Provided qualified personnel are available, approximately 10 to 15 percent (50 to 100 people) could be hired from the local work force for each spread. This may not be possible in more rural areas. The number of individuals in the work force for each county where a base for construction is planned is listed in Table 3.10.1-13.

TABLE 3.10.1-13
Pipeline Construction Spreads of the Proposed Project

Spread Number	Location	Approximate Length of Construction Spread (miles)	Base(s) for Construction [a]	Work Force in Respective Counties [b](2008)
Steele City Segment				
Spread 1	MP 0 to 64	64	Hinsdale, Montana, and Glasgow, Montana (both in Valley County)	3,649
Spread 2	MP 64 to 164	100	Glasgow, Montana (Valley County), and Circle, Montana (McCone County)	3,649 (Valley, County); 1,015 (McCone County)
Spread 3	MP 164 to 273	109	Glendive, Montana (Dawson County), and Baker, Montana (Fallon County)	4,386 (Dawson County); 1,824 (Fallon County)
Spread 4	MP 273 to 345	72	Buffalo, South Dakota (Harding County)	762
Spread 5	MP 345 to 448	104	Faith, South Dakota, and Union Center, South Dakota (both in Meade County)	12,579
Spread 6	MP 448 to 513	65	Phillip, South Dakota (Haakon County)	1,154
Spread 7	MP 513 to 616	103	Murdo, South Dakota (Jones County), and Winner, South Dakota (Tripp County)	694 (Jones County); 2,935 Tripp County)
Spread 8	MP 616 to 679	63	Fairfax, Nebraska (Custer, Nebraska) Stuart, Nebraska, and O'Neill, Nebraska (both in Holt County)	6,092 (Custer County); 6,092 (Holt County)

TABLE 3.10.1-13
Pipeline Construction Spreads of the Proposed Project

Spread Number	Location	Approximate Length of Construction Spread (miles)	Base(s) for Construction [a]	Work Force in Respective Counties [b](2008)
Spread 9	MP 679 to 789	109	Greeley, Nebraska (Greeley County), and Central City, Nebraska (Merrick County)	1,298 (Greeley County); 4,296 (Merrick County)
Spread 10	MP 789 to 852	63	York (York County), Nebraska, Beatrice, Nebraska (Gage County), and Fairbury, Nebraska (Jefferson County)	7,115 (York County); 4,394 (Jefferson County)
Gulf Coast Segment				
Spread 1	MP 0 to 95	95	Holdenville, Oklahoma (Hughes County)	5,046
Spread 2	MP 95 to 185	90	Paris, Texas (Lamar County)	23,811 (Lamar County)
Spread 3	MP 185 to 285	100	Mt. Pleasant, Texas (Titus County)	617
Spread 4	MP 285 to 371	86	Henderson, Texas (Rusk County), Nacogdoches, Texas (Nacogdoches County) Crockett, Texas Houston County), Jacksonville, Texas (Cherokee County)	24,081 (Rusk County); 30,614 (Nacogdoches County)
Spread 5	MP 371 to 435	64	Lufkin, Texas (Angelina County)	38,987 (Angelina County)
Spread 6	MP 435 to 484	49	Sour Lake, Texas (Hardin County)	25,947 (Hardin County)
Houston Lateral				
Spread 7	MP 0 to 49	49	Sour Lake, Texas, Liberty, Texas (Chambers County), Dayton, Texas (Liberty County)	14,254 (Chambers County); 31,455 (Liberty County)

[a] Some of the communities listed above were not included in Table 3.10.2 because they are located more than 2 miles from the proposed pipeline.
[b] Source: *Bureau of Labor Statistics, Local Area Unemployment Statistics, County Data. http://www.bls.gov/lau/#tables.*

Population

The number of residents within the region of influence would increase temporarily during construction with the influx of construction workers and proposed Project staff. The construction work force would consist of approximately 5,000 to 6,000 workers, including Keystone employees, contractor employees, and construction and environmental inspection staff. These workers would be distributed across the pipeline route by construction spread, with approximately 500 to 600 construction personnel allocated to each spread. Construction of the pump stations and delivery facilities would require additional staff. It is anticipated that an additional 20 to 30 workers per station would be required. Tank farm construction would involve approximately 30 to 40 construction personnel over a period of 15 to 18 months concurrent with the proposed Gulf Coast Segment construction.

Population impacts in the region of influence would depend upon the composition of the construction work force in terms of local versus non-local workers and the existing population of the area. Temporary local construction labor would be utilized where possible. It is estimated that 10 to 15 percent of the total construction work force could be hired from local communities, with the remaining workers (85 to 90

percent) from outside the local area. Few non-local workers would likely be accompanied by their children or other family members because of the mobile nature of the work force along the pipeline route during construction.

Housing

Construction Work Camps

Some more rural areas within Montana and South Dakota do not have sufficient temporary housing in the vicinity of the proposed route to house all construction personnel working on spreads in those areas. In those areas, four temporary work camps would be constructed to meet the housing needs of the construction work force. The two Montana camps would be located near Nashua in Valley County and near Baker in Fallon County. The two South Dakota camps would be located near Union Center in Meade County and near Winner in Tripp County. These temporary camps would supplement local housing in remote areas of Montana and South Dakota for the duration of construction in the area.

Each construction camp would be capable of housing up to 600 workers. However, the number and size of camps would be determined based upon the time available to complete construction and to meet Keystone's commercial commitments. Camps would typically include sleeping areas with shared and private baths, craft rooms, recreation facilities, media rooms, kitchen/dining facilities, laundry facilities, a security/infirmary unit, offices, and wastewater treatment facilities. These temporary construction camps would be permitted, constructed, and operated consistent with applicable county, state, and federal regulations. These construction camps would likely reduce but not eliminate impacts on nearby towns and public services.

Other Temporary Construction Housing

Non-local construction workers temporarily residing in other areas in the region of influence would require short-term accommodations. Because workers would not likely relocate with their families and their stay in any one community would be temporary, most workers would likely use temporary housing, such as hotels/motels, RV sites, and campgrounds. Most workers likely would prefer short-term accommodations, primarily hotels and motels, in the more populated, service-oriented communities located within a reasonable commuting distance from the work site. As local accommodations filled, workers would be forced to seek alternative accommodations, including RV parks and campgrounds, in smaller, more distant communities. Further, some employees could elect to utilize furnished apartments and rental homes due to the constrained availability of other accommodations, although this would likely be limited based upon extended-period lease requirements. Depending upon the location and available accommodations, workers could elect to reside temporarily in one location during the construction period or relocate within each spread as needed as construction proceeded along the pipeline route.

The construction work force could require nearly 2,900 housing units throughout the region of influence, or 450 to 510 housing units within any one construction spread, assuming that each worker would require his/her own unit. In total, there are approximately 91,000 vacant rentals, 30,000 hotel/motel rooms, and 4,700 RV sites available to serve the housing needs of the proposed Project. The anticipated proposed Project-related demand for housing would account for about 5 percent of all available temporary housing in the region of influence, or 17.0 percent of hotel/motel rooms plus RV sites. At a regional scale, therefore, it appears that the temporary housing available within the region of influence would be sufficient to meet the temporary and moderately increased demand for housing resulting from construction activities.

The availability of short-term housing varies across the pipeline route. In 2000, counties in Montana that would be crossed by the proposed Project had 1,414 available rental properties, hotel/motel rooms, and

RV sites, South Dakota had 9,987 units, Nebraska had 2,110 units, Kansas had 1,056 units, Oklahoma had 4,764 units, and Texas had 84,908 units available (see Table 3.10.1-7). Actual vacancy rates vary by year and season, with the spring through fall seasons having the lowest vacancy rates, so these numbers are only a representation of the housing that could be available and actual availability at any given time could be noticeably less. Also, it should be noted that additional units would be available in the counties surrounding those crossed by the proposed Project. More urban areas have more short-term housing available, particularly hotel and motel rooms.

Local Economic Activity

The proposed Project has the potential to generate substantial direct and indirect economic benefits for local and regional economies along the pipeline route. During construction, these benefits are derived from the construction labor requirements of the proposed Project and spending on construction goods and services that would not otherwise have occurred if the pipeline were not built. At the local level, these benefits would be in the form of employment of local labor as part of the construction work force and related income benefits from wage earnings, construction expenditures made at local businesses, and construction worker spending in the local economy. However, if a person were to leave an existing job to take a job building the proposed Project, only the additional income earned by that person would be considered a benefit of the proposed Project. The proposed Project job obtained by the local worker would become a local proposed Project-related benefit when the job that was left was filled by another worker.

Employment and Income

Construction of the proposed Project, including the pipeline and pump stations, would result in hiring approximately 5,000 to 6,000 workers over the three year construction period. As indicated above, it is expected that roughly 10 to 15 percent of the construction work force would be hired from local labor markets, thus 500 to 900 local workers would be hired throughout the entire region of influence, or 50 to 90 local workers per construction spread. As shown in Table 3.10.1-8, in 2008 within the counties crossed by the proposed Project, the average annual unemployed work force was 483 in Montana, 2,453 in South Dakota, 1,498 in Nebraska, 1,547 in Kansas, 5,217 in Oklahoma, and 121,346 in Texas. Thus, this total of 132,544 unemployed people in 2008 would exceed the proposed Project's local work force needs of up to 900 people as well as the total work force needs. Some short-term shifting in local job distribution could occur in all areas as a result of the proposed Project, but vacated jobs could be filled by other unemployed people.

Related income benefits would be substantial. The mean annual income (excluding benefits, estimated to be an additional 33 percent for workers' total compensation) for construction and extraction occupations in 2008 (BLS) was $38,310 in Montana, $31,860 in South Dakota, $36,910 in Nebraska, $39,030 in Kansas, $34,940 in Oklahoma, and $33,580 in Texas. Using $34,940 as an average annual income (the lower end of the mid-point as a conservative estimate of income benefits) for a total of 5,000 construction workers over a 24 month period, it is estimated that the proposed Project would generate $349.4 million in total wages. If the maximum construction work force were 6,000 people, a total of $419.28 million in wages would be generated. On a per spread basis, if it took a maximum of 9 months to construct each spread, construction income would range from an estimated $13.10 million for 500 workers/spread to $15.72 million for 600 workers/spread.

As noted in a recent news article (Dow Jones Newswires, September 14, 2010), a number of the jobs created by construction of the pipeline would be filled with union employees. As of that date, six unions had signed a Project Labor Agreement with Keystone, including:

- Laborers International Union of North American;
- International Brotherhood of Teamsters;
- AFL-CIO;
- United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada;
- Internal Union of Operating Engineers; and
- Pipeline Contractors Association.

Spending and Expenditures

In addition to payroll spending, construction would generate substantial expenditures on construction materials (e.g., pipe, valves, and pump stations), equipment and equipment rentals (see Table 2.3.2-1), and goods and services, both inside and outside of the region of influence. It is estimated that it would cost a total of $7.0 billion to construct the proposed Project. If one subtracts the above labor costs from this total, an estimated $6.58 to $6.65 billion would be spent on materials and supplies, easements, engineering, permitting, and other costs. Typically, spending on goods and services would include outlays for fuel supplies, hardware needs, and parts/equipment and could be spent more at the local level. Overall, construction of the proposed Project would result in a positive impact on the local economies in the region of influence.

Construction also would generate indirect local economic benefits from secondary activity spurred by the direct effects described above. This would include short-term benefits of increased business to local and statewide businesses providing supplies and services to proposed Project workers. Such businesses would include equipment suppliers, restaurants, gas stations and hotels. Spending by the non-local construction work force within local economies during the construction period could include expenditures on food, clothing, lodging, gasoline, and entertainment. The extent of local spending by non-local workers would be tied to labor earnings and individual spending patterns. Construction worker spending, in conjunction with outlays for construction goods and services, also would generate indirect economic benefits as these monetary flows circulated throughout the economy, based upon economic linkages among industries. These "ripple" effects, commonly referred to as "multiplier effects," would result from businesses buying from other businesses and could generate additional economic benefits within the region of influence. These impacts, however, have not been quantified for this analysis.

Labor and income benefits also would extend outside of the region of influence, based upon the employment of non-local labor for the proposed Project and expenditures on construction materials and services that would be imported into the area. Although these benefits would not be realized locally, they would represent a positive economic impact at the national level.

Environmental Justice

As described in Section 3.10.1.1, portions of the proposed pipeline and proposed pump stations would be located in areas with minority and low-income populations. Populations of concern from an environmental justice perspective were assessed at both the county and census block group level.

Minority and Low-Income Populations within Counties

The proposed Project would not cross within 2 miles of counties that had greater than 50 percent of the state-wide average for minority or low-income populations at the time of census data collection. However, 34 of the 59 counties were identified as having a meaningfully greater minority population than the state-wide average and 20 counties were identified as having a meaningfully greater low-income population than the state-wide average.

Table 3.10.1-14 provides a list of the counties within the proposed Project area and specifies:

- Whether a pipe yard (PY), a construction camp (CY), a contractors camp (CC), or a railroad siding facility (RRS/PY) is planned to be located within that county;
- Whether there is at least one minority population meaningfully greater than the overall state minority population in that county; and
- Whether the number of low-income individuals in that county is meaningfully greater than the state average.

These types of facilities are planned in 33 counties within the proposed Project area and 23 of those counties have one or more environmental justice percentages meaningfully greater than the state-wide averages.

These data suggest that potential impacts to minority and low-income populations during construction within counties crossed by the proposed Project corridor would be minor and would not disproportionately affect these populations when considered at the county population level.

TABLE 3.10.1-14
Location of Construction Facilities Relative to County Environmental Justice Statistics

		Statistic Meaningfully Greater than Respective State (2000)	
County	**Construction Facility[a]**	**Minority Population**	**Low-Income**
Steele City Segment			
Montana			
Phillips	PY	Yes	Yes
Valley	2 PY, 1 CY, 1 CC	Yes	No
McCone	2 PY, 1 CY	Yes	No
Dawson	2 PY, 1 CY	Yes	No
Prairie	No	No	No
Fallon	2 PY, 1 CC	No	No
South Dakota			
Harding	3 PY, 1 CY	No	Yes
Butte	No	Yes	No
Perkins	No	No	Yes
Meade	2 PY, 1 CY, 1 CC	Yes	No
Pennington	No	Yes	No
Haakon	2 PY, 1 CY	No	No

TABLE 3.10.1-14
Location of Construction Facilities Relative to County Environmental Justice Statistics

County	Construction Facility[a]	Statistic Meaningfully Greater than Respective State (2000)	
		Minority Population	Low-Income
Jones	2 PY, 1 CY	Yes	Yes
Lyman	No	Yes	Yes
Tripp	2 PY, 1 CY, 1 CC	Yes	Yes
Nebraska			
Keya Paha	1 PY	No	Yes
Rock	No	Yes	Yes
Holt	2 PY, 2 CY	No	Yes
Garfield	No	No	Yes
Wheeler	No	No	Yes
Greeley	1 PY, 1 CY	No	Yes
Boone	No	No	No
Nance	1 PY	No	Yes
Merrick	1 CY	No	No
Hamilton	1 PY	No	No
York	1 CY	No	No
Fillmore	1 PY	No	No
Saline	No	Yes	No
Jefferson	1 PY, 1 CY	No	No
New Cushing Extension Pump Stations			
Kansas			
Clay	No	No	No
Butler	No	Yes	No
Gulf Coast Segment			
Oklahoma			
Payne	No	Yes	Yes
Creek	No	Yes	No
Lincoln	1 PY, 1 CY	No	No
Okfuskee	No	Yes	Yes
Seminole	No	Yes	Yes
Hughes	1 PY, 1 CY, 1 PY/RS	Yes	Yes
Pontotoc	No	Yes	No
Coal	No	Yes	Yes
Atoka	No	Yes	No
Bryan	1 PY, 1 CY	Yes	Yes

TABLE 3.10.1-14
Location of Construction Facilities Relative to County Environmental Justice Statistics

County	Construction Facility[a]	Statistic Meaningfully Greater than Respective State (2000)	
		Minority Population	Low-Income
Texas			
Fannin	1 PY/RS	Yes	No
Lamar	1 PY, 1 CY, 1 RS, 1 PY/CY	Yes	No
Delta	No	No	No
Hopkins	No	Yes	No
Franklin	1 RS	Yes	No
Wood	No	No	No
Upshur	No	No	No
Smith	No	Yes	No
Rusk	1 CY	Yes	No
Cherokee	1 CY	Yes	No
Nacogdoches	1 CY	Yes	Yes
Angelina	1 CY, 1 RS, 1 PY/CY	Yes	No
Polk	2 PY	Yes	No
Liberty	1 CY	No	No
Hardin	1 RS	No	No
Jefferson	1 PY	Yes	No
Houston Lateral			
Texas			
Liberty	1 CY	No	No
Chambers	No	No	No
Harris	No	Yes	No

[a] Abbreviations: Pipe Yard (PY), Construction Camp (CC) and Contractor Yards (CY) Railroad Siding and or a Pipe Yard (RRS/PY).

Minority and Low-Income Populations within Census Block Groups

A total of 287 census block groups were assessed along the 4-mile-wide analysis corridor. Within these census block groups, 297 minority populations that were meaningfully greater than the state-wide average were identified, and 83 low-income populations that were meaningfully greater than the state-wide average were also identified. Of the 287 total census block groups occurring along the proposed Project corridor, 90 census block groups had no exceedances for any minority or low-income populations. Of the 197 census block groups that did show exceedances, 115 showed exceedances for one or more minority populations, 25 showed exceedances for only low-income populations, and 57 showed exceedances for one or more minority populations along with a low-income population.

These data suggest that potential impacts to the minority and low-income populations identified in this assessment within the 4-mile wide analysis area could occur. The analysis of minority and low-income populations along the proposed Project corridor, as previously stated, is inherently conservative since 269 of the census block groups analyzed were only partially within the analysis area and it is therefore likely

that the percentages of minority and low-income populations that actually occur within the 4-mile-wide analysis area are less than the percentages derived from the analysis. Only 18 of the census block groups analyzed fall entirely within the 4-mile-wide analysis area. These 18 census block groups occur for the most part in Harris, Jefferson, and Angelina counties in Texas (17 census block groups), and the remaining census block group occurs in Lincoln County, Oklahoma. These 18 census block groups occur within more populated areas along the proposed pipeline corridor. Of these, 11 census block groups show that one or more minority and/or low-income populations are greater than their state-wide averages (see Table 3.10.1-15).

TABLE 3.10.1-15
Census Block Groups Completely Contained within 4-Mile-Wide Analysis Area

Total Number of Census Block Groups	County, State	Nearest City or Town	Meaningfully Greater Minority Census Block Groups	Meaningfully Greater Low-Income Census Block Groups	Total Number of Census Block Groups Containing One or More EJ Group Exceedances[a]
1	Lincoln County, OK	Stroud	-	Yes	1
1	Angelina County, TX	Diboll	African American; Aggregate	Yes	1
1	Jefferson County, TX	Beaumont	African American; Aggregate	-	1
2	Jefferson County, TX	Port Neches	-	-	0
7	Jefferson County, TX	Nederland	Native American or Alaskan Native; Two or More Races	-	4
2	Jefferson County, TX	Central Gardens	Native American or Alaskan Native	-	1
2	Jefferson County, TX	Beaumont and Central Gardens	African American; Native American or Alaskan Native; Two or More Races; Aggregate	-	2
1	Harris County, TX	Channelview	African American; Other; Hispanic or Latino; Aggregate	-	1
1	Harris County, TX	Highlands	-	-	0
18	**Project Total**				**11**

[a] Exceedance criteria are 1.2 times the actual environmental justice (EJ) minority or low-income group population for each state.
Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. See http://factfinder.census.gov/home.

Impacts to minority and low-income populations during construction would include exposure to construction dust and noise, potential disruption to traffic patterns, and increased competition for social services in underserved populations. Construction dust and noise would be restricted to working hours during the construction period along each segment of the proposed Project route and impacts would diminish once construction activities ended. At any given location along the proposed pipeline route, the duration of the construction period would typically range from 20 to 30 working days.

To assess the potential impacts on minority and low-income populations in areas that could be underserved by health professionals, available medical facilities, or other health services, the minority and low-income populations identified in this analysis were compared to locations along the proposed Project

corridor that are listed on the Health and Human Services (HHS) Health Resource Services Administration (HRSA) website. Areas designated as Health Professional Shortage Areas (HPSA) and Medically Underserved Areas/Populations (MUA/P) in counties that contain census block groups with one or more minority and/or low-income population identified in this assessment are presented in Table 3.10.1-16 and Figures 3.10.1-7 through 3.10.1-13.

Based upon these data, any additional disruptions to medical service availability in areas with minority or low-income populations that are designated as either HPSA and/or MUA/P areas could lead to short-term impacts to these populations during the construction period. However, in areas in Montana and South Dakota where construction camps would be provided, minor medical needs of workers would be handled in these camps, thus reducing the potential need for medical services from the surrounding communities. In any case, given the transient nature of the workforce, the impact of increased demand for medical services on local minority and low-income populations would be minor and short-term.

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Steele City Segment						
Montana						
Phillips	1	1	Eastern Montana	County	Phillips Service Area	County
Valley	6	4	Eastern Montana	County	Valley Service Area	County
McCone	3	2	Eastern Montana	County	McCone Service Area	County
Dawson	2	0	NA*	NA	NA	NA
Prairie	1	1	Eastern Montana	County	Miles City Service Area	County
Fallon	3	1	-	-	-	-
Carter	1	0	NA	NA	NA	NA
Subtotal Montana	*17*	*9*	*4*	*-*	*4*	-
South Dakota						
Harding	2	2	Harding	County	Harding Service Area	County
Butte	1	0	NA	NA	NA	NA
Perkins	1	1	Catchment Area 8	County	Perkins Service Area	County
Meade	2	0	NA	NA	NA	NA
Ziebach	1	1	-	-	-	-
Pennington	1	0	NA	NA	NA	NA
Haakon	2	1	Catchment Area 2	County	West Haakon Service Area	Minor Civil Division

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

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			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Philip Clinic *503 W. Pine St.* *Philip, SD 57567*	Rural Health Center	-	-
Jones	1	1	Catchment Area 2	County	Jones Service Area	County
Lyman	1	1	Catchment Area 2	County	Lyman Service Area	County
			Lower Brule Sioux Tribe Clinic *601 Gall St.* *Lower Brule, SD 57548*	Indian Reservation	-	-
Tripp	8	7	Catchment Area 10	County	Tripp Service Area	County
Gregory	1	1	Catchment Area 10	County	Gregory Service Area	County
Subtotal South Dakota	*21*	*15*	*9*	*-*	*7*	*-*
Nebraska						
Keya Paha	1	1	Catchment Area 4	County	Keya Paha Service Area	County
Rock	1	1	Catchment Area 4	County	Rock Service Area	County
			Greater Sandhills Family Healthcare *101 E. South St.* *Bassett, NE 68714*	Rural Health Center	-	-
Holt	2	2	Catchment Area 4	County	Holt Service Area	County
			West Holt Medical Clinic *405 W. Pearl St.* *Atkinson, NE 68713*	Rural Health Center	-	-

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

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			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Greater Sandhills Family Healthcare *418 E. 5th St.* *Atkinson, NE 68713*	Rural Health Center	-	-
			Greater Sandhills Family Healthcare *110 W. 2nd St.* *Stuart, NE 68780*	Rural Health Center	-	-
			Avera Family Medicine *403 E. Hynes Ave.* *O'Neill, NE 68763*	Rural Health Center	-	-
			Avera Holt County Medicine Clinic *555 E. John St.* *O'Neill, NE 68763*	Rural Health Center	-	-
Garfield	1	0	NA	NA	NA	NA
Wheeler	1	1	Catchment Area 3	County	Wheeler Service Area	County
Greeley	2	0	NA	NA	NA	NA
Boone	2	0	NA	NA	NA	NA
Nance	1	1	Catchment Area 4	County	Genoa Service Area	County
			Lone Tree Medical Associates *901 Broadway St.* *Fullerton, NE 68638*	Rural Health Center	-	-
			Park Street Medical Clinic *505 S. Park St.* *Genoa, NE 68640*	Rural Health Center	-	-
Merrick	2	0	NA	NA	NA	NA
Hamilton	1	0	NA	NA	NA	NA

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Polk	1	0	NA	NA	NA	NA
York	3	0	NA	NA	NA	NA
Fillmore	2	0	NA	NA	NA	NA
Saline	2	0	NA	NA	NA	NA
Jefferson	3	1	-	-	-	-
Subtotal Nebraska	*25*	*7*	*13*	*-*	*5*	*-*
New Cushing Extension Pump Stations						
Kansas						
Clay	4	1	Mental Health Area 14	County	Low Income - Clay County[d]	County
			Clay Center Family Physicians *609 Liberty St.* *Clay Center, KS 67432*	Rural Health Center	-	-
Butler	1	0	NA	NA	NA	NA
Subtotal Kansas	*5*	*1*	*2*	*-*	*1*	*-*
Gulf Coast Segment						
Oklahoma						
Payne	2	1	Catchment Area 11	County	-	-
			Iowa Tribe of Oklahoma: Perkins Family Clinic *335588 E. 750 Rd.* *Perkins, OK 74059*	Native American Tribal Population	-	-
Creek	2	0	NA	NA	NA	NA

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Lincoln	6 (1)[f]	2 (1)[f]	Black Hawk Health Center *356110 East 930 Rd.* *Stroud, Ok 74079*	Native American Tribal Population	Lincoln Service Area	County
Okfuskee	5	4	Low Income Catchment Area 13	County	Okfuskee Service Area	County
			Okemah Indian Health Center *309 N. 14th St.* *Okemah, OK 74859*	Native American Tribal Population	-	-
Seminole	5	4	Catchment Area 7	County	Seminole Service Area	County
			Central Oklahoma Family Medical Center *527 W. 3rd St.* *Konawa, OK 74849*	Comprehensive Health Center	-	-
			Seminal Nation of Oklahoma – Wewoka Indian Health Clinic *S. Hwy. 56 & U.S. Hwy. 270 Junction* *Wewoka, OK 74884*	Native American Tribal Population	-	-
Hughes	9	8	Catchment Area 6	County	Hughes Service Area	County
			East Central Oklahoma Family Health Center *401 S. Washita St.* *Wetumka, OK 74883*	Comprehensive Health Center	-	-
Pontotoc	3	3	Catchment Area 7	County	Pontotoc Northeast Service Area	Minor Civil Division
			-	-	Pontotoc Northwest Service Area	Minor Civil Division

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			-	-	Pontotoc Southwest Service Area	Minor Civil Division
			Carl Albert Indian Hospital *1001 N. Country Club Rd. Ada, OK 74820*	Indian Health Service Facility	-	-
Coal	3	3	Catchment Area 6	County	Coal Service Area	County
Atoka	6	4	Catchment Area 6	County	Atoka Service Area	County
			ABC Medical Clinic *1508 S. Virginia Ave. Atoka, OK, 74525*	Rural Health Center	-	-
			Mack Alford Correctional Center *1151 N. U.S. Hwy. 69 Stringtown, OK 74569*	Correctional Facility	-	-
Bryan	3	3	Catchment Area 7	County		
			Choctaw Nation of Oklahoma - Durant Family Medicine Clinic *1600 W. University Blvd. Durant, OK 74701*	Native American Tribal Population	-	-
			Choctaw Nation of Oklahoma - Durant Health Center *1600 N. Washington Ave. Durant, OK 74701*	Native American Tribal Population	-	-
Choctaw	1	1	Catchment Area 6	County	Choctaw Service Area	County
			Choctaw Nation Health Clinic *410 N. M St. Hugo, OK 74743*	Native American Tribal Population	-	-

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Subtotal Oklahoma	*45 (1)[f]*	*33 (1)[f]*	*21*	-	*10*	-
Texas						
Fannin	2	0	NA	NA	NA	NA
Lamar	6	3	-	-	Lamar Service Area	County
Delta	1	1	-	-	Delta Service Area	County
Hopkins	5	3	-	-	Hopkins Service Area	County
Franklin	3	1	-	-	Franklin Service Area	County
Wood	8	3	Wood	County	Wood Service Area	County
			ETMC First Physician Health Clinic *5875 S. Hwy. 37* *Mineola, TX 75773*	Rural Health Clinic	-	-
Upshur	6	1	-	-	Upshur Service Area	County
Smith	12	8	Community Health Clinic of Northeast Texas *928 N. Glenwood Blvd.* *Tyler, TX 75702*	Comprehensive Health Center	Northern Tyler Service Area	CTs** 1, 2.01, 2.02, 3, 4, 6
			-	-	Troup Service Area	CT 21
			-	-	Smith Service Area	CTs 5, 7
Rusk	4	4	Rusk	County	Rusk Service Area	County
			Mount Enterprise Community Health Clinic *106 W. Rusk St.* *Mount Enterprise, TX 75681*	Federally Qualified Health Center	-	-

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Cherokee	5	2	Cherokee	County	South Cherokee County	CTs 9508, 9509, 9510, 9511
			Rusk State Hospital *1601 S. Dickinson Dr.* *Rusk, TX 75785*	State Mental Hospital	-	-
Nacogdoches	5	2	East Texas Community Health Services *1401 S. University Dr.* *Nacogdoches, TX 75961*	Comprehensive Health Center	Nacogdoches Service Area[de]	County
Angelina	11 (1)[f]	7 (1)[f]	Duncan Prison *1502 S. 1st St.* *Diboll, TX 75941*	Correctional Facility	Huntington Division Service Area	Huntington, Zavalia Minor Civil Division
			Lufkin State School *6844 U.S. Hwy.* *Pollok, TX 75969*	State Mental Hospital	-	-
Trinity	2	1	Trinity	County	Trinity Service Area	County
Polk	9	5	Polunsky Prison *3872 F.M. Rd. 350* *Livingston, TX 77351*	Correctional Facility	Polk Service Area	County
San Jacinto	1	0	NA	NA	NA	NA
Liberty	6	4	Health Center of Southeast Texas *401 E. Crockett St.* *Cleveland, TX 77327*	Comprehensive Health Center	Liberty Service Area	County
Hardin	5	2	Hardin	County	Hardin Service Area	County
Jefferson	43 (14)[f]	21 (7)[f]	Gulf Coast Health Center	Comprehensive	Port Arthur/Jefferson Service Area	CTs 51, 53, 54, 59, 59, 61, 62, 63, 69, 71

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			2548 Memorial Blvd. *Port Arthur, TX 77640*	Health Center		
			Federal Corrections Complex *5830 Knauth Rd.* *Beaumont, TX 77715*	Correctional Facility	Low Income - Jefferson Service Area[d]	CTs 113.01, 114, 115, 116
			-	-	Low Income - Inner City Beaumont[d]	CTs 1.03, 6, 7, 9, 10, 16, 17, 19, 20, 21, 22, 23, 24, 25, 26
Orange	1	1	-	-	Orange Service Area	CTs 202, 203, 208
			-	-	Vidor Service Area[de]	CTs 207, 214, 215, 216, 217, 218, 219, 220, 222
Subtotal Texas - Gulf Coast Segment	*135 (15)[f]*	*69 (8)[f]*	*16*	-	*22*	-
Houston Lateral						
Texas						
Liberty	17	10	Health Center of Southeast Texas *401 E. Crockett St.* *Cleveland, TX 77327*	Comprehensive Health Center	Liberty Service Area	County
Chambers	2	0	NA	NA	NA	NA

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Harris	24	16 (1)[f]	Third Ward Service Area	CTs 3122, 3123, 3124, 3125, 3128	Harris Service Area	CTs 4101, 4102, 4103, 4104, 4105, 4106
			East Central Service Area	CTs 2108, 2109, 2110, 2111, 2112, 2113, 2114, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122	Southern Third Ward Service Area	CTs 3122, 3123, 3124, 3127, 3128, 3129, 3130, 3132, 3133, 3134, 3135, 3136, 3137, 3138
			Casa De Amigos Catchment Area	CTs 2103, 2104, 2105, 2106, 2107, 5102, 5103, 5104, 5105, 5106, 5107, 5113, 5114, 5116	West Pasadena	CTs 3219, 3220, 3220, 3223, 3224, 3229, 3230, 3231, 3232
			Northeast Harris Service Area	CTs 2201, 2208, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311, 2312, 2313, 2314, 2315, 2316, 2319, 2320	South Service Area	CTs 3311, 3312

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Acres Home Service Area	CTs 5308, 5318, 5319, 5320, 5326, 5327, 5328, 5329, 5330, 5331, 5332, 5333, 5334	Northeast Central Service Area	CTs 3110, 3111
			Aldine Service Area	CTs 2218, 2219, 2220, 2221, 2222, 2223, 2229, 2230, 2231, 2317	Central Harris Service Area	CTs 2102, 2113, 2114, 5101
			Low Income – Ripley Service Area	CTs 3104, 3105, 3106, 3108, 3109, 3110, 3111, 3112, 3113, 3114, 3115, 3116, 3117, 3118, 3119, 3202, 3203, 3329	North Forest Service Area	CTs 2312, 2313, 2314, 2315, 2316, 2318, 2319, 2320, 2321, 2322, 2323
			South Central Houston Service Area	CTs 3308, 3311, 3312, 3313, 3314, 3315, 3316, 3317, 3318, 3319, 3320, 3321, 3322, 3323, 3324, 3326, 3327, 3328,	East Central Houston Service Area	CTs 2112, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Houston Healthcare for the Homeless *2505 Fannin St.* *Houston, TX 77002*	Comprehensive Health Center	Ripley Service Area	CTs 3101, 3103, 3104, 3105, 3106, 3107, 3108, 3109, 3112, 3113, 3114, 3115, 3117, 3118, 3119
			Harris County Hospital District *2525 Holly Hall St.* *Houston, TX 77054*	Comprehensive Health Center	South Central Harris County Service Area	CTs 3308, 3314, 3315, 3316, 3317, 3318, 3319, 3320, 3321, 3322, 3323, 3324, 3326, 3327, 3328
			South Central Houston Community Health Center *8610 Martin Luther King Blvd.* *Houston, TX 77033*	Comprehensive Health Center	Casa De Amigos Service Area	CTs 2103, 2104, 2105, 2106, 2107, 5102, 5103, 5104, 5105, 5106, 5107, 5113, 5114, 5116
			Spring Branch Community Health Center *1615 Hillendahl Blvd.* *Houston, TX 77055*	Comprehensive Health Center	Baytown Service Area	CTs 2534, 2541, 2542, 2543, 2544, 2545, 2546
			Pasadena Health Center *524 Pasadena Blvd.* *Pasadena, TX 77506*	Comprehensive Health Center	Galena Park/Jacinto City Service Area	CTs 2333, 2335, 2336, 2337

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Fourth Ward Clinic *277 W. Gray St.* *Houston, TX 77019*	Comprehensive Health Center	Acres Home Service Area	CTs 5308, 5318, 5319, 5327, 5331, 5333, 5334
			Legacy Community Health Systems *215 Westheimer Rd.* *Houston, TX 77006*	Comprehensive Health Center	Settegast Service Area	CTs 2201, 2207, 2208, 2209, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311
			El Centro De Corazon *5001 Navigation Blvd.* *Houston, TX 77011*	Comprehensive Health Center	Aldine Settegast Service Area	CTs 2218, 2219, 2221, 2222, 2229, 2317
			Houston Community Health Center *424 Hahlo St.* *Houston, TX 77020*	Comprehensive Health Center	North Central Service Area	CTs 2217, 2224, 2225, 2228, 2401, 2402, 2405
			Hope Clinic *7001 Corporate Dr.* *Houston, TX 77036*	Federally Qualified Health Center	Independence Heights Service Area	CTs 2202, 2203, 2204, 2205, 2206, 5303, 5304, 5305
			Immigration and Customs Enforcement *15850 Export Plaza Dr.* *Houston, TX 77032*	Correctional Facility	Trinity Gardens Service Area	CTs 2108, 2109, 2110, 2111

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Houston Area Community Services *3730 Kirby Dr.* *Houston, TX 77098*	Comprehensive Health Center	Low Income - Spring Branch Service Area[d]	CTs 5201, 5202, 5203, 5204, 5205, 5206, 5207, 5210, 5211, 5212, 5213, 5214, 5215, 5216, 5217, 5218, 5219, 5220, 5221, 5222, 5223, 5224, 5401
			Motherland *4040 Yale St.* *Houston, TX 77018*	Comprehensive Health Center	Low Income - Alief Service Area[d]	CTs 4330, 4332, 4334
			Federal Detention Center Houston *1200 Texas St.* *Houston, TX 77002*	Correctional Facility	Poverty/Spanish Speaking/Immigration Population - Southwest Houston[de]	CTs 4211, 4213, 4214, 4215, 4216, 4319, 4325, 4327, 4328, 4329
			-	-	Governor's Low Income - Southwest Harris County[de]	CTs 4336, 4532, 4533, 4534, 4535, 4536, 4537, 4538
			-	-	Low Income - Northwest Harris County[de]	CTs 2226, 2401, 2405, 2406, 5501, 5502, 5503, 5504, 5505,

TABLE 3.10.1-16
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Populations[a]	HPSA[b]		MUA/P[c,d]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
						5506, 5511, 5532, 5533
Subtotal Texas - Houston Lateral	*43 (2)[t]*	*26 (1)[f]*	*23*	*-*	*25*	*-*
Subtotal Texas[g]	*174 (17)[f]*	*93 (9)[f]*	*38*	*-*	*46*	*-*
Project Total	**287 (18)[f]**	**158[a] (10)[f]**	**87**	**-**	**73**	-

*NA = Not Applicable
**CT = Census Tract
[a] Of the 158 census block groups that did show state-wide exceedances for minority and/or low-income populations, 136 showed exceedances for one or more minority populations, 22 showed exceedances for only low-income populations, and 26 showed exceedances for one or more minority populations along with a low-income population.
[b] Health Professional Shortage Areas (HPSAs) were assessed in counties where minority and/or low-income populations were identified. HPSAs may be designated as having a shortage of primary medical care, dental or mental health providers. They may be urban or rural areas, population groups, medical facilities or other public facilities. Addresses are listed for medical and other public facilities. See Figures 3.10.1-7 through 3.10.1-13 for locations of HPSA areas.
[c] Medically Underserved Areas/Populations (MUA/Ps) were assessed in counties where minority and/or low-income populations were identified. MUAs may be a whole county or a group of contiguous counties, a group of county or civil divisions or a group of urban census tracts in which residents have a shortage of personal health services. MUPs may include groups of persons who face economic, cultural or linguistic barriers to health care. See Figures 3.10.1-7 through 3.10.1-13 for locations of MUA/P areas.
[d] Medically Underserved Population (MUP) designation.
[e] MUP designated at request of State Governor based on documented unusual local conditions and barriers to assessing personal health services.
[f] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.
[g] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal. Liberty County was only counted once for HPSAs and MUA/Ps.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.
U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home. U.S. Department of Health and Human Services. Health Resources and Services Administration. HPSAs and MUA/Ps data warehouse.
See http://datawarehouse.hrsa.gov/datadownload.aspx.

Several commenters have expressed concern about any impact on environmental justice communities and enquired about potential mitigation for these impacts. As stated previously, impacts to minority and low-income populations during construction would include exposure to construction dust and noise, potential disruption to traffic patterns, and increased competition for social services in underserved populations. Mitigation for these impacts to environmental justice communities would involve ensuring that adequate communication regarding the construction schedule and construction activities is provided to these communities in appropriate languages and with information on how to seek needed social services in the event of health or other social service disruption related to construction activities. In response to these concerns regarding mitigation, DOS determined that Keystone would develop public awareness materials with special emphasis on considerations of low income and minority communities. DOS also requested that Keystone provide information on its commitment at the corporate level to addressing environmental justice concerns. In response, Keystone provided the following information relative to its commitment to corporate social responsibility for environmental justice communities.

With respect to employment opportunities for all minority and low income populations, Keystone, as a subsidiary of TransCanada, is committed to employee and supplier diversity; has in place continuing Affirmative Action plans for females, minorities, individuals with disabilities and covered veterans; and supports a policy of equal opportunity for Minority and Women-Owned Business Enterprises (M/WBEs) and Historically Underutilized Businesses (HUBs).

In addition, Keystone has worked with Hispanic leaders, communities and organizations in order to keep minority and other special interest communities informed about the proposed Project and to seek the input of these communities. The relationship between Keystone and community leaders and interest groups facilitates community education on the proposed Project and its potential relevance to members; and establishes communications so that proposed Project contractors can quickly and efficiently communicate available jobs. Specific outreach efforts to Hispanic communities to date have included publishing and circulating a proposed Project brochure and other materials in Spanish and English, and steps are being taken to publish information in the media through relationships with the National Association of Hispanic Publications and other primarily Hispanic media. In addition, the Keystone U.S. Landowner Operations Hotline is staffed with bilingual personnel, the Integrated Public Awareness (IAP) program will utilize bilingual English/Spanish print materials and the design package would utilize bilingual warning signage in appropriate locations.

With regard to Native American populations, in 2008, Keystone hosted three meetings in Pierre, South Dakota, with approximately 17 Native American tribes attending to introduce Keystone and its tribal engagement approach. Keystone also coordinated tribal involvement in the cultural survey process and to date 25 tribal members, representing 12 tribes, have participated in cultural surveys. In 2009, Keystone established a position of Tribal Liaison in its Omaha, NE, office, in order to sustain the development of long term relationships with tribes. The Tribal Liaison has worked actively with the dozens of tribes located in proximity to the proposed Project on various initiatives of mutual interest, such as facilitating enhanced awareness of pipeline construction via "Pipeline 101" sessions, facilitating employment and business opportunities and community investment, as well as involving the tribes in Keystone's Integrated Public Awareness Program. The Tribal Liaison continues to maintain regular contact with the tribes and would continue to do so throughout proposed Project construction.

Operations Impacts

Housing

The limited number of permanent employees associated with the proposed Project would result in minor long-term impacts on housing. If all 20 operational employees were newly hired for the proposed Project

and moved into the proposed Project area, they would require a maximum of 20 housing units. The existing vacant housing in the proposed Project area could easily meet this housing need.

Local Economic Activity

The 20 permanent employees hired to operate the proposed Project would result in minor long-term positive impacts on employment levels in the counties crossed by the proposed Project.

During operation, the proposed Project would generate a demand for goods and services, including electrical power, which would result in economic benefits to the region. Two studies have been conducted about the broad economic benefits of the proposed Project on individual state and national economies. The summaries of the Perryman Group (2010) and Canadian Energy Research Institute (CERI 2009) studies are provided below.

Perryman Group Study

The draft EIS analyzed and described the number of construction jobs and associated economic activity that would be generated by the proposed Project. After publication of the draft EIS, DOS reviewed the Perryman Group study commissioned by Keystone to further assess potential economic benefits from the proposed Project. The results of the Perryman Group study vary from those within the draft EIS for several reasons. The draft EIS assessed proposed Project economic benefits over an assumed 50-year project lifetime whereas the Perryman study assessed benefits over an assumed 100-year project lifetime. It appears that the calculation of the multiplier (i.e., indirect and induced) impacts in the Perryman study were also based upon the assumed 100-year project lifetime. The potential impacts do not appear to be separately calculated for construction and operation. Additionally, the Perryman study included direct construction expenditures as well as multiplier (indirect and induced) effects, and it also provided estimates of person-years of employment (i.e., the number of jobs multiplied by the assumed project life [100 years]) (see Table 3.10.1-17). In contrast the draft EIS described the employment benefits in terms of the number of jobs generated and estimated that a total of 5,000 to 6,000 workers would be employed during the construction phase of the proposed Project, comprised of 500 to 600 workers per construction spread. An estimated 10 to 15 percent of the total work force (500 to 900) would be hired locally. The estimated number of construction jobs as presented in the draft EIS can be easily compared to the number of unemployed or underemployed people within a particular jurisdiction, and provided a convenient base of comparison between the affected environment and potential Project impacts. The draft EIS also assumed, consistent with the consensus in the economic literature, that the petroleum transported by the pipeline would replace dwindling and/or less reliable heavy crude oil supplies from Venezuela, Mexico, and other sources. Thus, there would be limited additional economic benefit associated with crude oil refining, although the more secure crude oil supply would reduce the potential for reductions in future economic activity. In contrast, the Perryman study (see Table 3.10.1-18) appeared to treat the petroleum originating from Canada as a new source and then calculated additional economic activity generated from the refining and sale of that petroleum.

The Perryman study suggested that: expenditures associated with the proposed Project would range from $421.8 million in Montana to $2.3 billion in Texas; personal income from the proposed Project would range from $286.5 million in Montana to $1.62 billion in Texas; and employment associated with the proposed Project would range from 5,102 person-years in South Dakota to 50,365 person-years in Texas.

TABLE 3.10.1-17
The Impact of Construction and Development of the Proposed Project on Business Activity in the United States, Results by State (in constant 2009 Dollars)

Area	Expenditures [a]	Gross Product	Personal Income	Person-Years of Employment
Montana	$421,781,495	$349,209,504	$286,493,336	5,531
South Dakota	$470,452,678	$389,475,130	$319,432,745	5,102
Nebraska	$467,918,488	$390,354,998	$314,522,511	7,551
Kansas	$683,162,244	$486,486,146	$376,570,636	6,721
Oklahoma	$1,224,379,199	$1,072,117,568	$874,286,846	14,440
Texas	$2,320,486,782	$1,986,265,640	$1,616,408,490	50,365
Rest of U.S.	$15,342,458,878	$4,931,526,907	$2,713,265,333	29,226
United States Total	$20,930,639,765	$9,605,435,892	$6,500,979,897	118,935

[a] Expenditures include direct expenditures for construction of the proposed Project, and also the multiplier (indirect and induced) effects from those direct expenditures.

Source: Perryman Group 2010.

TABLE 3.10.1-18
Ongoing Annual Gains in U.S. Business Activity Stemming from the Permanent Increase in Stable Oil Supplies Associated with the Implementation of the Proposed Project (billions of constant 2009 Dollars)

	"Normal" Oil Price Scenario	"High" Oil Price Scenario
Total Expenditures	$100.144	$221.305
Gross Product	$29.048	$64.193
Personal Income	$16.044	$35.455
Retail Sales	$5.869	$12.969
Person-Years of Employment [a]	250,348	553,235

[a] Please note that the table in the Perryman report defines this row as "Permanent Jobs", but Appendix B of the report indicates that these are actually "person-years of employment." Assuming that the detailed appendix is accurate, and that similar units of measure were used for this and the construction impact evaluation, we have taken the liberty to put the assumed appropriate label in this row.

Source: Perryman Group 2010.

Environmental Justice

Based upon an analysis of minority and low-income populations at the county and census block group level along the proposed Project corridor, it is not likely that proposed Project operation would disproportionately adversely impact minority and low-income populations. Nonetheless, it is important that the presence of populations that are meaningfully greater than state-wide averages at the county and census block group level be recognized and that communications during proposed Project operations appropriately target these populations for the common good.

The public review and comment process that DOS implemented during NEPA environmental review provided multiple opportunities at locations along the proposed Project corridor for public input. Meeting locations were selected to limit transportation distances for attendees to the degree practicable, irrespective of attendee minority or income status. Additionally, a series of consultation meetings conducted as part of the Section 106 NHPA consultation process occurred to facilitate participation by

consulting Indian tribes for both the Steele City Segment and the Gulf Coast Segment (including the Houston Lateral). Opportunities were provided at these consultation meetings to discuss issues associated with proposed Project construction and operation (see Section 3.11 for more information on the Section 106 NHPA process). Proposed Project-related spending and tax revenues (see Section 3.10.2.2) would result in economic benefits in the region of influence, which could positively affect low-income and minority populations through increased employment opportunities (and income benefits) and improved public service levels.

There would likely be no impacts to medical service availability in areas with minority or low-income populations that are designated as either HPSA and/or MUA/P areas during normal operation of the proposed Project due to the very small number of permanent employees along the proposed Project alignment. Potential impacts to minority and low-income populations resulting from an accidental release of crude oil from the proposed Project are addressed in Section 3.13.6.7.

As a result of the stringent safety and integrity measures incorporated into the design, construction, and operation of the proposed Project, as well as governing PHMSA pipeline safety regulations, the proposed Project would not likely pose a significant risk to residents along the route, whether in rural or urban areas. Further, there is no evidence that such risks would be disproportionately borne by minority or low-income populations identified within potentially affected communities in proximity to the proposed Project. Nonetheless, the community outreach activities described in the environmental justice construction impacts discussion above would also continue throughout the proposed Project operations.

Section 3.13 addresses the risks and associated impacts to public health and safety that would result from a pipeline crude oil release and also describes how applicable safety regulations and standards would minimize the potential risk of such releases. Section 3.14 addresses cumulative impacts potentially associated with proposed Project construction and operation. This section also considers impacts associated with refinery operations, including potential environmental justice implications relative to air emissions from the refining of WCSB crude oil.

In summary, the proposed Project would not likely result in disproportionate adverse impacts to minority or low-income populations in the region of influence.

3.10.2 Public Services, Tax Revenues, and Property Values

3.10.2.1 Environmental Setting

Public Services

The region of influence is served by a range of public services and service providers. Public services most pertinent to the proposed Project include police and fire protection and medical facilities.[2] Table 3.10.2-1 shows selected information for relevant public services in the region of influence. Generally, the extent of public service resources in a region is a function of its size, population, and number of established communities. Accordingly, public service infrastructure is typically not as developed in remote rural areas as in urban areas.

There are multiple law enforcement service providers in the region of influence, including state patrols, county sheriff departments, local police departments, and special law enforcement agencies such as university police. In many cases, mutual aid or cooperative agreements allow one agency to provide

[2] Education facilities are not addressed in the section because most construction workers are not expected to relocate with school-aged children; therefore, impacts on schools would be negligible.

support to other agencies in emergencies. On average, from 1 to 10 law enforcement agencies serve any given county. In the region of influence, the exception is Harris County, Texas, which is served by 36 law enforcement agencies.

A network of fire departments and districts provides fire protection and suppression services throughout the region of influence. Many of these organizations are staffed by volunteers, particularly in rural areas. In larger urban areas, fire protection staff typically is housed in fire stations. At the county level, the number of fire departments is approximately the same as the number of law enforcement agencies.

Table 3.10.2-1 also shows the nearest medical facilities to the proposed Project; specifically all critical access facilities that are located within 50 miles of the pipeline route. Non-federal, short-term, acute care facilities nearest the route are distinguished in the table based upon their likelihood of serving Project-related medical needs. In every county along the pipeline route, there is at least one acute care facility within the county or nearby in a neighboring county. These facilities would provide emergency medical care and, in some cases, would serve as the base for local emergency medical response and transport services for construction accidents or operating concerns.

TABLE 3.10.2-1
Existing Public Services and Facilities along the Proposed Project Route

State/County[a]	Police/Sheriff Departments[b]	Fire Departments[b]	Nearest Medical Facilities[c]
Steele City Segment			
Montana			
Phillips	1	2	Phillips County Hospital (Malta)
Valley	4	3	Frances Mahon Deaconess Hospital (Glasgow)
McCone	2	1	McCone County Health Center (Circle)
Dawson	2	4	Glendive Medical Center (Glendive)
Prairie	2	1	Prairie Community Health Center (Terry)
Fallon	2	2	Fallon Medical Complex (Baker)
South Dakota			
Harding	2	3	
Butte	2	3	
Perkins	3	2	
Meade	4	6	Sturgis Regional Hospital (Sturgis)
Pennington	5	14	Rapid City Regional Hospital (Rapid City)
Haakon	2	3	Hans P. Peterson Memorial Hospital (Philip)
Jones	2	1	
Lyman	1	3	
Tripp	2	1	Winner Regional Healthcare Center (Winner)
Nebraska			
Keya Paha	1	2	
Rock	1	0	Rock County Hospital (Bassett)
Holt	5	2	Avera St. Anthony's Hospital (O'Neil)
Garfield	3	0	Valley County Hospital: Burwell Medical Clinic (Burwell)

TABLE 3.10.2-1
Existing Public Services and Facilities along the Proposed Project Route

State/County[a]	Police/Sheriff Departments[b]	Fire Departments[b]	Nearest Medical Facilities[c]
Wheeler	1	0	
Greeley	2	3	
Boone	4	3	Boone County Health Center (Albion)
Nance	1	2	
Merrick	4	3	Litzenberg Memorial County Hospital (Central City)
Hamilton	2	4	Memorial Hospital (Aurora)
York	2	3	York General Hospital (York)
Fillmore	3	6	Fillmore County Hospital (Geneva)
Saline	4	5	
Jefferson	3	5	Jefferson Community Health Center (Fairbury); Thayer County Health Services (Hebron)
New Cushing Extension Pump Stations			
Kansas			
Clay[d]	4	3	Clay County Medical Center (Clay Center); *Mercy Regional Health Center (Manhattan)
Butler[d]	8	12	*Newton Medical Center (Newton); *Susan B. Allen Memorial Hospital (El Dorado); *Via Christi Riverside Medical Center (Wichita); *Wesley Medical Center (Wichita)
Gulf Coast Segment			
Oklahoma			
Lincoln	9	6	Prague Municipal Hospital (Prague); Stroud Regional Medical Center (Stroud)
Creek	10	10	Bristow Medical Center (Bristow); Sapulpa Hospital (Sapulpa); Saint John Sapulpa (Sapulpa
Okfuskee	4	6	Creek Nation Community Hospital (Okemah)
Seminole	5	6	Seminole Medical Center (Seminole)
Hughes	3	4	Holdenville General Hospital (Holdenville)
Coal	3	4	Mary Hurley Hospital (Coalgate)
Atoka	3	7	Atoka Memorial Hospital (Atoka)
Bryan	8	12	Medical Center of Southeastern Oklahoma (Durant)
Lincoln	9	6	Prague Municipal Hospital (Prague); Stroud Regional Medical Center (Stroud)
Texas			
Fannin	8	6	Northeast Medical Center (Bonham)
Lamar	7	12	Saint Joseph's (Paris); Dubuis Hospital of Paris (Paris); Paris Regional Medical Center (Paris)
Delta	5	2	Wintermute Memorial Hospital (Klondike)
Hopkins	5	8	Hopkins County Memorial Hospital (Sulphur Springs)

TABLE 3.10.2-1
Existing Public Services and Facilities along the Proposed Project Route

State/County[a]	Police/Sheriff Departments[b]	Fire Departments[b]	Nearest Medical Facilities[c]
Franklin	2	3	East Texas Medical Center (Mt. Vernon)
Wood	6	6	Presbyterian Hospital of Winnsboro (Winnsboro)
Upshur	4	7	
Smith	8	9	East Texas Medical Center (Tyler); Mother Frances Hospital (Tyler); University of Texas Health Center (Tyler)
Cherokee	5	6	Mother Frances Hospital (Jacksonville); Rusk State Hospital (Rusk)
Rusk	6	6	Henderson Memorial Hospital (Henderson)
Nacogdoches	4	11	Nacogdoches Medical Center (Nacogdoches)
Angelina	6	8	Woodland Heights Medical Center (Lufkin)
Polk	4	8	Memorial Medical Center (Livingston)
Liberty	6	11	Cleveland Regional Medical Center (Cleveland); Kersting Hospital (Liberty); Leggett Memorial Hospital (Cleveland); Liberty-Dayton Hospital (Liberty)
Hardin	6	4	
Jefferson	10	8	Saint Elizabeth Hospital (Beaumont); Debuis Hospital of Beaumont (Beaumont); Memorial Herman Baptist (Beaumont) Saint Mary Hospital (Port Arthur); Promise Specialty Hospital of Southeast Texas (Port Arthur); Mid-Jefferson Hospital (Nederland)
Houston Lateral			
Texas			
Liberty			*See Liberty County in Gulf Coast Segment, above*
Chambers	4	5	Bayside Community Hospital & Clinic (Anahuac)
Harris	36	41	Bay Area Surgicare Center (Webster); Bayshore Medical Center (Pasadena); Bayou City Medical Center (Houston); Ben Taub General Hospital (Houston); Children's Memorial Hermann Hospital (Houston); Saint Catherine Hospital (Katy); Saint John Hospital (Nassau Bay); Saint Joseph Hospital (Houston); Clear Lake Regional Medical Center (Webster); Cypress Creek Hospital (Houston); Cypress Fairbanks Medical Center (Houston); Dubuis Hospital of Houston (Houston); East Houston Regional Medical Center (Houston); Lyndon B. Johnson General Hospital (Houston); Quentin Mease Community Hospital (Houston); Kingwood Medical Center (Kingwood); Spring Branch Medical Center (Houston); West Houston Medical Center (Houston); Women's Hospital of Texas (Houston) Hermann Hospital (Houston); Kindred Hospital Bay Area (Pasadena); Kindred Hospital Houston (Houston); Kindred Hospital Houston Northwest (Houston); Memorial Hermann Northwest Hospital (Houston); Memorial Hermann Katy Hospital (Katy); Memorial Hermann Southeast Hospital (Houston); Memorial Hermann

TABLE 3.10.2-1 Existing Public Services and Facilities along the Proposed Project Route			
State/County[a]	Police/Sheriff Departments[b]	Fire Departments[b]	Nearest Medical Facilities[c]
			Southwest Hospital (Houston); Methodist Hospital (Houston); Methodist Willowbrook Hospital (Houston); San Jacinto Methodist Hospital (Houston); Michael E. Debakey VA Medical Center (Houston); Park Plaza Hospital (Houston); Parkview Community Hospital (Houston) Saint Joseph Hospital (Houston); Saint Luke's Episcopal Hospital (Houston); Twelve Oaks Medical Center (Houston); West Houston Medical Center (Houston); West Oaks Hospital (Houston)

[a] States and counties are listed geographically from north to south as proposed project crosses the area.

[b] Includes special law enforcement units for universities. Includes volunteer, district, city, and town fire departments (Capitol Impact 2006).

[c] All facilities listed are critical access facilities within approximately 50 miles of the project; those marked with and asterisk (*) are non-federal, short-term, acute care facilities (AHD 2006).

[d] Construction in these counties will be related to pump stations only.

There are multiple Local Emergency Planning Committees (LEPCs) established under the Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986 along the proposed pipeline corridor (see Table 3.13.5-7). These committees exist in cities and counties along the proposed Project corridor where the handling of hazardous or toxic materials in existing facilities or the transport of these materials through the committee areas of responsibility are known to occur based on reporting requirements included within EPCRA and the Superfund Amendments and Reauthorization Act (SARA) of 1986. Should the proposed Project be implemented, Keystone would reach out to LEPCs during and after the development of its Emergency Response Plan (ERP) and public awareness materials with special emphasis on considerations of low income and minority communities in those preparedness efforts.

Tax Revenues

The 2007 property taxes levied by county, the assessed value of property, and the implied effective tax rate by county for the proposed Project area of influence are presented in Table 3.10.2-2. Effective property tax rates in the area of influence ranged from a low of 1.05 percent of property value in Harding County, South Dakota to a high of 10.00 percent in Creek County, Oklahoma. In general, most of the property tax rates are between 1.00 and 3.00 percent, with an average of 2.06 percent. The property tax rates in Oklahoma are greater than the other counties within the area of influence, averaging 9.14 percent.

Various jurisdictions crossed by the proposed Project also assess sales and use taxes, which are based upon the value of goods and materials purchased, as well as income taxes levied on labor earnings. Applicable sales and income tax rates vary across counties. In some states, there also can be corporate taxes at both a state and local level. In addition, federal agencies assess fees for use of public lands for activities such as pipeline ROWs and electrical transmission line or electrical distribution line ROWs.

TABLE 3.10.2-2
2007 Property Tax Levy and Assessed Valuation by County

State/County	Taxes Levied ($)	Assessed Value ($)	Effective Tax Rate (%)
Steele City Segment			
Montana			
Phillips	5,365,348	321,173,215	1.67%
Valley	10,664,457	485,988,933	2.19%
McCone	3,164,719	191,888,122	1.65%
Dawson	9,655,689	389,463,999	2.48%
Prairie	1,653,199	94,403,567	1.75%
Fallon	4,841,377	334,310,467	1.45%
Subtotal Montana	*35,344,789*	*1,817,228,303*	*1.94%*
South Dakota			
Harding	2,226,716	212,834,056	1.05%
Butte	(a)	431,961,877	(a)
Perkins	3,264,315	242,943,061	1.34%
Meade	21,100,792	1,283,587,876	1.64%
Pennington	95,055,282	5,844,272,499	1.63%
Haakon	(a)	238,038,114	(a)
Jones	1,698,003	159,781,297	1.06%
Lyman	4,006,951	366,472,296	1.09%
Tripp	6,353,944	477,303,334	1.33%
Subtotal South Dakota	*133,706,003*	*9,257,194,410*	*1.44%*
Nebraska			
Keya Paha	2,973,340	197,869,109	1.50%
Rock	4,312,550	252,048,909	1.71%
Holt	20,636,815	1,207,224,347	1.71%
Garfield	2,820,969	167,106,798	1.69%
Wheeler	2,759,762	211,131,099	1.31%
Greeley	5,476,377	316,644,025	1.73%
Boone	11,719,719	692,307,733	1.69%
Nance	6,523,215	351,882,579	1.85%
Merrick	12,719,873	677,474,809	1.88%
Hamilton	18,045,995	1,087,894,709	1.66%
York	23,513,215	1,323,917,546	1.78%
Fillmore	13,731,263	753,036,314	1.82%
Saline	20,727,020	1,058,221,220	1.96%
Jefferson	13,245,717	717,959,001	1.84%
Subtotal Nebraska	*159,205,830*	*9,014,718,198*	*1.77%*

TABLE 3.10.2-2
2007 Property Tax Levy and Assessed Valuation by County

State/County	Taxes Levied ($)	Assessed Value ($)	Effective Tax Rate (%)
New Cushing Extension Pump Stations			
Kansas			
Clay	9,547,982	706,839,030	1.35%
Butler	79,382,164	5,849,633,370	1.36%
Subtotal Kansas	*88,930,146*	*6,556,472,400*	*1.36%*
Gulf Coast Segment			
Oklahoma			
Atoka	2,498,917	30,238,520	8.26%
Bryan	11,413,199	136,416,335	8.37%
Coal	958,960	11,798,330	8.13%
Creek	22,517,818	225,072,546	10.00%
Hughes	2,522,911	33,385,804	7.56%
Lincoln	7,058,488	78,055,230	9.04%
Okfuskee	1,959,761	23,543,168	8.32%
Payne	28,349,366	293,459,900	9.66%
Seminole	4,357,597	48,614,451	8.96%
Pontotoc	7,918,904	98,800,803	8.02%
Subtotal Oklahoma	*89,555,921*	*979,385,087*	*9.14%*
Texas			
Angelina	60,969,218	3,052,256,882	2.00%
Cherokee	34,338,336	1,812,810,085	1.89%
Delta	4,534,214	310,482,390	1.46%
Fannin	22,818,196	1,219,567,614	1.87%
Franklin	12,764,553	1,201,312,450	1.06%
Hardin	$45,760,882	2,061,986,220	2.22%
Hopkins	29,938,733	1,471,649,558	2.03%
Jefferson	506,643,329	18,574,203,161	2.73%
Lamar	47,442,151	2,229,909,021	2.13%
Liberty	81,305,222	4,153,229,220	1.96%
Nacogdoches	52,297,618	2,837,250,144	1.84%
Polk	36,050,016	2,111,521,453	1.71%
Rusk	67,211,423	4,444,332,830	1.51%
Smith	212,734,763	12,541,361,198	1.70%
Upshur	33,340,080	1,911,716,646	1.74%
Wood	41,862,352	2,910,033,737	1.44%
Subtotal Texas - Gulf Coast Segment	*1,290,011,086*	*62,843,622,609*	*2.05%*

TABLE 3.10.2-2 2007 Property Tax Levy and Assessed Valuation by County			
State/County	**Taxes Levied ($)**	**Assessed Value ($)**	**Effective Tax Rate (%)**
Houston Lateral			
Texas			
Liberty	*see above*	*see above*	*see above*
Chambers	126,062,105	6,078,153,460	2.07%
Harris	6,333,806,178	304,029,290,532	2.08%
Subtotal Texas - Houston Lateral	*6,459,868,283*	*310,107,443,992*	*2.08%*
Subtotal Texas	*7,749,879,369*	*372,951,066,601*	*2.08%*
Total Counties	**8,248,703,154**	**400,477,264,196**	***2.06%***

[a] County did not report.

Sources: South Dakota Property Tax Division - Equalized Valuations and Property Taxes Collected from All Sources, http://www.state.sd.us/drr2/propspectax/property/publications.htm; Nebraska Department of Revenue, Property Assessment Division, 2007 and 2008 Comparison, December 2008, http://pat.ne.gov/researchReports/map/index.html; Oklahoma - Personal Communication with Teresa Strawther, Ad Valorem Division, Oklahoma Tax Commission, July 27, 2009; Kansas Department of Revenue - http://www.ksrevenue.org/pdf/forms/08arcomplete.pdf; Texas Comptroller of Public Accounts - Taxes by County, http://www.window.state.tx.us/taxinfo/proptax/07taxrates/, Includes County, School and Special District Taxes on the County Valuation.

3.10.2.2 Potential Impacts

Construction Impacts

Public Services

The influx of construction workers into local communities has the potential to generate additional demands on local public services (e.g., emergency response, medical, police, and fire protection services). Various types of emergency events that required medical response could occur during construction (e.g. worker accidents). The magnitude of public service impacts would vary by community, depending upon the number of non-local workers and accompanying families, the size of the community, and duration of stay. Few non-local workers would likely be accompanied by family members because of the short construction period and transient nature of the work. Therefore, potential overall public service impacts associated with temporary increases in population would be short-term and minor in much of the proposed Project area.

The need for emergency response during construction in more urban areas would not likely impact existing overall emergency response capability based upon the proximity of existing public service facilities to the proposed Project ROW. However, the potential effects could be greater in rural areas where there are dispersed small towns and fewer services, and in these areas the response needs of up to 600 workers per spread could lead to short-term impacts on response services and providers. In Montana and South Dakota, the need for public services would be ameliorated by construction of the work camps, which would reduce the demand on public services in small towns and counties in the general area of the work camps.

DOS understands that Keystone would work with local law enforcement, fire departments, and emergency service providers, including medical aid facilities, to establish appropriate and effective emergency response measures. This information would be included in the emergency response plan (ERP) developed prior to the implementation of the proposed Project.

Tax Revenues and Fiscal Resources

The fiscal benefits during construction of the proposed Project would include short-term sales and income tax revenues. These new revenues should meet or exceed the funding required to provide project-related needs for most jurisdictions, because the proposed Project would not likely require substantial new government expenditures for public service impacts. The range of potential tax revenues during construction is described below.

In the short-term, the predominant source of tax revenues would be sales/use and fuel taxes levied on goods and services purchased during the construction period. This would include, for example, construction materials and construction worker spending in the local economy for basic living expenses such as food, housing, gasoline, and entertainment. It is difficult to quantify these short-term tax benefits because they would be dependent upon construction spending levels, the ability of local businesses to meet the demand for required materials and services, and the variability of applicable taxes and tax rates across jurisdictions affected by the proposed Project.

For employee-generated purchases, tax revenues would depend upon the proportion of the work force originating from the local area, the behavior of individual workers, and the duration of non-local worker residency. Some portion of the construction payroll would be retained and spent within the region of influence by the work force during the construction period. The resulting tax revenues generated by this spending would represent additional fiscal benefits resulting from the proposed Project.

Short-term fiscal benefits could also arise from fees assessed by federal agencies for the use of public land for pipeline and electrical transmission line or distribution line ROWs, as well as from local, state, and federal income taxes paid by corporations and employees serving the proposed Project. These taxes and fees would vary by region and were not quantified for this analysis.

Property Damages and Values

Potential damages to private property during proposed Project construction would be concentrated along the ROW and appurtenant facilities. Land disturbed by the proposed Project would be restored to the extent practicable; to repair or restore drain tiles, fences, and land productivity damaged or adversely affected during construction; and to compensate property owners for any additional damages caused by proposed Project construction. Construction of the proposed Project could lead to short-term impacts to property values due to short-term visual, noise, and land disturbance effects.

Operations Impacts

Public Services

No new housing would likely be needed for the 20 employees comprising the operational work force and there would be no long-term impacts associated with the proposed Project on public services and utilities.

Tax Revenue and Fiscal Resources

The proposed Project would generate varied tax revenues for local and state jurisdictions, as well as the federal government. The major incremental tax revenue at the state and local levels would be property taxes, which are based on the assessed value of proposed Project facilities and applicable tax rates. Generally, states assess the value of pipelines to facilitate consistent valuation among counties crossed by the facility within the state.

Once the proposed Project was constructed, it would generate long-term property tax revenues for the states and counties traversed by the pipeline, in accordance with applicable tax structures. Estimates of property taxes by state were developed based upon the value and/or length of pipe in the ground and quantity of aboveground facilities (see Table 3.10.2-3). The estimated tax data for Montana was developed by the Montana Department of Revenue (e-mail correspondence with Vern Fogle). An estimated $140.5 million in annual property tax revenues would be generated by the proposed Project in the region of influence. This estimate was based upon 2006 tax rates and an estimated $7.0 billion of capital costs. The estimate implies an average 2.0 percent effective tax rate on $7.0 billion. Most of these revenues, about $100.3 million, would be attributed to the Steele City Segment. The pump stations in Kansas would generate $2.0 million, the Gulf Coast Segment would generate $37.3 million, and the remaining $0.875 million would be generated in the Houston Lateral.

Annual property taxes for the proposed Project that would be paid by Keystone would represent 9.16 percent of the total annual property taxes assessed in 2006 in all counties that would be crossed by the proposed Project. This would represent a major fiscal benefit to the affected counties. The greatest percent increase over 2006 taxes, 42.7 percent, would occur along the proposed Steele City Segment. There would be an estimated 151 percent increase in property tax revenues in Montana compared to 2006, based upon an implied effective tax rate of 4.3 percent on the estimated capital costs of the proposed Project in Montana. This tax rate would be twice that of the proposed Project average tax rate across all counties.

If all estimated property taxes were paid for the new proposed Cushing Extension pump stations in Kansas, Keystone would pay $2 million in annual property taxes that would represent a 2.7 percent increase in annual property taxes for affected Kansas counties, compared to 2006 levels. However, Keystone has applied for a property tax exemption in the state of Kansas.

Along the proposed Gulf Coast Segment, there would be an 11.9 percent increase in annual property taxes, compared to 2006 levels, if the proposed Project was implemented. The increase in annual property taxes along the proposed Houston Lateral would be 0.1 percent above 2006 levels. Local counties would be the primary beneficiaries of these property tax benefits. Depending upon the size of the existing tax base of each county and assuming that the 2006 tax rates would remain in effect if the proposed Project was implemented, these revenues would represent a moderate to major long-term fiscal benefit.

TABLE 3.10.2-3
2006 Tax Levy and Estimated Proposed Project Property Tax by County

County	2006 Property Taxes Levied ($)	Estimated Property Tax for Proposed Project ($)	Estimated Proposed Project Property Tax as Percent of 2006 Property Taxes
Steele City Segment			
Montana			
Phillips	6,891,579	4,367,060	63.37%
Valley	12,731,805	14,860,604	116.72%
McCone	3,161,702	18,038,389	570.53%
Dawson	12,141,019	14,126,149	116.35%
Prairie	2,106,988	5,869,630	278.58%
Fallon	4,663,545	5,695,963	122.14%
Subtotal Montana	*41,696,638*	*62,957,795*	*150.99%*

TABLE 3.10.2-3
2006 Tax Levy and Estimated Proposed Project Property Tax by County

County	2006 Property Taxes Levied ($)	Estimated Property Tax for Proposed Project ($)	Estimated Proposed Project Property Tax as Percent of 2006 Property Taxes
South Dakota			
Harding	876,254	3,346,244	381.88%
Butte	1,811,097	134,730	7.44%
Perkins	1,290,869	624,306	48.36%
Meade	6,773,987	2,608,096	38.50%
Pennington	25,958,625	41,365	0.16%
Haakon	825,951	2,818,539	341.25%
Jones	612,854	2,044,666	333.63%
Lyman	1,057,054	489,057	46.27%
Tripp	2,197,509	3,298,393	150.10%
Subtotal South Dakota	*41,404,200*	*15,405,396*	*37.21%*
Nebraska			
Keya Paha	2,429,603	1,133,796	46.67%
Rock	4,031,120	649,588	16.11%
Holt	19,720,255	3,548,059	17.99%
Garfield	2,613,263	659,714	25.24%
Wheeler	2,699,567	1,328,431	49.21%
Greeley	5,144,809	1,714,863	33.33%
Boone	11,109,437	222,867	2.01%
Nance	6,195,427	1,280,136	20.66%
Merrick	12,327,924	1,581,338	12.83%
Hamilton	16,950,108	499,036	2.94%
York	22,800,935	2,175,921	9.54%
Fillmore	13,129,028	1,577,037	12.01%
Saline	19,624,429	1,339,885	6.83%
Jefferson	13,079,964	4,184,344	31.99%
Subtotal Nebraska	*151,855,869*	*21,895,015*	*14.42%*
New Cushing Extension Pump Stations			
Kansas			
Clay	9,037,940	1,542,806	17.07%
Butler	65,068,063	453,949	0.70%
Subtotal Kansas	*74,106,003*	*1,996,755*	*2.69%*
Gulf Coast Segment			
Oklahoma			
Lincoln	2,311,059	1,620,262	70.11%
Creek	31,369,794	411,919	1.31%
Okfuskee	3,409,877	1,239,748	36.36%
Seminole	9,064,881	2,169,785	23.94%
Hughes	6,340,078	2,188,917	34.53%
Coal	3,733,358	2,604,589	69.77%
Atoka	4,059,497	1,568,644	38.64%
Bryan	15,568,464	2,494,487	16.02%
Subtotal Oklahoma	*75,857,008*	*14,298,351*	*18.85%*

TABLE 3.10.2-3
2006 Tax Levy and Estimated Proposed Project Property Tax by County

County	2006 Property Taxes Levied ($)	Estimated Property Tax for Proposed Project ($)	Estimated Proposed Project Property Tax as Percent of 2006 Property Taxes
Texas			
Fannin	6,861,098	415,734	6.06%
Lamar	9,288,471	1,514,314	16.30%
Delta	1,457,836	1,550,784	106.38%
Hopkins	7,451,377	573,610	7.70%
Franklin	3,831,662	1,098,306	28.66%
Wood	10,396,712	1,863,930	17.93%
Upshur	8,345,374	348,966	4.18%
Smith	30,868,384	1,645,008	5.33%
Cherokee	10,459,552	1,393,088	13.32%
Rusk	13,641,514	646,068	4.74%
Nacogdoches	10,942,646	1,139,530	10.41%
Angelina	12,421,410	1,470,148	11.84%
Polk	12,316,738	3,015,148	24.48%
Hardin	10,863,453	593,311	5.46%
Liberty	21,705,512	4,156,875	19.15%
Jefferson	66,382,570	1,618,688	2.44%
Subtotal Texas - Gulf Coast Segment	*237,234,309*	*23,043,508*	*9.71%*
Houston Lateral			
Texas			
Liberty	see above	see above	see above
Chambers	26,053,006	207,106	0.79%
Harris	885,849,380	667,702	0.08%
Subtotal Texas - Houston Lateral	*911,902,386*	*874,808*	*0.10%*
Subtotal Texas	*1,149,136,695*	*23,918,316*	*2.08%*
Project Totals	**1,534,056,413**	**140,471,628**	**9.16%**

Sources: South Dakota Property Tax Division, Equalized Valuations and Property Taxes Collected from All Sources, http://www.state.sd.gov/applications/DLASearches/countymenu.aspx; Nebraska Department of Revenue, Property Assessment Division, 2007 and 2008 Comparison, December 2008. http://pat.ne.gov/researchReports/annual/pdf/2006/NE%20PA&T%20Annrpt2006%20part%201%20of%204%20Text%20&%20Tables%201-18.pdf.html ; Kansas Department of Revenue (KDOR) http://www.ksrevenue.org/pdf/forms/07arcomplete.pdf; Oklahoma, Personal Communication with Teresa Strawther, Ad Valorem Division, Oklahoma Tax Commission, July 27, 2009; Texas Comptroller of Public Accounts, taxes by County http://www.window.state.tx.us/taxinfo/proptax/annual06/table18.pdf

The Perryman study (2010) also found that significant local and state property tax revenues would be generated by the proposed Project, as shown in Table 3.10.2-4. These additional tax revenues could be used for a variety of purposes by each jurisdiction, including reducing potential impacts from the proposed Project, and improving existing services or providing new services to residents.

TABLE 3.10.2-4 Local and State Government Property Tax Revenues Associated with Development of the Proposed Project (millions of constant 2009 Dollars)		
State	**Local Government Revenues**	**State Government Revenues**
Montana	$1.410	$7.493
South Dakota	$1.596	$8.466
Nebraska	$1.814	$9.484
Kansas	$2.948	$15.013
Oklahoma	$3.959	$21.293
Texas	$7.699	$41.140
U.S. Total	**$99.095**	**$486.359**

Source: Perryman Group 2010.

Property Damages and Values

Although the permanent ROW would be restored after construction, continued access to the proposed Project ROW would be required to support surface and aerial inspections and any necessary repairs or maintenance for the useful life of the proposed Project. Potential damages to private property during proposed Project operation would likely be concentrated along the permanent ROW and at appurtenant facilities.

An indication of the potential impacts of the proposed Project on property values can be gained from the study of property value impacts from previous pipeline projects. A literature search was therefore conducted to assess impacts upon residential and agricultural property values associated with similar projects constructed in the recent past. Three relevant studies were reviewed, including INGAA (2001), Fruits (2008), and Palmer (2008). Key findings from these studies are summarized briefly below.

The INGAA Foundation (2001) conducted analyses of the effects of natural gas and products pipelines on property values in:

- A residential subdivision in Katy, Texas;
- Four residential subdivisions including vacant land in Medford, Oregon;
- A master planned commercial neighborhood in Irving, Texas; and
- A residential subdivision in Newtown, Connecticut.

The study analyzed paired sale comparisons and statistical analyses for:

- March 1996 through November 2000 in Katy, Texas;
- June 1992 through December 2000 in Medford, Oregon;
- February 1997 through September 2000 in Irving, Texas; and
- June 1993 through October 2000 in Newtown, Connecticut.

The study determined that construction and operation of the pipelines through these areas had no noticeable impact on property sales prices. The minor positive and negative price differences found were less than 5 percent, and most were positive. The study also concluded that there was no relationship to

the size of the pipeline (they studied 6, 10, 12, 20, 24, and 30-inch diameter pipelines), the products transported, or pipeline age (from 6 to 56 years old). In some cases, pipeline easements were "transformed into an amenity to the community, such as landscaped greenbelts, walking/jogging paths, and golf courses." The market demand (i.e., the number of days on the market) for properties was not apparently affected by a property's location relative to a nearby pipeline, although the market demand may have been positively influenced by the amenities developed along some of the pipeline easements. Further development of properties was not apparently affected by the presence of the pipelines.

Fruits (2008) evaluated the effects of the high-pressure, 24-inch natural gas South Mist Pipeline Expansion Project on the values of more than 10,000 residential properties located within 1 mile of the pipeline in Clackamas and Washington counties (in Oregon). The study determined that the presence of the pipeline had no economically significant effect on residential property values within 1 mile of the pipeline.

Palmer (2008) also evaluated the effects of the high-pressure, 24-inch natural gas South Mist Pipeline Expansion Project on the values of 18 properties, primarily residential and agricultural, sold from January 2004 to January 2008 in Clackamas and Washington counties in Oregon. Construction of that pipeline was completed in September 2004. The study found no measurable impacts to property values attributable to the presence of the pipeline. The differential prices ranged from -5.60 percent (i.e., price reduction) to +13.50 percent (i.e., price increase), with an average difference of +2.58 percent. In addition, buyers reported that they "felt the pipeline had little to no impact on their decisions to purchase the properties and did not perceive a long-term impact on [the] value of their property."

Thus, as shown by the above studies, residential and agricultural properties located on or adjacent to pipeline easements could have property values worth more or less than comparable nearby properties that were not encumbered by pipeline easements. However, those differences generally were statistically insignificant and the absolute dollars involved were not significant relative to the overall property value and sales prices. Thus, it does not appear that the proposed Project would have a major impact on residential and agricultural property values.

For a review of potential impacts to land values associated with oil spills and releases, see Section 3.13.5.8.

3.10.3 Traffic and Transportation

3.10.3.1 Environmental Setting

Highways, Major Roads, and Rural Roads

The proposed Project would meet or intersect many local, state, federal, and interstate roads and highways along its length. This section uses GIS data, which is accurate to plus or minus (+/-) 167 feet (ESRI 2008), to provide information about these roads and highways. Consequently, while the data are not intended for survey positional accuracy, they nonetheless provide adequate information to describe the roads and highways crossed. The roads and highways have been classified into four categories, based upon the U.S. Census Feature Class Codes:

- Category I: Local, Neighborhood, Rural or City roads;
- Category II: Secondary State and County Highways;
- Category III: Primary US and State Highways; and
- Category IV: Primary Limited Access or Interstate.

The roads in rural areas are well developed within the states the proposed Project would cross. Construction contractors would be required to submit a road use plan prior to mobilization, to coordinate with the appropriate state and county representatives to develop a mutually acceptable plan, and to obtain all necessary road permits. Inspection personnel would ensure that the construction contractor complied with these road-use plans and road-use permits.

Steele City Segment

The proposed Steele City Segment would extend from the border crossing near Morgan, Montana to Steele City, Nebraska. The proposed Steele City Segment would pass through Montana, South Dakota, and extend to the southern border of Nebraska. This segment of the proposed Project would cross three Interstate Highways, I-94, I-90, and I-80 (see Figure 3.10.3-1).

The proposed Steele City Segment would meet or intersect with a total of 722 roads in Categories I, II, III, and IV (Table 3.10.3-1), with the largest number of crossings in Montana (269), followed by Nebraska (260) and South Dakota (193).

TABLE 3.10.3-1
Intersections of Steele City Segment with Roads, by State

State	Road Category	Road Name	Number of Road Intersections
Montana	Category I		254
	Category II	Marsh Rd	1
		Old Us Hwy 10	1
		River Rd	1
		Rock Creek Rd	1
		SR 117	1
		SR 24	1
		SR 243	1
		SR 7	1
		Weldon Rd	1
	Category III	SR 13	1
		SR 200	2
		US 12	1
		US 2	1
	Category IV	I 94	1
Subtotal Montana			*269*
Nebraska	Category I		238
	Category II	SR 11	1
		SR 12	1
		SR 137	1
		SR 14	1
		SR 15	1
		SR 22	1
		SR 4	1
		SR 41	1
		SR 56	1
		SR 66	1
		SR 70	1
		SR 74	1

TABLE 3.10.3-1 Intersections of Steele City Segment with Roads, by State			
State	**Road Category**	**Road Name**	**Number of Road Intersections**
		SR 8	1
	Category III	SR 92	1
		US 136	1
		US 20	1
		US 281	1
		US 30	1
		US 34	1
		US 6	1
		US 81	1
	Category IV	I 80	1
Subtotal Nebraska			*260*
South Dakota	Category I		174
	Category II	Bad River Rd	1
		CR 35	1
		CR 797	1
		CR 867	1
		CR S6 Jones	1
		CR S9 Jones	1
		SR 16	1
		SR 20	1
		SR 34	1
		SR 53	1
		SR 73	1
		SR 79	1
	Category III	US 14	1
		US 18	1
		US 183	2
		US 212	1
		US 85	1
	Category IV	I 90	1
Subtotal South Dakota			*193*
Total Steele City Segment Intersections			**722**

Notes: SR = State Route; US = U.S. Highway; I = Interstate; CR = County Road
Source: ESRI Data & Maps 9.3 [DVD]. 2008. Environmental Systems Research Institute, Redlands, California, USA.

Gulf Coast Segment

The proposed Gulf Coast Segment would pass through Oklahoma and Texas, starting from Cushing, Oklahoma and extending to Nederland in Jefferson County, Texas. This segment would cross Interstate Highways I-44, I- 40, I-30, I-20, and I-10. It would also parallel SR 146 in Texas for approximately 7.5 miles (see Figure 3.10.3-2). The proposed Gulf Coast Segment would meet or intersect with 488 roads in Categories I, II, III, and IV (Table 3.10.3-2). This total would include 339 roads in Texas and 149 roads in Oklahoma.

TABLE 3.10.3-2
Intersections of Gulf Coast Segment with Roads, by State

State	Road Category	Road Name	Number of Road Intersections
Oklahoma	Category I		134
	Category II	SR 1	1
		SR 3	1
		SR 31	1
		SR 56	1
		SR 7	1
		SR 9	1
		SR 99	1
		SR 99a	1
	Category III	SR 66	1
		US 270	1
		US 62	1
		US 69	1
		US 70	1
	Category IV	I 40	1
		I 44	1
Subtotal Oklahoma			*149*
Texas	Category I		271
	Category II	Berard	1
		E Fm 852	1
		Fm 137	1
		Fm 16	1
		Fm 1911	1
		Fm 2122	1
		Fm 225	2
		Fm 2352	1
		Fm 2869	1
		Fm 3357	1
		Fm 343	1
		Fm 38	2
		Fm 62	1
		Fm 71	1
		Fm 770	1
		Fm 787	1
		Fm 79	1
		Fm 839	1
		Fm 900	1
		Fm 942	2
		Fm 943	1
		Fm Road 2088	1
		Fm Road 69	1
		Hillebrandt Rd	1
		HWY 1448	1

TABLE 3.10.3-2
Intersections of Gulf Coast Segment with Roads, by State

State	Road Category	Road Name	Number of Road Intersections
		S Major Dr	1
		S Pine Island Rd	1
		SE Fm 13	1
		SR 103	1
		SR 105	1
		SR 11	1
		SR 124	1
		SR 135	1
		SR 146	2
		SR 154	1
		SR 155	1
		SR 19	1
		SR 204	1
		SR 21	1
		SR 31	1
		SR 326	1
		SR 347	1
		SR 37	1
		SR 64	1
		SR 7	1
		SR 94	1
		Tyrrell Park Rd	1
		W Port Arthur Rd	1
		Walden Rd	1
	Category III	US 190	1
		US 271	1
		US 287	1
		US 59	1
		US 67	1
		US 69	2
		US 79	1
		US 80	1
		US 82	1
		US 84	1
		US 90	1
	Category IV	I 10	1
		I 20	1
		I 30	1
Subtotal Texas			*339*
Total Gulf Coast Segment Intersections			**488**

Source: ESRI Data & Maps 9.3 [DVD]. 2008. Environmental Systems Research Institute, Redlands, California, USA.

Houston Lateral

The proposed Houston Lateral would extend from the proposed Gulf Coast Segment in Liberty County, Texas, for approximately 49 miles to Harris County, Texas. This segment would intersect U.S. Highway 90 (see Figure 3.10.3-3). The proposed Houston Lateral would meet or intersect 51 roads (see Table 3.10.3-3), within Categories I, II, and III.

TABLE 3.10.3-3
Intersections of Houston Lateral with Roads

State	Road Category	Road Name	Number of Road Intersections
Texas	Category I		43
	Category II	Fm 1409	1
		Fm 160	1
		Fm 1942 Rd	1
		Fm 563	1
		Sheldon Rd	1
		SR 134	1
		SR 146	1
	Category III	US 90	1
Total Houston Lateral Intersections			**51**

Source: ESRI Data & Maps 9.3 [DVD]. 2008. Environmental Systems Research Institute, Redlands, California, USA.

Railroads

The proposed Project would also cross several railway service tracks. Table 3.10.3-4 lists the railroad names and owners. As shown, there would be 43 total intersections, including seven in Montana, five in Nebraska, five in Oklahoma, two in South Dakota, and 24 in Texas.

The Burlington Northern Santa Fe (BNSF) has main, branch, and spur tracks in the states that would be traversed by the pipeline.[3] The proposed Project route would cross the BNSF main tracks in the Montana Operating Division, running between Snowden and Shelby and between Snowden and Jones Junction. In Nebraska, the proposed Project would cross the BNSF main track in the Nebraska Operating Division, between Lincoln and Hastings. In the BNSF Kansas Operating Division, the proposed Project would cross two main tracks, one between Newton and Los Animas Junction and the other between Wichita and Amarillo (Texas). The proposed Project route would also cross several branch tracks, spurs, and short line tracks throughout the BNSF system area.

The Union Pacific Railroad (UPRR) has main, branch, and spur tracks throughout Nebraska and Kansas[4]. In Nebraska, the proposed route would cross a UPRR main track between Omaha and North Platte. In Kansas, the proposed Project would cross several main tracks connecting Topeka, Wichita, and other cities. In Oklahoma and Texas, the proposed Project route would cross UPRR main tracks running between Dallas and Houston and other cities in Texas and Louisiana.

[3] See the BNSF system map at http://www.bnsf.com/tools/reference/division_maps, accessed August 3, 2009.
[4] See the UPRR system map at http://www.uprr/com/aboutup/maps/sysmap/index.shtml, accessed August 3, 2009.

Other railroads would also be crossed by the proposed Project route in South Dakota, Nebraska, Oklahoma, and Texas, including the Southern Kansas and Oklahoma; United States Gypsum; Nebraska Central Railroad; Stillwater Central Railroad; Kiamichi Railroad; Dakota, Minnesota and Eastern Railroad; Dakota Southern Railway; Dallas, Garland, and Northeastern Railroad; Moscow Camden and San Augustine Railroad; Kansas City Southern Railroad; Texas Southeast Railway; and Port Terminal Railroad Association.

TABLE 3.10.3-4
Intersection of Proposed Project with Railroads, by Segment and State

Segment	Railroad Name	Railroad Owner (Reporting Mark)	Number of Rail Intersections
Steele City Segment			
Montana			
	Burlington Northern Railroad	BNSF (Burlington Northern Santa Fe)	7
Subtotal Montana			*7*
South Dakota			
	Dakota, Minnesota & Eastern Railroad	DME (Dakota Minnesota & Eastern Railroad Corporation)	1
	South Dakota State Railroad	DSRC (Dakota Southern Railway Company	1
Subtotal South Dakota			*2*
Nebraska			
	Burlington Northern Railroad	BNSF (Burlington Northern Santa Fe)	2
	Union Pacific Railroad	Union Pacific (UP)	3
Subtotal Nebraska			*5*
Gulf Coast Segment			
Oklahoma			
	Burlington Northern Railroad	BNSF (Burlington Northern Santa Fe)	2
	Burlington Northern Railroad	St. Louis-San Francisco Railway Company	1
	Union Pacific Railroad	UP (Union Pacific)	2
Subtotal Oklahoma			*5*
Texas			
	AT and SF Railway	BNSF (Burlington Northern Santa Fe)	1
	Missouri Pacific Railroad	DGNO (Dallas, Garland & Northeastern Railroad, Inc.)	1
	Unnamed	UP (Union Pacific)	10
	Moscow Camden San Augustine RR	MCSA (Moscow Camden San Augustine RR)	1
	Northeast Texas Rural Rail	Northeast Texas Rural Rail Transportation District	1
	Kansas City Southern Railway	KCS (Kansas City Southern Railway)	2
	Texas Southeastern Railroad	TSE (Texas Southeast Railway)	2
Subtotal Texas – Gulf Coast Segment			*18*

TABLE 3.10.3-4 Intersection of Proposed Project with Railroads, by Segment and State			
Segment	**Railroad Name**	**Railroad Owner (Reporting Mark)**	**Number of Rail Intersections**
Houston Lateral			
Texas			
	Missouri Pacific Railroad	PTRA (Port Terminal Railroad Association)	1
	Railroad	UP (Union Pacific)	2
	Southern Pacific Railroad	UP (Union Pacific)	1
	Unnamed	UP (Union Pacific)	2
Subtotal Texas – Houston Lateral			*6*
Total Intersections			**43**

Source: ESRI Data & Maps 9.3 [DVD]. 2008. Environmental Systems Research Institute, Redlands, California, USA.

3.10.3.2 Potential Impacts

Construction Impacts

Public and existing private roads to access most of the construction ROW would be utilized. Each state has various road construction projects planned or underway. However, because specific construction dates for the proposed Project are unknown, potential conflicts with roadway construction are uncertain. Nonetheless, construction across roads and highways would comply with the requirements of the road crossing permits and approvals (Appendix B, CMR Plan).

Construction, mitigation, and reclamation actions presented in the proposed Project CMR Plan (Appendix B) would be implemented, except where those actions would conflict with federal, state, or local rules and regulations or other permits or approvals. It is unlikely that any improvement or maintenance would be required for paved roads before or during construction, while some gravel and dirt roads could require upgrades and maintenance. Construction across paved roads, highways, and rail routes would concur with the requirements stipulated in the road and railroad crossing permits and approvals obtained prior to construction. Generally, all roads and railroads would be traversed by borings that would involve excavation of a pit on each side of the roadway, placing required equipment into the pits, and boring a hole with a diameter as large as the pipeline itself.

Construction activities could result in short-term impacts to traffic and transportation infrastructure. Traffic volumes along roads proximate to the pipeline route could increase with movements of construction-related employees, equipment, and materials. Bored roadway crossings would reduce or eliminate the need for road closures, although temporary road closures could be required in some cases. However, impacts to local traffic would be minor and temporary.

Use of open-cut methods, where permitted by local authorities and private owners, would be employed to traverse mostly smaller unpaved roads and driveways. This method would require temporary closure of the feature to traffic and use of detours. If such detours were not feasible, at least one lane of traffic would be kept open other than when it would be necessary to close the road completely to install the pipeline. In general, open-cut road crossings would be finished and the subject roads resurfaced within two days. At each such crossing, signs would be posted and other measures as required by federal, state, and local transportation agencies would be utilized to minimize traffic disturbances and ensure safety.

Many commenters expressed concern about the potential for damage to roads and roadway structures during construction of the proposed Project and safety along roadways in the vicinity of the proposed route during construction. Keystone has committed to a program that would include inspection of roadways and roadway structures, repair of damage that may occur to those facilities, establishment of an approved Traffic Management Plan, and coordination with state and local transportation agencies.

Condition of Roads and Roadway Structures

If the proposed Project receives all permits and approvals, Keystone would work with state and local road officials, the pipeline construction contractor, and a third-party road consultant to identify routes that would be used for moving materials and equipment between storage and work yards to the pipeline, valve, and pump station construction sites. When these routes are mutually agreed upon, the road consultant would document the existing conditions of roads, including a video record. When construction is completed, the same parties would review the road conditions, and Keystone would restore the roads to their preconstruction condition or better. This restoration would be paid for by Keystone.

Keystone would also perform a preliminary evaluation to determine the design-rated capacity of bridges anticipated to be used during construction. Keystone's pipeline contractor would inspect all bridges it intends to use prior to construction and confirm that the capacity of the bridges is adequate for the anticipated weights. In cases where the bridges are not adequate to handle the maximum weight, an alternate route would be used. The pipeline contractor would also inspect cattle guard crossings prior to their use. If they are determined to be inadequate to handle anticipated construction traffic, the cattle crossing may be matted, or Keystone would establish an alternate crossing, enhance existing structures, and, if needed, install new infrastructure with the landowner's approval. All such actions would be paid for by Keystone.

During construction, Keystone and the pipeline contractor would maintain roads used for construction in a condition that is safe for both the public and the work force. Local road officials would be actively engaged in the routine assessment of current road conditions.

Traffic Safety

Keystone would follow all federal, state, and local safety plans and signage as set forth in current Manuals of Uniform Traffic Control for streets and highways, or in similar documents issued by regulatory agencies along the proposed route. This would include compliance with all state and local permits pertaining to road and crossing infrastructure usage.

Keystone would require that each construction contractor submit a road use plan prior to mobilization, coordinate with the appropriate state and county representatives to develop a mutually acceptable plan, and obtain all necessary road use permits. The road use plans would identify potential scenarios that may occur during construction based on surrounding land use, known recreational activities, and seasonal influences (such as farming), and would establish measures to reduce or avoid effects to the local communities. Keystone would also have inspection personnel monitor road use activities to ensure that the construction contractors comply with the road use plans and stipulations of the road use permits.

Operations Impacts

No substantive ongoing impacts to roads and railroads from operation and maintenance of the proposed Project would be expected. Operation and maintenance activities could require occasional use of roads to access the proposed Project ROW. Typically, these activities would use less equipment and personnel than would be used during construction.

3.10.4 Connected Actions

3.10.4.1 Power Distribution Lines and Substations

Construction of the substations, transformers, and necessary electrical power distribution lines would impact local economies by creating temporary employment, and potentially through the purchase of goods and services, and taxes on those goods. The magnitude of the positive economic impact is not known because an estimate of the construction costs for the substations, transformers, and electrical power distribution lines from the various local power providers is not available. The economic impact would be distributed throughout the proposed Project area. Table 3.10.4-1 shows the geographic distribution of the planned improvements to power infrastructure, as a proxy for estimating the geographic distribution of the economic impact. In general, relatively more transformers and miles of electrical power distribution lines would be required for the proposed Steele City Segment. Also included in Table 3.10.4-1 are the number and names of the local power providers.

TABLE 3.10.4-1
Summary of Power Supply Requirements for Proposed Project Pump Stations and Tank Farm

Segment	Number of Transformers	Miles of Power Distribution lines	Number of Power Providers	Power Provider
Steele City Segment				
Montana	6	135.8	5	Big Flat Electric Cooperative, NorVal Electric Cooperative, McCone Electric Cooperative, Tongue River Electric Cooperative, Montana-Dakota Utilities Company
South Dakota	7	159.1	3	Grand Electric Cooperative, West Central Electric Cooperative, Rosebud Electric Cooperative
Nebraska	5	69.6	5	Niobrara Valley Electric, Loup Valleys Rural PPD, Southern Power District, Perennial PPD, Norris PPD
New Cushing Extension Pump Stations				
Kansas	2	13.5	2	Clay Center Public Utility, Westar Energy
Gulf Coast Segment				
Oklahoma	4	12.7	4	Oklahoma Gas and Electric Company, Canadian Valley Electric Cooperative/PSO, People's Electric Cooperative/PSO, Southeastern Electric Cooperative
Texas	6	17.9	4	Lamar Electric Cooperative, Wood County Electric Cooperative, Cherokee County Electric Cooperative, Sam Houston Electric Cooperative

Property Damages and Values

The power distribution permanent ROW would be restored after construction and access would be required to the ROW for the life of the proposed Project pump stations and tank farm. Each power provider would develop detailed power line construction and operation procedures to address site specific conditions (see Section 2.5.1 for details). The potential impacts of the proposed Project power distribution lines on property values are examined below.

Three early studies (Blinder 1979) (Brown 1976) (Kinnard et al. 1984; as cited by Delaney and Timmons 1992) found that tall electrical transmission lines did not affect nearby residential or agricultural property

values. A 1978 study of agricultural land in west-central Minnesota found that the landowners were inconvenienced by the presence of a transmission line, but had not paid less for their land (Kroll and Priestly, 1992). However, a similar west-central Minnesota study in 1982 found that landowners experienced a 0 to 20 percent reduction in property values, depending upon the amount of disruption to their farm operations (Kroll and Priestly 1992).

Later studies (Colwell and Foley 1979; as cited by Delaney and Timmons 1992) showed that electrical transmission lines had a negative effect on property values. The most common reason given by one study was the visual impact of the transmission line, followed by the perceived health risk (Delaney and Timmons 1992). One study (Colwell 1990) showed that over time the negative impacts to property values decreased, indicating a reduced concern about the facilities. In the mid-1990s, a study of the effects of high-voltage transmission lines on upper-priced residential and vacant lot property values in urban, suburban, and rural areas of western Wisconsin showed that very minor positive and negative impacts occurred, indicating that there was virtually no impact (Solum 1995).

In 1996, an evaluation of the effects of transmission lines on residential property values in Seattle and Vancouver, Washington found little impact (Cowger et al. 1996). The literature review completed for that study also indicated the following:

- Overhead transmission lines can reduce the value of residential and agricultural property. The impact is usually small (0 to 10 percent) for single-family residential properties.
- Other factors such as location, improvements, and lot size are more likely to be major determinants of sale price.
- Impacts on sales are most likely to occur on property crossed or immediately adjacent to the lines.
- In areas where the ROW has been landscaped or developed for recreational use, positive impacts have been measured.
- Impacts may be greater for small properties than for larger properties.
- Impacts are more pronounced immediately after construction of a new line and diminish over time.

The Public Service Commission of Wisconsin reviewed, as part of a transmission line EIS, approximately 30 papers, articles, and court cases from 1987 through 1999 concerning property value impacts (PSCW 2000). That literature review found that the average decrease in property values appeared to be 4 to 7 percent in Minnesota, Wisconsin, and the Upper Peninsula of Michigan. That analysis provided six additional observations:

- A potential reduction in sale price for single family homes may range from 0 to 14 percent.
- Adverse effects on the sale price of smaller properties could be greater than the effects on the sale price of larger properties.
- Other amenities, such as proximity to schools or jobs, lot size, square footage of a house, and neighborhood characteristics, often have a much greater effect on sale price than the presence of a power line.
- Adverse effects created by the presence of a transmission line appear to diminish over time.
- Effects on the sale price of property most often are observed for property crossed by or immediately adjacent to a transmission line.

- The value of agricultural property is likely to decrease if the transmission line poles are placed in an area that inhibits farm operations.

Based upon a review of the literature, it appears that the power distribution lines required for the proposed Project would have a minor impact on property values due to the following factors:

- Many of the power distribution ROWs would be located in rural areas;
- Many of the power distribution lines would be located more than 300 feet from residences; and
- Most properties that would be crossed by power distribution ROWs are relatively large parcels/tracts.

3.10.4.2 Big Bend to Witten 230-kV Transmission Line

Construction of the proposed Big Bend to Witten 230-kV transmission line and the new proposed Big Bend Substation would impact local economies by creating temporary employment, and potentially through the purchase of goods and services, and taxes on those goods. The magnitude of the positive economic impacts could not be determined because an estimate of construction costs for this connected action was not available. The economic impacts would likely be concentrated in Lyman and Tripp counties in south-central South Dakota. The currently proposed alternative alignments for the Big Bend to Witten 230-kV Transmission Line would cross the Lower Brule Indian Reservation.

3.10.4.3 Bakken Marketlink and Cushing Marketlink Projects

Construction and operation of the Bakken Marketlink Project would include metering systems, three new storage tanks near Baker, Montana, and two new storage tanks within the boundaries of the proposed Cushing tank farm. Keystone reported that the property proposed for the Bakken Marketlink facilities near Pump Station 14 is currently used as pastureland and hayfields and that a survey of the property indicated that there were no waterbodies or wetlands on the property. DOS reviewed aerial photographs of the area and confirmed the current use of the land and that there are no waterbodies or wetlands associated with the site. A site inspection by the DOS third-party contractor confirmed these findings. As a result, the potential socioeconomic impacts associated with expansion of the pump station site to include the Bakken Marketlink facilities would likely be similar to those described above for the proposed Project pump station and pipeline ROW in that area.

The Cushing Marketlink project would be located within the boundaries of the proposed Cushing tank farm of the Keystone XL Project and would include metering systems and two storage tanks. As a result, the socioeconomic impacts of construction and operation of the Cushing Marketlink Project would be the same as potential impacts associated with construction and operation of the proposed Cushing tank farm described in this section.

Currently there is insufficient information to complete an environmental review of the Marketlink projects. The permit applications for these projects would be reviewed and acted on by other agencies. Those agencies would conduct more detailed environmental reviews of the Marketlink projects. Potential socioeconomic impacts would be evaluated during the environmental reviews for these projects and would be evaluated and avoided, minimized, or mitigated in accordance with applicable regulations.

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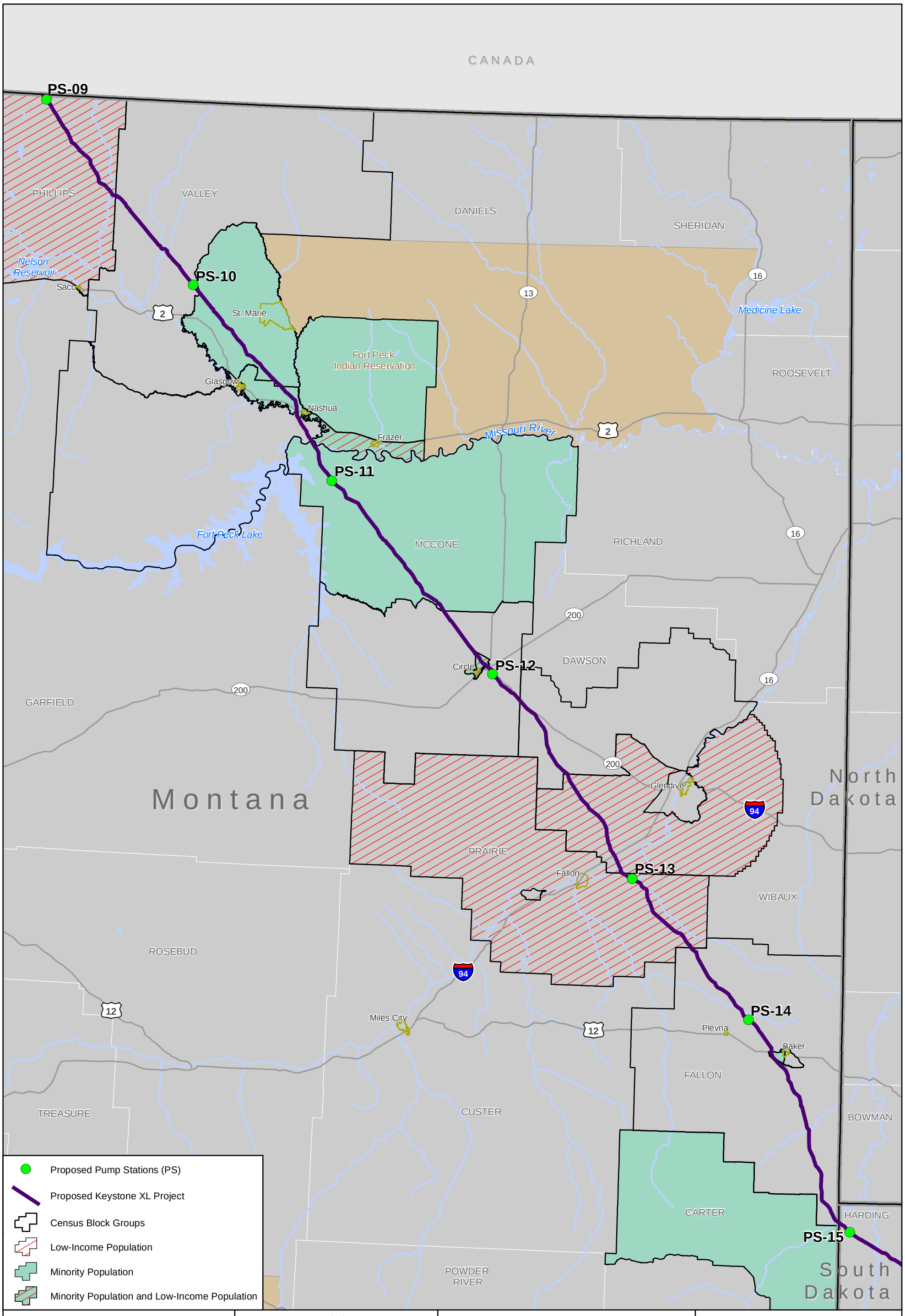
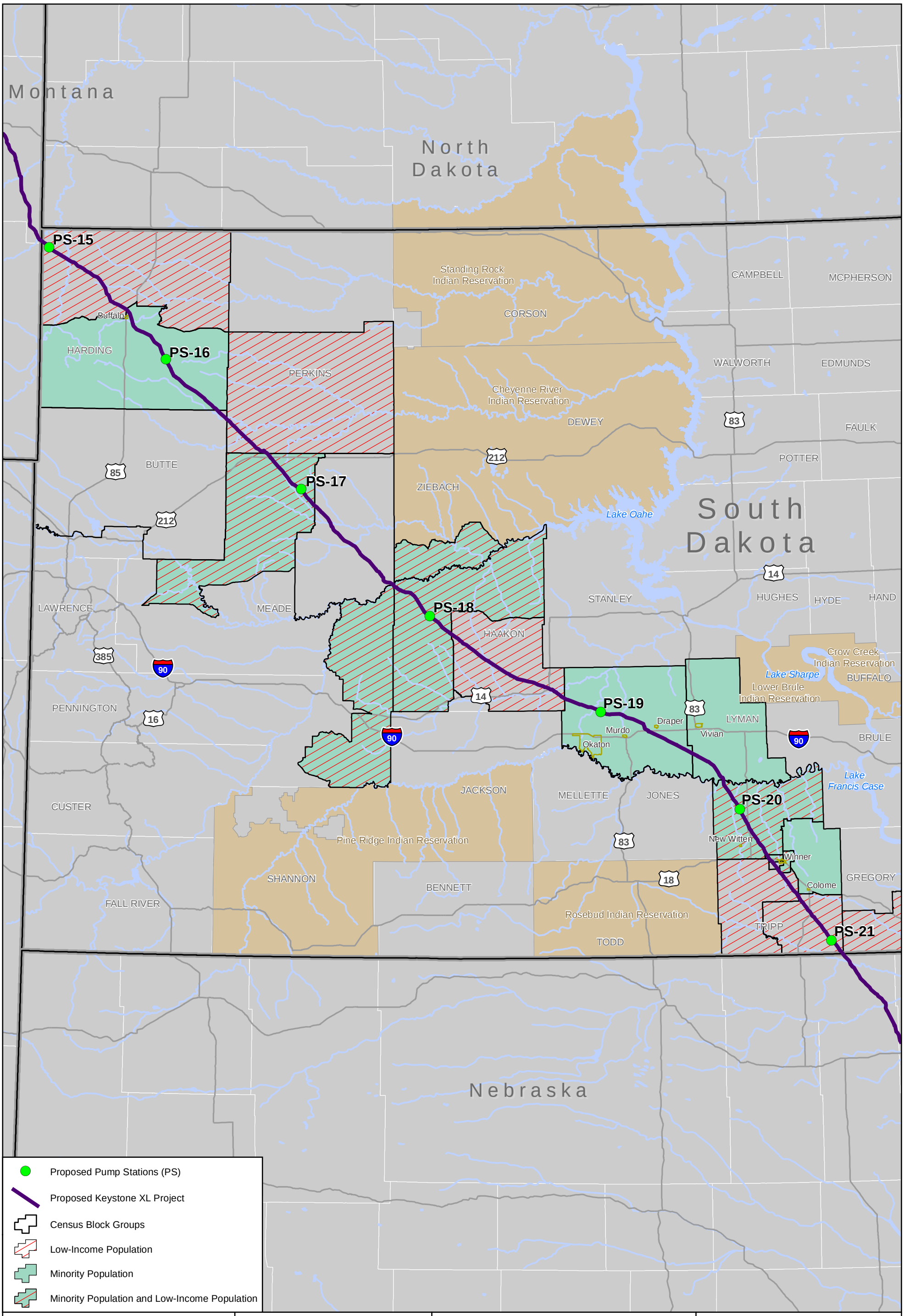


KEYSTONE XL PROJECT

Figure 3.10.1-1

Environmental Justice (Montana)


Montana
North Dakota
South Dakota
Nebraska
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PS-16
PS-17
PS-18
PS-19
PS-20
PS-21
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PERKINS
CORSON
Standing Rock Indian Reservation
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MCPHERSON
WALWORTH
EDMUNDS
Cheyenne River Indian Reservation
DEWEY
FAULK
POTTER
ZIEBACH
BUTTE
LAWRENCE
MEADE
STANLEY
HUGHES
HYDE
HAND
HAAKON
Lake Oahe
Crow Creek Indian Reservation
Lake Sharpe
Lower Brule Indian Reservation
BUFFALO
BRULE
LYMAN
Draper
Murdo
Vivian
Okaton
Lake Francis Case
PENNINGTON
CUSTER
JACKSON
MELLETTE
JONES
Pine Ridge Indian Reservation
New Witten
Winner
GREGORY
Colome
SHANNON
BENNETT
FALL RIVER
Rosebud Indian Reservation
TRIPP
TODD
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212
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90
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Proposed Pump Stations (PS)
Proposed Keystone XL Project
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population
Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI.
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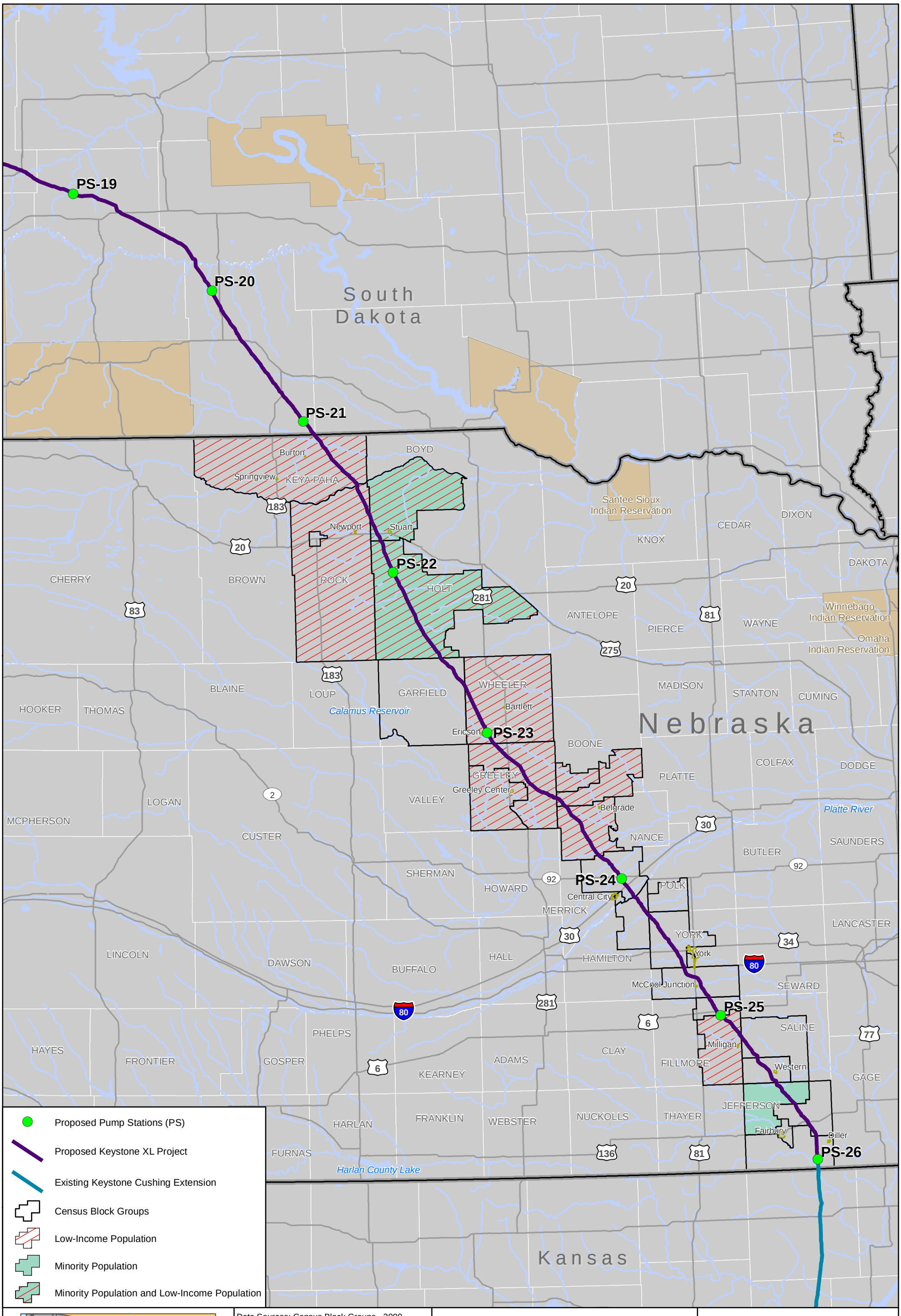
KEYSTONE XL PROJECT
Figure 3.10.1-2
Environmental Justice (South Dakota)


PS-19
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Nebraska
Kansas
Burton
Springview
KEYA PAHA
BOYD
Santee Sioux Indian Reservation
DIXON
CEDAR
KNOX
DAKOTA
Winnebago Indian Reservation
Omaha Indian Reservation
Newport
Stuart
CHERRY
BROWN
ROCK
HOLT
ANTELOPE
PIERCE
WAYNE
BLAINE
LOUP
GARFIELD
WHEELER
MADISON
STANTON
CUMING
HOOKER
THOMAS
Calamus Reservoir
Bartlett
Ericson
BOONE
COLFAX
DODGE
GREELEY
Greeley Center
PLATTE
LOGAN
VALLEY
Belgrade
Platte River
MCPHERSON
CUSTER
NANCE
BUTLER
SAUNDERS
SHERMAN
HOWARD
POLK
Central City
MERRICK
LANCASTER
YORK
York
LINCOLN
DAWSON
BUFFALO
HALL
HAMILTON
McCool Junction
SEWARD
PHELPS
SALINE
Milligan
HAYES
FRONTIER
GOSPER
CLAY
ADAMS
FILLMORE
Western
GAGE
KEARNEY
JEFFERSON
HARLAN
FRANKLIN
WEBSTER
NUCKOLLS
THAYER
Fairbury
Diller
FURNAS
Harlan County Lake
Proposed Pump Stations (PS)
Proposed Keystone XL Project
Existing Keystone Cushing Extension
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population
Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI.
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KEYSTONE XL PROJECT
Figure 3.10.1-3
Environmental Justice (Nebraska)

Nebraska

Kansas

Oklahoma

PS-26

PS-27

PS-29

PS-32

PROPOSED CUSHING TANK FARM

WASHINGTON
REPUBLIC
MARSHALL
NEMAHA
NORTON
PHILLIPS
JEWELL
Kickapoo Indian Reservation
ATCHISON
JACKSON
CLOUD
Green
Clay Center
POTTAWATOMIE
Potawatomi Indian Reservation
Waconda Lake
Webster Reservoir
MITCHELL
OSBORNE
Tuttle Creek Lake
JEFFERSON
GRAHAM
CLAY
RILEY
Wakefield
ROOKS
OTTAWA
Milford Lake
SHAWNEE
Clinton Lake
ELLIS
LINCOLN
GEARY
WABAUNSEE
Wilson Lake
DICKINSON
TREGO
OSAGE
RUSSELL
SALINE
ELLSWORTH
Marion Lake
FRANKLIN
BARTON
MORRIS
Melvern Lake
NESS
RUSH
Cheyenne Bottoms
MCPHERSON
LYON
RICE
MARION
John Redmond Reservoir
PAWNEE
CHASE
COFFEY
HODGEMAN
STAFFORD
HARVEY
Potwin
GREENWOOD
ALLEN
BUTLER
WOODSON
RENO
El Dorado Lake
EDWARDS
Cheney Reservoir
FORD
PRATT
KINGMAN
SEDGWICK
ELK
WILSON
KIOWA
COWLEY
CLARK
HARPER
SUMNER
MONTGOMERY
BARBER

Proposed Pump Stations (PS)
Proposed Cushing Tank Farm
Proposed Keystone XL Project
Existing Keystone Cushing Extension
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population

Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI.

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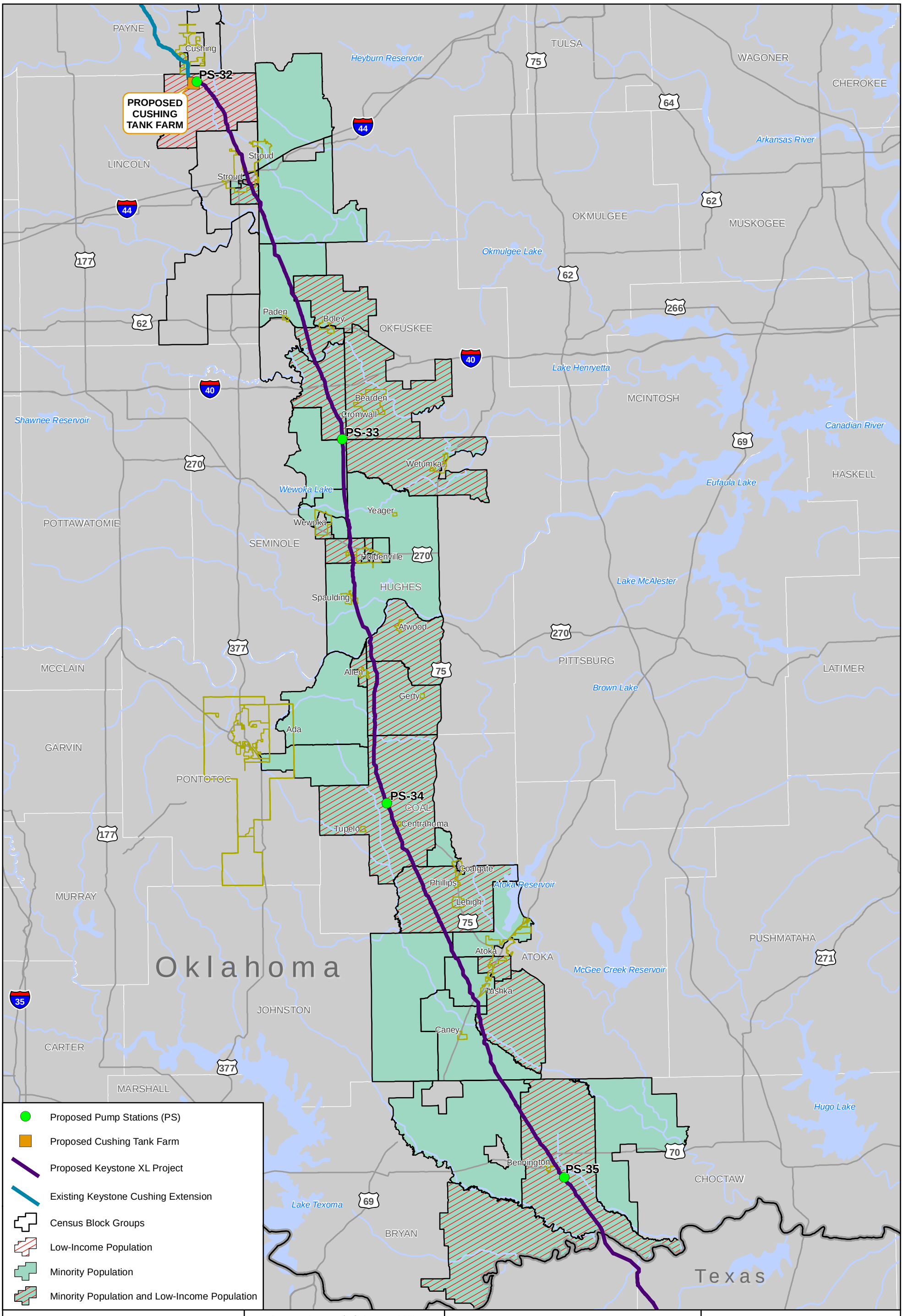
KEYSTONE XL PROJECT

Figure 3.10.1-4

Environmental Justice (Kansas)


PAYNE
Cushing
PS-32
PROPOSED CUSHING TANK FARM
Heyburn Reservoir
TULSA
WAGONER
CHEROKEE
Arkansas River
LINCOLN
Stroud
OKMULGEE
MUSKOGEE
Okmulgee Lake
Paden
Boley
OKFUSKEE
Lake Henryetta
MCINTOSH
Bearden
Cromwall
PS-33
Shawnee Reservoir
Canadian River
Wetumka
HASKELL
Wewoka Lake
Eufaula Lake
Yeager
Wewoka
POTTAWATOMIE
SEMINOLE
Holdenville
HUGHES
Lake McAlester
Spaulding
Atwood
PITTSBURG
LATIMER
MCCLAIN
Allen
Gerty
Brown Lake
Ada
GARVIN
PONTOTOC
PS-34
COAL
Centrahoma
Tupelo
Coalgate
Phillips
Atoka Reservoir
Lehigh
MURRAY
PUSHMATAHA
Atoka
ATOKA
McGee Creek Reservoir
Tushka
Oklahoma
JOHNSTON
Caney
CARTER
MARSHALL
Hugo Lake
Bennington
PS-35
CHOCTAW
Lake Texoma
BRYAN
Texas
Proposed Pump Stations (PS)
Proposed Cushing Tank Farm
Proposed Keystone XL Project
Existing Keystone Cushing Extension
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population
Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI.
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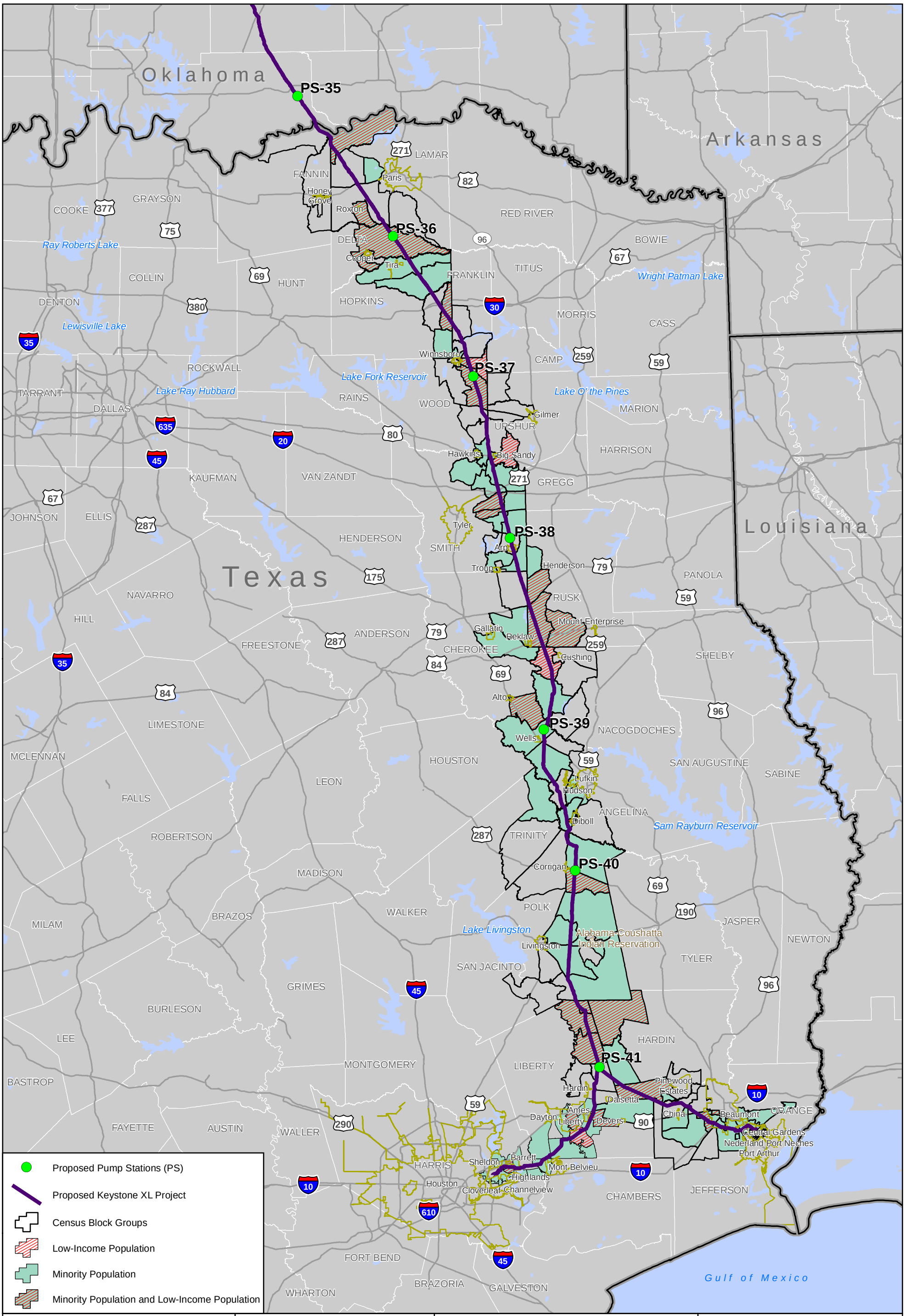
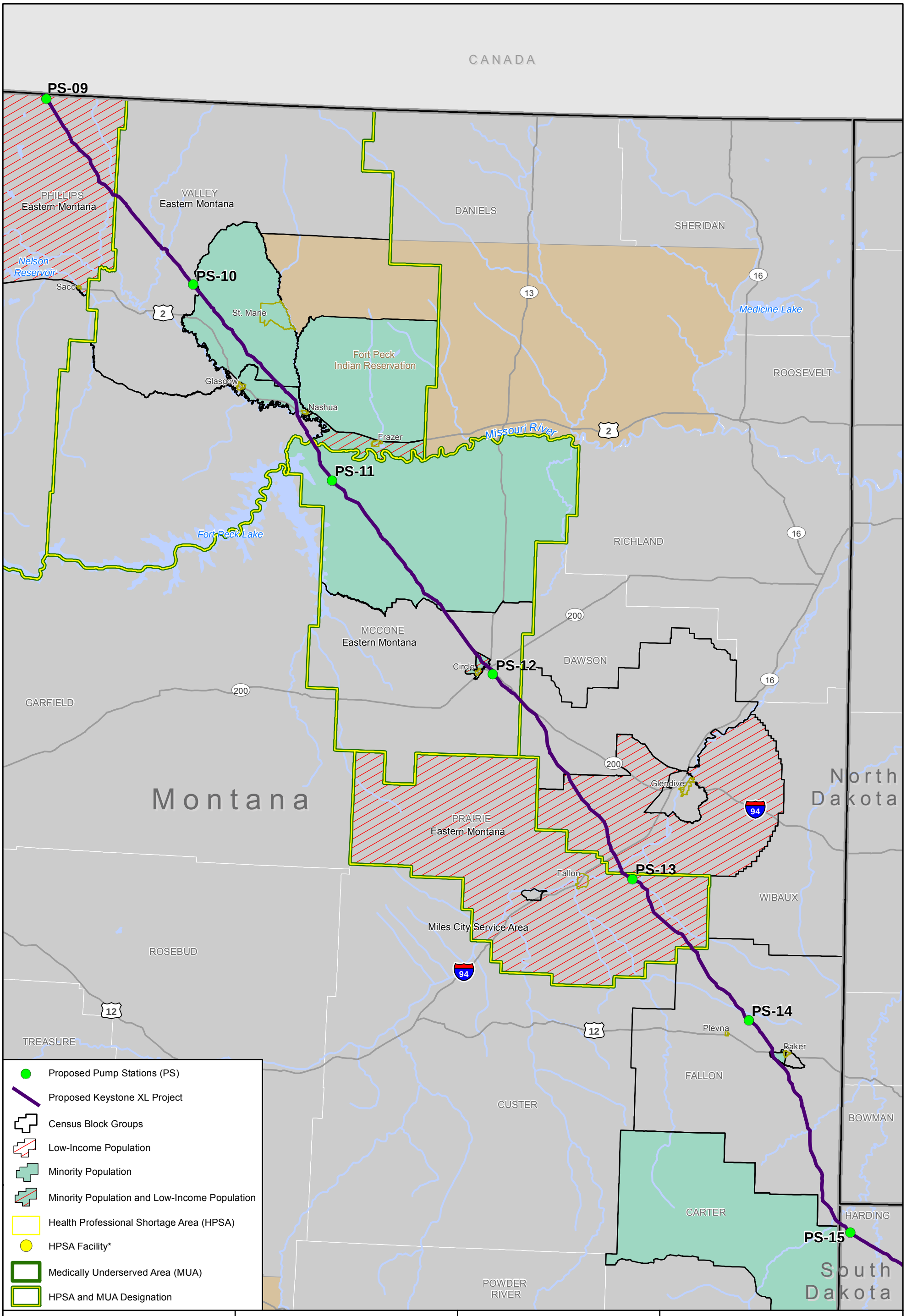
KEYSTONE XL PROJECT
Figure 3.10.1-5
Environmental Justice (Oklahoma)


Oklahoma
Arkansas
Texas
Louisiana
PS-35
PS-36
PS-37
PS-38
PS-39
PS-40
PS-41
Paris
Honey Grove
Roxton
Cooper
Tira
Winnsboro
Gilmer
Hawkins
Big Sandy
Tyler
Arp
Troup
Henderson
Gallatin
Rekiaw
Mount Enterprise
Cushing
Alto
Wells
Lufkin
Hudson
Diboll
Corrigan
Livingston
Alabama-Coushatta Indian Reservation
Hardin
Pinewood Estates
Daisetta
Ames
Dayton
Liberty
Devers
China
Beaumont
Central Gardens
Nederland
Port Neches
Port Arthur
Sheldon
Barrett
Mont Belvieu
Highlands
Houston
Cloverleaf
Channelview
LAMAR
FANNIN
RED RIVER
BOWIE
DELTA
TITUS
FRANKLIN
HUNT
COOKE
GRAYSON
COLLIN
DENTON
HOPKINS
MORRIS
CASS
CAMP
ROCKWALL
TARRANT
DALLAS
RAINS
WOOD
UPSHUR
MARION
HARRISON
KAUFMAN
VAN ZANDT
GREGG
SMITH
HENDERSON
RUSK
PANOLA
NAVARRO
HILL
ANDERSON
FREESTONE
CHEROKEE
SHELBY
JOHNSON
ELLIS
LIMESTONE
NACOGDOCHES
MCLENNAN
HOUSTON
SAN AUGUSTINE
SABINE
FALLS
LEON
ANGELINA
ROBERTSON
TRINITY
MADISON
POLK
JASPER
NEWTON
WALKER
BRAZOS
MILAM
LEE
BURLESON
GRIMES
SAN JACINTO
TYLER
HARDIN
MONTGOMERY
LIBERTY
BASTROP
FAYETTE
AUSTIN
WALLER
HARRIS
ORANGE
JEFFERSON
CHAMBERS
FORT BEND
BRAZORIA
GALVESTON
WHARTON
Ray Roberts Lake
Lewisville Lake
Lake Ray Hubbard
Lake Fork Reservoir
Wright Patman Lake
Lake O' the Pines
Sam Rayburn Reservoir
Lake Livingston
Gulf of Mexico
Proposed Pump Stations (PS)
Proposed Keystone XL Project
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population
Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI.
0 5 10 20
Miles
KEYSTONE XL PROJECT
Figure 3.10.1-6
Environmental Justice (Texas)



Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI; HPSA, MUA - HRSA.

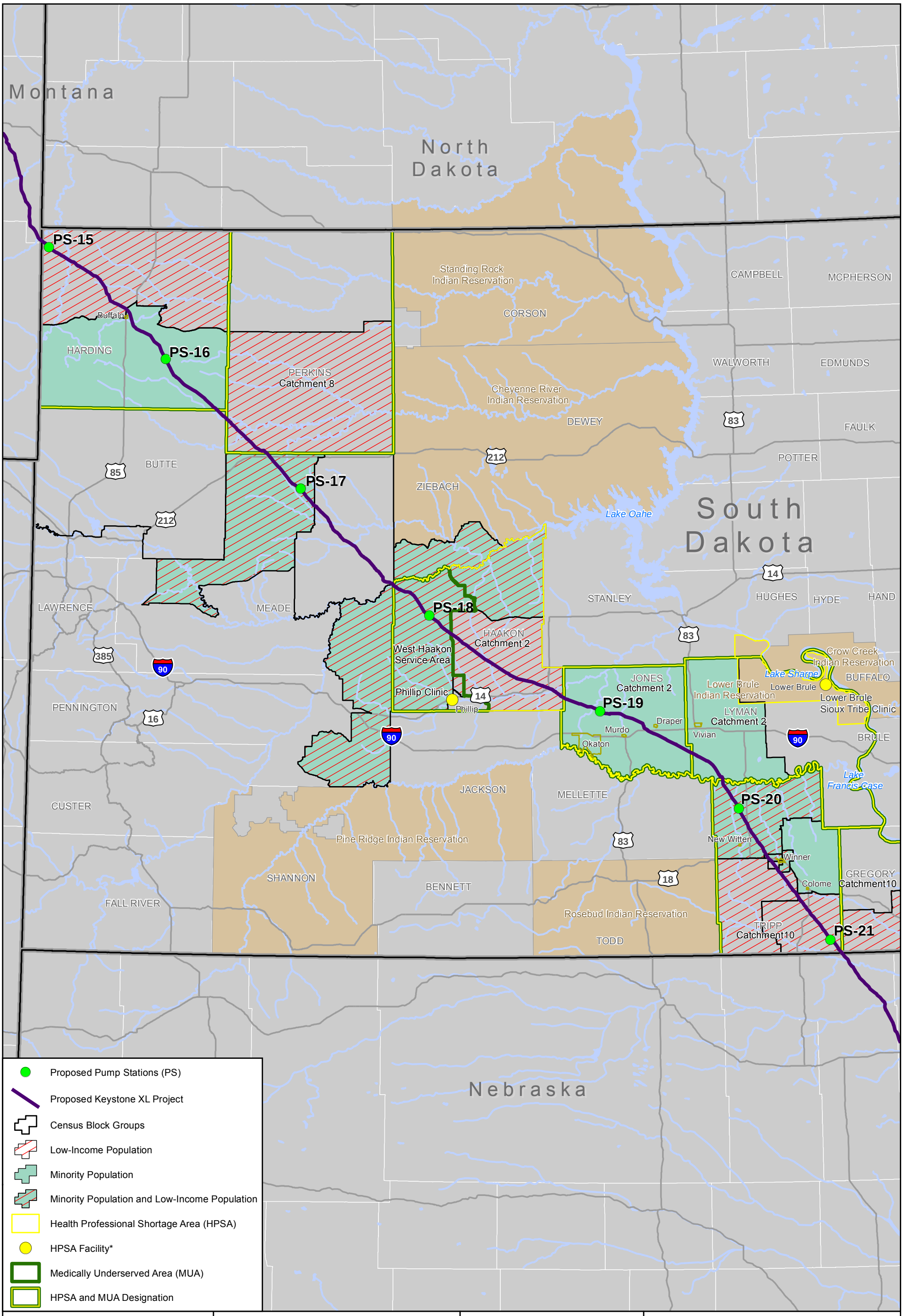
Notes: HPSA and MUA designations are not included if status is withdrawn, proposed withdrawal, or rejected. Prairie County is located in the Miles City Service Area. *HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

0 5 10 20 Miles

KEYSTONE XL PROJECT

Figure 3.10.1-7

Environmental Justice Analysis - HPSA and MUA Designations (Montana)



Data Sources: Census Block Groups, MCDs - 2000 US Census; Reservations, Basemap - ESRI; HPSA, MUA - HRSA.

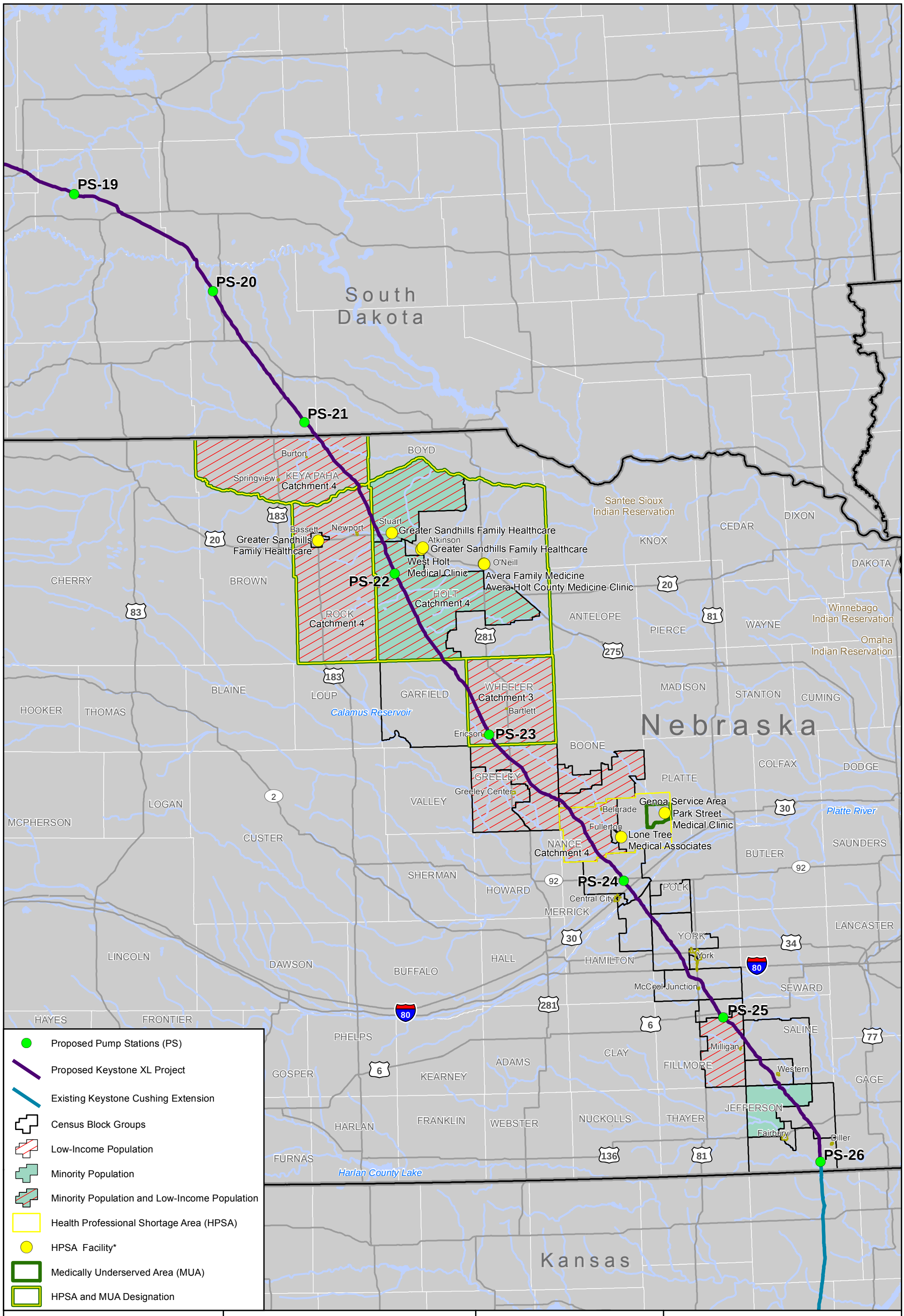
Notes: HPSA and MUA designations are not included if status is withdrawn, proposed withdrawal, or rejected. HPSAs include the Lower Brule Indian Reservation.
*HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

0 5 10 20 Miles

KEYSTONE XL PROJECT

Figure 3.10.1-8

Environmental Justice Analysis - HPSA and MUA Designations (South Dakota)



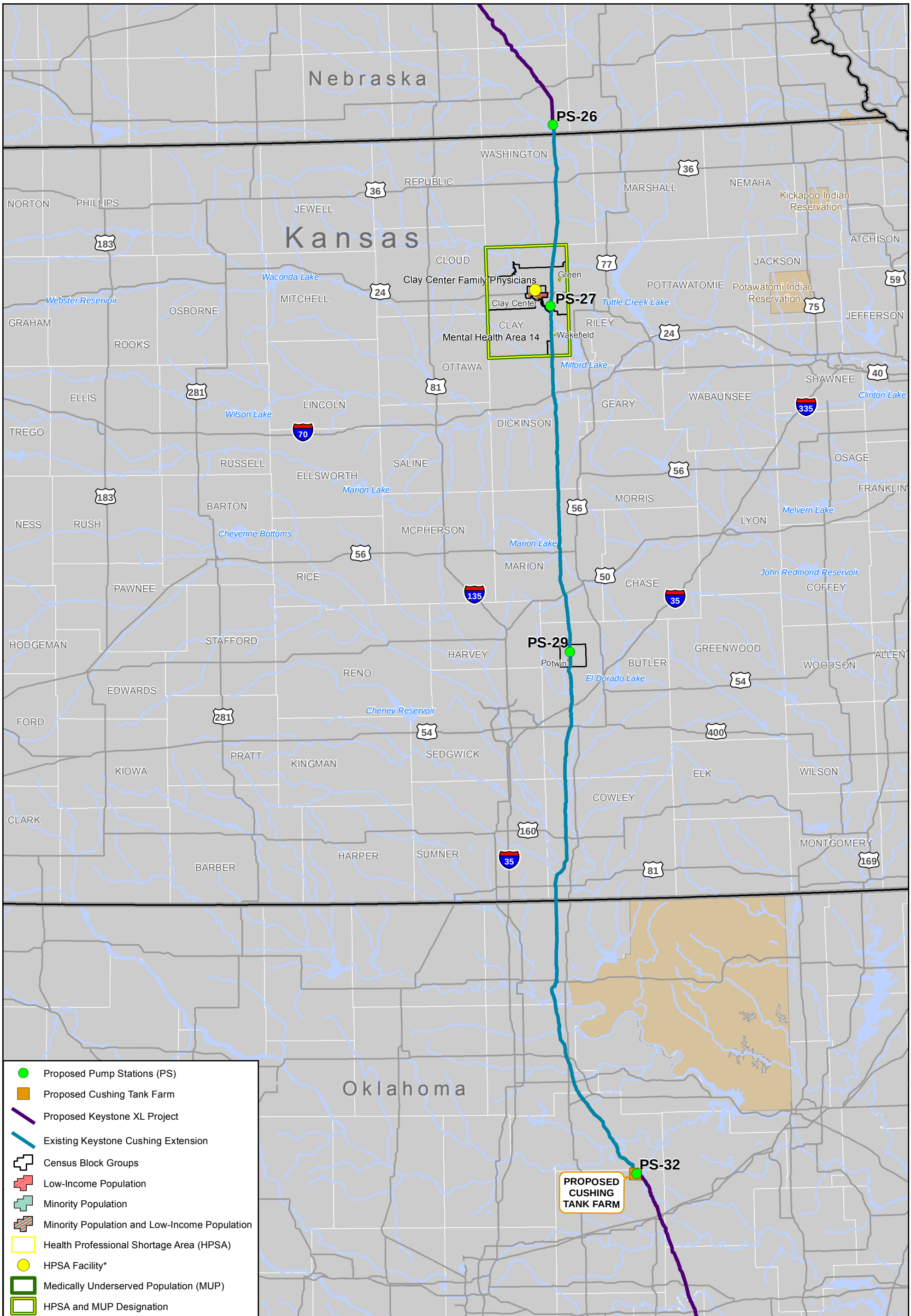
Data Sources: Census Block Groups, MCDs - 2000 US Census; Reservations, Basemap - ESRI; HPSA, MUA - HRSA.

Notes: HPSA and MUA designations are not included if status is withdrawn, proposed withdrawal, or rejected.
*HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

KEYSTONE XL PROJECT

Figure 3.10.1-9

Environmental Justice Analysis - HPSA and MUA Designations (Nebraska)



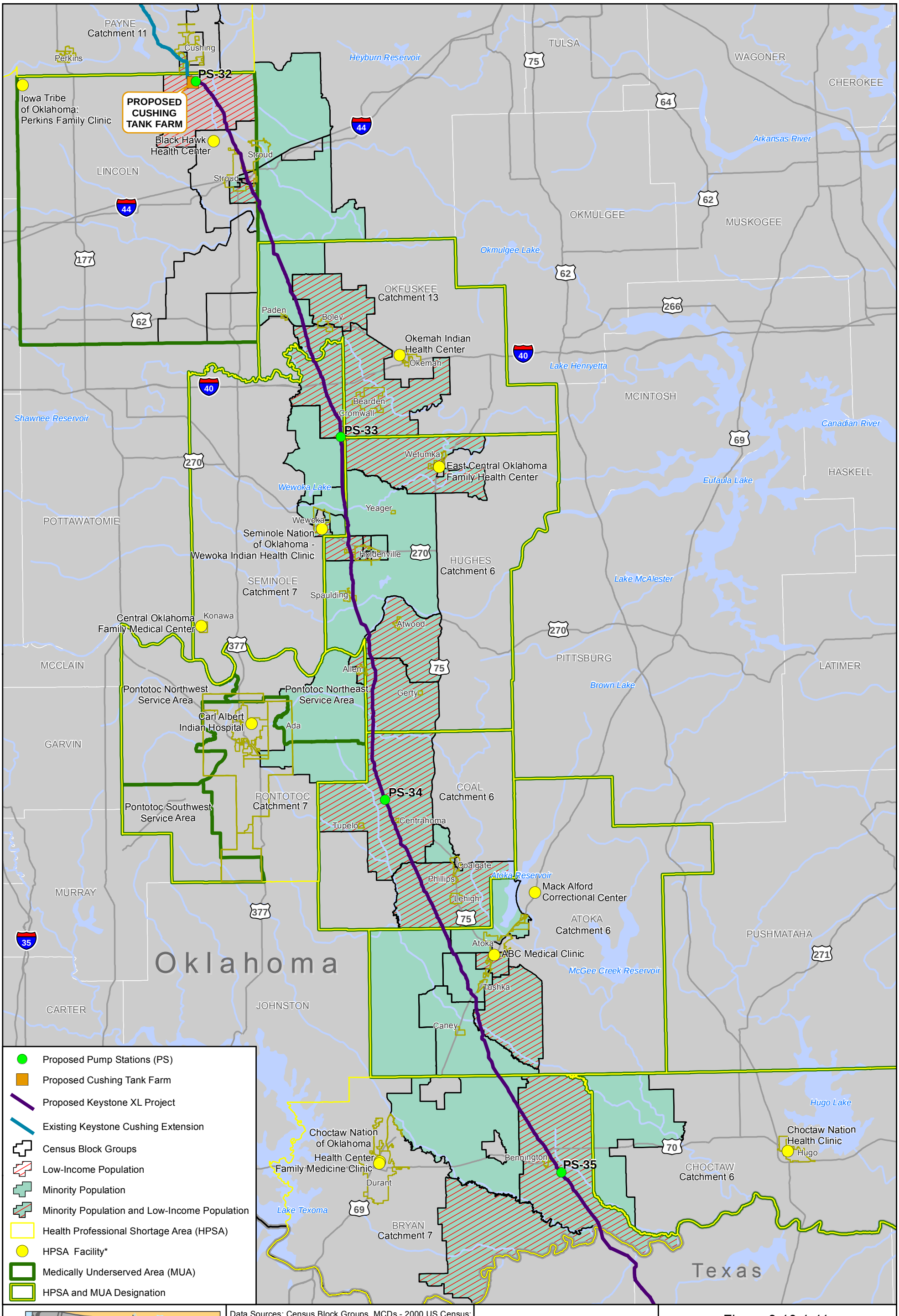
Data Sources: Census Block Groups - 2000 US Census; Reservations, Basemap - ESRI; HPSA, MUP - HRSA.

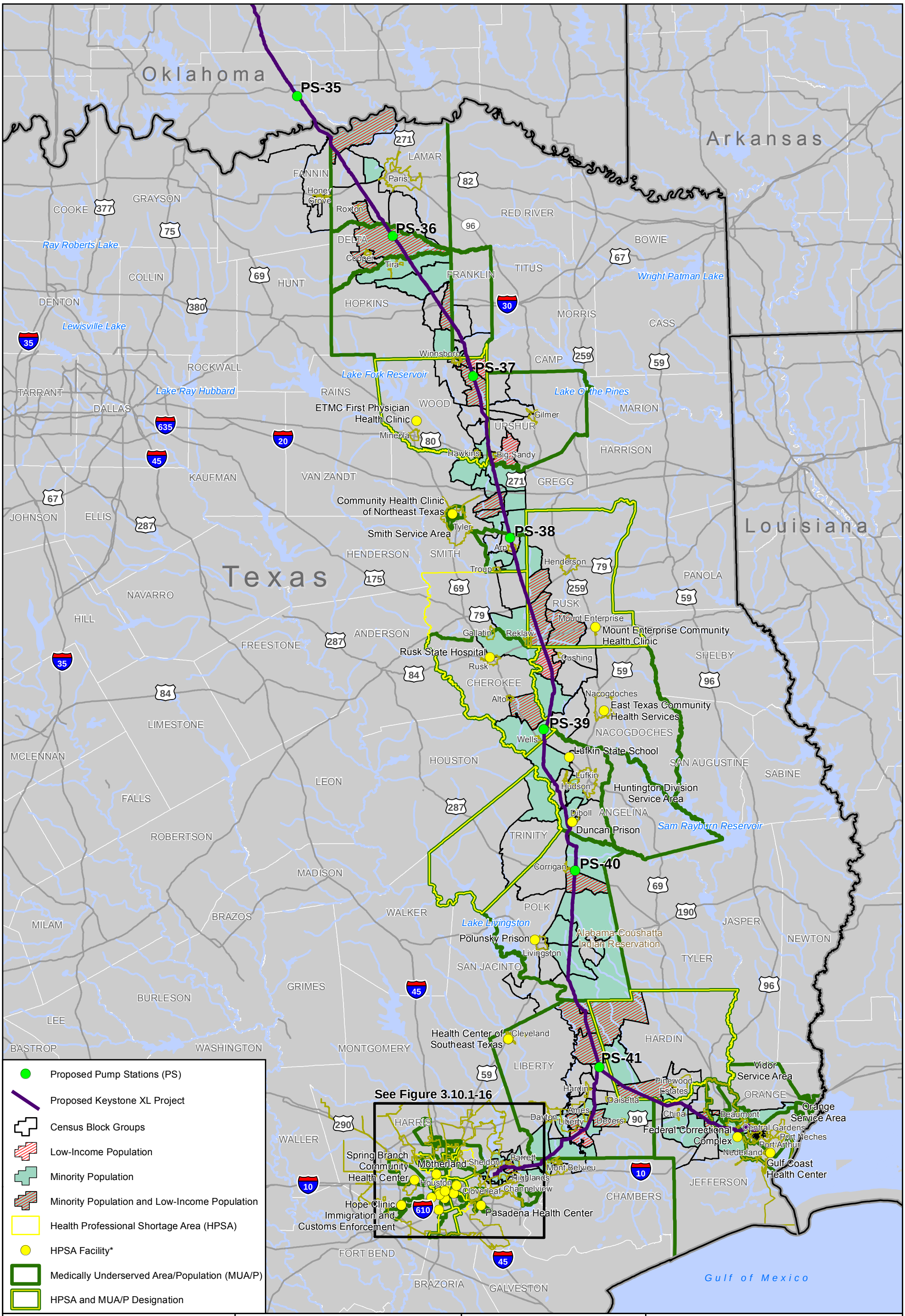
Notes: HPSA and MUP designations are not included if status is withdrawn, proposed withdrawal, or rejected. *HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

KEYSTONE XL PROJECT

Figure 3.10.1-10

Environmental Justice Analysis - HPSA and MUP Designations (Kansas)


PAYNE
Catchment 11
Cushing
Perkins
Heyburn Reservoir
TULSA
WAGONER
CHEROKEE
PS-32
Iowa Tribe
of Oklahoma:
Perkins Family Clinic
PROPOSED
CUSHING
TANK FARM
Black Hawk
Health Center
Stroud
Stroud
LINCOLN
Arkansas River
OKMULGEE
MUSKOGEE
Okmulgee Lake
OKFUSKEE
Catchment 13
Paden
Boley
Okemah Indian
Health Center
Okemah
Lake Henryetta
MCINTOSH
Shawnee Reservoir
Bearden
Cromwall
PS-33
Canadian River
Wetumka
East Central Oklahoma
Family Health Center
HASKELL
Wewoka Lake
Eufaula Lake
Yeager
POTTAWATOMIE
Wewoka
Seminole Nation
of Oklahoma -
Wewoka Indian Health Clinic
Holdenville
HUGHES
Catchment 6
SEMINOLE
Catchment 7
Spaulding
Lake McAlester
Central Oklahoma
Family Medical Center
Konawa
Atwood
PITTSBURG
LATIMER
MCCLAIN
Allen
Gerty
Brown Lake
Pontotoc Northwest
Service Area
Pontotoc Northeast
Service Area
Carl Albert
Indian Hospital
Ada
GARVIN
PS-34
COAL
Catchment 6
PONTOTOC
Catchment 7
Pontotoc Southwest
Service Area
Tupelo
Centrahoma
Coalgate
Phillips
Atoka Reservoir
Mack Alford
Correctional Center
MURRAY
Lehigh
ATOKA
Catchment 6
PUSHMATAHA
Atoka
ABC Medical Clinic
McGee Creek Reservoir
Oklahoma
Tushka
CARTER
JOHNSTON
Caney
Hugo Lake
Choctaw Nation
of Oklahoma
Health Center
Family Medicine Clinic
Durant
Bennington
PS-35
CHOCTAW
Catchment 6
Choctaw Nation
Health Clinic
Hugo
Lake Texoma
BRYAN
Catchment 7
Texas
Proposed Pump Stations (PS)
Proposed Cushing Tank Farm
Proposed Keystone XL Project
Existing Keystone Cushing Extension
Census Block Groups
Low-Income Population
Minority Population
Minority Population and Low-Income Population
Health Professional Shortage Area (HPSA)
HPSA Facility*
Medically Underserved Area (MUA)
HPSA and MUA Designation
Data Sources: Census Block Groups, MCDs - 2000 US Census; Reservations, Basemap - ESRI; HPSA, MUA - HRSA.
Notes: HPSA and MUA designations are not included if status is withdrawn, proposed withdrawal, or rejected.
*HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".
0 3 6 12
Miles
KEYSTONE XL PROJECT
Figure 3.10.1-11
Environmental Justice Analysis - HPSA and MUA Designations (Oklahoma)



Data Sources: Census Block Groups, MCDs, Census Tracts - 2000 US Census; Reservations, Basemap - ESRI.

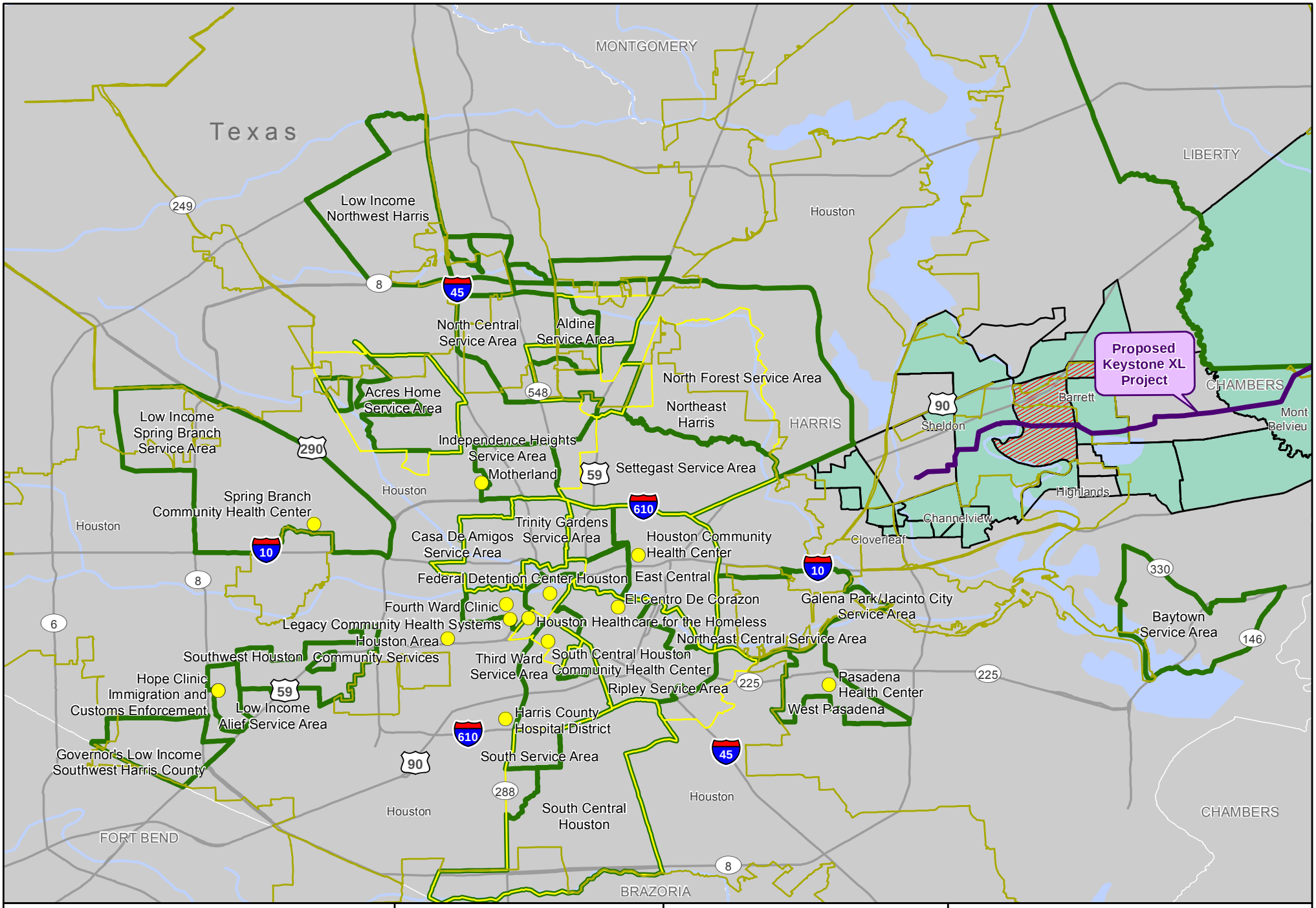
Notes: HPSA and MUA/P designations are not included if status is withdrawn, proposed withdrawal, or rejected. *HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

0 5 10 20 Miles

KEYSTONE XL PROJECT

Figure 3.10.1-12

Environmental Justice Analysis - HPSA and MUA/P Designations (Texas)



Census Block Groups
Minority Population
Low-Income Population
Minority Population and Low-Income Population
Health Professional Shortage Area (HPSA)
HPSA Facility*
Medically Underserved Area/ Population (MUA/Ps)
HPSA and MUA/P Designation

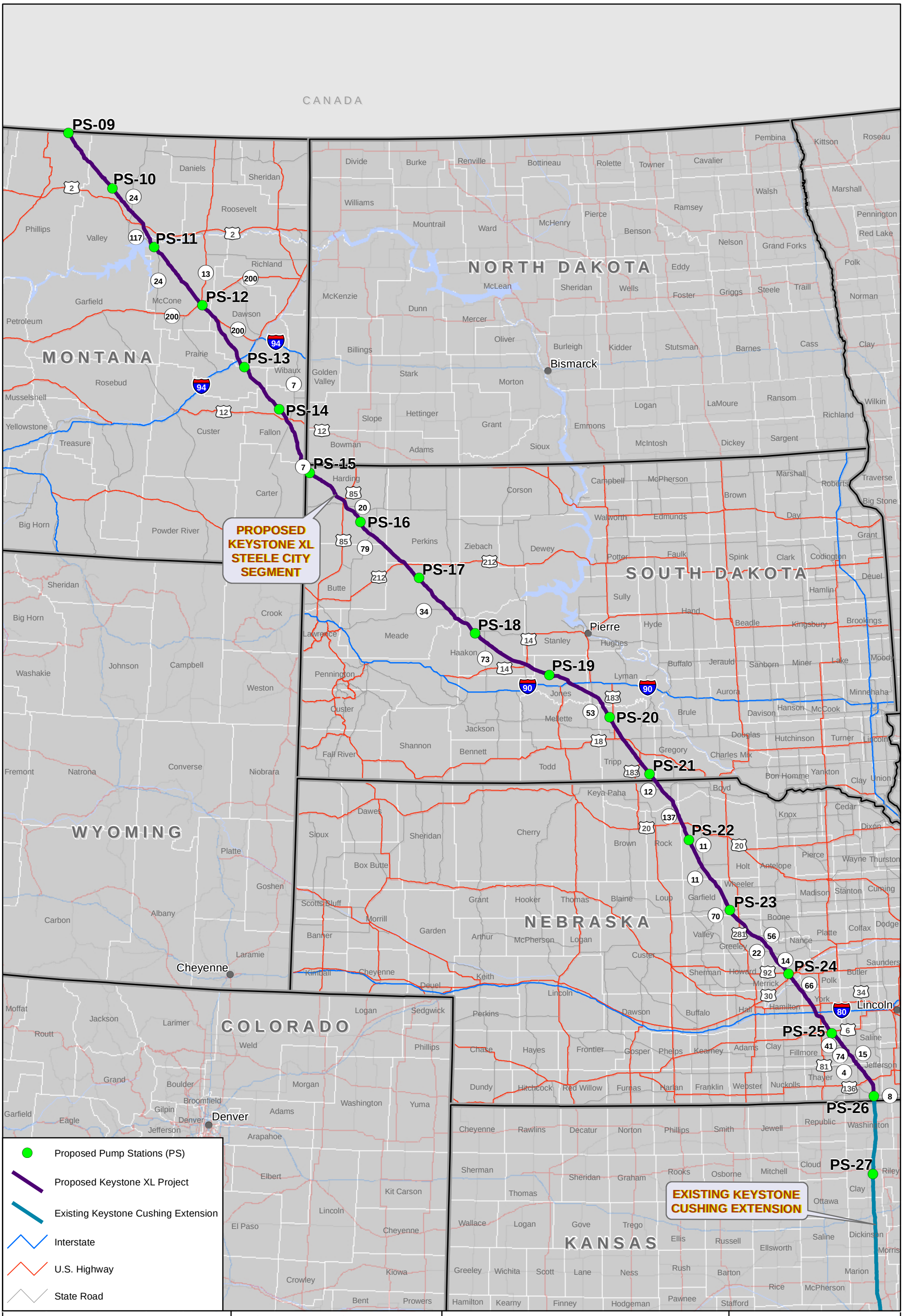
Data Sources: Census Block Groups, MCDs, Census Tracts - 2000 US Census; Reservations, Basemap - ESRI.

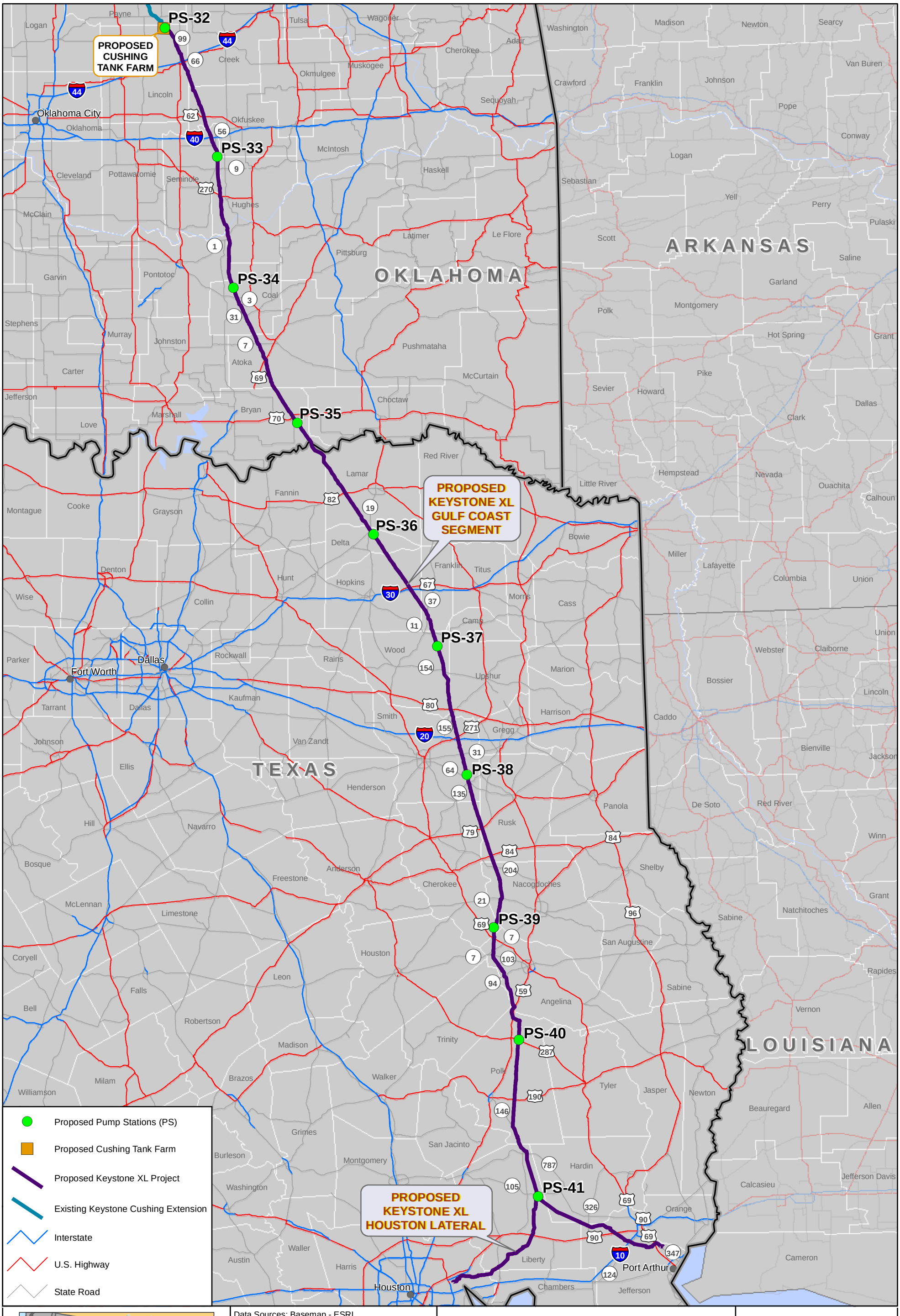
Notes: HPSA and MUA/P designations are not included if status is withdrawn, proposed withdrawal, or rejected. *HPSA facilities are defined as either a "federally qualified health center" or a "federally qualified health center look-alike".

0 1 2 4 Miles

KEYSTONE XL PROJECT

Figure 3.10.1-13
Environmental Justice Analysis - HPSA and MUA/P Designations (Harris County, Texas)

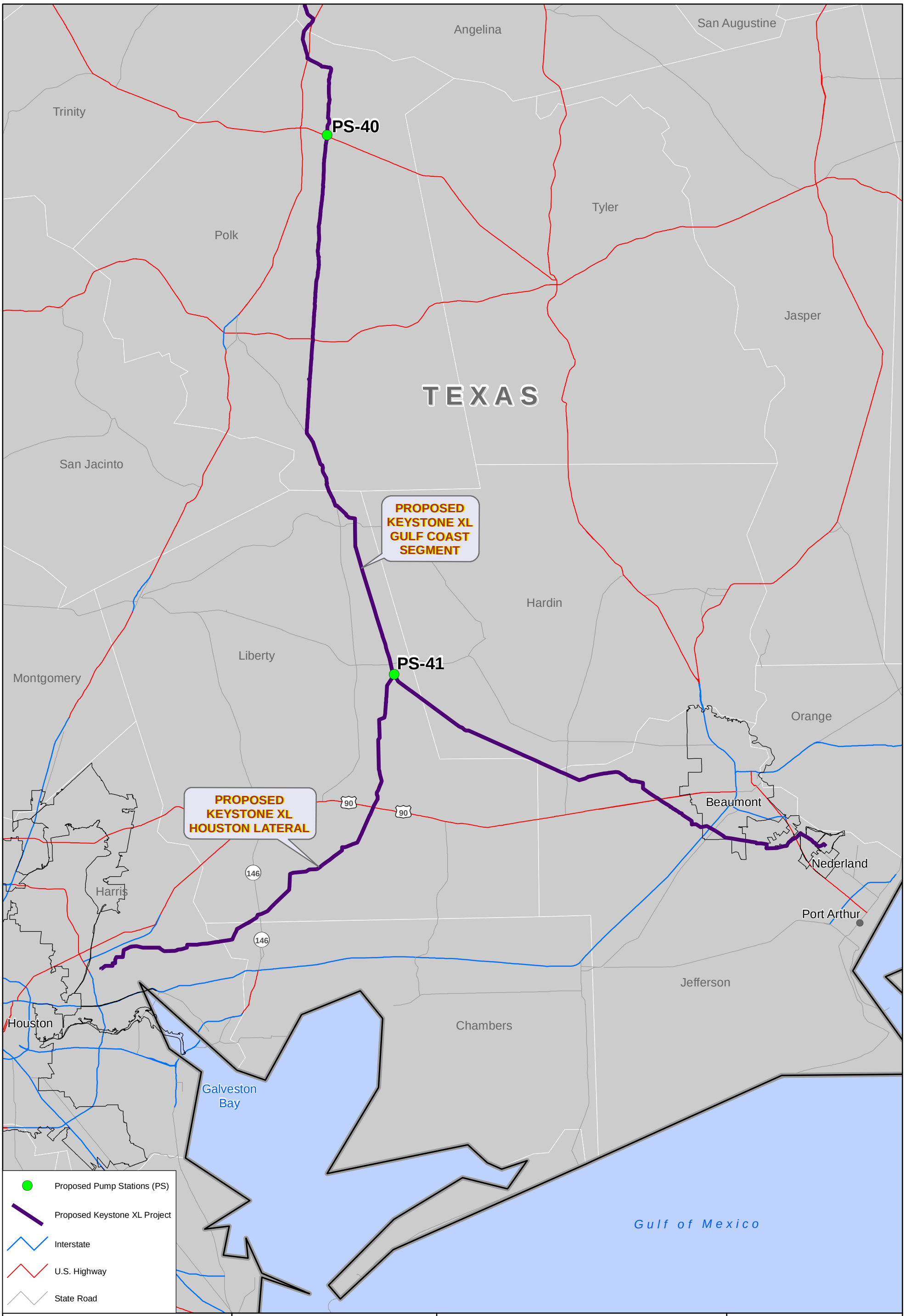

CANADA
PS-09
PS-10
PS-11
PS-12
PS-13
PS-14
PS-15
PS-16
PS-17
PS-18
PS-19
PS-20
PS-21
PS-22
PS-23
PS-24
PS-25
PS-26
PS-27
PROPOSED KEYSTONE XL STEELE CITY SEGMENT
EXISTING KEYSTONE CUSHING EXTENSION
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
WYOMING
COLORADO
KANSAS
Bismarck
Pierre
Cheyenne
Denver
Lincoln
Proposed Pump Stations (PS)
Proposed Keystone XL Project
Existing Keystone Cushing Extension
Interstate
U.S. Highway
State Road
Data Sources: Basemap - ESRI.
0 15 30 60
Miles
KEYSTONE XL PROJECT
Figure 3.10.3-1
Major Roads
Steele City Segment



KEYSTONE XL PROJECT

Figure 3.10.3-2

Major Roads
Gulf Coast Segment


Angelina
San Augustine
Trinity
PS-40
Tyler
Polk
Jasper
TEXAS
San Jacinto
PROPOSED KEYSTONE XL GULF COAST SEGMENT
Hardin
Liberty
PS-41
Montgomery
Orange
PROPOSED KEYSTONE XL HOUSTON LATERAL
90
90
Beaumont
Nederland
146
Harris
Port Arthur
146
Jefferson
Houston
Chambers
Galveston Bay
Gulf of Mexico
Proposed Pump Stations (PS)
Proposed Keystone XL Project
Interstate
U.S. Highway
State Road
Data Sources: Basemap - ESRI.
N
W
E
S
0 3 6 12
Miles
KEYSTONE XL PROJECT
Figure 3.10.3-3
Major Roads
Houston Lateral

3.11 CULTURAL RESOURCES

Cultural resources include the locations of human activity, occupation, or usage that contain materials, structures, or landscapes that were used, built, or modified by people. For example, for the proposed Project, cultural resources include precontact Native American archaeological sites, historic period farmsteads, or a district of historic buildings. For the purposes of the proposed Project, field studies to identify cultural resources assess archaeological resources (sites), historic resources (buildings, structures, objects, and districts), and properties of religious and cultural significance, including Traditional Cultural Properties (TCPs). Paleontological resources are discussed in Section 3.1.

3.11.1 Section 106 National Historic Preservation Act

This proposed Project is considered an undertaking under Section 106 of the National Historic Preservation Act (NHPA). Section 106 of the NHPA, as amended, requires the U.S. Department of State (DOS) as the lead federal agency to consider effects on historic properties before an undertaking occurs. For this proposed Project, the DOS is complying with Section 106 of the NHPA in parallel with NEPA (see Notice of Intent, 74 FR 5019). The intent of Section 106 is for federal agencies to take into account the effects of a proposed "undertaking" on any historic properties situated within the APE and to consult with the Advisory Council on Historic Preservation (ACHP), State Historic Preservation Officers (SHPOs), federally recognized Indian tribes, other federal agencies with concurrent undertakings as a result of the project, applicants for federal assistance, local governments, and any other interested parties regarding the proposed undertaking and its potential effects on historic properties.

In this Section, the effects to historic properties are analyzed under the regulations of Section 106 as proposed Project "effects." A "historic property" is defined as any district, archaeological site, building, structure, or object that is either listed, or eligible for listing, in the National Register of Historic Places (NRHP). Under this definition, historic and archaeological resources present within a project's Area of Potential Effect (APE) are not historic properties if they do not meet the eligibility requirements for listing in the NRHP. For the purposes of this Section, the term "historic resource" refers to buildings, structures, objects, and districts that may or may not meet NRHP criteria of evaluation. Likewise, "archaeological resource" refers to a site that may or may not meet the NRHP criteria of evaluation. The term "sites of religious and/or cultural significance" refers to areas of concern to Indian tribes that, in consultation with the respective tribe(s), may or may not be eligible for listing in the NRHP. These sites may also be considered TCPs.

To be considered eligible for listing in the NRHP, a property must retain integrity and be greater than 50 years of age, although there are provisions for listing cultural resources of more recent origin if they are of "exceptional" importance. The intent of Section 106 is for federal agencies to take into account the effects of a proposed "undertaking" on any historic properties situated within the APE and to consult with the ACHP, SHPOs, federally recognized Indian tribes, applicants for federal assistance, local governments, and any other interested parties regarding the proposed undertaking and its potential effects on historic properties. The proposed Project is considered an undertaking under Section 106 and the lead federal agency is DOS.

The implementing regulation of Section 106 is 36 CFR Part 800 (2004). This regulation establishes a process of identifying historic properties that may be affected by the proposed undertaking; assessing the undertaking's effects on those resources; and engaging in consultation that seeks ways to avoid, reduce, or mitigate any effects on NRHP-listed or eligible properties. Effects include, but are not limited to, destruction or alteration of all or part of a property; isolation from or alteration of its surrounding environment; introduction of visual, audible, or atmospheric elements that are out of character with the

property or that alter its setting; transfer or sale of a federally owned property without adequate conditions or restrictions regarding preservation, maintenance, or use; and neglect of a property resulting in its deterioration or destruction.

36 CFR Part 800 specifies that several state, tribal, and federal agencies must be consulted. This includes each SHPO whose state would physically include any portion of the APE. The SHPO is appointed by each state to protect the interests of its citizens with respect to issues of cultural heritage. Section 101(b)(3) of the NHPA provides each SHPO a prominent role in advising the responsible federal agencies and ACHP. In addition to the SHPO, the lead federal agency has an obligation to work with state and local governments, private organizations, and individuals during the initial planning and development of the Section 106 process.

On non-tribal lands, DOS, in consultation with the SHPOs, Tribal Historic Preservation Officers (THPOs) and other consulting parties, assesses the need for historic and archaeological resource investigations in the proposed Project APE, generates and approves methodologies for undertaking such investigations within the state, and evaluates the preliminary NRHP status of any historical or archaeological resources located within the APE. The SHPO also assists the lead federal agency, DOS, and ACHP in assessing any potential effects to historic properties. The SHPOs also work with DOS, the proposed Project proponent (Keystone), ACHP, and Indian tribes to mitigate any adverse effects that could occur to historic properties. On Indian tribal lands, the Section 106 responsibilities of the SHPO can also be assumed by a THPO under Section 101(d)(2) of the NHPA.

On January 28, 2009, DOS issued a Notice of Intent (NOI) to prepare an EIS under NEPA for the proposed Project. Along with the NOI, DOS notified the public of its intent to conduct a parallel Section 106 process along with the NEPA compliance process. On January 30, 2009, DOS invited Indian tribes and state and federal agencies by letter to become consulting parties for the proposed Project and notified the consulting parties that DOS would be the lead federal agency. Additional Indian tribes and agencies were identified by the BLM and an invitation was forwarded to those parties on February 19, 2009. Another letter from DOS sent March 1, 2009 again invited Indian tribes that had not responded to the initial invitations. Those Indian tribes that did not respond to the first or second written invitations were called via phone on March 18 and March 19, 2009. Since March 2009, several additional tribes and agencies have contacted DOS to become consulting parties. Section 3.11.4 includes information on all of the consulting parties and the consultation process.

On March 30, 2009, DOS developed the APE for the proposed Project and requested comments from consulting parties that included the SHPOs, Indian tribes, and other federal agencies. DOS has continued consultation with these parties as determinations are made concerning NRHP eligibility of identified resources, proposed Project effects on historic properties, and resolution of any adverse effects.

Section 106 recognizes the importance of consulting with Indian tribes when federal undertakings occur. Specifically, 36 CFR 800.2(c)(2)(ii) notes: "Section 101(d)(6)(B) of the NHPA requires the agency official to consult with any Indian tribe or Native Hawaiian organization that attaches religious and cultural importance to historic properties that may be affected by an undertaking. This requirement applies regardless of the location of the historic property." In addition, 36 CFR 800.2(c)(2)(ii)(B) says the "Federal Government has a unique legal relationship with Indian tribes set forth in the Constitution of the United States, treaties, statutes, and court decisions. Consultation with Indian tribes should be conducted in a sensitive manner respectful of tribal sovereignty. Nothing in this part alters, amends, repeals, interprets or modifies tribal sovereignty, any treaty rights, or other rights of an Indian tribe, or preempts, modifies or limits the exercise of any such rights."

DOS is consulting with Indian tribes and the SHPOs regarding the identification, evaluation, and mitigation of historic properties located on non-tribal lands. If a THPO assumes the Section 106 responsibilities of the SHPO on tribal lands, all consultations regarding the proposed Project and its potential effects on historic properties within the relevant tribal lands will be through the THPO. In the event that the tribe has not identified a THPO, the lead federal agency is required to consult with both the SHPO and the Indian tribe's designated Cultural Resource Specialist for any effects on historic properties.

Section 106 regulations state that each SHPO (or THPO, if they have assumed the SHPO's role) is required to respond within 30 days of receiving a request to review a proposed action, or a request to review a federal agency's finding or determination regarding historic properties located within the proposed Project APE. In the event that the SHPO/THPO does not respond within this timeframe, 36 CFR 800.3(c)(4) states that the lead agency can decide to (1) proceed to the next step in the application process based on any earlier findings or determinations that have been made up to that point; or (2) consult directly with the ACHP in lieu of the SHPO/THPO. If, after this step is followed, the SHPO or THPO decides to re-enter the Section 106 process, 36 CFR 800.3(c)(4) further states that the lead agency official may continue the consultation proceeding without being required to reconsider previous findings or determinations. TransCanada Keystone Pipeline, LP (Keystone), the proposed Project Applicant, provided information, analyses, and recommendations to assist DOS in complying with NEPA and Section 106, in accordance with NHPA regulations.

3.11.1.1 National Register of Historic Places

Not all archaeological resources, historic resources, or sites of religious and traditional significance are considered historic properties under Section 106. To be designated as a historic property, the resource must be listed, or eligible for listing, in the NRHP. The criteria (36 CFR 60.4 [a–d]) used to evaluate the significance of a resource are as follows:

- It is associated with events that have made a significant contribution to the broad patterns of American history; or
- It is associated with the lives of past significant persons; or
- It embodies the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or
- It has yielded or may be likely to yield, information important in history or prehistory.

Properties also need to exhibit integrity of location, materials, setting, design, association, workmanship, and feeling and must also be at least 50 years old. However, under Criteria Consideration G, a property achieving significance within the past 50 years is eligible if it is of exceptional importance.

The analysis in the EIS consists of a summary of all cultural resources that have been reported to DOS for the proposed Project. This includes cultural resources assessed as being eligible and ineligible for listing in the NRHP, and cultural resources for which NRHP eligibility has not been evaluated. The reported cultural resources are divided into three main temporal groupings: precontact period, historic period, and multi-component. Precontact resources are sites that contain material evidence of Native American activities before Europeans entered the proposed Project area. Examples of precontact sites include, but are not limited to, rock art; camp or village sites; rock shelters; and scatters of stone, bone, or ceramic tool-making debris. Historic period resources can include recent Native American activity locations but generally reflect Euro-American activities of the last 250 years. These can include residential, government, or commercial structures; farmsteads; mining sites; roads or railways; and ceramic, metal,

and glass artifact scatters. Multi-component resources are locations where both Historic period and precontact cultural remains are present.

3.11.1.2 Properties of Religious and Cultural Significance (Including TCPs)

Historic properties include sites of religious or cultural significance (including TCPs) that meet the NRHP criteria of eligibility but that do not necessarily have physical evidence of human activity. National Register Bulletin 38 defines TCPs as locations that embody the ~~b~~beliefs, customs, and practices of a living community of people that have been passed down through the generations, usually orally or through practice. The traditional cultural significance of a historic property, then, is significance derived from the role the property plays in a community's historically rooted beliefs, customs, and practices" that are essential for continuing the cultural identity of the community. In some tribal cultures, culture and religion are intertwined in which case a historic property may have both cultural and religious significance. As noted in Bulletin 38, a property's religious significance does not preclude its eligibility for the NRHP. As a part of Section 106 consultation, funding for TCP studies has been offered to every consulting tribe. The Indian tribes who have completed TCP studies under this program for the proposed Project are listed in Table 3.11.4-3. DOS has consulted and will continue to consult with Indian tribes to assist in determining the best ways to identify, evaluate, and mitigate potential effects to TCPs. The summary of this tribal consultation is in Section 3.11.4.3.

3.11.1.3 Archaeological Resources Protection Act and Native American Graves Protection and Repatriation Act

In addition to Section 106, the Archaeological Resources Protection Act of 1979 (ARPA) (16 USC 470; 43 CFR 7) requires federal land-owning agencies to issue ARPA permits to qualified individuals, institutions, or firms that conduct archaeological surveys within federal and Indian lands. The proposed Project has the potential to be within federally controlled, maintained, managed, or owned lands, including BLM lands, Reclamation lands, and USACE managed lands.

The Native American Graves Protection and Repatriation Act (NAGPRA 1990) applies to all federal and tribal lands. NAGPRA effectively protects tribal burial sites and rights to items of cultural significance, including human remains, funerary objects, sacred objects, and objects of cultural patrimony (25 USC §3001[3]; 43 CFR 10). On federal lands, intentional excavation and removal of Native American human remains and objects from federal or tribal lands for discovery, study, or removal is permissible only if an ARPA permit is issued by a federal land-holding agency. Consultation with Native Americans must occur prior to the issuance of an ARPA permit and removal of human remains and objects requires the consent of the applicable Native American tribe. NAGPRA applies to all federal and tribal lands affected by the proposed Project. Each state has statutes that govern the inadvertent discovery and/or excavation of human remains as well as artifacts on private lands.

3.11.2 Project Setting

3.11.2.1 Project Area

The proposed Project area contains cultural resources resulting from human settlement and other activities over the last 10,000 years. These include archaeological sites, special activity areas such as food processing sites, cemeteries, and sites of spiritual and traditional use. Later historic activities expressed on the landscape include mining-related resources, railroads, commercial buildings, domestic residences, and agricultural buildings. Many of these cultural resources are associated with mineral exploration, transportation, settlement, logging, and agricultural production. Lands and resources within and outside the respective Reservations are very important to Native American peoples for subsistence gathering, for

the collection of plants for medicines, for spiritual and ceremonial purposes, and for everyday life. This section, therefore, summarizes the cultural resources aspects of the proposed Project in relation to each individual affected state.

3.11.2.2 Area of Potential Effect and State by State Efforts to Identify Historic Properties

The Area of Potential Effect (APE) is defined as the —geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist" (36 CFR 800.16(d)). For the purposes of the proposed Project and Section 106 of the NHPA, the APE consists of a 300-foot-wide survey area that includes a 110-foot wide construction ROW that will primarily be collocated along existing pipeline facilities/easements. A 50-foot-wide permanent ROW would be retained to accommodate proposed Project operations and maintenance. The 300-foot wide corridor will allow for minor adjustments or route variations as they become known. Other areas that may lie outside of the proposed construction ROW but that are considered a part of the proposed APE include temporary work spaces, access roads, storage/warehouse yards, pump stations and valves, and associated electrical transmission/distribution lines.

Where access was available, cultural resource surveys were conducted within the APE for the proposed Project by SWCA Environmental Consultants and American Research Group (ARG). These were the consultants employed by the Applicant. The titles and authors of the cultural resource surveys are listed below in the state by state descriptions. The survey results were submitted from the Applicant to DOS, reviewed, and either approved or sent back to the Applicant for additional information. Once DOS was satisfied with the content of individual survey reports, a preliminary determination of NHPA eligibility and effects was completed, and reports were then sent to the SHPOs and consulting parties for their review and concurrence. The proposed Project APE through each state and respective counties is described in Table 3.11.2-1.

TABLE 3.11.2-1
Area of Potential Effect for the Proposed Project Corridor by State

State	Counties	Corridor Area of Potential Effect
Montana	Dawson, Fallon, McCone, Phillips, Prairie, and Valley	300 feet (if existing pipeline is present then 300 feet from the centerline of outermost existing pipeline)
South Dakota	Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, Gregory and Tripp	300 feet (if existing pipeline is present then 300 feet from the centerline of outermost existing pipeline)
Nebraska	Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson	300 feet (if existing pipeline is present then 300 feet from the centerline of outermost existing pipeline)
Kansas	Butler and Clay	Area of soil disturbance related to construction of two pumping stations.
Oklahoma	Lincoln, Okfuskee, Creek, Seminole, Hughes, Coal, Atoka, Bryan, Grady, and Pottawatomie	300 feet (if existing pipeline is present then 300 feet from the centerline of outermost existing pipeline)
Texas	Angelina, Chambers, Cherokee, Delta, Fannin, Franklin, Hardin, Harris, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, and Wood	300 feet (if existing pipeline is present then 300 feet from the centerline of outermost existing pipeline)

Montana

Within Montana, the proposed Project would cross state lands including Dawson, Fallon, McCone, Phillips, Prairie, and Valley counties, in addition to lands managed by Reclamation and USACE. Prior to the initiation of Montana fieldwork, literature searches were conducted for the proposed Project route and route variations developed during MDEQ review and advanced engineering analysis. These pre-fieldwork activities occurred on:

- April 14-18, 2008 and May 23, 2008 using Montana SHPO Cultural Resources Annotated Bibliography System Report (CRABS) and the Cultural Resource Information Systems Report (CRIS) under SHPO Project Number 2008052306;
- April 23, 2008 using records at the BLM Miles City Field Office; and
- During 2009 and 2010 prior to each addendum report field survey program.

Cultural resource surveys in Montana summarized in the EIS were conducted between 2008 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Berg, C. et al. 2008a. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.
- Cooper, J. et al. 2009. Addendum 1: Additional Fieldwork Results. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.
- Zietz, V. et al. 2009. Addendum 2: Additional Fieldwork Results. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.
- Baer, S. et al. 2009. Addendum 3: Additional Fieldwork Results. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.
- Marmor, J. et al. 2009. Addendum 4: Architectural Field Inspection and Visual Impact Analysis. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.
- Crossland, N. et al. 2010. Addendum 5: Additional Fieldwork Results. Class III Cultural Resources Survey for the Steele City Segment in Montana of the Keystone XL Project, Dawson, Fallon, McCone, Phillips, Prairie, and Valley Counties, Montana. SWCA Environmental Consultants. Broomfield, CO.

The 2008-2009 file searches of the proposed Project route identified 695 previous inventories, which documented 216 archaeological sites and historic structures. These file searches were completed for a 2-mile area. The 216 previously recorded sites consisted of 148 precontact archaeological sites, 5 historic archaeological sites, 6 multi-component archaeological sites, and 57 historic structures. None of the precontact sites are eligible for listing in the NRHP. The 57 historic structures included 27 homesteads, 9 railroad crossings, 8 bridges, 4 canal systems, a cemetery, a trading post and 2 crossings of the Lewis and

Clark National Historic Trail (LCNHT). Thirteen of the historic structures are eligible for listing in the NRHP, including 7 railroads (24VL0099, 24MC0097, 24MC0257, 24DW0419, 24DW0426, 24FA0382, and 24VL1628); 2 railroad bridges (24MC0413 and 24MC0414); 2 canals (24DW0289 and 24VL1194); a road bridge (24VL1833); and a cemetery site (24PE0633).

The file searches along the proposed power distribution line routes identified 317 previously recorded archaeological sites and historic structures within the 2-mile files search corridor. Of these, 218 were precontact archaeological sites, 47 were historic archaeological sites, 8 were multi-component sites, 24 did not have an identified time period, and 31 were historic structures. Thirteen of the precontact archaeological sites are eligible for listing in the NRHP. These sites include lithic scatters (24FA0611, 24FA0613, 24FA0614, 24FA0615, 24FA0616, 24FA0617, 24FA0618, 24FA0619, and 24FA0622); stone circle sites (tipi ring sites) (24FA0625, 24PH1162, 24PH3547, and 24PH3548); and a rock cairn and alignment (24PH3183). One of the multi-component sites (24FA0621), a precontact lithic scatter with rock piles and an historic herder camp, was eligible for listing in the NRHP. Thirteen of the historic structures are identified as eligible for listing in the NRHP. These 13 sites consist of railroads (24FA0382, 24MC0097, 24MC0257, 24MC0413, 24MC0414, 24MC0415, 24PH3008, and 24VL0099) and agricultural/irrigation (24DW0289, 24PE0267, 24PH2710, 24PH3103, and 24VL1194).

The file searches along the proposed access road routes identified 121 previously recorded sites and historic structures within the 2-mile file search corridor. Of these, 84 were precontact archaeological sites, 5 were historic archaeological sites, 3 were multi-component sites, 13 did not have an identified time period, and 15 were historic structures. None of the precontact archaeological sites are eligible for listing in the NRHP. Three of the historic structures are identified as eligible for listing in the NRHP. They include portions of three historic railroads (24FA0382, 24DW0426, 24VL0099).

The file searches along the proposed ancillary facilities identified 14 sites that were previously recorded within the 2-mile file search corridor. Of these, 13 were historic structures and 1 was an undated rock cairn (24VL1109). Of the historic structures, 6 are identified as eligible for listing in the NRHP. These six sites include railroads (24VL0099 [3 segments], 24MC0257, 24DW0426, and a canal (24DW0289).

The 2010 file searches along the proposed MDEQ reroutes identified 45 sites or segments of sites that were previously recorded within the 2-mile file search corridor. Of these, 36 were precontact archaeological sites, 5 were historic archaeological sites, one was a multi-component archaeological site, and 3 were historic structures. Two of the historic structures are identified as eligible for listing in the NRHP. They are historic railroad bridges (24MC0413 and 24MC0414). An additional ten sites were previously recorded within the 2-mile file search corridor related to proposed access roads associated with the MDEQ route variations. Four of the sites were precontact archaeological sites, five were historic structures, and one was a historic archaeological site.

The findings of the field surveys and previously recorded cultural resources found only within the proposed Project APE are summarized in Table 3.11.3-1.

South Dakota

Within South Dakota, the proposed Project would cross Butte, Haakon, Harding, Jones, Lyman, Meade, Gregory, Perkins, and Tripp counties. Prior to the initiation of South Dakota fieldwork, literature searches were conducted for the proposed Project route and for the Niemi route variation developed during landowner negotiations. These pre-fieldwork activities occurred on:

- May 7 and 8, 2008 at the South Dakota State Archaeological Resource Center (SARC); and
- During 2009 and 2010 subsequent file searches were conducted for each addendum report, including the report addressing the proposed Niemi route variation.

Cultural resource surveys in South Dakota summarized in the EIS were conducted between 2008 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Berg, C. et al. 2008b. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, and Tripp Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Barnes, Z. et al. 2009. Addendum 1: Additional Fieldwork Results. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, and Tripp Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Doyle, S. et al. 2009. Addendum 2: Additional Fieldwork Results. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, Tripp, and Gregory Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Salisbury, E. et al. 2010. Addendum 3: Additional Fieldwork Results. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, Tripp, and Gregory Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Marmor, J. et al. 2010. Addendum 4: Architectural Field Inspection and Visual Impact Analysis. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, Tripp, and Gregory Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Boyer, N. et al. 2010. Addendum 5: Additional Fieldwork Results. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, Tripp, and Gregory Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.
- Burkard, J. et al. 2010. Addendum 6: Additional Fieldwork Results. Level III Cultural Resources Survey for the Steele City Segment in South Dakota of the Keystone XL Project, Butte, Haakon, Harding, Jones, Lyman, Meade, Perkins, and Tripp Counties, South Dakota. SWCA Environmental Consultants. Broomfield, CO.

The initial file searches identified 52 previous inventories, which documented 49 archaeological sites and 15 historic structures along the proposed Project route. These file searches were completed for a 2-mile area. The 49 previously recorded archaeological sites consisted of 33 precontact sites, 10 historic sites, and 6 sites that did not have an identified time period. Only one of the precontact sites (39MD0502) was previously identified as potentially eligible for the NRHP, but South Dakota had not concurred with this determination. None of the historic sites are listed as eligible for the NRHP. Only one site (39BU0039) located within the 2-mile buffer (based on previously recorded location information) is located within the proposed 300-foot survey corridor for the proposed Project. Of the 15 historic structures, 6 are historic bridges, and 9 are historic buildings including a school house, barns, and a ranch. None of the historic bridges are eligible for listing in the NRHP. However, three of the structures, including two barns (TP00000010 and TP00000018) and one ranch (PE00000020), are eligible for the NRHP.

During the preparation of the subsequent reports for the proposed Project corridor, power distribution line routes, access roads, ancillary facilities, additional file searches identified 137 previous inventories, which documented an additional 91 archaeological sites and 61 historic structures. These searches revealed that two of the archaeological sites, historic sites (39HK0103 and 39JN2007) and ten historic structures (HN0000009, HK0000007 GR00000207, JN46415/JN00000044, TP00000001, TP00000002, TP00000049, TP00000066, TP00000069, and TP00000071) are eligible for the NRHP.

The findings of the field surveys and previously recorded cultural resources found only within the proposed Project APE are summarized in Table 3.11.3-2.

Nebraska

Within Nebraska, the proposed Project would cross Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson counties. Prior to the initiation of Nebraska fieldwork, literature searches were conducted for the proposed Project route. These pre-fieldwork activities occurred on:

- April 11, April 22 and May 22, 2008 at the Nebraska State Historical Society (NSHS) in Lincoln, Nebraska;
- During April 2008, a research design and methodology for cultural resources field studies was submitted to the Nebraska SHPO (Fink et al., 2008). Approval from SHPO was received on May 27, 2008.

Cultural resource surveys in Nebraska summarized in the EIS were conducted between 2008 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Fink, M. et al. 2008. A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.
- Lomas, M. 2009a. Addendum No. 1: A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.
- Anderson J. and M. Lomas. 2009. Addendum No. 2: A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.
- Lomas, M. and K. Lomas. 2009. Addendum No. 3: A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.
- Titus, S. and M. Lomas. 2010. Addendum No.4: A Phase I Cultural Resources Survey of the Steel City Segment in Nebraska of the proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Filmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.
- Lomas, M. et al. 2010. Addendum No. 5: A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Project in Keya Paha, Rock, Holt,

Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.

- Lomas, M. et al. 2011. Addendum No. 6: A Phase I Cultural Resources Survey of the Steele City Segment in Nebraska of the Proposed Keystone XL Pipeline Project in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, Boone, Nance, Merrick, Hamilton, York, Fillmore, Saline, and Jefferson Counties, Nebraska. American Resources Group, Ltd. Carbondale, IL.

The initial file search identified 60 previous inventories, which documented 57 archaeological sites and 220 historic structures near the proposed Project route. These file searches were completed for a 2-mile area. The 57 previously recorded archaeological sites consisted of 30 precontact sites, 23 historic sites, one site containing both precontact and historic components, and three sites that did not have an identified time period. Only one archaeological site within the 2-mile corridor is listed in the NRHP. Site 25NC2, the Horse Creek site, is a historic Pawnee earth lodge village, occupied between 1810 and 1842. This site is not located within the proposed 300-foot survey corridor. Of the 220 historic structures, 36 have been evaluated as eligible or potentially eligible for listing in the NRHP. Eleven of the historic structures were identified adjacent to the 300-foot corridor. Only one of the historic structures adjacent to the 300-foot survey corridor, the District 81 Shiloh School, has been recommended as potentially eligible for listing in the NRHP. The school building, YK-00-183, is a Craftsman-style schoolhouse built in 1920.

The findings of the field surveys and previously recorded cultural resources found only within the proposed Project APE are summarized in Table 3.11.3-3.

Kansas

Within Kansas, the proposed Project would cross Washington, Clay, Dickinson, Marion, Butler, and Cowley counties. Prior to the initiation of Kansas fieldwork, literature searches were conducted for the proposed Project route. These pre-fieldwork activities occurred in March 2006, in which a research design and methodology was submitted to the Kansas SHPO and approved by SHPO the same year.

The purpose of the research design was to present the field methods to be used to assess the proposed Cushing Extension and to identify historic properties within the APE. It was based on the results of the site file research and results of previous surveys. The design incorporated a sampling strategy that assessed the route in terms of high and low probabilities for containing Section 106-defined historic properties (excluding TCPs); this strategy follows procedures accepted by the SHPO and FERC for pipeline projects in Kansas. The submitted research design used the preliminary proposed Project route as its basis; subsequent alterations to the route did not require submission of a new research design but involved implementation of the general procedures outlined in the research design.

Cultural resource surveys in Kansas summarized in the EIS were conducted between 2009 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Lomas, M. 2009b. A Phase II Cultural Resources Survey of Pump Stations 27 and 29 for the Proposed Keystone XL Pipeline Project, Clay and Butler Counties, Kansas. American Resources Group, Ltd. Carbondale, IL.
- Titus, S. and M. Lomas. 2010. Addendum No. 1: A Phase II Cultural Resources Survey of Pump Stations 27 and 29 for the purposed Keystone XL Pipeline Project, Clay and Butler Counties, Kansas, American Resources Group, Ltd. Carbondale, IL.

Through previous work within the APE, two archaeological sites within the proposed Project pump station locations were identified. One site, 14BU131, was a historic period scatter, and the other site,

14CY120, was a historic railroad bed. Both sites were recommended as not eligible for listing in the NRHP. Additional reports that include information about the power distribution lines will be submitted to and reviewed by DOS in accordance with 36 CFR Part 800 and the PA.

The findings of the field surveys and previously recorded cultural resources within the proposed Project APE are summarized in Table 3.11.3-4.

Oklahoma

Within Oklahoma, the proposed Project would cross Lincoln, Okfuskee, Creek, Seminole, Hughes, Coal, Atoka, Bryan, Grady, and Pottawatomie counties. Prior to the initiation of Oklahoma fieldwork, literature searches were conducted for the proposed Project route. These pre-fieldwork activities occurred in:

- April and May 2008, at the Oklahoma Archaeological Survey, the Oklahoma SHPO, and the Oklahoma Historical Society, as well as the Museum of the Red River in Idabel and the Texas Archaeological Research Laboratory; and
- June 2008 to April 2010, at the Oklahoma Archaeological Survey, the Oklahoma SHPO, and the Oklahoma Historical Society, as well as the Museum of the Red River in Idabel and the Texas Archaeological Research Laboratory.

Cultural resource surveys in Oklahoma summarized in the EIS were conducted between 2008 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Miller, K. et al. 2008. Cultural Resource Inventory of the Keystone XL Pipeline Project: Gulf Coast Segment in Oklahoma: Payne, Lincoln, Okfuskee, Creek, Seminole, Hughes, Coal, Atoka, and Bryan Counties, Oklahoma. SWCA Environmental Consultants. Austin, TX.
- Carpenter, S. et al. 2009. Cultural Resource Inventory of the Keystone XL Pipeline Project: Gulf Coast Segment in Oklahoma, Lincoln, Okfuskee, Creek, Seminole, Hughes, Coal, Atoka, and Bryan Counties, Oklahoma. SWCA Environmental Consultants. Austin, TX.
- Carpenter, S. et al. 2010. Cultural Resource Inventory of the Keystone XL Pipeline Project: Gulf Coast Segment in Oklahoma. Lincoln, Okfuskee, Creek, Seminole, Hughes, Coal, Atoka, Bryan, Grady, and Pottawatomie Counties, Oklahoma. SWCA Environmental Consultants. Austin, TX.
- Acuňa, L. I. et al. 2010. Addendum Report No. 1. Additional Cultural Resources Inventory on the Keystone XL Pipeline Project: Gulf Coast Segment in Oklahoma: Lincoln, Creek, Okfuskee, Seminole, Hughes, Coal, Atoka, and Bryan Counties, Oklahoma. SWCA Environmental Consultants. Austin TX.

The SWCA draft Cultural Resource Inventory report was submitted to the Oklahoma SHPO in 2008 to simultaneously identify and evaluate resources as well as provide recommendations concerning effects stemming from the proposed Project. The report describes background research and field efforts conducted within Oklahoma portion of the proposed Project in compliance with Section 106 requirements. An additional three reports were submitted in 2009-2010 to DOS. These reports included a revised report with additional background research and field efforts in previously inaccessible areas, a comprehensive draft final report that includes the cumulative cultural resources findings of the archaeological, historical, and architectural historical investigations, including the assessment of historic viewsheds of above-ground facilities and an addendum report that includes additional surveyed areas. These reports have been forwarded to and reviewed by DOS and distributed to consulting parties for review consistent with 36 CFR Part 800.

The file searches identified 80 previous inventories, which documented 226 previously recorded sites within the 2 mile wide corridor. This includes 126 site leads from General Land Ownership (GLO) maps, 78 archaeological sites, 29 historic cemeteries, one un-dated resource, and 19 resources recorded in the Oklahoma Landmark Inventory. Of these, 9 sites, one historic roadway (Route 66), and two historic cemeteries are recorded within or immediately adjacent to the proposed Project route. The archaeological sites include three precontact sites (34HU21, 34AT56, and 34CO53) and six historic sites (34LN182, 34AT661, 34AT662, 34BR263, 34BR322, 34HU94).

The findings of field surveys and previously recorded cultural resources within the proposed Project APE are summarized in Table 3.11.3-5.

Texas

Within Texas, the proposed Project would cross Angelina, Cherokee, Delta, Fannin, Franklin, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, and Wood counties. Survey protocols in High Probability Areas (HPA) were prepared by the Applicant and accepted by DOS, Texas Historical Commission (THC), and SHPO. All HPAs were field-verified and subject to 100 percent coverage. In addition, moderate-probability areas were ground-truthed. The procedures used to identify historic properties of cultural and religious significance (including TCPs) are outlined in the discussion of the consultation process (see Section 3.11.4). DOS required that the Applicant also complete historical architectural inventories of the proposed Project corridor and ancillary facilities. TCH and SHPO concurred with DOS that these inventories should be completed. Prior to the initiation of Texas fieldwork, background literature and record searches were conducted for the proposed Project route. These pre-fieldwork activities occurred in:

- April and May 2008, the Texas Archeological Research Library (TARL) and THC were accessed for a review of USGS topographic maps and archaeological site files;
- May 2008, a research design and survey protocols for cultural resources field studies were submitted to the THC and SHPO; and
- June 2009, additional research design and survey protocols that defined the scope of resources that required review by an architectural historian were adopted by DOS and submitted to the THC and SHPO.

Cultural resource surveys in Texas summarized in the EIS were conducted between 2008 and 2010. These reports were submitted to DOS upon completion and are listed below:

- Carpenter, S. et al. 2008. "Cultural Resource Inventory of the Keystone XL Project, Gulf Coast Segment in Texas: Angelina, Cherokee, Delta, Fannin, Franklin, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, and Wood Counties, Texas." TransCanada Keystone XL Project, Cultural Report, Gulf Coast – Texas (Confidential Section 106 Consultation Field Survey Reports in Keystone 2009c). SWCA, Austin.
- Lawrence, K. et al. 2008. Final Draft: Cultural Resource Inventory of the Keystone XL Houston Lateral: Liberty, Chambers, and Harris Counties, Texas. TransCanada Keystone XL Project, Cultural Report, Houston Lateral – Texas (Confidential Section 106 Consultation Field Survey Reports in Keystone 2009c). SWCA, Austin.
- Lawrence, K. et al. 2009. Cultural Resource Inventory of the Keystone XL Pipeline Project Gulf Coast Segment Crude-Oil Pipeline: Houston Lateral, Liberty, Chambers, and Harris Counties, Texas. TransCanada Keystone XL Project, Cultural Report, Houston Lateral – Texas (Confidential Section 106 Consultation Field Survey Reports in Keystone 2009c) SWCA, Austin.

- Carpenter S. et al. 2009. Cultural Resource Inventory of the Keystone XL Gulf Coast Segment in Texas, Angelina, Cherokee, Delta, Fannin, Franking, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, and Wood Counties, Texas. SWCA, Austin.
- Carpenter S. et al. 2010. Cultural Resource Inventory of the Keystone XL Gulf Coast Segment in Texas, Angelina, Cherokee, Delta, Fannin, Franklin, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Polk, Rusk, Smith, Upshur, and Wood Counties, Texas. SWCA, Austin.
- Stotts, M. et al. 2010. Addendum Report No. 1. Additional Cultural Resource Inventory on the Keystone XL Pipeline Project: Gulf Coast Segment in Texas. Angelina, Cherokee, Delta, Fannin, Franklin, Hardin, Hopkins, Jefferson, Lamar, Liberty, Nacogdoches, Orange, Polk, Rusk, Smith, Upshur, and Wood Counties, Texas. SWCA, Austin.

The file searches identified 29 previous inventories, which documented 212 archaeological sites, 40 cemeteries, and 14 historic markers in the Texas section of the Gulf Coast Segment of the proposed Project route, and no cultural resources within the Houston Lateral. These file searches were completed for a 2-mile area. The 212 previously recorded archaeological sites consisted of 106 precontact sites, 91 historic sites (of which 56 are historic structures), and 15 sites containing both precontact and historic components. Several of the previously recorded sites within the 300-foot survey corridor have been determined eligible for listing in the NRHP. Additionally, one is a National Historic Trail. All of the 40 cemeteries are historic resources, which are typically not recorded as archaeological sites, but are protected under Texas state law.

The findings of field surveys and previously recorded cultural resources found only within the proposed Project APE are summarized in Table 3.11.3-6.

3.11.3 NRHP Eligibility, Effects, and Mitigation

After the APE is identified and surveyed, the DOS is responsible for assessing the potential effects of the proposed Project to historic properties. When adverse effects are anticipated, the DOS must avoid, minimize, or mitigate these effects. This section summarizes the types of effects, types of avoidance and effect minimization measures, as well as potential mitigation measures. This section also provides a state by state breakdown of proposed Project effects to historic resources and archaeological sites and what measures are proposed to avoid, minimize, or mitigate adverse effects.

Section 106 of the NHPA (as codified in 36 CFR 800.5) requires federal agencies to apply the "criteria of adverse effect" to determine whether a project will affect historic properties. Effects are found when an undertaking alters, directly or indirectly, the characteristics of a historic property that qualify it for inclusion in the NRHP, in a manner that diminishes the historical integrity of the property. Reasonably foreseeable effects caused by the undertaking may occur later in time, be distant, or be cumulative. Federal agencies are required to consult with consulting parties when there are potential adverse effects. The consultation should attempt to resolve adverse effects and develop mitigation measures as necessary.

For the proposed Project, the principal types of effects that could occur include physical destruction or damage, to all or part of the property, caused by trenching or related excavations or boring; introduction of visual, atmospheric, or audible elements that diminish the integrity of the property's significant historic features by short-term construction of the proposed Project or construction of above ground appurtenant facilities and roads; and change of the character of the property's use or of physical features within the property's setting that contribute to its significance.

Historic properties under Section 106 are determined eligible by the lead federal agency with the concurrence of the applicable land managing agency (i.e., BLM) and SHPO/THPO. A PA has been

prepared in order to provide a process for DOS and the Section 106 Consulting parties to implement the avoidance of adverse effects to historic properties. For those historic properties where avoidance is not feasible, a Treatment Plan will be prepared consistent with the stipulations of the PA. Cultural resources that are considered "unevaluated" have not been sufficiently assessed at this time to finalize an eligibility determination for the NRHP. These sites must either be further assessed through NRHP evaluation procedures or will be treated by DOS as a historic property and mitigation plans must be developed.

Avoidance can be achieved by moving the proposed Project corridor or the location of proposed Project facilities. Avoidance can also be achieved by keeping construction activities away from NRHP-eligible properties, limiting the effect to existing demonstrated disturbance areas, or digging underneath the cultural deposits by boring or horizontal direct drilling (HDD).

The results of NRHP assessments provided by the Applicant must be filed with DOS at least 30 days prior to construction commencing in the area demonstrating that historic properties designated as unevaluated are not historic properties. Alternatively, the Applicant must provide plans that detail the specific avoidance procedures to be implemented in order to avoid effects to each eligible and unevaluated site, using the procedures described below. DOS and the consulting parties would evaluate the submitted information, following the protocols outlined in any PA developed for the proposed Project.

The following mitigation measures are applicable for historic properties for a finding of No Effect or No Adverse Effect:

(1) Avoidance through centerline or access road route variation or proposed Project feature relocation

For each route variation or feature relocation, the Applicant would file with DOS a map at 1:24,000 scale or better that clearly shows the original surveyed corridor or feature location, the known boundaries of the eligible or unevaluated property, the route variation or feature relocation that avoids the property, and survey information showing that no historic properties are located within the route variation or feature relocation.

(2) Avoidance through abandonment

For each abandonment, the Applicant would file a letter with DOS that states the facility or road at which the eligible or unevaluated property was located and a statement that the facility or road is no longer associated with the proposed Project.

(3) Avoidance through boring or HDD

For each instance, the Applicant would file with DOS a map and technical drawing that clearly shows the projected depth below surface and the entrance and exit points of the drill in relation to the boundaries of the eligible or unevaluated property.

(4) Avoidance by narrowing the construction corridor ("neck down")

For each instance, the Applicant would file with DOS an alignment sheet map at 1:500 scale or better that clearly shows the construction corridor (including additional temporary workspace) in relation to the eligible or unevaluated property boundary. Prior to any construction commencing in the area, safety fencing must be erected along the relevant outer edges of the eligible or unevaluated property. A qualified monitor must be present during installation of the proposed Project in that area to ensure that accidental effects do not occur to the property.

(5) Avoidance through the use of existing roadways as proposed Project access roads to the extent practicable

For each instance, the Applicant would file with DOS an alignment sheet map at 1:500 scale that clearly shows the existing roadway in relation to the eligible or unevaluated property, a description of the existing state of the roadway, and a statement that proposed Project traffic would be limited entirely to the existing roadway and that the road would not be widened or upgraded as a result of the proposed Project.

Short-term construction-related effects would be mitigated by implementing measures such as the use of construction mats. If effects should occur to any historic property or unevaluated cultural resource, they would be resolved through consultation with all consulting parties.

3.11.3.1 State-by-State Analyses of Proposed Project Effects to Cultural Resources

Montana

Cultural Resource pedestrian surveys and inventories conducted through August 2010 within the proposed Project APE included:

- 328.6 miles of the proposed Project centerline (including reroutes and realignments);
- 107.26 miles of access roads;
- 169.95 miles of power distribution lines;
- 101.4 miles of proposed MDEQ reroutes; and,
- 1,313.49 acres of proposed ancillary facility sites.

To date, 311 cultural resources were identified during the cultural resources inventory in Montana, including 195 archaeological sites, 49 historic structures, and 67 isolated finds. The results of the surveys performed, recommendations of eligibility by the Applicant, determinations of eligibility by DOS, and concurrence from SHPO are shown in Table 3.11.3-1.

Additional cultural resource surveys for the proposed Project corridor, reroutes, access roads, and ancillary facilities are forthcoming. These reports will be reviewed by DOS and then forwarded to the applicable consulting parties consistent with 36 CFR Part 800 and the PA.

Archaeological Sites

Details on the 262 archaeological sites and isolates are listed below:

- Of the 15 previously recorded archaeological sites there were 7 precontact sites, 3 historic sites, 3 multi-component sites, and 2 sites that did not have an identified time period;
- Of the 180 newly recorded archaeological sites there were 98 precontact sites, 47 historic sites, 7 multi-component sites, and 28 sites that did not have an identified time period;
- Of the 67 isolated finds recorded during the field survey there were 43 precontact site, 22 historic sites and 2 multi-component sites;
- 8 of the previously recorded archaeological sites and 34 of the newly identified archaeological sites in the Montana section have been recorded as eligible; and
- 103 additional sites are considered unevaluated.

Avoidance is recommended for all eligible and unevaluated sites. By avoiding these sites, the proposed Project will have no effect on these historic properties. By definition, the isolated finds are not eligible for listing in the NRHP. Eleven sites in the APE will be avoided by narrowing the construction corridor: 24MC0461, 24MC0467, 24MC0476, 24PH4162, 24PH4313, 24PH4315, 24PH4316, 24VL0805, 24VL1912, 24VL1920, 24VL1933. These sites consist of precontact stone circles, precontact and historic stone features, an undated stone cairn, and a historic homestead. One additional site, 24PH0037, located on a construction access road is a stone feature site on an existing road. In addition to narrowing the construction corridor, the Applicant proposes matting or mat bridges to enable equipment and vehicles to cross the resource without damaging the integrity of the site. Ten sites will not be avoided: 24MC0481, 24PH4144, 24PH4145, 24PH4146, 24PH4163, 24VL0962, 24VL0972, 24VL0979, 24VL1269/24VL1274, and 24VL1919. For those historic properties where avoidance is not feasible, a treatment plan will be prepared consistent with the stipulations of the PA.

Of the 195 archaeological sites, 103 (96 newly recorded and 7 previously recorded) remain unevaluated. Some of these sites are considered potential properties of religious and cultural significance including TCPs and may be eligible for inclusion in the NRHP. DOS will continue to consult with Indian tribes and agencies about the significance of the sites and work to avoid any detrimental effects to the resources.

Historic Structures

Details on the 49 historic structures are listed below:

- 30 structures were previously recorded, including several segments of railways and canals and two homesteads;
- 19 structures were newly recorded, including farmsteads, ranch complexes and a pump house;
- 6 structures have been recorded as eligible; and
- 6 structures are unevaluated.

Avoidance is recommended for all eligible or unevaluated sites. Nine historic properties in the APE will be avoided with boring or HDD: 24DW0289, 24DW0419, 24DW0426, 24FA0382, 24MC0257 (2 segments), 24VL0099 (2 segments), and 24VL1194. These sites consist of historic railroads, railroad grades, and canals. Two unevaluated sites located in the construction access roads APE—24VL1938 and 24VL1940—are historic home/farmsteads located along existing roads. Additional research will be conducted to determine NRHP eligibility and determination of proposed Project effects. For those historic properties where avoidance is not feasible, a treatment plan will be prepared consistent with the stipulations of the PA.

Historic Trail

The proposed Project route crosses the LCNHT at two locations. Although cultural resource investigations conducted in the vicinity of the trail did not identify any archaeological remains, historic artifacts, or culturally-constructed features associated with the LCNHT, the Missouri River corridor and the Yellowstone River corridor are within a BLM Special Resource Management Area (SRMA) established for the LCNHT. Also, the LCNHT is not generally defined by physical trail remains. The tangible elements of the LCNHT in the current proposed Project corridor are defined by the rivers and river banks that the Lewis & Clark route followed, with the maintenance of the historic setting of this route along these river ways, comparable to the natural descriptions found in expedition journals, being integral to the resource. There is no adverse effect to the LCNHT route since it is not possible to define an exact location or physical trail remains where the expedition crossed the proposed Project route. A PA

is being prepared to direct how DOS and the other identified stakeholders will determine and implement avoidance and other mitigation of adverse effects to all historic properties potentially to be affected by the proposed Project.

Stone Circle Sites (Tipi Rings)

Tipi Rings, also known as stone circles, are stone features that are the primary representative of precontact Native American settlement in Montana. Tipi Rings are made up of stones assembled in concentric rings and were used by Native Americans to anchor their dwellings. Sites can consist of a single ring to many dozen. Tipi ring sites often include additional features such as pits and hearths, and may include artifacts such as fire cracked rock, animal bone, and stone tools. Table 3.11.3-1 is a listing of all historic structures in Montana, the majority of the list is devoted to the stone tipi rings. The proposed Project APE contains many unevaluated stone circle sites (Table 3.11.3-1) that were identified during cultural resource surveys. The recordation and evaluation of these sites are guided by the *Recordation Standards and Evaluation Guidelines for Stone Circle Sites* (MT SHPO, 2002). Several of these sites may be adversely affected by the proposed Project. DOS will continue to work with the Indian tribes, BLM, MT SHPO, and the Applicant to avoid or treat sites that will be adversely affected by the proposed Project. DOS conducted site visits with the Blackfeet and Chippewa-Cree tribes and BLM and MDEQ along the proposed Project route in Montana to consult on and discuss stone circle sites, identify avoidance options, and to describe proposed Project effects. For a list of dates regarding DOS consultation with Montana Indian tribes, please refer to Table 3.11.4-3.

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24DW0289 (five segments)	Previously recorded Historic canal	Eligible, non- and contributing segments	Eligible, non- and contributing segments	Avoid contributing segment by bore	Pending
24DW0419 (two segments)	Previously recorded Historic railroad	Eligible, contributing segment	Eligible	Avoid with bore and fence	Pending
24DW0426 (four segments)	Previously recorded Historic railroad	Eligible, contributing segment	Eligible, contributing segment	Avoid with bore and fence	Pending
24DW0524	Historic transportation corridor	Not Eligible	Not Eligible	No Further Work	Concur
24DW0525	Historic homestead	Unevaluated	Unevaluated	Avoided	Pending
24DW0530	Historic homestead	Not Eligible	Not Eligible	No Further Work	Concur
24DW0531	Historic homestead	Not Eligible	Not Eligible	Avoided	Concur
24DW0551	Precontact open camp	Eligible	Eligible	Avoidance	Pending
24DW0552	Historic homestead/ farmstead	Not Eligible	Not Eligible	No Further Work	Concur
24DW0553	Historic road	Not Eligible	Not Eligible	No Further Work	Concur
C001DA001	Historic isolate	Not Eligible	Not Eligible	Avoided	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
C001DA002	Historic isolate	Not Eligible	Not Eligible	Avoided	Concur
C001DA003	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57DA001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57DA002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57DA003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57DA005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57DA008	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C82DA002	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C107DA005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
24FA0382	Previously recorded Historic railroad	Eligible, contributing segment	Eligible, contributing segment	Avoid with bore and fence	Pending
24FA0749	Historic pump house	Not Eligible	Not Eligible	No Further Work	Concur
24FA0750	Precontact lithic scatter and possible pronghorn processing locale	Unevaluated	Unevaluated	Avoided with Centerline Adjustment	Pending
24FA0751	Historic debris scatter	Not Eligible	Not Eligible	No Further Work	Concur
24FA0752	Historic artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
24FA0753	Historic railroad grade	Potentially Eligible	Unevaluated	Avoided	Pending
24FA0754	Historic debris scatter	Not Eligible	Not Eligible	No Further work	Concur
24FA0755	Precontact stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24FA0756	Historic berm/dam	Not Eligible	Not Eligible	No Further Work	Concur
24FA0760	Historic well	Not Eligible	Not Eligible	No Further Work	Concur
24FA0761	Historic windmill/well pump	Not Eligible	Not Eligible	No Further Work	Concur
24FA0762	Precontact lithic scatter	Not Eligible	Not Eligible	No Further Work	Concur
24FA0763	Historic rock cairn	Not Eligible	Not Eligible	No Further Work	Concur
24FA0770	Historic artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
C001FA003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001FA004	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001FA005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001FA006	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001FA007	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
C57FA003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57FA004	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C57FA006	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58FA001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58FA002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58FA003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58FA004	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58FA005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C104FA001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C104FA002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C104FA003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C210FA001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
24MC0257 (four segments)	Previously recorded Historic railroad	Eligible, segment within APE noncontributing	Not Eligible	Avoid with bore and fence	Concur
24MC0461	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24MC0462	Undated stone cairn	Potentially Eligible	Eligible	Avoided with Centerline Adjustment	Pending
24MC0463	Precontact stone feature and lithic scatter	Potentially Eligible	Eligible	Avoided with Centerline Adjustment	Pending
24MC0464	Historic homestead	Unevaluated	Unevaluated	Avoided with Centerline Adjustment	Pending
24MC0465	Precontact stone feature and lithic scatter	Potentially Eligible	Eligible	Avoided with Centerline Adjustment	Pending
24MC0466	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided with Centerline Adjustment	Pending
24MC0467	Precontact stone alignment and lithic scatter	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24MC0468	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided with Centerline Adjustment	Concur
24MC0469	Historic boxcar structure	Unevaluated	Unevaluated	Avoided	Pending
24MC0476	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24MC0477 (two segments)	Historic road	Not Eligible	Not Eligible	No Further Work	Concur
24MC0478	Historic ranch complex	Unevaluated	Unevaluated	Fence and Monitor	Pending
24MC0480	Undated stone cairns	Potentially Eligible	Not Eligible	Avoided with Centerline Adjustment	Concur
24MC0481	Undated stone cairns	Potentially Eligible	Unevaluated	Avoidance	Pending
24MC0482	Historic road	Not Eligible	Not Eligible	No Further Work	Concur
24MC0483	Historic windmill	Not Eligible	Not Eligible	No Further Work	Concur
24MC0628	Historic farmstead	Unevaluated	Unevaluated	Artifact movement, fencing, monitoring	Pending
C001MC001	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001MC003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C54MC001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C56MC006	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C56MC007	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C56MC009	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C82MC001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C104MC001	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C210MC001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
24PE0720	Historic farmstead	Unevaluated	Not Eligible	Avoided with Centerline Adjustment	Pending
24PE0721	Historic homestead	Unevaluated	Unevaluated	Avoided	Pending
24PE0723	Historic ranch complex	Unevaluated	Unevaluated	Fence and Monitor	Pending
24PE0730	Historic homestead /Farmstead	Unevaluated	Unevaluated	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Pending
24PE0731	Historic homestead	Not Eligible	Not Eligible	No Further Work	Concur
24PH008/ 1781/1801	Previously recorded precontact stone circle	Potentially Eligible	Eligible	Avoided with reroute	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24PH0037	Previously recorded Undated stone cairn and depression	Potentially Eligible	Unevaluated	Avoidance	Pending
24PH1759	Previously recorded precontact stone circle	Potentially Eligible	Eligible	Avoided with reroute	Pending
24PH1790	Previously recorded Historic rock cairns/ depression/artifact scatter	Unevaluated	Eligible	Avoided with reroute	Pending
24PH1805	Previously recorded Historic homestead	Unevaluated	Unevaluated	Fence and monitor	Pending
24PH3008/ 4167 (five segments)	Historic railroad grade	Eligible	Eligible	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Concur
24PH3462	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4144	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance	Pending
24PH4145	Precontact stone circle and rock cairn	Potentially Eligible	Unevaluated	Avoidance	Pending
24PH4146	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance	Pending
24PH4159	Precontact stone circle	Potentially Eligible	Eligible	Avoided	Pending
24PH4160	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4161	Undated stone cairns	Potentially Eligible	Eligible	Avoided	Pending
24PH4162	Precontact / Historic stone features	Potentially Eligible	Eligible	Avoided with reroute/ Fence and Monitor	Pending
24PH4163	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4164	Undated rock cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4165	Undated rock cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4166	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4168	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4169	Historic artifact scatter / Precontact	Potentially Eligible	Unevaluated	Avoidance, Native American	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
	stone feature			Consultation	
24PH4218	Previously recorded Precontact stone feature	Potentially Eligible	Eligible	Avoided with reroute	Pending
24PH4219	Precontact stone feature	Potentially Eligible	Eligible	Avoided with reroute	Pending
24PH4220	Precontact stone feature	Potentially Eligible	Eligible	Avoided with reroute	Pending
24PH4221	Precontact stone feature	Potentially Eligible	Eligible	Avoided with reroute	Pending
24PH4222	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4223	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4224	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4225	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4226	Historic artifact scatter / Precontact stone feature	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4227	Historic debris scatter	Not Eligible	Not Eligible	No Further Work	Concur
24PH4228	Undated stone cairn	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4229	Precontact stone feature and lithic scatter	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4230	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4231	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4232	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4233	Precontact stone feature	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4234	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4235	Precontact stone cairn	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24PH4236	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4237	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4238	Undated stone cairn	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4239	Precontact stone feature	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4240	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4241	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4242	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4243	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4244	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4245	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4265	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24PH4266	Undated stone cairn	Potentially Eligible	Eligible	Avoided	Pending
24PH4267	Historic farmstead	Eligible	Eligible	Fence and monitor	Concur
24PH4268	Precontact stone feature	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24PH4269	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24PH4313	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24PH4314	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24PH4315	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24PH4316	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4317	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24PH4318	Historic Homestead/ Farmstead	Not Eligible	Not Eligible	No Further Work	Concur
24PH4319	Precontact/Contact stone circle, cairn/ Depression, Artifact Scatter	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4320	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4321	Precontact stone feature	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4322	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24PH4323	Historic homestead	Not Eligible	Not Eligible	No Further Work	Concur
24PH4324	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24PH4337	Precontact stone circle/ Historic artifact scatter	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4338	Precontact stone feature	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4339	Historic stone alignment, depression, artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
24PH4340	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4341	Historic stone alignment	Not Eligible	Not Eligible	Avoided/ Reroute rejected	Concur
24PH4342	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4343	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4344	Precontact stone feature	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4345	Precontact stone circle, artifact scatter	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4346	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4347	Precontact stone feature, artifact scatter	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4348	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24PH4349	Precontact stone feature	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4350	Historic homestead	Eligible	Eligible	Avoided/ Reroute rejected	Pending
24PH4351	Precontact stone feature	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24PH4352	Historic artifact scatter	Not Eligible	Not Eligible	Avoided/ Reroute rejected	Concur
24PH4353	Precontact stone circle	Unevaluated	Unevaluated	Avoidance	Pending
24PH4354	Historic homestead	Not Eligible	Not Eligible	No Further Work	Concur
24PH4355	Historic depression, artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
C54PH002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C002PH003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C002PH004	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C002PH005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C63PH006	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C84PH002	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C84PH003	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C83PH007	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C104PH001	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001PR002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001PR004	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001PR005	Precontact /Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001PR007	Precontact /Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C001PR008	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58PR002	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58PR003	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58PR004	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58PR005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C58PR006	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
24VL0041	Previously recorded historic homestead	Eligible	Eligible	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24VL0099 (nine segments)	Previously recorded historic railroad	Eligible, contributing segment	Eligible	Avoid with bore	Pending
24VL0805	Previously recorded undated stone cairn	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL0938	Previously recorded precontact stone circle	Unevaluated	Unevaluated	Avoidance	Pending
24VL0962	Previously recorded precontact / Historic stone feature site, lithic scatter, historic artifact scatter	Potentially Eligible	Unevaluated	Avoidance	Pending
24VL0972	Previously recorded precontact / Historic stone circle and cairn, historic fence line	Potentially Eligible	Unevaluated	Avoidance	Pending
24VL0979	Historic homestead	Eligible	Eligible	Avoidance	Concur
24VL1194	Previously recorded historic canal	Eligible	Eligible	Avoid with bore	Concur
24VL1269/ 24VL1274	Previously recorded precontact stone circle	Potentially Eligible	Unevaluated	Avoidance	Pending
24VL1273	Previously recorded precontact stone feature	Potentially Eligible	Eligible	Avoided with Reroute	Pending
24VL1298	Previously recorded historic homestead / Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1628 (two segments)	Previously recorded historic railroad	Eligible, Non-contributing segment	Eligible, Non-contributing segment	No Further Work	Concur
24VL1700	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided with Centerline adjustment	Pending
24VL1712	Previously recorded precontact stone feature	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1875	Historic homestead	Unevaluated	Unevaluated	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Pending
24VL1889	Historic canal	Not Eligible	Not Eligible	Avoided	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24VL1890	Historic artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
24VL1891	Precontact stone circle and cairn	Potentially Eligible	Unevaluated	Avoided with Centerline adjustment	Pending
24VL1892	Historic artifact scatter	Not Eligible	Not Eligible	No Further Work	Concur
24VL1893	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1894	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1895	Precontact stone circle, cairn, lithic scatter	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1896	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided with Centerline adjustment	Pending
24VL1897	Historic animal pen	Not Eligible	Not Eligible	No Further Work	Concur
24VL1898	Historic stone alignment	Not Eligible	Not Eligible	No Further Work	Concur
24VL1899	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided	Concur
24VL1900	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided	Concur
24VL1901	Historic fence line and associated debris	Not Eligible	Not Eligible	No Further Work	Concur
24VL1902	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1903	Precontact stone circle	Potentially Eligible	Eligible	Avoided	Pending
24VL1904	Precontact stone circle and cairn	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1905	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided	Concur
24VL1906	Undated stone feature	Potentially Eligible	Unevaluated	Avoided with Centerline adjustment	Pending
24VL1908	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1909	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24VL1910	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1911	Undated rock cairn	Potentially Eligible	Not Eligible	Avoided with Centerline adjustment	Concur
24VL1912	Historic homestead	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL1913	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1914	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1915	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1916	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1917	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1918	Historic homestead	Eligible	Unevaluated	Shift road, Fence and Monitor	Pending
24VL1919	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance	Pending
24VL1920	Historic artifact scatter	Unevaluated	Unevaluated	Non-contributing portion in ROW/Fence and Monitor	Pending
24VL1921	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1922	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided with Centerline adjustment	Pending
24VL1923	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1924	Precontact stone cairn	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1925	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1926	Historic homestead	Potentially Eligible	Not Eligible	Avoided with Centerline adjustment	Concur
24VL1927	Historic homestead	Unevaluated	Not Eligible	Avoided with Centerline adjustment	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24VL1928	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided	Concur
24VL1929	Precontact stone feature	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1930	Undated stone cairn	Potentially Eligible	Not Eligible	Avoided with Centerline adjustment	Concur
24VL1931	Undated stone feature	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1932	Historic fence line	Not Eligible	Not Eligible	Avoided	Concur
24VL1933	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL1934	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1935	Historic debris scatter / Precontact stone feature	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1936	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL1937	Precontact stone feature	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL1938	Historic ranch complex	Unevaluated	Unevaluated	Avoidance	Pending
24VL1939	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided/Fence and Monitor	Pending
24VL1940	Historic farmstead	Unevaluated	Unevaluated	Avoidance	Pending
24VL1941	Undated stone cairn	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1942	Historic artifact scatter / Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1946	Precontact stone circle	Potentially Eligible	Eligible	Avoided with Centerline adjustment	Pending
24VL1947	Historic dump	Not Eligible	Not Eligible	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Concur
24VL1948	Precontact stone circle	Potentially Eligible	Unevaluated	Avoided	Pending
24VL1949	Historic road	Not Eligible	Not Eligible	No Further Work	Concur
24VL1950	Historic homestead	Not Eligible	Not Eligible	No Further Work	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
24VL1951	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance	Pending
24VL1952	Precontact stone circle	Potentially Eligible	Unevaluated	Avoidance, Native American Consultation	Pending
24VL1953	Historic school	Eligible	Eligible	Avoidance/Span Transmission Lines over Resource, No Ground Disturbance	Pending
24VL1959	Precontact stone circle	Unevaluated	Unevaluated	Avoidance	Pending
24VL1960	Historic homestead	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1961	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1962	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1963	Historic homestead	Not Eligible	Not Eligible	Avoided/ Reroute rejected	Concur
24VL1964	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1965	Precontact stone circle	Unevaluated	Unevaluated	Avoidance	Pending
24VL1966	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1967	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1968	Precontact stone circle	Unevaluated	Unevaluated	Avoided/ Reroute rejected	Pending
24VL1969	Historic stone alignment	Not Eligible	Not Eligible	Avoided/ Reroute rejected	Concur
24VL1972	Historic ditch	Not Eligible	Not Eligible	No Further Work	Concur
C002VA007	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA002	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C63VA003	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA005	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA006	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA007	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C54VA008	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA013	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
C54VA006	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C55VA009	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur

TABLE 3.11.3-1
Archaeological Sites and Historic Structures Identified in Montana within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Montana SHPO/ THPO Concurrence with DOS Findings
C66VA001	Historic isolate	Not Eligible	Not Eligible	No Further Work	Concur
C69VA001	Precontact isolate	Not Eligible	Not Eligible	No Further Work	Concur
Lewis and Clark National Historic Trail	Historic trail	Eligible	Eligible	Avoidance, Monitoring	Pending

As of May 2011, 5.7 miles of the proposed Project centerline in Montana need to be surveyed for historic properties due to a lack of owner permission to access the property. Additional surveys of access roads and ancillary facilities will also need to be conducted once they are identified. Once owner permission is obtained, the remaining areas will be surveyed and documented in future reports. The cultural resource surveys for proposed Project route variations, gap analysis, and extra work spaces will be documented in future reports. Upon receipt, DOS will review these reports consistent with 36 CFR Part 800 and the PA.

South Dakota

Cultural Resource pedestrian surveys and inventories conducted through May 2011 within the proposed Project APE included:

- 312.20 of the proposed Project centerline;
- 27.68 miles of access roads;
- 143.54 miles of power distribution lines; and
- 2,717.67 acres of proposed ancillary facility sites.

To date, 120 cultural resources were identified during the cultural resource inventory in South Dakota, including 54 archaeological sites, 6 historic structures, and 60 isolated finds. The results of the surveys performed, recommendations of eligibility by the Applicant, determinations of eligibility by DOS, and concurrence from SHPO are shown in Table 3.11.3-2.

Additional cultural resource surveys within the proposed Project APE may occur as the proposed Project design is finalized. Reports for any additional surveys will be reviewed by DOS and then forwarded to the applicable consulting parties consistent with 36 CFR Part 800 and the PA.

Archaeological Sites

Details on the 108 archaeological sites and isolates are listed below:

- Of the 48 previously-unrecorded and 6 previously recorded archaeological sites there were 8 precontact sites, 33 historic sites, 5 multi-component sites, and 8 sites without an identified time period; and

- Of the 60 isolated finds, there were 33 precontact sites, 25 historic sites, and 2 multi-component sites.

Four of the archaeological sites in the South Dakota section have been recorded as eligible, 23 are recommended as not eligible, 25 sites are considered unevaluated, and eligibility determinations for 2 sites require additional SHPO consultation. Avoidance is recommended for all eligible or unevaluated sites. For sites that require additional SHPO consultation, the sites will be avoided until consultation is concluded. By avoiding these sites, the proposed Project will not affect historic properties. By definition, the isolated finds are not eligible for listing in the NRHP.

Historic Structures

Details on the 6 historic structures are listed below:

- 2 structures were previously-unrecorded;
- 4 structures were previously-recorded;
- 1 structure is listed in the NRHP (PE00000020);
- 3 structures are eligible for the NRHP;
- 1 structure is not eligible; and
- 1 structure is considered unevaluated.

Avoidance is recommended for all listed, eligible, or unevaluated cultural resources. By avoiding these sites, the proposed Project will not affect historic properties.

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39BU0039	Precontact stone circle	Potentially eligible	Unevaluated	Avoidance	Concur
39BU0447	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39BU0448	Historic artifact scatter / Precontact isolate	Unevaluated	Unevaluated	Avoidance	Concur
39BU0449	Undated stone cairn	Potentially eligible	Unevaluated	Avoidance	Concur
39GR0159	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39GR0160	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39GR0161	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39GR0162	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39GR0163	Historic well and artifact scatter / Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39GR0164	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39GR0165	Historic farmstead	Eligible	Eligible	Avoidance/Span transmission line over site, no ground disturbance	Concur
39GR0166	Historic farmstead	Unevaluated	Unevaluated	Avoidance /Span transmission line over site, no ground disturbance	Concur
39GR0167	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39GR0168	Historic farmstead	Unevaluated	Unevaluated	Avoidance/Span transmission line over site/ Additional consultation by DOS	SHPO did not concur
39GR0169	Historic farmstead	Eligible	Eligible	Avoidance/Span transmission line over site, no ground disturbance	Concur
39GR0170	Historic foundation and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39GR0171	Historic farmstead	Unevaluated	Unevaluated	Avoidance/Span transmission line over site, no ground disturbance	Concur
39GR0172	Historic farmstead	Unevaluated	Unevaluated	Avoidance/Span transmission line over site, no ground disturbance	Concur
39GR0173	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HK0136	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HK0137	Historic isolate	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39HK0138	Historic homestead	Unevaluated	Unevaluated	Avoidance	Concur
39HK0139	Historic well and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39HK0140	Historic farmstead	Unevaluated	Unevaluated	Avoidance/ Span transmission line over site, no ground disturbance/ Additional consultation by DOS	SHPO did not concur
39HK0141	Historic trash dump	Unevaluated	Unevaluated	Avoidance/Span transmission line over site, no ground disturbance	Concur
39HK0142	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HK0143	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HK0144	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HN0998	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Pending
39HN1078	Undated stone cairn	Potentially eligible	Unevaluated	Avoidance	Concur
39HN1079	Undated stone cairn	Potentially eligible	Unevaluated	Avoidance	Concur
39HN1080	Precontact stone features	Unevaluated	Unevaluated	Avoidance	Concur
39HN1081	Historic artifact scatter / Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1082	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1083	Historic isolate / Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1129	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1130	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39HN1131	Historic depressions and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39HN1132	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1133	Precontact artifact scatter	Not Eligible	Unevaluated	No further work	Concur, avoidance or additional testing requested
39HN1134	Historic rock art	Not Eligible	Not Eligible	No further work	Concur
39HN1135	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1136	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1137	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1138	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1139	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1140	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39HN1141	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1142	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1143	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1144	Precontact stone cairn	Unevaluated	Unevaluated	Avoidance	Concur
39HN1145	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1146	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1147	Historic homestead	Eligible	Eligible	Avoidance/ Span transmission line over site, no ground disturbance	Pending
39HN1148	Undated stone cairn	Unevaluated	Unevaluated	Avoidance, Native American consultation	Pending

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39HN1149	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1150	Historic homestead	Unevaluated	Unevaluated	Avoidance/Span transmission line over site, no ground disturbance	Pending
39HN1151	Undated stone cairn	Unevaluated	Unevaluated	Avoidance	Concur
39HN1152	Undated stone cairn	Unevaluated	Unevaluated	Avoidance, Native American consultation	Pending
39HN1153	Historic homestead	Unevaluated	Unevaluated	Avoidance/ Span power distribution lines over resource, no ground disturbance	Pending
39HN1156	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1157	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1158	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1159	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1160	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39HN1163	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39HN1164	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Pending
39HN1165	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
39HN1166	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39HN1167	Undated cairn	Potentially Eligible	Unevaluated	Avoidance	Concur
39JN0050	Historic stock pond and trash scatter	Not Eligible	Not Eligible	No further work	Concur
39JN0051	Historic farm/ranch	Eligible	Eligible	Avoidance	Concur

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39JN0052	Historic trash dump	Not Eligible	Not Eligible	No further work	Concur
39JN0053	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39JN0054	Historic train passenger car	Not Eligible	Not Eligible	No further work	Concur
39JN0055	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39JN0056	Historic farmstead / Precontact isolate	Unevaluated	Unevaluated	Additional consultation by DOS	SHPO did not concur
39JN0057	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39JN2007	Previously recorded historic railroad	Eligible	Eligible	Avoidance by bore	Concur
39LM009	Historic farmstead	Unevaluated	Unevaluated	Avoidance	Concur
39LM0518	Historic trash scatter	Not Eligible	Not Eligible	No further work	Concur
39LM0519	Historic burial place	Eligible	Eligible	Avoidance	Concur
MD01900001	Historic church	Not Eligible	Not Eligible	No further work	Concur
39MD0820	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0821	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0822	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0823	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
39MD0824	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39MD0825	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0826	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0827	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0834	Historic isolate / Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0835	Historic artifact scatter	Eligible	Eligible	Avoidance, Fence and Monitor	Concur
39MD0849	Historic grave	Not Eligible	Not Eligible	Avoidance	Concur

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39MD0850/ MD00000335	Historic schoolhouse (standing structure)	Eligible	Eligible	Avoidance, Fence, and Monitor	Pending
39MD0851	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0852	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39MD0871	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39PE0398	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39PE0399	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39PE0400	Undated rock alignment	Unevaluated	Unevaluated	Avoidance	Concur
39PE0402	Historic artifact scatter	Unevaluated	Unevaluated	Avoidance	Concur
39PE0405	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39PE0406	Historic depression and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39PE0414	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39PE0415	Historic homestead	Unevaluated	Unevaluated	Avoidance	Pending
39PE0418	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39TP0056	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0057	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0058	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
39TP0059	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0060	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0061	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0062	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
39TP0063	Historic farmstead	Eligible	Eligible	Avoidance/Span transmission line over site, no ground disturbance	Concur

TABLE 3.11.3-2
Archaeological Sites and Historic Structures Identified in South Dakota within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	South Dakota SHPO/THPO Concurrence with DOS Finding
39TP0064	Historic isolate	Not Eligible	Not Eligible	No further work	Pending
39TP0065	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
39TP0066	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Pending
39TP0067	Historic stone wall and scatter	Unevaluated	Unevaluated	Testing or Avoidance	Concur
PE00000020	Previously recorded historic homestead	Listed in NR	Listed in NR	Avoidance	Concur

As of May 2011, 1.8 miles of the proposed Project centerline in South Dakota need to be surveyed for historic properties due to a lack of owner permission to access the property. Additional surveys of access roads and ancillary facilities will also need to be conducted once they are identified. Once owner permission is obtained, the remaining areas will be surveyed and documented in future reports. The cultural resources surveys for proposed Project route variations, gap analysis, and extra work spaces will be documented in future reports. Upon receipt, DOS will review these reports consistent with 36 CFR Part 800 and the PA.

Nebraska

Cultural Resource pedestrian surveys and inventories conducted through May 2011 within the proposed Project APE included:

- 308.12 miles of the proposed Project centerline (including reroutes and realignments);
- 16.5 miles of access roads; and
- 986.86 acres of proposed ancillary facilities, staging areas, pump stations, and work spaces.

To date, 91 cultural resources were identified in Nebraska, including 21 archaeological sites, 69 historic structures, and one isolated find. The results of the surveys performed, recommendations of eligibility by the Applicant, the determinations of eligibility by DOS, and concurrence from the SHPO are shown in Table 3.11.3-3.

Addendum reports detailing any additional required cultural resource surveys will be reviewed by DOS and then forwarded to the applicable consulting parties consistent with 36 CFR 800 and the PA.

Archaeological Sites

Details on the 22 archaeological sites and isolates are listed below:

- 10 were precontact sites;
- 11 were historic sites;
- 1 isolated find was historic;
- 13 sites are recommended as not eligible; and
- 8 sites are considered unevaluated.

One of the historic sites (25HM25) is possibly associated with a Pawnee Nation Indian burial ground and may be protected under Nebraska's Unmarked Human Burial Law. The site will be avoided during construction activities. DOS is consulting with the Pawnee Nation and the SHPO regarding this site, and conducting additional surveys for avoidance of sensitive areas.

Avoidance is recommended for all eligible or unevaluated sites. By avoiding these sites, the proposed Project will not affect historic properties. By definition, the isolated finds are not eligible.

Historic Structures

Details on the 65 historic structures (standing structures, farmsteads, roads, canals, railroads, and railroad beds) are listed below:

- 58 historic structures were previously-unrecorded;
- 7 structures were previously-recorded;
- 50 structures are not eligible; and
- 7 structures are considered unevaluated.

Avoidance is recommended for all eligible, unevaluated, and pending sites. By avoiding these sites, the proposed Project will not affect historic properties.

Historic Trails

The proposed Project route crosses the Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails in the vicinity of the Platte River. The physical area where these trails cross the proposed Project APE have been surveyed but no cultural resources associated with the trails have been identified. No effects to intact segments of historic trails situated in Nebraska have been identified during cultural resource surveys. If an intact segment of any of these trails is identified during future work, DOS will work with the NPS to identify and avoid or mitigate adverse effects to historic trails.

TABLE 3.11.3-3
Archaeological Sites and Historic Structures Identified in Nebraska within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Eligibility Determination by DOS	Action Recommended by Applicant	Nebraska SHPO/THPO Concurrence with DOS Finding
25BO54	Historic farmstead/rural household	Potentially Eligible	Unevaluated	Avoidance, fence	Concur
25BU69	Active railroad	Not eligible	Eligible	No further work	Pending
25FM23	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25FM24	Active railroad	Not Eligible	Not Eligible	No further work	Concur
25FM25	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25FM26	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25FM27	Precontact limited activity site	Not Eligible	Not Eligible	No further work	Concur
25FM28	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25GF16	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
25GY51	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25GY52	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25GY53	Historic livestock feed lot	Not Eligible	Not Eligible	No further work	Concur
25HM24	Precontact limited activity site	Not Eligible	Not Eligible	No further work	Concur
25HM25	Historic burial ground	Unevaluated	Unevaluated	Avoidance	Consultation with Pawnee Nation ongoing
25HM26	Historic road	Not Eligible	Not Eligible	No further work	Concur
25HM27	Historic dump	Not Eligible	Not Eligible	No further work	Concur
25HM28	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25HM29	Active railroad	Not Eligible	Not Eligible	No further work	Concur
25HM30	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25HM31	Historic dump	Not Eligible	Not Eligible	No further work	Concur
25HM32	Active railroad	Not eligible	Eligible	No further work	Pending

TABLE 3.11.3-3
Archaeological Sites and Historic Structures Identified in Nebraska within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Eligibility Determination by DOS	Action Recommended by Applicant	Nebraska SHPO/THPO Concurrence with DOS Finding
25HT44	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25HT45	Historic road	Not Eligible	Not Eligible	No further work	Concur
25HT46	Historic road	Not Eligible	Not Eligible	No further work	Concur
25HT52	Active railroad	Not Eligible	Eligible	No further work	Pending
25HT53	Former rail bed	Not Eligible	Not Eligible	No further work	Pending
25HT54	Commercial/ Industrial railroad buildings & structures	Not eligible	Not eligible	No further work	Pending
25HT505 (25HT54)	Possible flour mill	Not eligible	Unevaluated, pending further research	No further work	Pending
25JF43	Previously recorded historic windmill structure	Not Eligible	Not Eligible	No further work	Pending
25JF45	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25JF46	Active railroad	Not Eligible	Not Eligible	No further work	Concur
25JF47	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25JF48	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25JF49	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25JF50	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25JF51	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25JF52	Precontact field camp	Potentially Eligible	Unevaluated	Avoidance, fence	Concur
25JF53	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25JF54	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25JF55	Active railroad	Not eligible	Eligible	No further work	Pending
25JF56	Agricultural outbuilding	Not eligible	Unevaluated, pending further research	No further work	Pending

TABLE 3.11.3-3
Archaeological Sites and Historic Structures Identified in Nebraska within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Eligibility Determination by DOS	Action Recommended by Applicant	Nebraska SHPO/THPO Concurrence with DOS Finding
25JF507	Steam Roller Mill Site	Unevaluated	Unevaluated	Avoidance/ Need additional field research	Pending
25KP150	Precontact field camp	Potentially Eligible	Unevaluated	Avoidance, fence	Concur
25KP151	Precontact field camp	Potentially Eligible	Unevaluated	Avoidance, fence	Concur
25KP339	Historic dump	Not Eligible	Not Eligible	No further work	Concur
25KP345	Precontact rock ring	Potentially Eligible	Unevaluated	Avoidance, Fencing	Concur (Recom. DOS consult with tribes)
25MK17	Historic dump	Not Eligible	Not Eligible	No further work	Concur
25MK18	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25MK19	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25MK20	Previously recorded Historic farmstead/rural household	Potentially Eligible	Unevaluated	Avoidance	Concur
25MK21	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25MK22	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25MK23	Historic dump	Not Eligible	Not Eligible	No further work	Concur
25MK24	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25NC143	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25NC144	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25NC145	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25NC146	Historic canal	Not Eligible	Not Eligible	No further work	Concur
25RO13	Historic road	Not Eligible	Not Eligible	No further work	Concur
25SA73	Kasak Cemetery	Not Eligible / Protected	Not Eligible/ Protected	Avoidance by Bore	Concur
25SA86	Precontact limited activity site	Not Eligible	Not Eligible	No further work	Concur
25SA87	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-3
Archaeological Sites and Historic Structures Identified in Nebraska within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Eligibility Determination by DOS	Action Recommended by Applicant	Nebraska SHPO/THPO Concurrence with DOS Finding
25SA88	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25SA89	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25VY56	Active railroad	Not eligible	Eligible	No further work	Pending
25WH4	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25WH5	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur
25YK17	Precontact field camp	Potentially Eligible	Unevaluated	Avoidance, fence	Concur
25YK18	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK19	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK20	Active railroad	Not Eligible	Not Eligible	No further work	Concur
25YK21	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK22	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK23	Historic artifact scatter	Potentially Eligible	Unevaluated	Avoidance	Concur
25YK24	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK25	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur
25YK26	Precontact limited activity site	Not Eligible	Not Eligible	No further work	Concur
25YK27	Historic farmstead	Not Eligible	Not Eligible	No further work	Concur
25YK28	Precontact field camp	Not Eligible	Not Eligible	No further work	Concur
25YK29	Historic farm outbuilding /activity area	Not Eligible	Not Eligible	No further work	Concur
25YK30	Historic farm outbuilding /activity area	Not Eligible	Not Eligible	No further work	Concur
25YK31	Historic farmstead/rural household	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-3
Archaeological Sites and Historic Structures Identified in Nebraska within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Eligibility Determination by DOS	Action Recommended by Applicant	Nebraska SHPO/THPO Concurrence with DOS Finding
C102RK001	Historic Farmstead	Unknown	Unevaluated	Avoidance, Complete Phase 1 shovel testing	Pending/Additional information needed
C203GR002AP	Historic building	Unevaluated	Unevaluated	No further work due to reroute	No Concurrence/ Outside APE
C201JE003AP	Historic farmstead	Not evaluated due to access	Unevaluated	No further work due to reroute	No Concurrence/ Outside APE
C201JE004AP	Historic farmstead	Not evaluated due to access	Unevaluated	No further work due to reroute	No Concurrence/ Outside APE
C201JE005AP	Historic farmstead	Not Eligible	Unevaluated	No further work due to reroute	No Concurrence/ Outside APE
HT 13-001 (25HT54)	C&NW Railway Depot	Eligible	Eligible	Avoidance	Pending
HT13-040 (25HT54)	Railway freight depot	Not eligible	Not eligible	No further work	Pending
NC00-042	Historic building	Not Eligible	Not Eligible	No further work	Pending
Oregon, California, Mormon Pioneer, and Pony Express National Historic Trails	Historic trails	Unevaluated	Unevaluated	Avoidance, Monitoring, and site forms to be prepared by the Applicant	Pending

As of May 2011, 9.3 miles of the proposed Project centerline, 1.05 miles of access roads, and 60.3 acres of ancillary facilities in Nebraska were not surveyed due to a lack of owner permission to access the property. Once owner permission is obtained, the remaining proposed Project areas will be surveyed and documented in future reports. The cultural resource surveys for the proposed Project route variations, gap analysis, and extra work spaces are anticipated and will be documented in future reports. Upon receipt, DOS will review these reports consistent with 36 CFR Part 800 and the PA.

Kansas

Cultural Resource pedestrian surveys and inventories for two proposed Project pump stations (PS-27 and PS-29) and power distribution lines were conducted through May 2011. The results of the surveys performed, recommendations of eligibility from the Applicant, the determinations of eligibility by DOS, and concurrence from SHPO are shown in Table 3.11.3-4.

Additional surveys include 0.54 mile segment of the 4.61 mile power distribution line (noted above) will be performed when landowner permission is obtained. Reports describing the surveys will be submitted to DOS for review once they are completed and then forwarded to the applicable consulting parties consistent with 36 CFR Part 800 and the PA.

Archaeological Sites

No new archaeological sites were identified in the potential pump station locations surveyed.

- One previously-recorded site (14BU131) was determined not eligible for listing in the NRHP.
- An additional site (14CY120) recommended by the Applicant as not eligible, has also been identified during a survey of a 4.61-mile power distribution line. The site was determined not eligible for the NRHP.

Historic Structures

No historic structures were identified in the potential pump station locations surveyed.

Historic Trails

The proposed Project route does not cross the Santa Fe National Historic Trail (SFNHT). No effects to the trail are anticipated. If this should change, DOS will work with NPS to identify and avoid or mitigate any detrimental effects to the resource.

TABLE 3.11.3-4
Archaeological Sites and Historic Structures Identified in Kansas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Kansas SHPO/THPO Concurrence with DOS Finding
14BU131	Previously recorded historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
14CY120	Historic railroad bed	Not Eligible	Not Eligible	No further work	Concur

Oklahoma

Cultural Resource pedestrian surveys and inventories conducted through May 2011 within the proposed Project APE included:

- 155.41 miles of the proposed Project centerline (the remaining 0.27 miles of survey area could not be assessed due to a lack of access the property);
- 3 pump stations;
- 8 ancillary facilities; and
- 59 access roads.

As part of the investigations, 62 backhoe trenches and 3,426 shovel tests were placed within the survey area. In total, 93 cultural resources were identified during the cultural resource inventory in the Gulf Coast Segment in Oklahoma. Of those 93 cultural resources, 70 are archaeological sites, 32 are historic structures, and 18 are isolated finds. The results of the surveys performed, recommendations of eligibility

by the Applicant, determinations of eligibility by DOS, and concurrence from SHPO are shown in Table 3.11.3-5.

Archaeological Sites

Details on the 88 archaeological sites and isolates are listed below:

- 30 were precontact sites;
- 30 were historic sites;
- 10 were multi-component sites;
- 18 isolated finds which were historic (including 13 precontact and 5 historic sites);
- 6 sites have been recorded as eligible;
- 53 sites are recommended as not eligible; and
- 11 sites are considered unevaluated.

Avoidance is recommended for all eligible, unevaluated, and pending sites. By avoiding these sites, the proposed Project will not affect historic properties. By definition, the isolated finds are not eligible for listing in the NRHP.

Historic Structures

Details on the 34 historic structures identified are listed below:

- Some structures were recorded as individual architectural resources and some as resources within archaeological sites;
- 4 structures have been recorded as eligible;
- 22 structures are not eligible; and
- 8 structures are considered unevaluated.

Avoidance is recommended for all listed, eligible, and unevaluated sites. By avoiding these sites, the proposed Project will not affect historic properties. DOS is also consulting with the Oklahoma SHPO to identify additional measures to avoid or mitigate proposed Project effects.

Historic Route

The proposed Project route crosses the Historic Route 66 (designated 34LN164/CCUL2ALNx.001), which falls under the purview of the Route 66 Corridor Preservation Program administered by the NPS's National Trails System Office. Additionally, portions of Route 66 in Oklahoma are listed in the NRHP. Though the segment within the proposed Project area is not listed, it could be a contributing segment according to NRHP Criteria for Evaluation and specific considerations established in the statewide NRHP nomination form. Cultural resource investigations conducted in the vicinity of the route identified a portion of the abandoned roadbed. The Applicant's architectural historian and archaeologists completed a site form and historic preservation resource identification form for Route 66. The proposed Project will avoid potential effects to Route 66 by boring beneath the historic resource.

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34AT56/ 34AT662	Historic structure and artifact scatter / Precontact artifact scatter	Not Eligible	Not Eligible	No further work	No Concurrence/ Outside APE
34AT661	Historic structure, artifact scatter / Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
High Hill Cemetery	Historic cemetery	Not Eligible	Not Eligible	Avoidance	Concur
34AT664	Historic artifact scatter	Not Eligible	Not Eligible	No further work	No Concurrence/ Outside APE
34AT665	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT666	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT667	Historic structure / Precontact lithic scatter	Unevaluated	Unevaluated	No further work	No Concurrence/ Outside APE
34AT669	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT670	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT671	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT672	Historic debris / Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34AT673	Precontact campsite	Unevaluated	Unevaluated	Avoidance	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
34BR322	Previously recorded historic farmstead	Not Eligible	Not Eligible	No further work	Concur
34BR338	Historic artifact scatter	Not Eligible	Not Eligible	No further work	No Concurrence/ Outside APE

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34BR339	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34BR340	Historic artifact scatter / Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34BR341	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
NA	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
34CO146	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34CO147	Historic structure ruins and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34CO148	Precontact lithic scatter and midden	Eligible	Eligible	Avoidance	Concur
34CO149	Historic structure ruins and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34CO150	Precontact lithic scatter and hearth	Eligible	Eligible	Avoidance	Concur
34CO151	Historic barn and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34CO152	Historic grave	Not Eligible	Not Eligible	No further work	Concur
34CO153	Precontact lithic reduction loci	Not Eligible	Not Eligible	No further work	Concur
34CO154	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34CO155	Historic cistern and debris	Not Eligible	Not Eligible	No further work	Concur
34CO158	Historic farmstead	Unevaluated	Unevaluated	Avoidance/No further work	No Concurrence/ Outside APE
34CO159[1]	Historic structural remains	Not Eligible	Not Eligible	No further work	Pending
34CO160[2]	Precontact open camp	Unevaluated	Unevaluated	Avoidance	Pending
34CO161[3]	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Pending

[1] Formerly referred to in the Draft EIS as CARC2ACOX.008.
[2] Formerly referred to in the Draft EIS as CARC1ACOX.009.
[3] Formerly referred to in the Draft EIS as CARC2ACOX.009.

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34CO162	Historic well and structural remnants	Not Eligible	Not Eligible	No further work	Pending
CIF2A COx.002	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
CIF1A COx.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
CIF2A COx.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Pending
34CR189	Historic residential remnants	Not Eligible	Not Eligible	No further work	Concur
CIF2A CRx.003	Historic isolate	Not Eligible	Not Eligible	No further work	Pending
34HU21	Historic culvert / Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU134	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU135	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU136	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU137	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU138	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU139	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU140	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU141	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34HU142	Precontact open camp	Not Eligible	Not Eligible	No further work	Concur
34HU143	Precontact lithic scatter; historic well, artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34HU144	Precontact open camp	Unevaluated	Unevaluated	Avoidance	Concur
34HU145	Precontact campsite	Unevaluated	Unevaluated	Avoidance	Concur

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34HU146	Historic ceramic / Precontact open campsite	Unevaluated	Unevaluated	Avoidance	Concur
34HU147	Historic abandoned railroad	Eligible	Eligible	Avoidance by bore	Concur
34HU148	Historic farmstead	Unevaluated	Unevaluated	No further work	No Concurrence/ Outside APE
34HU149	Historic farmstead	Unevaluated	Unevaluated	No further work	No Concurrence/ Outside APE
Holdenville Airport	Historic airport buildings	Eligible	Eligible	Avoidance	Concur
NA	Precontact lithic debitage	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
NA	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
34LN160	Historic stone house ruin / Precontact artifact scatter	Unevaluated	Unevaluated	No further work	No Concurrence/ Outside APE
34LN161	Historic artifact scatter, probable homestead site	Not Eligible	Not Eligible	No further work	Concur
34LN162	Historic trash dump	Not Eligible	Not Eligible	No further work	Concur
34LN163	Cultural landscape key west town site	Eligible	Eligible	Avoidance	Concur
34LN178	Historic homestead	Eligible	Eligible	Avoidance	Concur
34LN182	Historic structural remains	Not Eligible	Not Eligible	No further work	Concur
CIF1A LNx.001	Historic isolate	Not Eligible	Not Eligible	No further work	Pending
34LN187	Historic structural debris and remnants	Not Eligible	Not Eligible	No further work	Pending

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34LN188	Historic structural remnants of infrastructure and building, historic artifact dump	Unevaluated	Unevaluated	No further work; portion of site in proposed Project area does not contribute to site's significance	Pending
34LN164/ CCUL2A LNx.001	Historic Route 66 roadway	Eligible, Contributing segment	Eligible, Contributing segment	Avoidance by bore	Concur
CHSS1 ACRx.001	Historic standing structure / complex	Not Eligible	Not Eligible	No further work	Pending
CHSS2A LNx.001	Residence	Not Eligible	Not Eligible	No further work	Concur
CHSS4AL Nx.001	Historic farm complex	Not Eligible	Not Eligible	Avoidance	No Concurrence/ Outside APE
34OF97	Historic structural remains and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34OF98	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34OF99	Historic artifact scatter / Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34OF100	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
34OF101	Precontact open campsite	Not Eligible	Not Eligible	No further work	Concur
34OF102	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34OF103	Historic cemetery	Not Eligible	Not Eligible	No further work Avoidance	Concur
CIF1A OFx.001	Precontact lithic projectile point/drill isolate	Not Eligible	Not Eligible	No further work	Pending
CHSS1A OFx.001	Historic standing structure / complex	Not Eligible	Not Eligible	No further work	Concur
NA	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
34SM130	Historic Baker Cemetery 1900-1907	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-5
Archaeological Sites and Historic Structures Identified in Oklahoma

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Oklahoma SHPO/THPO Concurrence with DOS Finding
34SM131	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34SM132	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
34SM133	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur

As of May 2011, 0.27 miles of proposed Project centerline, 2.88 miles of access roads, 9.03 acres of temporary workspaces, 0.39 acres of survey area adjustments, and 240.3 acres of ancillary facilities in Oklahoma could not be surveyed, due to a lack of landowner permission to access properties. Once owner permission is obtained, the remaining proposed Project areas will be surveyed and documented in future addenda reports. Surveys are ongoing. Upon receipt of the additional information, DOS will review the addenda reports consistent with 36 CFR Part 800 and the PA.

Texas

Cultural Resource pedestrian surveys and inventories conducted for the Gulf Coast Segment through May 2011 within the proposed Project APE included:

- 203.35 miles of the proposed Project centerline (the remaining 3.13 miles of HPAs were not inventoried due to landowner access restrictions);
- 11.9 miles of proposed access roads;
- 26.57 acres of temporary work spaces; and
- 73.65 acres of ancillary facilities.

Cultural Resource pedestrian surveys and inventories conducted of the Houston Lateral section through May 2011 included:

- 6.44 miles of HPAs for which the Texas Historical Commission (THC) required to survey. The remaining 7.96 miles of HPAs were not inventoried due to landowner access restrictions.
- No inventories have been conducted on proposed access roads, power distribution lines, and ancillary facilities, but reports on these inventories are anticipated when the inventories are completed. Inventories will be conducted by architectural historians of historic structures located outside of the HPAs in the proposed Project corridor.

As required by DOS, the inventories include the architectural historian's assessment of historic structures located throughout the proposed Project corridor, not just within HPAs. Reports will be prepared for those areas that have yet to be surveyed. These reports will be reviewed by DOS consistent with 36 CFR Part 800 and the PA.

To date, 113 cultural resources were identified during the cultural resource inventory of the proposed Project of the Gulf Coast Segment in Texas. Of those 113 cultural resources, 55 are archaeological sites,

14 are architectural resources, 19 are classified as both archaeological and architectural resources, and 25 are isolated finds. The results of the surveys performed, recommendations of eligibility by the Applicant, determinations of eligibility by DOS, and concurrence from SHPO are shown in Table 3.11.3-6.

Additional cultural resource surveys are forthcoming. The results of these investigations will be detailed in addenda reports, which will be reviewed by DOS and then forwarded to the applicable consulting parties consistent with 36 CFR Part 800 and the PA. No cultural resources were identified in the Houston Lateral section.

Archaeological Sites

Details on the 80 archaeological sites and isolated finds are listed below:

- 35 were precontact sites;
- 9 were historic sites;
- 11 were multi-component sites;
- 19 sites were recorded as both archaeological and architectural resources, 13 of which were historic sites and 6 were multi-component sites;
- 2 of the archaeological sites have been recorded as eligible;
- 40 sites are recommended as not eligible;
- 32 sites are considered unevaluated; and
- Of the 25 isolated finds there were 16 precontact sites and 9 historic sites.

Avoidance is recommended for all eligible and unevaluated sites. By avoiding these sites, the proposed Project will not affect historic properties. By definition, the isolated finds are not eligible for listing in the NRHP.

Historic Structures

Details on the 33 historic structures are listed below:

- Of the 33 historic structures identified, all are either listed as individual architectural resources or resources within archaeological sites;
- 5 have been recorded as cemeteries including 1 modern pet cemetery;
- 2 structures have been recorded as eligible;
- 19 have been recommended as not eligible; and
- 13 are considered unevaluated.

Avoidance is recommended for all listed, eligible, and unevaluated sites. By avoiding these sites, the proposed Project will not affect historic properties. Although four of the historic cemeteries have been determined not eligible for the NRHP and one cemetery is still unevaluated for NRHP eligibility, avoidance is recommended in accordance with Texas state law.

Historic Trails

The proposed Project route crosses the El Camino Real de Los Tejas National Historic Trail (ELTE NHT) in Nacogdoches County. The trail was used by Native Americans in the precontact period, then through the Spanish Colonial Period (1690–1821) to connect colonial capitals and missions, and later by Anglo-American settlers in the area. At least four segments of historic roadbeds, which are potentially associated with the ELTE NHT have been identified as historic properties in the proposed Project area. These are recorded as components within archaeological sites 41NA156 (eligible), 41NA316 (unevaluated), 41NA317 (unevaluated) and 41NA329 (unevaluated). As requested by DOS historic property site forms have been completed for these trail segments that cross the proposed Project APE so that they can be evaluated for the NRHP. DOS has worked with Indian tribes, NPS and Texas SHPO to identify and avoid or mitigate adverse effects to the resources. Two agency meetings between DOS and NPS were held on February 18, 2009 and November 11, 2009 to discuss the proposed Project, and the location of the ELTE NHT segments. During the meeting, resources associated with the trail including sites 41NA156, 41NA316, 41NA317, and 41NA329, were visited and preferred avoidance and/or mitigation measures were discussed. Additional information concerning the trail segments has been submitted including site forms for trail segments previously unidentified. LIDAR imagery, shallow trenching, and magnetometers may be used to pinpoint the location of the trail in the APE. The Applicant has developed plans to avoid the trail segments and associated resources. However, one site, 41NA329, has yet to be fully assessed, and avoidance measures cannot be implemented until the historic nature and precise extent of the resource are fully delineated. DOS has developed a Historic Trail and Archaeological Monitoring Plan (HTAM Plan) to avoid effects on the historic trail in consultation with the Indian tribes, NPS, and Texas SHPO. If necessary, DOS will continue to work with these parties under the stipulations of the PA to develop additional mitigation measures for proposed Project effects.

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
41AG196	Precontact camp	Unevaluated	Unevaluated	Avoidance	Concur
41AG197	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41AG198	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41AG199	Historic cemetery	Not Eligible	Not Eligible	Avoidance	Concur
41AG200	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41AG201	Precontact artifact scatter and probable campsite	Eligible	Unevaluated	Portion in APE not eligible	Pending
41AG202	Historic standing structures and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
CIF6B AG34.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
41CE417	Historic standing structure	Unevaluated	Unevaluated	Avoidance	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
41CE418	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41CE419	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41CE430	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41CE431	Historic artifact scatter and structural remnant / Precontact artifact scatter and settlement	Eligible	Unevaluated	Avoidance	Concur
41CE435	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Pending
CIF2B CE14.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41DT266	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41DT267	Precontact artifact scatter and possible open campsite	Unevaluated	Unevaluated	Avoidance by bore	Concur
41DT268	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Pending
41DT269	Precontact artifact scatter and possible open campsite	Not Eligible	Not Eligible	No further work	Concur
41DT276	Precontact Open Campsite	Unevaluated	Unevaluated	Avoidance by matting	Concur
CHSS7B HP01.001	Historic-age levee	Unevaluated	Unevaluated	Avoidance by bore	Concur
CHSS7B AG00.001	Historic residential complex	Unevaluated	Unevaluated	Avoidance	Concur
CHSS8B JF106.001	Historic residential complex	Unevaluated	Unevaluated	Avoidance	Concur
CHSS9B DTx.003(#6)	c. 1950-55 Domestic building	Not Eligible	Not Eligible	No further work	Concur
CHSS9B DTx.001 (#8)	c. 1940 Domestic complex	Not Eligible	Not Eligible	No further work	Concur
CHSS9B DTx.002(#9)	c. 1940 Storage building	Not Eligible	Not Eligible	No further work	Concur
CIF7B DT13.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
41FK63	Previously recorded Historic artifact scatter / Precontact artifact scatter and possible occupation area	Unevaluated	Unevaluated	Avoidance	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
41FK104	Precontact open camp	Eligible	Unevaluated	Avoidance	Concur
41FK130	Historic standing structure	Not Eligible	Unevaluated	Avoidance	Pending
41FK131	Precontact artifact scatter, occupation	Unevaluated	Unevaluated	Avoidance	Concur
41FK132	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41FK133	Historic farmstead and scatter (early to mid-20th century residential site)	Not Eligible	Not Eligible	No further work	Concur
41FK134	Precontact pottery scatter, possible occupation area	Unevaluated	Unevaluated	Avoidance	Concur
41FK135	Precontact open campsite	Not Eligible	Not Eligible	No further work, not in APE	Pending
41FK136	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41FK137	Precontact artifact scatter, possible occupation area	Unevaluated	Unevaluated	Avoidance	Concur
41FK138	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41FK139	Multi-component site	Unevaluated	Unevaluated	Avoidance	Concur
CIF4B FK04.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
CIF7B FK104.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
CIF7B FK104.002	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
CIF6B FK07.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
41FN91/ 41FN87	Historic artifact scatter / Precontact lithic debris	Unevaluated	Unevaluated	Avoidance	Concur
41HP241	Historic artifact scatter / Precontact artifact scatter and possible settlement	Eligible	Unevaluated	Avoidance	Concur
41HP242	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41HP244	Historic farm complex	Eligible	Eligible	Eligible portion to be avoided	Concur
CHSS9B HP201.001 (#12)	c. 1950 Domestic building	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
CIF2B HP12.001	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
CIF4B HP23.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41JF92	Historic railroad grade	Not Eligible	Un Evaluated	No further work	Pending
Central Gardens	17 Domestic buildings c. 1930-55	Not Eligible	Not Eligible	No further work	Concur
41LB78	Previously recorded precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41LR2	Historic artifact scatter / Precontact village	Eligible	Eligible	Avoidance by bore	Concur
41LR314	Historic artifact scatter / Precontact lithic debris	Unevaluated	Unevaluated	Avoidance	Concur
41LR315	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41LR316	Historic trash dump	Not Eligible	Not Eligible	No further work	Concur
CIF6B LR19.001	Historic isolate	Not Eligible	Not Eligible	No further work	N/A*
CIF8B LR24.001	Historic isolate	Not Eligible	Not Eligible	No further work	N/A*
41NA156	Previously recorded Historic slave quarters and residence / Precontact artifact scatter and possible settlement (association with ELTE NHT)	Eligible/ Building is unevaluated	Eligible/ Building is unevaluated	Avoidance by bore	Concur
41NA307	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41NA308	Historic Euro-American cemetery/ precontact scatter	Not Eligible	Not Eligible	Cemetery avoided/scatter-no further work	Concur
41NA314	Historic artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41NA315	Historic foundation and artifact scatter	Unevaluated	Unevaluated	Avoidance	Concur
41NA316	Historic trail (association with ELTE NHT)	Unevaluated	Unevaluated	Avoidance	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
41NA317	Historic artifact scatter / precontact settlement	Historic scatter not eligible / Precontact eligible	Unevaluated	Avoidance	Concur
41NA318	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41NA319	Historic artifact scatter / Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41NA329 El Camino Real de Los Tejas National Historic Trail	Historic road	Unevaluated	Unevaluated	Avoidance, more research needed with NPS to identify contributing segments	Concur
CHSS9B NAx.001 (#21)	c. 1935 Domestic building	Not Eligible	Not Eligible	No further work	Concur
CHSS9B NAx.002 (#22)	c. 1930 Domestic building	Not Eligible	Not Eligible	No further work	Concur
CIF6B NA09.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
CIF4B NA12.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41PK258	Precontact artifact scatter	Unevaluated	Unevaluated	Avoidance	Concur
41PK260	Precontact lithic scatter	Unevaluated	Unevaluated	Avoidance	Concur
41PK261	Precontact artifact scatter	Unevaluated	Unevaluated	Avoidance	Concur
41PK262	Precontact artifact scatter	Not Eligible	Not Eligible	No further work	Concur
41PK263	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41PK264	Precontact lithic scatter	Not Eligible	Not Eligible	No further work	Concur
41PK266	Precontact lithic scatter and historic highway 35	Not Eligible	Not Eligible	No further work, site outside APE	Pending
41PK267	Precontact lithic scatter	Not Eligible	Not Eligible	No further work, site outside APE	Pending
41PK268	Precontact Open Campsite	Not Eligible	Not Eligible	No further work	Pending
CHSS9BPKx. 001 (#23)	c. 1940 Domestic complex	Not Eligible	Not Eligible	No further work	Concur
CIF8B PK04.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
CIF6B PK09.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
CIFBWD30.001	Historic scatter	Not Eligible	Not Eligible	No further work	Pending
CIF7B PK10.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
CIF8B PK25.001	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
CIF9B PK36.001	Precontact isolate	Not Eligible	Not Eligible	No further work	N/A*
41RK97	Previously recorded historic oil pumping station and camp	Unevaluated	Unevaluated	Avoidance	Concur
41RK588	Historic artifact scatter / Precontact artifact scatter and possible open camp	Historic component Not Eligible, Precontact component Eligible	Unevaluated	Eligible portion to be avoided	Concur
41RK601	Precontact artifact scatter with historic isolate	Not Eligible	Not Eligible	No further work	Concur
CHSS9BRKx.001 (#19A)	c. 1940 Domestic building	Not Eligible	Not Eligible	No further work	Concur
CHSS9BRKx.002 (#19)	c. 1940 Domestic building	Not Eligible	Not Eligible	No further work	Concur
CIF2B RK07.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41SM40	Precontact subsurface campsite	Unevaluated	Unevaluated	Avoidance	Concur
41SM287	Previously recorded precontact open camp	Unevaluated	Unevaluated	Avoidance	Concur
41SM397	Historic church complex	Eligible	Unevaluated	Eligible portion to be avoided	Concur
41SM405	Precontact subsurface campsite	Unevaluated	Unevaluated	Avoidance	Concur
41SM424	Precontact Lithic Scatter	Not Eligible	Not Eligible	No further work	Concur
CIF7B SM06.001	Historic isolate	Not Eligible	Not Eligible	No further work	N/A*
Starrville Cemetery	Historic cemetery	Unevaluated	Unevaluated	Avoidance	Concur
CIF7B SM104.001	Historic isolate	Not Eligible	Not Eligible	No further work	N/A*
CIF7B SM115.001	Historic well pad	Not Eligible	Not Eligible	No further work	Concur

TABLE 3.11.3-6
Archaeological Sites and Historic Structures Identified in Texas within the Proposed Project APE

Site #	Description	NRHP Eligibility Recommendation from Applicant	NRHP Determination by DOS	Action Recommended by Applicant	Texas SHPO/THPO Concurrence with DOS Finding
41UR85	Paron Church and Smith Cemetery (small precontact scatter)	Not Eligible	Not Eligible	Church and cemetery avoided/scatter no further work	Concur
41UR325	Historic barn, shed, and artifact scatter	Not Eligible	Not Eligible	No further work	Concur
CIF UR02.001	Precontact isolate	Not Eligible	Not Eligible	No further work	Concur
41WD649	Precontact lithic scatter, possible open campsite	Unevaluated	Unevaluated	Avoidance	Concur
41WD650	Historic well or cistern	Not Eligible	Not Eligible	No further work	Concur
41WD651	Modern pet cemetery	Not Eligible	Not Eligible	No further work	Concur
41WD653	Precontact pottery scatter	Not Eligible	Not Eligible	No further work	Concur
CIF4B WD02.001	Historic isolate	Not Eligible	Not Eligible	No further work	Concur
CIF8BNA107.001	Historic ceramic isolate	Not Eligible	Not Eligible	No Further work	N/A*

*TX SHPO says isolated finds do not require NRHP eligibility assessment.

As of May 2011, 3.13 miles of HPAs along the proposed Project centerline, 1.77 miles of access roads, 32.60 acres of temporary workspaces, 5.52 acres of survey area adjustments, and 127.10 acres of ancillary facilities along the Gulf Coast Segment could not be surveyed due to a lack of landowner permission to access the properties. For the Houston lateral 7.96 miles of survey area could not be surveyed due to a lack of landowner permission to access the properties. Once owner permission is obtained, the remaining proposed Project areas will be surveyed and documented in future addenda reports. Upon receipt, DOS will review these reports consistent with 36 CFR Part 800 and the PA.

3.11.3.2 Programmatic Agreement

A Programmatic Agreement (PA) is an agreement between DOS and the affected tribes regarding the responsibilities that DOS has to each tribe during the construction of the pipeline. The PA also lays out how disputes between tribes and the Applicant will be resolved once construction begins. Under Section 106 of the NHPA, a final PA must be signed by all signatory parties. There are two types of parties to the PA: consulting parties and signatory parties. As the lead federal agency, DOS , determines whether a party is a consulting or signatory party. If a party is determined to be a consulting party, then the PA can still go into effect with or without the signature of the consulting party. However if a party is determined to be a signatory party, then their signature on the PA is essential for the PA to go into effect and compliance under the NHPA has not happened until the signatory party has signed the PA.

The use of a PA for the proposed Project is consistent with 36 CFR 800.4(b)(2), which provides that when ~~–a~~lternatives under consideration consist of corridors or large land areas, or where access to properties is restricted, the agency official may use a phased process to conduct identification and

evaluation efforts." The PA will allow DOS and the consulting parties to continue and eventually complete the identification and evaluation of historic properties pursuant to the provisions in the PA should the proposed Project receive all necessary certifications and permits. The proposed Project design, including a determination of the final alignment after all route variations are assessed, continues to evolve as a result of the NEPA and Section 106 processes, continuing engineering analysis, and ongoing landowner and land manager negotiations. The evaluation of historic properties for the proposed Project will not be completed until full access to all parcels along the proposed corridor is feasible. Additionally, The PA, therefore, will ensure that appropriate consultation procedures are followed and that cultural resources surveys would be completed prior to construction. Appendices to the PA will include an Unanticipated Discovery Plan, Tribal Monitoring Plan, as well as an HTAM Plan. These plans are more specifically described in Sections 3.11.6 (Unanticipated Discovery Plans) and 3.11.7 (Monitoring Plans).

Signatory parties to this agreement include DOS, BLM, USACE, Reclamation, Western, RUS, NRCS, FSA, ACHP, BIA and the SHPOs of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Invited signatories include MDNRC, MDEQ, and TransCanada Keystone Pipeline, LP. Both signatory parties and invited signatories retain the same rights within the agreement in regard to seeking amendments or termination of the agreement. Additional parties, such as Indian tribes, that retain an interest in the proposed Project and that agree to the contents the PA, called —oncurring parties", may also sign the PA, but these parties would not retain the same rights to amend or terminate the agreement.

DOS has circulated multiple drafts of the PA to the consulting parties, including:

- A first draft was provided to the consulting parties on July 13, 2009. Comments were received and evaluated by DOS;
- A second draft was provided to the consulting parties on September 28, 2009. DOS conducted a webinar with the consulting parties on October 7, 2009 to describe the rationale for changes incorporated into the second draft of the PA. Comments received on the second draft were reviewed;
- A third draft of the PA was provided to consulting parties on December 31, 2009. Comments on the third draft PA were accepted until February 1, 2010;
- A fourth draft of the PA which was attached as Appendix S to the draft EIS and released on April 16, 2010. Comments on the fourth draft were received and reviewed;
- A fifth draft of the PA was provided to consulting parties on June 4, 2010. Comments on this draft, including those provided at meetings with the consulting party in June 2010, were received and reviewed;
- A sixth draft of the PA was provided to consulting parties on November 24, 2010 and discussed at the December 2010 Section 106 Meeting in Washington DC; and
- A seventh draft (final copy) of the PA was sent to consulting parties for signature on June 30, 2011. The final PA is provided as Appendix S of the final EIS.

3.11.4 Consultation

3.11.4.1 Introduction

Under Section 106 of the NHPA, the lead federal agency is required to share proposed Project information and consult with consulting parties. This includes Indian tribes, SHPOs, local governments, and applicants for federal permits. For this proposed Project, DOS is consulting with six SHPOs, over 95

Indian tribes, numerous federal and state agencies and local governments, and seeking the views of the public. Government-to-government Section 106 consultation meetings, direct mailings, teleconferencing, direct telephone communications, and email have been used to keep consulting party members informed and to solicit comments on the proposed Project. Numerous Section 106 meetings have been held to work through project agreements including the PA, TCP studies, Tribal Monitoring Plan and the Historical and Archaeological Monitoring Plan. See Figure 3.11.4-2 for a list of Section 106 meetings with Indian tribes and agencies. Appendix S includes a more extensive Master Correspondence Table that summarizes DOS consultation for the proposed Project.

Informal discussions with SHPOs and Indian tribes were initiated by the Applicant and their consultants in 2008 and 2009 when a number of tribal engagement meetings were conducted in an effort to inform interested Indian tribes of the proposed Project and seek initial comments. DOS recognized its lead federal agency status under Section 106 and its responsibilities to consult directly with the Indian tribes, SHPOs, and agencies in its NOI issued on January 28, 2009 in the FR.

3.11.4.2 Federal and State Agency Consultation

In compliance with NEPA and Section 106, DOS is consulting with federal agencies whose participation in the proposed Project was considered an undertaking as per 36 CFR 800.16(y). These agencies include BLM, the Bureau of Reclamation (Reclamation), Western, RUS, NRCS, FSA, BIA, and USACE. The ACHP has also formally entered into consultation with DOS. DOS has also consulted with the NPS due to agency interest in the proposed Project. In coordination with DOS, each of these agencies are reviewing the cultural resource findings as appropriate given their responsibilities as discussed in Section 1.0.

DOS is also consulting with state agencies, including the SHPOs in the six states crossed by the proposed Project corridor as well as the Montana DNRC and the Montana DEQ, who is the lead for the Montana Environmental Policy Act (MEPA). Consultation has occurred with these groups in person as well as by email, and teleconference. Several agencies have attended the agency and tribal Section 106 consultation meetings held in May, July, October and November 2009 and February, June and December 2010 (See Table 3.11.4-2). DOS is also consulting with Basin Electric Power Cooperative due to the associated 230kV transmission line project.

3.11.4.3 Tribal Consultation

Consistent with 36 CFR Part 800, DOS has engaged Indian tribes in government-to-government consultation. The list of Indian tribes that were notified for this proposed Project was derived from lists maintained by DOS, BLM, USACE, SHPOs, state tribal liaisons, THPOs, the BIA, and recommendations from other Indian tribes. In compliance with 36 CFR 800.2 and confidentiality requirements, DOS provided consulting Indian tribes with findings or determinations that were derived from historic properties reports prepared for portions of the proposed Project's APE. Indian tribes initially were invited to consult regarding the proposed Project by letters dated January 30, 2009. Additional tribal members identified by the BLM were invited to consultation by letters dated February 19, 2009. Another letter from DOS dated April 1, 2009 again invited Indian tribes that had not yet responded to the invitations. Phone calls were also made on March 18 through March 23, 2009 to Indian tribes that had not yet responded.

Following these invitations, 45 Indian tribes notified DOS that they would like to become consulting parties. Additionally, two Indian tribes are undecided and have been participating in calls and meetings. Nineteen Indian tribes have notified DOS that they do not wish to consult on the proposed Project and/or have no objection to the proposed Project, but would like to be notified should human remains be found.

Twenty-seven Indian tribes did not respond to requests for consultation. Indian tribes that DOS contacted are listed in Table 3.11.4-1 and the list of consultation meetings is included in Table 3.11.4-2.

To facilitate consulting party participation in Section 106 consultation, DOS has conducted government-to-government and agency consultation meetings in both the Steele City Segment and the Gulf Coast Segment of the proposed Project. Steele City Segment meetings were held in Rapid City, South Dakota (May and July 2009) in Pierre, South Dakota (February 2010), in Billings, Montana (October 2009 and June 2010), and near Malta, Montana (October 2009). Gulf Coast Segment meetings were held in Oklahoma City, Oklahoma (May and July 2009), in Dallas, Texas (November 2009) and in Tulsa, Oklahoma (June 2010). Transcripts for all of the meetings held to date have been prepared and distributed to the consulting parties. DOS also held a Section 106 consultation meeting in Washington, D.C. in December 2010.

Nine tribes listed in Table 3.11.4-3 have completed TCP studies within the proposed Project APE. DOS has reviewed and approved the reports. DOS continues to consult with the tribes regarding recommendations made in these reports concerning the eligibility of a historic property and/or proposed Project effects. DOS will make determinations of eligibility and proposed Project effect and attempt to resolve any adverse effects to historic properties. A Tribal Monitoring Plan (TMP) has been developed as a result of the TCP studies. DOS has consulted with tribes in identifying areas along the mainline APE that will be monitored during construction if the proposed Project is permitted. DOS will continue working with the Applicant and tribes on refining the areas of concern within the TMP (see Section 3.11.7).

TABLE 3.11.4-1
Tribes Consulted under Section 106 for the Proposed Project

	Interested/Consulting Party	Tribe
1	Yes	Absentee-Shawnee Tribe of Indians of Oklahoma
2	No	Alabama Quassarte Tribal Town
3	Yes	Alabama-Coushatta Tribe of Texas
4	No response	Apache Tribe
5	Yes	Blackfeet Nation
6	Yes	Caddo Nation of Oklahoma
7	No	Cherokee Nation
8	Yes	Cheyenne River Sioux Tribe
9	Yes	Cheyenne-Arapaho Tribe of Oklahoma
10	No	Chickasaw Nation of Oklahoma
11	Yes	Chippewa-Cree Indians
12	Yes	Choctaw Nation of Oklahoma
13	No response	Citizen Potawatomi Nation
14	No	Comanche Nation
15	No response	Confederated Salish and Kootenai Tribes of the Flathead Indian Nation
16	No response	Crow Creek Sioux Tribe
17	Yes	Crow Tribe of Indians
18	Yes	Delaware Nation
19	No	Delaware Tribe of Indians
20	No response	Eastern Band of Cherokee Indians

TABLE 3.11.4-1
Tribes Consulted under Section 106 for the Proposed Project

	Interested/Consulting Party	Tribe
21	No response	Eastern Shawnee Tribe
22	No response	Eastern Shoshone Tribe
23	No response	Flandreau Santee Sioux Tribe
24	No response	Forest County Potawatomi Community of Wisconsin Potawatomi Indians
25	Yes	Fort Peck Tribes
26	No	Fort Sill Apache Tribe
27	Yes	Gros Ventre and Assiniboine Tribe of Ft. Belknap
28	No	Gun Lake Potawatomi
29	No response	Hannahville Indian Community of Michigan
30	Yes	Ho-Chunk Nation of Wisconsin
31	No	Huron Potawatomi Nation
32	Yes	Iowa Tribe of Kansas and Nebraska
33	Yes	Iowa Tribe of Oklahoma
34	No response	Jena Band of Choctaw Indians
35	Undecided	Jicarilla Apache Tribe
36	Yes	Kaw Nation
37	Yes	Kialegee Tribal Town of the Creek Nation of Oklahoma
38	No	Kickapoo Traditional Tribe of Texas
39	Yes	Kickapoo Tribe of Kansas
40	No response	Kickapoo Tribe of Oklahoma
41	Yes	Kiowa Indian Tribe of Oklahoma
42	Yes	Lower Brule Sioux Tribe
43	Yes	Lower Sioux Indian Community
44	Yes	Miami Tribe of Oklahoma
45	Yes	Mille Lacs Band of Ojibwe
46	No	Modoc Tribe of Oklahoma
47	Yes	Muscogee (Creek) Nation
48	No response	Nez Perce
49	Yes	Northern Arapaho Tribe
50	Yes	Northern Cheyenne Tribe
51	Yes	Northern Ute Tribe
52	No response	Oglala Sioux Tribe
53	No response	Omaha Tribe of Nebraska
54	Yes	Osage Nation of Oklahoma
55	No	Otoe-Missouri Tribe
56	No response	Ottawa Tribe of Oklahoma
57	Yes	Pawnee Nation of Oklahoma
58	No	Peoria Indian Tribe of Oklahoma
59	No response	Poarch Band of Creek Indians

TABLE 3.11.4-1
Tribes Consulted under Section 106 for the Proposed Project

	Interested/Consulting Party	Tribe
60	No response	Pokagon Band of Potawatomi Indians of Michigan
61	Yes	Ponca Tribe of Indians of Oklahoma
62	Yes	Ponca Tribe of Nebraska
63	No response	Prairie Band of Potawatomi Indians
64	No	Prairie Island Indian Community
65	No	Quapaw Tribe
66	No response	Red Lake Band of Chippewa Indians of Minnesota
67	Yes	Rosebud Sioux Tribe
68	Yes	Sac & Fox Nation of Oklahoma
69	No	Sac and Fox Nation of Missouri in Kansas and Nebraska
70	No response	Sac and Fox Tribe of the Mississippi in Iowa
71	Yes	Santee Sioux Tribe of Nebraska
72	No	Seminole Nation
73	No	Seneca-Cayuga Tribe of Oklahoma
74	Undecided	Shakopee Mdewakanton Sioux
75	Yes	Shoshone-Bannock Tribe
76	No response	Shawnee Tribe
77	Yes	Sisseton-Wahpeton Oyate Sioux
78	No response	Southern Ute Indian Tribe
79	Yes	Spirit Lake Tribe
80	Yes	Standing Rock Sioux Tribe
81	No	Stockbridge-Munsee Tribe
82	No response	Thlopthlocco Tribal Town
83	Yes	Three Affiliated Tribes
84	Yes	Tonkawa Tribe
85	No response	Trenton Indian Service Area
86	Yes	Turtle Mountain Band of Chippewa
87	No	United Keetoowah Band of Cherokee Indians
88	No response	Upper Sioux -Pezihutazizi Kapi
89	No response	Ute Mountain Tribe
90	No	White Earth Band of Minnesota Chippewa
91	Yes	Wichita and Affiliated Tribes
92	Yes	Winnebago Tribe
93	No response	Wyandotte Nation
94	Yes	Yankton Sioux
95	No	Ysleta del Sur Pueblo

TABLE 3.11.4-2
List of DOS Group Consultation Meetings and Webinars with Tribes

Date	Place	Tribes Present	Agencies Represented[a,b]
May 12, 2009	Rapid City, South Dakota	Ponca Tribe of NE, Standing Rock Sioux, Cheyenne River Sioux, Rosebud Sioux, Santee Sioux, Sisseton Wahpeton Oyate, Oglala Sioux, Iowa Tribe of KS and NE	BIA, BLM, NPS, USACE, SD SHPO, DOS
May 14, 2009	Oklahoma City, Oklahoma	Osage Nation, Kickapoo, Cheyenne-Arapaho, Pawnee Nation of Oklahoma, Kickapoo Tribe in Kansas, Caddo Nation, Delaware Nation, Muscogee Nation, Absentee-Shawnee	USACE, OK SHPO, DOS
July 14, 2009	Rapid City, South Dakota	Fort Peck, Lower Sioux, Ponca Tribe, Northern Cheyenne, Rosebud Sioux, Cheyenne River Sioux, Three Affiliated Tribes, Mille Lacs Band of Ojibwe, Kickapoo Tribe in Kansas	USACE, Western, MT DEQ, BLM, DOS
July 28, 2009	Oklahoma City, Oklahoma	Pawnee Nation of Oklahoma, Iowa Tribe of KS and NE, Alabama Coushatta Tribe, Muscogee Nation, Osage Nation, Kaw Nation, Choctaw Nation, Delaware Nation, Kickapoo Tribe KS, Absentee Shawnee Tribe	USACE, NPS, OK SHPO, DOS
October 7, 2009	Webinar	Cheyenne River Sioux Tribe, Osage Nation of Oklahoma, Pawnee Nation of Oklahoma, Rosebud Sioux Tribe, Sisseton-Wahpeton Oyate Sioux, Turtle Mountain Band of Chippewa	Reclamation, BLM, MT DEQ, USACE, Texas Historical Commission
October 20-21, 2009	Billings, MT	Blackfeet Nation, Chippewa-Cree, Spirit Lake, Lower Sioux Indian Community, Yankton Sioux, Cheyenne River Sioux, Rosebud Sioux, Standing Rock Sioux, Turtle Mountain Band of Chippewa, Mille Lacs Band of Ojibwe, Osage Nation, Fort Belknap, Northern Cheyenne	BLM, USACE, BIA, Western, DOS, Montana SHPO, MT DEQ
October 22, 2009	Malta, MT (vicinity)	Chippewa-Cree, Blackfeet	MT DEQ, DOS
November 12-13, 2009	Dallas, TX	Kaw Nation, Choctaw, Pawnee Nation, Kialegee Tribal Town, Muscogee (Creek) Nation, Osage nation, Alabama-Coushatta Tribe, Absentee Shawnee Tribe, Lower Sioux	USACE, NPS, DOS
February 25, 2010	Pierre, SD	Lower Brule Tribe	Western, BEPC
June 22-23, 2010	Billings, MT	Chippewa Cree, Blackfoot Tribe, Standing Rock Sioux, Turtle Mountain, Northern Arapaho, Ft. Peck Tribes, Mille Lacs, Ponca Tribe, Yankton Sioux	BLM, USACE, BEPC, DOS
June 23, 24, 2010	Tulsa, OK	Pawnee Nation, Alabama Coushatta Tribe, Choctaw, Kaw Nation, Muscogee Nation, Osage, Sac and Fox Nation	USACE, DOS
June 23, 2010	Tulsa, OK	Pawnee Nation	DOS
December 7, 2010	Washington, D.C.	Alabama Coushatta, Blackfeet, Chippewa Cree, Choctaw, Fort Peck Tribe, Iowa Nation, Kilagee (Creek) Nation, Northern Arapaho, Osage, Pawnee Nation, Sac and Fox Nation, Yankton Sioux	ACHP, BIA, USACE, Western, EPA, USDA FSA, BLM, MTDEQ, DOS, CEQ
December 8, 2010	Washington, DC	Pawnee Nation	USACE, Nebraska SHPO, DOS
March 30, 2011	Rapid City, SD	Cheyenne River Sioux	South Dakota SHPO, DOS

[a] Representatives from TransCanada have attended several of the tribal consultation meetings at the request of tribes. Meetings attended by TransCanada include May 14, 2009, October 20-21, 2009, November 12-13, 2009, June 22-25, 2010, September 9, 2010, December 7, 2010, and December 8, 2010.

[b] Project specialists from Cardno-ENTRIX attended all tribal consultation meetings.

TABLE 3.11.4-3
List of Tribes participating in Traditional Cultural Property Studies

Tribe	Date of Contact	Date SOW Received	Date of Response	Date TCP Received	Date TCP Accepted
Alabama-Coushatta Tribe of Texas	8/24/2009	8/24/2009	9/14/2009	3/23/2010	4/08/2010
Blackfeet Nation	8/18/2009	8/24/2009	9/14/2009	12/15/2009	1/25/2010
Caddo Nation	8/7/2009	8/7/2009	9/14/2009	1/2011[a]	N/A
Cheyenne and Arapaho Tribes of Oklahoma	8/14/2009	8/24/2009	9/14/2009	1/01/2010	4/16/2010
Fort Peck	8/10/2009	11/20/2009	11/30/2009	SOW withdrawn	N/A
Lower Sioux	8/4/2009	8/11/2009	9/14/2009	SOW withdrawn	N/A
Spirit Lake Tribe	8/11/2009	8/11/2009	9/14/2009	10/01/2010	3/17/2010
Muscogee (Creek) Nation	8/14/2009	11/20/2009	11/30/2009	SOW withdrawn	N/A
Kialagee Tribal Town	8/10/2009	8/10/2009	9/14/2009	SOW withdrawn	N/A
Turtle Mountain	8/11/2009	9/22/2009	9/24/2009	6/2010	8/30/2010
Northern Arapaho	10/26/2009	Pending	Pending	10/10/2010	12/01/2010
Yankton Sioux and Santee Sioux Tribes	8/13/2009	Pending	Pending	11/30/2010	1/26/2011
Rosebud Sioux Tribe	11/12/2009	11/20/2009	11/30/2009	SOW withdrawn	N/A
Pawnee Nation	9/11/2009	9/1/2009	9/14/2009	4/12/2010	5/25/2010

[a] Prepared and funded by NPS.

3.11.5 Public Involvement

Consistent with 36 CFR 800.2(d)(1–3), DOS has followed ACHP guidance in its efforts to seek the views of the public in the Section 106 process through the NEPA process. As stated previously, DOS placed notices in the Federal Register (including the Receipt of Application and Scoping Notices) and provided copies of the application to local communities within the proposed Project APE. Twenty scoping meetings were held in the vicinity of the proposed Project corridor between February 9 through April 8, 2009 DOS provided direct mailings to stakeholders through mailing lists that included approximately 700 individuals and organizations.

After the draft EIS was published, DOS held 21 comment meetings in the proposed Project vicinity between May and June 2010. DOS also received comments from the public on the draft EIS by phone, mail, fax, and web. Many commenters expressed concern relating to the protection of historic properties and the Section 106 consultation process. These comments were responded to and have been incorporated into Section 3.11 of the final EIS.

3.11.6 Unanticipated Discovery Plans

Unanticipated Discovery Plans are plans approved by DOS for the proper response and treatment of any discoveries that are made during construction. Examples of this are human remains and other cultural

artifacts. The plans will be prepared for Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. They have been prepared in consultation with consulting parties including Indian tribes and agencies. The Applicant will implement these plans, with DOS oversight, in the event that unanticipated cultural materials or human remains are encountered during the construction phase of the proposed Project and will apply to federal, state, and private lands.

3.11.7 Monitoring Plans

Monitoring plans describe how construction will be monitored for compliance with Section 106 of the NHPA. Monitoring plans have been prepared to assist in identifying and minimizing proposed Project effects on important cultural resources and would be implemented through the PA.

- An HTAM Plan was prepared to address archaeological issues and potential effects to the El Camino Real de los Tejas National Historic Trail. The first draft of the HTAM Plan was distributed for comment to consulting parties. The Final HTAM Plan is included as a confidential Appendix to the PA.
- A Tribal Monitoring Plan was also developed for the proposed Project and sent out for review in June 2010. Comments from tribes and agencies were incorporated into a second draft that was submitted to consulting parties for review on November 23, 2010. The Tribal Monitoring Plan is included as a confidential Appendix to the PA.

Both plans have been prepared in consultation with the consulting parties for the proposed Project that includes the SHPOs of the six states, Indian tribes, as well as state and federal agencies. The Applicant would implement these plans, with DOS oversight, in the event that unanticipated cultural materials or human remains are encountered during the construction phase of the proposed Project and will apply to federal, state, and private lands. These plans are stipulations of the PA.

3.11.8 Connected Actions

DOS has consulted with ACHP concerning DOS responsibility under Section 106 of the NHPA in regards to the proposed electrical energy distribution lines that would provide the power to proposed Project pump stations. These lines would be designed and constructed by local power providers along the proposed Project corridor. DOS has also consulted with ACHP regarding the proposed Big Bend to Witten 230-kV transmission line that would be designed and constructed by a combination of Western and BEPC. As a result of these discussions, DOS as the lead federal agency for Section 106 has made a determination that its responsibility to ensure Section 106 compliance extends to the proposed distribution lines but not the Big Bend to Witten 230-kV transmission line. RUS is the lead federal agency for the Big Bend to Witten project and will assume Section 106 responsibilities and the potential development of a separate PA between RUS, BEPC and the LBST. These connected actions are progressing under different schedules than the proposed Project, and in many cases the alignments for the required facilities have not yet been firmly established and cultural resource surveys of the routes have not been conducted. The connected actions would also be covered under the PA that DOS and the consulting parties are developing for the proposed Project. This would ensure that identification, evaluation, and mitigation of historic properties would occur prior to construction of these connected actions.

3.11.8.1 Power Distribution Lines and Substations

The cultural resources information collected during surveys along electrical power distribution lines is presented in the State-by-State analyses (Section 3.11.3.1) for ease of reference. For those power distribution lines where the Applicant has selected a local power provider and preliminary distribution

line route selection has occurred, some surveys related to historic properties have been completed (Tables 3.11.3-1 through 3.11.3-6).

The work in each state that has been completed to date and the work that remains to be conducted include:

- In Montana, 169.95 miles of power distribution line have been surveyed to date;
- In South Dakota, 143.54 miles of power distribution line have been surveyed to date;
- In Nebraska, no power distribution lines have been surveyed to date;
- In Kansas, 4.07 miles of power distribution line have been surveyed to date;
- In Oklahoma, 5.4 miles of power distribution lines have been surveyed to date; and
- In Texas, no power distribution lines have been surveyed to date.

3.11.8.2 Big Bend to Witten 230-kV Transmission Line

A proposed 230-kv electrical transmission line would cross the Lower Brule Sioux Reservation (LBSR). BIA would be responsible for supplying ARPA permits for archaeological investigations on LBSR land, while the BLM, Reclamation, and USACE would be responsible for supplying ARPA permits on their respective lands. An ARPA permit can be granted by BIA only if the respective tribe with jurisdiction over the land consents. Terms and conditions may be added to the permit by the jurisdictional tribe. Tribal conditional permits to conduct archaeological surveys on reservation lands may also be required by the tribe.

No cultural resource studies or historical property surveys specific to the proposed Big Bend to Witten 230-kV transmission line have been completed to date. A portion of the Big Bend to Witten 230-kV transmission line would cross the Reservation of the Lower Brule Sioux Tribe (LBST), and a new substation (Lower Brule Substation) that is a part of the transmission system would also be constructed on the reservation. BEPC has applied for funding through RUS. RUS is the lead federal agency for the Big Bend to Witten project and will assume Section 106 responsibilities and the potential development of a separate PA between RUS, BEPC and the LBST.

There are two conceptual alternative transmission corridors (A and B) that have been proposed at this time, and there are multiple potential routings within each of these corridors. Alternative corridor B has been developed by Western and BEPC with the cooperation of the LBST, and at this time is the favored corridor by all stakeholders. An additional and separate NEPA environmental review of the selected route and alternatives for the Big Bend to Witten 230-kV transmission line are currently being conducted. The design and environmental review of the proposed 230-kV transmission line are on a different schedule than the proposed Project itself. Regional transmission system reliability concerns are not associated with the initial operation of the proposed pump stations, but rather with later stages of proposed Project operation at higher levels of crude oil throughput.

3.11.8.3 Bakken Marketlink and Cushing Marketlink Projects

Construction and operation of the Bakken Marketlink Project would include metering systems, three new storage tanks near Baker, Montana, and two new storage tanks within the boundaries of the proposed Cushing tank farm. Keystone reported that the property proposed for the Bakken Marketlink facilities near Pump Station 14 is currently used as pastureland and hayfields and that a survey of the property indicated that there were no cultural resources. DOS reviewed aerial photographs of the area and

confirmed the current use of the land. A site inspection by the DOS third-party contractor confirmed these findings. However, currently there is insufficient information to complete an assessment of potential cultural resources impacts of the Bakken Marketlink Project. Once Keystone Marketlink, LLC submits permit applications for the projects, the assessment of cultural resources would be conducted by other agencies.

The Cushing Marketlink project would be located within the boundaries of the proposed Cushing tank farm of the Keystone XL Project and would include metering systems and two storage tanks. As a result, the impacts of construction and operation of the Cushing Marketlink Project on cultural resources would be the same as potential impacts associated with construction and operation of the proposed Cushing tank farm described in this section.

3.11.9 References

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3.12 AIR QUALITY AND NOISE

3.12.1 Air Quality

The proposed Project would include installation of pipeline and construction of pump stations and associated facilities such as the proposed Cushing tank farm and two surge relief tanks at the end of the Gulf Coast Segment. The proposed pump stations would be electrically driven, with electricity to be provided from existing local electric utilities. Back-up power at each pump station would be provided by an uninterruptible power supply (UPS). No back-up generators at pump stations are planned and, therefore, no fuel storage tanks would be located at pump stations. However, back-up generators and associated fuel tanks would be located at MLV stations.

3.12.1.1 Environmental Setting

Regional Climate

The proposed Project would be constructed in portions of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. The proposed Project in Montana, South Dakota, Nebraska, and Kansas is located within a zone characterized by a humid continental climate that occurs where polar and tropical air masses collide. The humid continental climate zone is noted for its variable weather patterns and large temperature ranges, with summer high temperatures averaging over 89 ˚F, and winter low temperatures averaging between 12 to 20 ˚F. The proposed Project in Texas and Oklahoma is located within a zone characterized by a humid subtropical climate, noted for its warm summer months and relatively mild winters. The daily temperature range within this climate zone tends to be very small, and tropical air masses and warm ocean currents create air mass instability that produces moderate amounts of precipitation during most of the year. Representative climate data for Circle, Montana; Midland, South Dakota; Lincoln, Nebraska; Marion Lake, Kansas; Cushing, Oklahoma; and Beaumont and Houston, Texas are presented in Table 3.12.1-1.

TABLE 3.12.1-1
Representative Climate Data in the Vicinity of the Proposed Pipeline

Location/ Measurement (Average)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
Circle, Montana													
Maximum temperature (ºF)	26.0	33.1	43.2	57.7	68.8	78.2	86.9	85.8	73.4	59.7	42.0	30.2	57.1
Minimum temperature (ºF)	3.8	10.6	19.4	31.1	41.5	50.3	55.8	53.9	42.8	31.9	19.0	8.2	30.7
Total precipitation (inches)	0.4	0.3	0.6	1.3	2.0	2.6	1.9	1.3	1.3	0.8	0.4	0.4	13.3
Total snowfall (inches)	5.6	3.4	3.6	2.2	0.4	0.0	0.0	0.0	0.1	0.9	2.6	5.1	23.9
Snow depth (inches)	4	4	1	0	0	0	0	0	0	0	0	2	1
Midland, South Dakota													
Maximum temperature (ºF)	32.8	38.3	47.2	62.4	73.2	82.5	90.8	89.9	79.2	65.7	48.1	36.6	62.2
Minimum temperature (ºF)	6.0	11.1	20.2	32.6	44.1	54.0	59.6	57.4	45.9	33.5	20.1	10.2	32.9
Total precipitation (inches)	0.3	0.4	1.1	1.6	2.8	3.1	2.2	1.7	1.4	1.1	0.5	0.3	16.4
Total snowfall (inches)	3.9	5.8	6.4	1.8	0.2	0.0	0.0	0.0	0.0	0.6	3.1	4.4	26.2
Snow depth (inches)	1	1	1	0	0	0	0	0	0	0	0	1	0
Lincoln, Nebraska													
Maximum temperature (ºF)	33.8	39.9	50.7	63.8	73.9	84.6	89.3	86.6	78.6	66.3	49.7	37.5	62.9
Minimum temperature (ºF)	12.2	17.8	27.5	38.9	50.2	60.7	66.0	63.6	53.1	40.3	27.4	16.5	39.5
Total precipitation (inches)	0.7	0.9	2.1	2.9	4.3	3.6	3.4	3.4	3.0	1.9	1.5	0.8	28.4
Total snowfall (inches)	6.4	5.3	5.1	1.4	0.0	0.0	0.0	0.0	0.0	0.6	2.6	5.4	26.7
Snow depth (inches)	2	2	0	0	0	0	0	0	0	0	0	1	0
Marion Lake, Kansas													
Maximum temperature (ºF)	37.9	43.9	55.1	66.1	75.1	84.8	91.4	89.9	81.0	69.1	53.7	41.8	65.8
Minimum temperature (ºF)	17.1	21.3	31.6	42.6	52.8	62.5	67.7	65.4	55.8	43.7	31.8	21.7	42.8
Total precipitation (inches)	0.7	0.9	2.4	3.0	4.6	4.9	3.8	3.8	3.2	2.8	1.7	1.0	33.0
Total snowfall (inches)	1.1	1.1	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.0	4.0
Snow depth (inches)	0	0	0	0	0	0	0	0	0	0	0	0	0
Cushing, Oklahoma													
Maximum temperature (ºF)	45.8	52.2	61.2	71.0	78.4	86.5	92.7	92.4	83.6	73.4	59.4	49.0	70.5

TABLE 3.12.1-1
Representative Climate Data in the Vicinity of the Proposed Pipeline

Location/ Measurement (Average)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
Minimum temperature (ºF)	24.6	29.8	38.6	48.1	58.2	66.7	71.3	69.9	61.5	49.7	38.1	28.3	48.7
Total precipitation (inches)	1.2	1.9	3.2	3.7	5.8	4.4	2.9	2.7	4.1	3.4	2.9	1.9	38.2
Total snowfall (inches)	3.0	1.7	0.9	T	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	7.1
Snow depth (inches)	0	0	0	0	0	0	0	0	0	0	0	0	0
Beaumont, Texas													
Maximum temperature (ºF)	61.5	65.3	72.0	77.8	84.3	89.4	91.6	91.7	88.0	80.5	70.9	63.9	78.1
Minimum temperature (ºF)	42.9	45.9	52.4	58.6	66.4	72.3	73.8	73.2	69.4	59.6	50.8	44.5	59.2
Total precipitation (inches)	5.7	3.4	3.8	3.8	5.8	6.6	5.2	4.8	6.1	4.7	4.7	5.2	59.8
Houston, Texas													
Maximum temperature (ºF)	59.1	65.9	75.4	76.4	84.7	89.7	88.7	93.4	90.1	84.3	74.2	70.8	79.4
Minimum temperature (ºF)	45.1	46.7	58.3	59.0	69.1	75.1	75.5	78.0	74.5	64.1	55.6	49.6	62.6
Total precipitation (inches)	6.7	1.4	8.8	4.8	9.6	5.6	10.0	7.2	6.3	1.8	4.4	1.6	68.2

Notes:

ºF = Degrees Fahrenheit

T = Trace amounts

Source: Keystone 2009c.

Ambient Air Quality

Ambient air quality standards are regulated by federal, state, and local agencies. EPA has established national ambient air quality standards (NAAQS) for six criteria pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter (PM_{10} particulates and $PM_{2.5}$ particulates), carbon monoxide (CO), ozone (O_3), and lead (Pb). The NAAQS were developed to protect human health (primary standards) and human welfare (secondary standards). State air quality standards cannot be less stringent than the NAAQS. South Dakota, Nebraska, Kansas, Oklahoma, and Texas have adopted ambient air quality standards equivalent to the NAAQS for all six criteria pollutants, whereas Montana has more stringent standards as discussed in detail in Appendix I. Table 3.12.1-2 lists the NAAQS for the six criteria pollutants.

TABLE 3.12.1-2
National Ambient Air Quality Standards

Pollutant	Time Frame	Primary	Secondary
Particulate matter less than 10 microns in diameter	Annual[a]	Revoked	Revoked
	24-hour[b]	150 µg/m^3	150 µg/m^3
Particulate matter less than 2.5 microns in diameter	Annual[c]	15 µg/m^3	15 µg/m^3
	24-hour[d]	35 µg/m^3	NA
Sulfur dioxide	Annual	0.030 ppm (80 µg/m^3)	NA
	24-hour[b]	0.14 ppm (365 µg/m^3)	NA
	3-hour[b]	NA	0.5 ppm (1,300 µg/m^3)
Carbon monoxide	8-hour[b]	9 ppm (10,000 µg/m^3)	NA
	1-hour[b]	35 ppm (40,000 µg/m^3)	NA
Nitrogen dioxide	Annual	0.053 ppm (100 µg/m^3)	0.053 ppm (100 µg/m^3)
	1-hour[e]	0.100 ppm	NA
Ozone	8-hour[f]	0.075 ppm (147 µg/m^3)	0.075 ppm (147 µg/m^3)
	1-hour[g]	0.12 ppm (235 µg/m^3)	0.12 ppm (235 µg/m^3)
Lead	3-month rolling[h]	0.15 µg/m^3	0.15 µg/m^3
	Quarterly	1.5 µg/m^3	1.5 µg/m^3

[a] Due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution, the United States Environmental Protection Agency revoked the annual PM_{10} standard of 50 µg/m^3 in 2006 (effective December 17, 2006).

[b] Not to be exceeded more than once per year.

[c] To attain this standard, the 3-year average of the weighted annual mean particulate matter less than 2.5 microns in diameter concentrations from single- or multiple community-oriented monitors must not exceed 15.0 µg/m^3.

[d] To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m^3 (effective December 17, 2006).

[e] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 0.100 ppm (effective January 22, 2010).

[f] To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations, measured at each monitor within an area over each year, must not exceed 0.075 ppm (effective May 27, 2008).

[g] The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is < 1. As of June 15, 2005, EPA revoked the 1-hour ozone standard in all areas, except the fourteen 8-hour ozone nonattainment Early Action Compact Areas.

[h] Final rule signed October 15, 2008.

Notes:

µg = Microgram(s)
m^3 = Cubic meter(s)
NA = Not applicable
ppm = Part(s) per million

Source: EPA 2009a.

EPA uses four classifications to define relative air quality within specified zones in the United States. These four classifications are:

- Attainment – areas where the ambient air concentration of a pollutant is less than the NAAQS;
- Nonattainment – areas where the ambient air concentration of a pollutant is greater than the NAAQS;
- Maintenance – areas previously designated as nonattainment areas that have more recently demonstrated compliance with the NAAQS and are treated as attainment areas for the purposes of permitting stationary sources (individual states may have specific provisions to ensure that the area would continue to comply with the NAAQS); and
- Unclassifiable – areas where no ambient air quality data are available. Unclassifiable areas are treated as attainment areas for the purposes of permitting stationary sources.

A network of ambient air quality monitoring stations has been established by EPA and state and local agencies to measure and track the background concentrations of criteria pollutants across the United States, and to assist in designation of nonattainment areas. To characterize the background air quality in the regions surrounding the proposed Project area, data from air quality monitoring stations were obtained. A summary of the available regional background air quality concentrations for 2008 is presented in Table 3.12.1-3.

The proposed Project would pass through areas in Texas that are classified as nonattainment areas for the 8-hour ozone federal standard. These areas include Liberty, Hardin, Jefferson, Harris, and Chambers counties. While ozone is not emitted directly into the air, it typically develops within inversion-layers in the presence of sunlight (ultraviolet light) through photochemical reactions between atmospheric oxygen, oxides of nitrogen (NOx), and volatile organic compounds (VOCs). The major sources of NOx and VOC precursor emissions include motor vehicles, industrial facilities, electric utilities, gasoline storage facilities, chemical solvents, and biogenic sources. During the construction and operation phases of the proposed Project, some NOx and VOC precursor emissions could occur within designated nonattainment areas (e.g. through the use of motor vehicles and temporary fuel storage facilities) and therefore a General Conformity Determination is required (see Sections 3.12.1.2 and 3.12.1.3).

TABLE 3.12.1-3
2008 Regional Background Air Quality Concentrations for the Project [a]

Location	PM_{10} ($\mu g/m^3$) 24-Hr[b]	$PM_{2.5}$ ($\mu g/m^3$) Annual	$PM_{2.5}$ ($\mu g/m^3$) 24-Hr[c]	SO_2 (ppm) Annual	SO_2 (ppm) 24-Hr[b]	SO_2 (ppm) 3-Hr[b]	CO (ppm) 8-Hr[b]	CO (ppm) 1-Hr[b]	NO_2 (ppm) Annual	O_3 (ppm) 8-Hr[d]	O_3 (ppm) 1-Hr[b]
Montana											
Flathead County	--	--	--	--	--	--	1.9	3.4	--	0.057	0.061
Rosebud County	45	--	--	--	--	--	--	--	--	--	--
Yellowstone County	--	6.66	15.7	0.004	0.021	0.043	--	--	--	--	--
South Dakota											
Jackson County	56	5.80	12.8	0.002	0.005	0.006	--	--	0.001	0.052	0.058
Meade County	32	--	--	--	--	--	--	--	--	0.060	0.068
Pennington County	110	8.16	21.6	--	--	--	--	--	--	--	--
Nebraska											
Douglas County	124	9.81	22.0	0.002	0.017	0.050	2.0	2.9	--	0.058	0.068
Hall County	--	8.21	18.6	--	--	--	--	--	--	--	--
Lancaster County	--	8.30	23.4	--	--	--	1.8	4.5	--	0.051	0.059
Kansas											
Sedgwick County	62	10.15	22.9	--	--	--	1.5	2.7	0.009	0.067	0.077
Shawnee County	49	10.47	19.5	--	--	--	--	--	--	0.065	0.072
Sumner County	--	9.48	22.3	0.002	0.003	0.004	--	--	0.004	0.068	0.080
Oklahoma											
Creek County	--	--	--	--	--		--	--	--	0.069	0.085
Kay County	84	--	--	0.003	0.018	0.037	0.3	0.3	--	0.069	0.090
Lincoln County	--	--	--	--	--	--	--	--	--	0.061	0.073
Tulsa County	77	12.10	24.7	0.007	0.036	0.067	1.3	1.9	0.011	**0.079**	0.099
Texas											
Gregg County	--	--	--	0.002	0.013	0.055	--	--	0.007	0.071	0.101
Harris County	127	14.26	32.4	0.002	0.015	0.046	5.2	8.1	0.015	**0.083**	0.122
Jefferson County	--	10.41	32.6	0.003	0.018	0.064	0.7	1.7	0.008	**0.078**	0.099

[a] The values shown are the highest reported during the year by all monitoring sites in a county.
[b] Data represents the second-highest daily maximum concentrations.
[c] Data represents the 98th percentile of 24-hour average $PM_{2.5}$ concentrations.
[d] Data represents the fourth-highest daily maximum 8-hour average ozone concentrations.

Notes:
µg = Microgram(s)
CO = Carbon monoxide
m^3 = Cubic meter(s)
NO_2 = Nitrogen dioxide
O_3 = Ozone
ppm = Part(s) per million
PM_{10} = Particulate matter less than 10 microns in diameter
$PM_{2.5}$ = Particulate matter less than 2.5 microns in diameter
SO_2 = Sulfur dioxide

Source: EPA 2009b.

3.12.1.2 Regulatory Requirements

The Clean Air Act (CAA) and its implementing regulations (42 USC 7401 et seq., as amended in 1977 and 1990) are the basic federal statutes and regulations governing air pollution in the United States. The following requirements have been reviewed for applicability to the proposed Project:

- New Source Review (NSR)/Prevention of Significant Deterioration (PSD);
- Air Quality Control Regions (AQCRs);
- New Source Performance Standards (NSPS);
- National Emission Standards for Hazardous Air Pollutants (NESHAPs)/Maximum Achievable Control Technology (MACT);
- Chemical Accident Prevention Provisions;
- Title V Operating Permits/State Operating Permits;
- Other Applicable State Permits;
- General Conformity Rule; and
- Greenhouse Gases (GHG).

New Source Review/Prevention of Significant Deterioration

The NSR permitting program was established as part of the 1977 Clean Air Act Amendments (CAAA). NSR is a preconstruction permitting program that is designed to ensure that air quality is not significantly degraded from the addition of new or modified major emissions sources.[1] In poor air quality areas, NSR requires that new emissions do not inhibit progress toward cleaner air. In addition, the NSR program requires that any large new or modified industrial source would be as clean as possible, and that the best available pollution control is utilized. The NSR permit establishes allowable construction procedures, emission source operations, and applicable emission limits relevant to the permitted action.

If construction or modification of a major stationary source would result in emissions greater than the established significance threshold for a pollutant within an attainment area, the project must be reviewed in accordance with PSD regulations. Construction or modification of a major or, in some jurisdictions, non-major stationary source in a designated nonattainment or designated maintenance area (Section 175A) requires that the project be reviewed in accordance with nonattainment NSR regulations.

The proposed Project includes the construction of a tank farm within a designated attainment area in Cushing, Oklahoma. The proposed tank farm includes three crude oil storage tanks, each with a capacity of 350,000 barrels (14,700,000 gallons). Estimated emissions are less than the 100-ton-per year (tpy) significance threshold level for a petroleum storage and transfer unit with a total storage capacity exceeding 300,000 barrels (i.e., one of the 28 named source types subject to the 100 tpy significance threshold for PSD permitting; see Table 3.12.1-4). In addition, mobile source emissions and fugitive emissions during the construction phase would be excluded from the determination of "potential to emit"

[1] A major stationary pollutant source in a nonattainment area has the potential to emit more than 100 tpy of any criteria pollutant. In PSD areas, the threshold level may be either 100 or 250 tpy, depending on whether the source is classified as one of the 28 named source categories listed in Section 168 of the CAA.

for applicability purposes in accordance with the CAA. Therefore, the proposed tank farm would not trigger PSD review.

TABLE 3.12.1-4
Estimated Emissions from the Cushing Tank Farm in Oklahoma

Emission Unit	VOC (tpy)	Total HAPs (tpy)	Maximum Individual HAP (tpy)
Crude Oil Tank #1	12.71	0.37	0.34 (hexane)
Crude Oil Tank #2	12.71	0.37	0.34 (hexane)
Crude Oil Tank #3	12.71	0.37	0.34 (hexane)
Fugitive Emissions	5.10	0.46	0.36 (hexane)
Total	43.23	1.57	1.38 (hexane)

Notes:
tpy = Tons per year
HAP = Hazardous air pollutant
Source: Keystone 2010a.

The proposed Project also includes construction and operation of two (primary and back-up) surge relief tanks within a designated nonattainment area in Jefferson County, Texas at the end of the Gulf Coast Segment. Each tank would have a capacity of approximately 10,417 barrels (435,514 gallons) with two carbon adsorption beds each, in series, for an approximate 90 percent removal of VOC emissions. Although the actual number of surge relief events that could occur during proposed Project operations is not known, the emissions estimates were based on Keystone estimate that there would be an average of one surge relief event per month for a total of 12 surge relief events per year. In that scenario, estimated emissions would be less than the 100-ton-per year (tpy) significance threshold level for a new source subject to nonattainment area pre-construction review requirements in a moderate ozone nonattainment area (see Table 3.12.1-5). Mobile source emissions and fugitive emissions during the construction phase would be excluded from the determination of ~~p~~potential to emit" for applicability purposes in accordance with the CAA. Based on those assumptions, the proposed surge relief tanks would not trigger NSR review.

TABLE 3.12.1-5
Estimated Emissions from the Surge Relief Tanks in Texas

Emission Unit	VOC (tpy)	Total HAPs (tpy)	Maximum Individual HAP (tpy)
Surge Relief Tanks (12 events per year)	1.33	0.039	0.0113 (cyclohexane)
Fugitive Emissions	14.69	0.740	0.206 (xylene)
Total	16.02	0.779	0.208 (xylene)

Notes:
tpy = Tons per year
HAP = Hazardous air pollutant
Source: Keystone 2010a.

During construction, temporary diesel-fired generator engines could be used at temporary construction camps if commercial electrical power is unavailable. These camps would be located within designated attainment areas near Nashua and Baker, Montana, and Union Center and Winner, South Dakota. If

commercial electrical power is acquired from local utilities, emergency back-up temporary diesel-fired generator engines could still be used at these locations. The temporary diesel-fired generator engines would be considered nonroad engines under 40 CFR 89.2 if they meet the definitions of portable or transportable, and are on location for less than 12 consecutive months. Nonroad engine emissions would be excluded from the determination of "potential to emit" for applicability purposes in accordance with the CAA. Consequently, emissions would be less than the 250 tpy significance threshold level, and PSD review would not be triggered. However, if the temporary diesel-fired generator engines are considered stationary rather than nonroad, estimated emissions would still be less than the 250 tpy significance threshold level (see Tables 3.12.1-6 and 3.12.1-7 and PSD review would not be triggered.

TABLE 3.12.1-6
Estimated Emissions Per Construction Camp [a, b]

Pollutant	Annual Emissions (tpy)
Nitrogen Oxides + Nonmethane Hydrocarbon	61.80
Carbon Monoxide	54.07
Particulate Matter	3.09
Sulfur Oxides	4.31
Lead	7.2e-04

Notes:
tpy = Tons per year
[a] Emission estimates include four, 400-kW generator engines per camp.
[b] Engines would be "Tier 3" certified and assumed to operate 8,760 hours per year for worst-case emissions.
Source: Keystone 2009c.

TABLE 3.12.1-7
Estimated Emissions Per Emergency Generator [a, b]

Pollutant	Annual Emissions (tpy)
Nitrogen Oxides + Nonmethane Hydrocarbon	15.45
Carbon Monoxide	13.52
Particulate Matter	0.77
Sulfur Oxides	1.08
Lead	1.8e-04

Notes:
tpy = Tons per year
[a] Emission estimates include one, 400-kW generator engine.
[b] Engine would be "Tier 3" certified and assumed to operate 8,760 hours per year for worst-case emissions.
Source: Keystone 2009c.

The proposed Project also includes construction and operation of back-up generators and associated fuel tanks located at MLV stations. Emissions would be negligible since the units would only operate in upset conditions. Consequently, emissions would be less than the 250 tpy significance threshold level, and PSD review would not be triggered.

Air Quality Control Region

Air Quality Control Regions (AQCRs) are categorized as Class I, Class II, or Class III. Class I areas (commonly called "pristine areas") include:

- International parks;
- National wilderness areas that exceed 5,000 acres in size;
- National memorial parks that exceed 5,000 acres in size; and
- National parks that exceed 6,000 acres and were in existence on August 7, 1977 (the effective date of the 1977 Amendments).

In addition, Indian tribes that have received "Treatment in the Same Manner as a State" (TAS) designations can redesignate Class II tribal lands to Class I. Class II areas include all attainment and not classifiable areas not designated as Class I areas (unless subsequently redesignated). Class III areas are not defined in the statute and refer to areas wherein a state decides not to afford the protections associated with either the pristine or Class II areas. Class III designations are intended for heavily industrialized zones, must meet all requirements outlined in 40 CFR Part 51.166 and can be made only on request.

If a new source (or a major modification to an existing source) is subject to the PSD program requirements and is within 62 miles (100 kilometers) of a Class I area, the proposed facility is required to notify the appropriate federal officials and to assess the impacts of the proposed project on the Class I area. The following Class I areas are within 62 miles (100 kilometers) of the Project ROW: Badlands/Sage Creek Wilderness and Badlands National Park in South Dakota; Theodore Roosevelt National Park in North Dakota; and Fort Peck Indian Reservation in Montana. However, the proposed Project does not include construction or operation of significant stationary sources of air pollutants subject to the PSD program requirements. Therefore, the proposed Project does not trigger a federal Class I area impact assessment.

New Source Performance Standards

The New Source Performance Standards (NSPS), codified at 40 CFR Part 60, establish requirements for new, modified, or reconstructed units in specific source categories. NSPS requirements include emission limits, monitoring, reporting, and record keeping.

As described previously, the proposed Project includes construction of a tank farm in Cushing, Oklahoma and a surge relief tank in Jefferson County, Texas. The regulation at 40 CFR 60 Subpart Kb applies to storage vessels containing volatile organic liquids (VOLs) with a capacity greater than 75 m^3 (approximately 19,800 gallons). As stated in 40 CFR 60.112b(a), the owner or operator of a storage vessel with a design capacity greater than or equal to 151 m^3 (approximately 39,900 gallons) containing a VOL that has a maximum true vapor pressure greater than or equal to 5.2 kPa (approximately 0.7 psia) shall equip each storage vessel with one of several control options:

- A fixed roof in combination with an internal floating roof;
- An external floating roof;
- A closed vent system and control device; or
- A system equivalent to those described above.

The crude oil tanks to be located at the Cushing, Oklahoma tank farm and the surge relief tanks to be located at Nederland, Texas, would be installed with a fixed roof in combination with an internal floating roof, or an external floating roof. If internal floating roofs are the selected technology, as required by 40 CFR 60.112b(a)(1)(ii), each internal floating roof would be equipped with a mechanical shoe seal (a metal sheet connected by braces to the floating roof and held against the wall of the storage vessel by springs or weighted levers). A flexible coated fabric envelope would span the ~~a~~annular space" between the metal sheet and the floating roof. If external roofs are the selected technology, as required by 40 CFR 112b(a)(2)(i), each external floating roof would be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device would consist of a lower primary seal, and an upper secondary seal. The proposed Project would be required to comply with all applicable provisions of Subpart Kb, and the General Provisions in 40 CFR 60 Subpart A.

During construction, temporary fuel storage systems would be located at contractor yards and pipe yards. Each system would consist of temporary aboveground 10,000- to 20,000-gallon onroad and off-road diesel skid mounted tanks and/or 9,500-gallon gasoline fuel trailers. Normally, a two to three day supply of fuel would be maintained in storage, resulting in approximately 30,000 gallons in storage volume at each fuel storage location. The regulatory applicability of 40 CFR 60 Subpart XX depends on the gasoline throughput of transfer facilities. As long as the throughput of proposed Project transfer facilities are less than 75,700 liters per day (i.e., 19,998 gallons per day), they would be exempt from Subpart XX. In addition, fuel tanks smaller than 75 m^3 (19,800 gallons) constructed after July 23, 1984 would be exempt from the requirements of 40 CFR 60 Subpart Kb.

Construction camp generator engines in Montana and South Dakota that are on site less than 12 months and that qualify as nonroad engines per 40 CFR 89.2 would not be considered stationary units and would not be subject to 40 CFR 60 Subpart IIII. However, back-up generators at MLV stations would be stationary units subject to 40 CFR 60 Subpart IIII. The regulations at 40 CFR 60 Subpart IIII apply to stationary compression ignition internal combustion engines manufactured after April 1, 2006 or modified or reconstructed after July 11, 2005. Subpart IIII requires that these engines be certified to meet the emission standards in 40 CFR 60.4201 for nitrogen oxides (NOx), particulate matter (PM), carbon monoxide (CO), and non-methane hydrocarbons (NMHC). In addition, owners and operators of the engines must use low sulfur fuel, and beginning October 1, 2010, ultra low sulfur fuel. The regulation has specific provisions for emergency engines starting in 40 CFR 60.4202.

No other subparts would apply because the proposed Project does not include construction or operation of any other specific source category of air pollutants.

National Emission Standards for Hazardous Air Pollutants/Maximum Achievable Control Technology

National Emission Standards for Hazardous Air Pollutants/Maximum Achievable Control Technology (NESHAPs), codified in 40 CFR Parts 61 and 63, regulate hazardous air pollutant (HAP) emissions. Part 61 was promulgated prior to the 1990 CAAA and regulates only eight types of hazardous substances (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride). The proposed Project would not include facilities that fall under one of the source categories regulated by Part 61; therefore, the requirements of Part 61 are not applicable.

The 1990 CAAA established a list of 189 additional HAPs, resulting in the promulgation of Part 63. Also known as the Maximum Achievable Control Technology (MACT) standards, Part 63 regulates HAP emissions from major sources, area sources, and specific source categories. Part 63 considers any source with the potential to emit 10 tpy of any single HAP or 25 tpy of HAPs in aggregate as a major source of HAPs. Area sources consist of smaller-size facilities that release lesser quantities of HAPs that are of concern when large numbers of sources are located in heavily populated areas. As currently projected,

neither the Cushing tank farm nor any other proposed Project facilities would have the potential to emit HAP emissions greater than 10 tpy for a single HAP, nor would they have the potential to emit multiple HAPs at a quantity equal to or greater than 25 tpy. The proposed Project facilities therefore would not be considered a major source of HAP emissions. However, the proposed Project would require the use of stationary engines at the MLV stations and may require the use of stationary engines at construction work camps if local electrical power is not available. Those engines would be subject to area source provisions in 40 CFR 63 Subpart ZZZZ for stationary reciprocating internal combustion engines (RICE). If the generator engines are located at construction camps for less than 12 months and considered nonroad engines per 40 CFR 89.2, the engines would not be considered stationary units nor would they be subject to this subpart.

Chemical Accident Prevention Provisions

The chemical accident prevention provisions, codified in 40 CFR Part 68, are federal regulations designed to prevent the release of hazardous materials in the event of an accident and to minimize potential impacts if a release did occur. The regulations contain a list of substances and threshold quantities for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more substances on this list in a quantity equal to or greater than specified in the regulation, the facility must prepare and submit a Risk Management Plan. If a facility does not have a listed substance onsite, or if the quantity of a listed substance is below the applicability threshold, the facility does not need to prepare a Risk Management Plan. No hazardous materials subject to the Chemical Accident Prevention Provision/Risk Management Plan (40 CFR Part 68) would be stored at any of the proposed Project aboveground facilities.

Title V Operating Permits/State Operating Permits

Title V of the federal CAA requires individual states to establish an air operating permit program. The requirements of Title V are outlined in 40 CFR Parts 70 and 71, and the permits required by these regulations are often referred to as Part 70 or 71 permits. The permit includes air pollution requirements that apply to an emissions source, including emissions limits and monitoring, record keeping, and reporting requirements. It also requires that the emissions source report its compliance status with respect to permit conditions to the permitting authority. Operating permits (also known as Title V permits) are required for all major stationary sources. What constitutes a major source varies according to what pollutant(s) are being emitted and the attainment designation of the area where the source is located. In general, a source is considered to be a major source under Title V if it emits or has the potential to emit:

- 100 tpy or more of any criteria air pollutant in an attainment area[2];
- 10 tpy or more of a single HAP; or
- 25 tpy of cumulative HAPs.

During construction, temporary diesel-fired generator engines could be used at temporary construction camps if commercial electrical power is unavailable. These camps would be located within designated attainment areas near Nashua and Baker, Montana, and Union Center and Winner, South Dakota. If commercial electrical power is acquired from local utilities, emergency back-up temporary diesel-fired

[2] Lower thresholds apply in nonattainment areas (but only for the pollutant that are in nonattainment). For the Beaumont-Port Arthur 8-hour ozone nonattainment area, the region is currently classified as moderate nonattainment. For moderate ozone nonattainment, the thresholds are 100 tpy or more of VOCs or NOx.

generator engines could still be used at these locations. In Montana, the State of Montana Department of Environmental Quality (MDEQ) has authority to implement the Title V program. Regulations are contained in the Administrative Rules of Montana, Title 17, Chapter 8, Subchapter 12. The diesel-fired generator engines and emergency back-up generators at each camp in Montana would not have potential emissions that exceed the Title V threshold of 100 tpy (see Tables 3.12.1-6 and 3.12.1-7). Consequently, proposed temporary construction camps in Montana would not trigger Title V permitting.

In South Dakota, the State of South Dakota Department of Environment and Natural Resources (SD DENR) has authority to implement the Title V program, and operating permit program for minor sources not subject to Title V. Regulations are contained in the Administrative Rules of South Dakota, Chapters 74:36:04-05. SD DENR exempts sources from the requirements for a minor operating permit as described in Chapter 74:36:04:03, including facilities that have the potential to emit 25 tons or less per year of any criteria pollutant. The diesel-fired generator engines and emergency back-up generators at each camp in South Dakota would not have potential emissions that exceed the Title V threshold of 100 tpy (see Tables 3.12.1-6 and 3.12.1-7). However, the generator engines would have potential emissions greater than the minor operating permit threshold. Consequently, Project camps in South Dakota would not trigger Title V permitting, but appear to trigger the need for a minor operating permit unless exemptions exist and are met for temporary nonroad engines.

As described previously, the proposed Project includes construction of a tank farm in Cushing, Oklahoma. In Oklahoma, the State of Oklahoma Department of Environmental Quality (ODEQ) has authority to implement the Title V Operating Permits Program. Air pollution control regulations are contained in Oklahoma Administrative Code, Title 252, Chapter 100. The Cushing tank farm has emissions below the Title V permit thresholds (see Table 3.12-4). In addition, tanks subject to 40 CFR 60 Subpart Kb are not required to obtain a Title V permit if emissions are below Title V major thresholds. Consequently, the tank farm would not trigger Title V permitting.

The proposed Project would also include construction and operation of two surge relief tanks in Jefferson County, Texas at the end of the Gulf Coast Segment. In Texas, the State of Texas Commission of Environmental Quality (TCEQ) has authority to implement the Title V Operating Permits Program. Air pollution control regulations are contained in Texas Administrative Code, Title 30, Chapter 122. The TCEQ requires a Title V operating permit for all sources that have potential emissions of 100 tpy or more of any criteria air pollutant, 10 tpy or more of a single HAP, or 25 tpy of cumulative HAPs (see footnote 2). The surge relief tanks would have emissions below the Title V permit thresholds (see Table 3.12-5). In addition, tanks subject to 40 CFR 60 Subpart Kb are not required to obtain a Title V permit if emissions are below Title V major thresholds. Consequently, the relief tanks would not trigger Title V permitting.

The proposed Project also includes construction and operation of back-up generators and associated fuel tanks located at MLV stations. Emissions would be negligible since the units would only operate in upset conditions. However, the engines would be subject to 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ. Consequently, Title V permitting may be required at locations where state agencies require a permit based on federal regulation applicability.

State Preconstruction Permits

In Montana, MDEQ requires preconstruction air quality permits under the Administrative Rules of Montana (ARM), Title 17, Chapter 8, Subchapter 7. Permitting is required for sources that have potential emissions that exceed 25 tpy and are not excluded under ARM 17.8.744 (i.e., emergency back-up generators). The temporary diesel-fired generator engines at each camp in Montana would have potential emissions that exceed the preconstruction permit threshold of 25 tpy (see Tables 3.12.1-6 and 3.12.1-7).

Consequently, Project camps in Montana would appear to trigger requirements for preconstruction permitting unless exemptions exist and are met for temporary nonroad engines.

In Oklahoma, ODEQ requires preconstruction air quality permits (major and minor) under Oklahoma Administrative Code, Title 252, Chapter 100. Permitting is required for all sources with actual emissions greater than 5 tpy. The Cushing tank farm would have emissions above the minor permit thresholds (see Table 3.12-4). Consequently, the tank farm would trigger preconstruction permitting.

In Texas, TCEQ requires preconstruction air quality permits under Texas Administrative Code, Title 30, Chapter 116. Permitting is required for all sources except those considered de minimis for air emissions. State air authorizations for activities that produce more than a de minimis level of emissions but less than other NSR permitting options (i.e., less than 25 tpy of SO_2, PM_{10}, and VOC; less than 250 tpy CO; and less than 100 tpy NOx) qualify for a permit by rule. The surge relief tanks are not a listed de minimis source, and have emissions less than NSR permitting thresholds (see Table 3.12-5). Consequently, the relief tanks would trigger the requirements for a permit by rule.

For emergency generators at MLV stations, preconstruction permitting may be required by state agencies that require a permit based on federal regulation applicability. Emissions would be negligible since the units would only operate in upset conditions. However, the engines would be subject to 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

General Conformity Rule

The General Conformity Rule was designed to compel federal agencies to require that proposed projects conform to the applicable State Implementation Plan (SIP). General Conformity regulations apply for pollutant emissions within project areas designated as nonattainment for these pollutant emissions (or, for ozone, its precursors NOx and VOC) that are not subject to NSR and where pollutant emissions are greater than the significance thresholds established in the General Conformity regulations or exceed 10 percent of the total emissions budget for the entire nonattainment area. Federal agencies are able to make a positive conformity determination when:

- Emissions from the project are specifically identified and accounted for in the SIP attainment or maintenance demonstration; or
- Emissions from the action are fully offset within the same area through a revision to the SIP, or a similarly enforceable measure that creates emissions reductions so that there is no net increase in emissions of that pollutant.

For the proposed Project, Liberty, Hardin, Jefferson, Harris, and Chambers counties in Texas are designated as nonattainment areas for the 8-hour federal ozone standard (precursors are NO_X and VOC). Therefore, emissions of NOx and VOCs from sources related to the proposed Project would be considered under the General Conformity Rule, including a comparison of potential emissions to applicability threshold levels and a conformity determination if the emissions are greater than applicability threshold levels. For more details on Keystone's General Conformity analysis, see Section 3.12.1.3 and Appendix Q.

Greenhouse Gases

On October 30, 2009, the EPA promulgated the first comprehensive national system for reporting emissions of carbon dioxide (CO_2) and other GHG produced by major sources in the United States. Through this new reporting, EPA will have comprehensive and accurate data about the production of GHG in order to confront climate change. Approximately 13,000 facilities, accounting for about 85 to 90

percent of industrial GHG emitted in the United States are covered under the rule. The new reporting requirements apply to suppliers of fossil fuel and industrial chemicals, manufacturers of certain motor vehicles and engines (not including light and medium duty on-road vehicles), as well as large direct emitters of GHG with emissions equal to or greater than a threshold of 25,000 metric tpy. This threshold is equivalent to the annual GHG emissions from just over 4,500 passenger vehicles. The direct emission sources covered under the reporting requirement include energy intensive sectors such as cement production, iron and steel production, electricity generation, and oil refineries, among others. The gases covered by the rule are CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), sulfur hexafluoride (SF_6), and other fluorinated gases, including nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFE). Because CO_2 is the reference gas for climate change, measures of non-CO_2 GHG are converted into CO_2-equivalent values (CO_2-e) based on their potential to absorb heat in the atmosphere. The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

According to the preamble of the rule, the U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations includes storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading operations. EPA did not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions (accounting for much less than 1 percent) and the difficulty in defining a facility. The responsibility for reporting would instead be placed on the processing plants and refineries. Consequently, the proposed pipeline Project would not trigger GHG reporting requirements.

On June 2, 2010, the EPA issued a final rule that establishes an approach to addressing GHG emissions from stationary sources under the CAA permitting programs. These stationary sources would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule sets thresholds for GHG emissions that define when the CAA permits under the NSR/PSD and the Title V Operating Permits programs are required for new or existing industrial facilities. The rule ~~"ta~~ilors" the requirements to limit which facilities will be required to obtain NSR/PSD and Title V permits and cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation's largest emitters (e.g., power plants, refineries, and cement production facilities).

For sources permitted between January 2, 2011 and June 30, 2011, the rule requires GHG permitting for only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHG) and that emit GHG emissions of at least 75,000 tpy. In addition, only sources required to have Title V permits for non-GHG pollutants will be required to address GHG as part of their Title V permitting (note: the 75,000 tpy CO_2-e limit does not apply to Title V). For sources constructed from July 1, 2011 to June 30, 2013, the rule requires PSD permitting for first-time new construction projects that emit GHG emissions of at least 100,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In addition, sources that emit or have the potential to emit at least 100,000 tpy CO_2-e and that undertake a modification that increases net emissions of GHG by at least 75,000 tpy CO_2-e will also be subject to PSD requirements. Under this scenario, operating permit requirements will for the first time apply to sources based on their GHG emissions, even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tpy CO_2-e will be subject to Title V permitting requirements. The proposed Project is not subject to PSD and would have emissions of CO_2-e less than

the applicable thresholds for any of the stationary sources (i.e., construction camp, tank farm, and surge relief tanks). Note that emissions from fugitive dust and mobile sources (on-road and non-road) are not included in the emission estimates for permit applicability of a stationary source. Consequently, the proposed Project would not be subject to the federal GHG permitting rule. EPA plans further rulemaking that would possibly reduce the permitting thresholds for new and modified sources making changes after June 30, 2013.

For further information on the cumulative impacts of GHG and climate change, refer to Section 3.14.

3.12.1.3 Potential Impacts and Mitigation

Construction Impacts

Air quality impacts associated with construction of the proposed Project would include emissions from fugitive dust, fossil-fuel fired construction equipment, open burning, and temporary fuel transfer systems and associated storage tanks.

Fugitive Dust

Fugitive dust is a source of respirable airborne particulate matter, including PM_{10} and $PM_{2.5}$. Fugitive dust results from land clearing, grading, excavation, concrete work, blasting and dynamiting, and vehicle traffic (including construction camp traffic) on paved and unpaved roads. The amount of dust generated is related to the type and duration of construction activities, silt and moisture content of the soil, wind speed, frequency of precipitation, vehicle traffic, vehicle types, and roadway characteristics. Fugitive dust generation would be greater in fine-textured soils during drier summer and autumn months.

Emissions of particulate matter arising from fugitive dust are regulated by state and local agencies. Typically, the regulations require measures to prevent particulates from becoming airborne, such as application of dust suppressants. Specific requirements can also include development and approval of a fugitive dust control plan. The Project would affect approximately 23,768 acres of land in six states during the construction phase. The majority of potential fugitive dust generation in a given location would occur within a 30-day construction period prior to final grading, seeding, and mulching of the ROW. Fugitive dust impacts during construction would therefore be temporary and localized.

Fugitive dust during construction would be controlled using BMPs such as applying water sprays and surfactant chemicals and quickly stabilizing disturbed areas (see CMR Plan, Appendix B). Additional dust control measures may be required by state or local ordinances.

Fossil-Fueled Construction Equipment

Construction camp generators, large earth-moving equipment, skip loaders, trucks, nonroad engines, and other mobile sources may be fueled by diesel or gasoline and are sources of combustion emissions, including NOx, CO, VOCs, SO_2, PM_{10}, $PM_{2.5}$, and small amounts of HAPs. Gasoline and diesel engines must comply with the EPA mobile source regulations in 40 CFR Part 86 for onroad engines and 40 CFR Part 89 and 90 for nonroad engines. EPA has established rules in 40 CFR 80 that require significant reductions in the sulfur content of diesel fuel used in onroad and off-road engines. As of June 1, 2006, 80 percent of diesel fuel for onroad use was required to have a sulfur content no greater than 15 ppm. As of June 1, 2007, diesel fuel for nonroad engines was required to have a sulfur content no greater than 500 ppm. As of December 1, 2010, EPA required that all on and off-road (nonroad) diesel fuel would not exceed 15 ppm sulfur (i.e., ultra low sulfur fuel).

The construction equipment listed in Table 3.12.1-8 would be used in a typical construction spread. The pipeline would be constructed in 17 construction spreads (Section 2.2.5). Each spread would require approximately 6 to 8 months to complete.

TABLE 3.12.1-8
Construction Equipment per Spread for the Project [a, b]

Equipment Description	Units per Spread	Equipment Rating (hp)	Hours of Operation (hours/day)	Fuel Type
Automobile	50	500	2	Gasoline/ Diesel
Bus	7	190	3	Diesel
Pickup 4x4	100	500	5	Gasoline/Diesel
Welding Rig	30	400	10	Gasoline/Diesel
Winch Truck	3	650	8	Diesel
Dump Truck	1	650	8	Diesel
Flatbed Truck	8	650	9	Diesel
Fuel Truck	2	650	9	Diesel
Grease Truck	1	1	9	Diesel
Mechanic Rig	1	500	10	Diesel
Skid Truck	1	650	10	Diesel
Stringing Tr. and Tr.	15	650	10	Diesel
Truck and Float	9	650	10	Diesel
Truck and Lowboy	5	650	10	Diesel
D-7 Dozer	12	240	8	Diesel
D-8 Dozer	22	310	8	Diesel
D-8 Ripper	0	310	0	Diesel
D-5 Tow	2	90/120	8	Diesel
D-7 Tow	1	200/240	8	Diesel
D-6 Tack	3	200	8	Diesel
CAT 225	7	150	8	Diesel
CAT 235	26	250	8	Diesel
CAT 235 w/Hammer	0-1	260	8	Diesel
Bending Machine 22-36	1	159	8	Diesel
Crane LS-98A (35 ton)	0-2	230	8	Diesel
Farm Tractor	2	60	8	Diesel
Frontend Loader 977	2	190	8	Diesel
Motor Grader 14G	2	200	8	Diesel
Sideboom 571	1	200	8	Diesel
Sideboom 572	1	200/230	8	Diesel
Sideboom 583	22	300/310	8	Diesel
Sideboom 594	4	410	8	Diesel
Air Compressor 1750 cfm	3-9	50	8	Gasoline

TABLE 3.12.1-8 Construction Equipment per Spread for the Project [a, b]				
Equipment Description	**Units per Spread**	**Equipment Rating (hp)**	**Hours of Operation (hours/day)**	**Fuel Type**
Generators	9	10	8	Gasoline
Pump – 3"	1	20	8	Gasoline
Pump - 6"	9	40	8	Gasoline

[a] In addition to the equipment listed above, ten 10-hp diesel or gasoline generators could be used per spread.

[b] Construction equipment listed in this table does not directly correlate to equipment listed in Table 2.4.2-1; however, total horsepower is similar for the purposes of the air emissions analysis. In addition, the list does not include generators proposed for construction camps (emissions from generators at construction camps are included in Table 3.12.1-9).

Source: Keystone 2009c; Keystone 2010a.

Four 400-kW generator engines would be installed at construction camps near Nashua and Baker, Montana, and Union Center and Winner, South Dakota if commercial electrical power is unavailable. If commercial electrical power is acquired, one 400-kW emergency back-up generator would still be installed at these locations. All fossil-fueled construction equipment would be maintained in accordance with manufacturer's recommendations to minimize construction-related emissions.

Open Burning

The burning of slash materials could be required along the route, although the quantities and locations cannot be determined prior to construction since actual slash materials may be burned, chipped, or hauled for disposal in a suitable landfill depending on construction conditions and landowner requirements.

Necessary permits for slash burning would be acquired prior to construction. Open burning regulations, including restrictions on burn location, material, and time, as well as consideration of local air quality, would be followed. Required burning would be done within the ROW in small piles to avoid damage to trees or other structures.

Temporary Fuel Transfer Systems and Associated Storage Tanks

Temporary fuel storage systems would be located at contractor yards and pipe yards. Although temporary fuel transfer systems and tanks have the potential to release VOC emissions, VOC releases would be minimal since low vapor pressure diesel fuels would be the primary fuel stored.

Summary

Estimates of construction emissions from the proposed Project are provided in Table 3.12.1-9. Construction air emissions typically would be localized, intermittent, and temporary since pipeline construction would move through an area relatively quickly. In addition, the total emissions listed in Table 3.12.1-9 would be the total from all of the 17 construction spreads along the proposed route. The localized emissions at each spread would be much less, likely no more than about 6 percent (1/17 of the values listed in Table 3.13.1-9). The temporary construction camps in Montana would likely trigger requirements for preconstruction permits and in South Dakota would likely trigger requirements for a minor operating permit unless exemptions apply for temporary nonroad engines. The construction-related emissions associated with the proposed Project would be temporary and localized and would not produce major long-term effects on local or regional air quality.

TABLE 3.12.1-9
Estimated Direct Construction Emissions for the Proposed Project

Emission Source	NOx (tons)	CO (tons)	VOC (tons)	SO_2 (tons)	PM (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	CO_2-e[a] (tons)
Construction emissions								
Construction camps[b]	494.4	432.6	46.4	33.0	24.7	24.7	24.7	108288.0
On-road vehicles	37.5	232.6	12.9	0.2	1.4	1.4	1.4	16094.3
Non-road equipment	596.4	697.4	51.0	25.2	25.0	25.0	25.0	85162.4
Open burning	19.8	1159.8	85.2	--	185.9	132.6	112.7	27433.0
Fugitive dust	--	--	--	--	1480.9	740.5	111.1	--
Paved road dust	--	--	--	--	117.8	18.5	1.9	--
Total construction emissions (3-yr combined)	**1148.1**	**2522.4**	**195.5**	**58.4**	**1835.7**	**942.7**	**276.8**	**236977.7**

[a] CO_2 equivalent is conservatively estimated by assuming all total organic compounds are methane and multiplying by 21 for the global warming potential (GWP) for methane.
[b] Construction camp emission estimates include four construction camps with four, 400-kW generator engines per camp operating for 2 years.

Notes:

NOx = Oxides of nitrogen.
CO = Carbon monoxide.
VOC = Volatile organic compounds.
SO_2 = Sulfur dioxide.
PM = Particulate matter.
PM_{10} = Particulate matter less than 10 microns in diameter.
$PM_{2.5}$ = Particulate matter less than 2.5 microns in diameter.
CO_2-e = Carbon dioxide equivalents.

Source: Keystone 2009c; Keystone 2010a.

Operations Impacts

Estimated air emissions associated with the operation of the proposed Project are provided in Table 3.12.1-10. Operational impacts would include minimal fugitive emissions from crude oil pipeline connections and pumping equipment at the pump stations, minimal emissions from mobile sources, and VOC and HAP emissions from the crude oil storage tanks at the Cushing tank farm and the surge relief tanks in Jefferson County, Texas. Pipeline pumps would be electrically powered. MLVs would have back-up generators for emergencies and upsets; therefore, emissions would be negligible.

Operational emissions for the Cushing tank farm were estimated assuming that each tank would have an internal self-supporting roof, that each tank would undergo 32 product turnovers annually and that each tank would have a mechanical shoe seal (primary) with no secondary seal. These estimated operational emissions suggest that the proposed Project would not cause or contribute to a violation of any federal, state, or local air quality standards, and also suggest that the proposed Project operations would not trigger the requirement for a Title V operating permit, although they would likely trigger the requirement for a preconstruction permit.

The proposed Project also includes operation of two surge relief tanks in Jefferson County, Texas. The tanks would have a capacity of 10,417 barrels each (435,514 gallons). The surge relief tanks would not trigger the requirement for a Title V operating permit, but would trigger the requirement for a preconstruction permit. Although located in a nonattainment area, the tanks would not trigger NSR review.

TABLE 3.12.1-10
Estimated Direct Operations Emissions for the Proposed Project

Emission Source	NOx (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	CO_2-e[a] (tpy)
Operating emissions								
Tank farm	--	--	43.23	--	--	--	--	--
Surge relief tanks[b]	--	--	16.02	--	--	--	--	--
Pump station fugitives[c]	--	--	6.82	--	--	--	--	84.63
On-road vehicles[d]	6.7E-05	1.5E-03	7.2E-05	8.0E-07	3.7E-02	5.8E-03	5.7E-04	4.3E-02
Total operating emissions	**6.7E-05**	**1.5E-03**	**66.07**	**8.0E-07**	**3.7E-02**	**5.8E-03**	**5.7E-04**	**84.63**

[a] CO_2 equivalent emission is conservatively estimated by assuming all total organic compounds are methane and multiplying by 21 for the global warming potential (GWP) for methane.

[b] Emissions are for 12 surge relief events per year.

[c] Pump station emissions include combined emissions from 30 pumping stations along the Steele City and Gulf Coast Segments. The CO_2 equivalent emissions listed for pump stations is for emissions from maintenance vehicles traveling to and from the pump stations. There are no CO_2 equivalent emissions from pump stations.

[d] The operational emissions noted from onroad vehicles include mobile emissions from the Cushing tank farm only.

Notes:

NOx = Oxides of nitrogen
CO = Carbon monoxide
VOC = Volatile organic compounds
SO_2 = Sulfur dioxide
PM = Particulate matter
PM_{10} = Particulate matter less than 10 microns in diameter
$PM_{2.5}$ = Particulate matter less than 2.5 microns in diameter
CO_2-e = Carbon dioxide equivalents

Source: Keystone 2009c; Keystone 2010a.

General Conformity

Section 176(c) of the CAA prohibits federal actions in nonattainment or PSD maintenance areas that do not conform to the relevant SIP for the attainment and maintenance of NAAQS. Therefore, the purpose of the General Conformity Determination is to provide that: (1) federal activities do not interfere with the emission budgets in the SIPs; (2) federal actions do not cause or contribute to new violations; and (3) the NAAQS are attained and maintained. Conformity can be demonstrated by showing: (1) that emission increases are allowed in the SIP; (2) that the state agrees to include emission increases in the SIP; (3) that no new violations of NAAQS, or that no increase in the frequency or severity of violations would occur; (4) that appropriate offsets exist; and (5) that mitigation is possible. Actions that are excluded from the General Conformity Determination include those already subject to NSR and those covered by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) or other environmental laws.

The proposed Project would cross five counties that are designated as nonattainment for the federal ozone standard. Liberty, Chambers, and Harris counties are counties located in the Houston-Galveston-Brazoria 8-hour ozone nonattainment area. This area is currently classified as severe nonattainment for the 1997 8-hour ozone standard and has a maximum target date to achieve attainment for this standard of June 15, 2019. Hardin and Jefferson counties are located in the Beaumont-Port Arthur 8-hour ozone nonattainment area. This area is currently classified as moderate nonattainment for the 1997 8-hour ozone standard and has a maximum target date to achieve attainment for this standard of June 15, 2010. EPA is making a final determination that the Beaumont-Port Arthur nonattainment area has attained the 1997 8-hour ozone NAAQS, based on complete, quality-assured, and certified ambient air quality

monitoring data for 2006–2008. Preliminary data available for 2009 and 2010, show that the area continues to attain the 1997 8-hour ozone NAAQS.

Emissions of ozone precursor compounds (NOx and VOCs) would be evaluated against the General Conformity applicability threshold levels and nonattainment area emissions budgets. Written approval of conformance with the SIP would be necessary for the proposed Project if estimated emissions are above the General Conformity applicability threshold levels (see Table 3.12.1-11 for estimated emissions).

TABLE 3.12.1-11
Estimated Emissions from Activities in Nonattainment Areas for the Proposed Project

Emission Source	NOx (tpy)	VOC (tpy)
Beaumont-Port Arthur 8-hour Moderate Ozone Nonattainment Area (Hardin and Jefferson Counties, Texas)		
Annual general conformity applicability threshold levels	**100**	**100**
Construction emissions - 2011		
Onroad equipment	3.94	1.45
Nonroad equipment	66.08	12.15
Open burning	4.75	22.29
Total construction emissions	74.78	35.89
Below thresholds?	Yes	Yes
Operating emissions - 2012		
Surge Relief Tanks[a]	--	16.02
Below thresholds?	Yes	Yes[a]
Houston-Galveston-Brazoria 8-hour Severe Ozone Nonattainment Area (Liberty, Harris, and Chambers Counties, Texas)		
Annual general conformity applicability threshold levels	**25**	**25**
Construction emissions - 2011		
Onroad equipment	2.51	0.94
Nonroad equipment	35.95	2.84
Open burning	1.50	7.01
Total construction emissions	39.96	10.79
Below thresholds?	**No**	Yes
Construction emissions - 2012		
Onroad equipment	3.87	1.33
Nonroad equipment	56.29	4.15
Open burning	5.25	24.64
Total construction emissions	65.41	30.12
Below thresholds?	**No**	**No**
Operating emissions - 2012		
(Pump station No. 41)	--	0.01
Below thresholds?	Yes	Yes

[a] Emissions of VOC are for 12 surge relief events per year.

Notes:
NOx = Oxides of nitrogen
VOC = Volatile organic compounds
tpy = Tons per year

Source: Keystone 2010a; Keystone 2010b.

As shown in Table 3.12.1-11, NOx emissions for both 2011 and 2012 construction and VOC emissions for 2012 construction in the Houston-Galveston-Brazoria 8-hour ozone nonattainment area would exceed the General Conformity threshold of 25 tons per year. The emissions calculations completed for the General Conformity Determination (Keystone 2010b) for nonroad mobile sources are conservative and based on EPA's Tier 2 engine standards. Various actions as part of the Texas SIP could be used to mitigate emissions during construction activity, including:

- Utilize construction contractors that participate in the Texas Emission Reduction Plan (TERP) grant program or require contractors to apply for TERP grant funds,
- Give preference through the bidding process to "Green/Clean" Contractors,
- Require construction contracts to use diesel fuels that meet the Texas Low Emission Diesel (TxLED) standards, and
- Require construction contractors to use Best Management Practices (BMP) in relation to air quality.

When determining if a project conforms to the relevant SIP, the emissions from the project are compared to the allowable emissions inventory to determine if the expected emissions increase can be accommodated in the SIP emissions budget. As discussed in the General Conformity Determination (Keystone 2010b), TCEQ staff reviewed the May 23, 2007 revision of the Houston/Galveston Area SIP for 8-Hour Ozone and determined the 2011 and 2012 compliance year emission inventories for the construction emissions category. TCEQ staff compared the estimated proposed Project construction emissions for both NOx and VOC to the SIP emissions budget for 2011 and 2012 and determined the emissions to be below the emissions budgets allocated to the construction emissions category. Therefore, construction emissions for the proposed Project should be accounted for in the SIP emissions budget and the proposed activities would not cause new violations of the standards and/or cause an increase in the frequency or severity of previous violations.

All other emissions for construction and operations in the Beaumont-Port Arthur and Houston-Galveston-Brazoria 8-hour ozone nonattainment areas would be below the General Conformity significance thresholds (Table 3.12.1-11). Therefore, construction and operation of the proposed Project in these areas are presumed to conform to the SIP.

3.12.1.4 Connected Actions

Power Distribution Lines and Substations

The following measures, and other BMPs, would be implemented by servicing electric cooperatives or their contractors in the modification or construction of electric distribution lines and substations:

- Servicing electric cooperatives or their contractors would utilize such practicable methods and devices as are reasonably available to control, prevent, and otherwise minimize atmospheric emissions or discharges of air contaminants. Dust control watering of access roads and work areas would occur during the project when air quality is compromised by construction activities. Disturbed areas would be scarified to facilitate natural revegetation, provide for proper drainage, and prevent erosion.
- Equipment and vehicles that show excessive emissions of exhaust gases due to poor engine adjustments, or other inefficient operating conditions, would not be operated until repairs or adjustments are made.

Big Bend to Witten 230-kV Transmission Line

The following measures, and other BMPs, would be implemented by servicing electric cooperatives or their contractors in the construction of Big Bend to Witten 230-kV transmission line:

- Servicing electric cooperatives or their contractors would utilize such practicable methods and devices as are reasonably available to control, prevent, and otherwise minimize atmospheric emissions or discharges of air contaminants. Dust control watering of access roads and work areas would occur during the project when air quality is compromised by construction activities. Disturbed areas would be scarified to facilitate natural revegetation, provide for proper drainage, and prevent erosion.
- Equipment and vehicles that show excessive emissions of exhaust gases due to poor engine adjustments, or other inefficient operating conditions, would not be operated until repairs or adjustments are made.

Bakken Marketlink Project

The Bakken Marketlink Project would include the construction of facilities to provide crude oil transportation service from near Baker, Montana to Cushing, Oklahoma via the proposed Project and from Cushing to delivery points at Nederland and Moore Junction, Texas via the proposed Project. The Bakken Marketlink Project would consist of piping, booster pumps, meter manifolds, and two tank terminals; one terminal would be at or near Baker, Montana, and the second would be at the proposed Cushing tank farm. The tank farm near Baker would consist of two, 250,000-barrel tanks that would be used to accumulate crude from connecting third-party pipelines and terminals and a 100,000-barrel tank that would be used for operational purposes. The Bakken Marketlink facilities at the Cushing tank farm would consist of two 250,000-barrel tanks that would be used for batch accumulation from the Baker facilities. The project would result in air emissions from construction and operation, but the extent of air emissions is unknown at this time. Consequently, air quality permitting and compliance efforts will be handled separately by appropriate regulatory agencies. The applicable federal, state, and local regulations would be followed to achieve compliance with air quality requirements.

Cushing Marketlink Project

The Cushing Marketlink Project would include construction and operation of facilities that would provide crude oil transportation service from Cushing, Oklahoma via the proposed Project to delivery points at Nederland and Moore Junction, Texas. The project would include construction and operation of metering systems and batch accumulation tankage consisting of two 350,000 barrel tanks, with one tank dedicated for light sweet crude. The tanks would be located within the proposed Project's Cushing tank farm property, which also would house Pump Station 32. The Cushing Marketlink Project would result in air emissions from construction and operation, but the extent of air emissions is unknown at this time. Consequently, air quality permitting and compliance efforts will be handled separately by appropriate regulatory agencies. The applicable federal, state, and local regulations would be followed to achieve compliance with air quality requirements.

3.12.2 Noise

3.12.2.1 Environmental Setting

The ambient sound level of a region is defined by the total noise generated within the specific environment and is usually comprised of sound emanating from natural and artificial sources. At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions and the effects of seasonal vegetative cover.

The proposed Project would be constructed in primarily rural agricultural areas of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. It is estimated that the existing ambient noise level in the proposed Project area is in the range of 40 dBA (rural residential) to 45 dBA (agricultural cropland). Ambient (background) noise levels occur from roadway traffic, farm machinery on a seasonal basis, pets, and various other household noises. Areas of the proposed Project along major highways and interstates may experience higher ambient noise levels of approximately 68 dBA to 80 dBA (EPA 1978). These are assumed noise levels.

Noise Receptors near the Pipeline ROW

Aerial photography and field survey data were used to identify areas containing structures within 25 feet and 500 feet of the proposed pipeline centerline (Table 3.12.2-1). There are approximately 170 structures within 25 feet and 2,325 structures within 25 feet to 500 feet of the proposed ROW. Of those totals, there are approximately 29 residences (i.e., homes, mobile homes, cabins) within 25 feet and 788 residences within 25 feet to 500 feet of the proposed ROW. For additional discussion of structures close to the ROW, see Section 3.9.1.2.

TABLE 3.12.2-1
Structures near the Proposed Project Construction ROW

State	County	Number of Structures within 25 feet of the Construction ROW		Number of Structures ≤ 500 feet and > 25 feet from the Construction ROW	
		Structures [a]	Residences [b]	Structures [a]	Residences [b]
Steele City Segment					
Montana	Phillips	0	0	9	2
	Valley	2	0	38	3
	McCone	2	0	21	0
	Dawson	3	0	21	0
	Prairie	0	0	3	0
	Fallon	2	0	25	2
South Dakota	Harding	3	0	19	0
	Butte	0	0	0	0
	Perkins	1	0	3	0
	Meade	2	0	22	0
	Pennington	0	0	0	0
	Haakon	4	0	26	0

TABLE 3.12.2-1
Structures near the Proposed Project Construction ROW

State	County	Number of Structures within 25 feet of the Construction ROW		Number of Structures ≤ 500 feet and > 25 feet from the Construction ROW	
		Structures [a]	Residences [b]	Structures [a]	Residences [b]
	Jones	0	0	3	0
	Lyman	1	0	9	0
	Tripp	4	0	14	0
Nebraska	Keya Paha	2	0	3	0
	Rock	0	0	2	0
	Holt	3	0	11	0
	Garfield	0	0	0	0
	Wheeler	1	0	4	0
	Greeley	0	0	8	1
	Boone	0	0	0	0
	Nance	0	0	11	0
	Merrick	7	0	25	1
	Hamilton	1	0	5	0
	York	1	0	28	1
	Fillmore	1	0	22	0
	Saline	1	0	13	0
	Jefferson	0	0	18	2
Kansas	NA	0	0	0	0
Gulf Coast Segment					
Oklahoma	Lincoln	4	0	91	26
	Creek	0	0	0	0
	Okfuskee	7	0	61	20
	Seminole	6	1	51	13
	Hughes	7	2	88	26
	Coal	1	0	56	17
	Atoka	1	0	50	18
	Bryan	2	1	51	13
Texas	Fannin	0	0	1	1
	Lamar	7	1	89	24
	Delta	6	2	41	13
	Hopkins	7	0	78	29
	Franklin	4	2	68	32
	Wood	2	1	140	65
	Upshur	7	1	31	10
	Smith	16	9	258	142

TABLE 3.12.2-1 Structures near the Proposed Project Construction ROW					
		Number of Structures within 25 feet of the Construction ROW		Number of Structures ≤ 500 feet and > 25 feet from the Construction ROW	
State	County	Structures [a]	Residences [b]	Structures [a]	Residences [b]
	Cherokee	1	0	33	9
	Rusk	10	2	44	17
	Nacogdoches	5	1	123	45
	Angelina	2	1	80	34
	Polk	9	4	112	43
	Liberty	4	0	76	28
	Hardin	5	0	15	5
	Jefferson	6	1	221	78
Houston Lateral					
Texas	Liberty	6	0	66	37
	Chambers	0	0	2	1
	Harris	4	0	41	30

[a] Structure totals include residences, homes, cabins, mobile homes, power poles, pools, wells, damns, bridges, barns, garages, churches, etc.

[b] Residence totals include residences, home, cabins, and mobile homes.

Source: Keystone 2009d.

Noise Receptors near Pump Stations

There are approximately 197 structures within 0.5 mile of proposed Project pump stations (Table 3.12.2-2). Prior to construction, the presence of structures in proximity to the proposed Project pump stations would be verified and residential occupancy would be determined.

TABLE 3.12.2-2 Structures within 0.5 and 1 Mile of Proposed Project Pump Stations			
Pump Station No.	Milepost (0 at US border)	Number of Structures within One-half Mile[a]	Number of Structures within One Mile[a]
Steele City Segment			
Montana			
PS-09	1.3	5	15
PS-10	49.5	0	4
PS-11	98.4	6	11
PS-12	149.1	0	13
PS-13	199.6	0	10
PS-14	237.1	0	9

TABLE 3.12.2-2
Structures within 0.5 and 1 Mile of Proposed Project Pump Stations

Pump Station No.	Milepost (0 at US border)	Number of Structures within One-half Mile[a]	Number of Structures within One Mile[a]
South Dakota			
PS-15	285.6	0	0
PS-16	333.6	0	1
PS-17	387.3	0	7
PS-18	440.1	1	5
PS-19	496.0	4	15
PS-20	546.7	14	26
PS-21	591.9	5	23
Nebraska			
PS-22	642.4	3	19
PS-23	694.9	15	24
PS-24	752.1	16	32
PS-25	800.8	4	9
PS-26	851.6	5	47
Keystone Cushing Extension			
Kansas			
PS-27	49.7	15	32
PS-29	144.6	0	14
Gulf Coast Segment			
Oklahoma			
PS-32	0.0	13	41
PS-33	49.0	7	43
PS-34	95.4	0	26
PS-35	147.4	19	49
Texas			
PS-36	194.5	0	41
PS-37	238.6	25	92
PS-38	284.0	19	89
PS-39	338.1	4	4
PS-40	380.5	0	106
PS-41	435.1	17	88

[a] Structure totals include residences, homes, cabins, mobile homes, power poles, pools, wells, damns, bridges, barns, garages, churches, etc.

Source: Keystone 2009c.

3.12.2.2 Regulatory Requirements

Two measurements used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level (Leq(24)) and the day-night sound level (Ldn). The Leq(24) is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The Ldn is the Leq(24) with 10 decibels on

the A-weighted decibel scale (dBA) added to nighttime sound levels between the hours of 10 p.m. and 7 a.m. to account for people's greater sensitivity to sound during nighttime hours.

In 1974, EPA published "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety." This document provides information for state and local agencies to use in developing their ambient noise standards. EPA identified outdoor and indoor noise levels to protect public health and welfare. An Leq(24) of 70 dB was identified as the level of environmental noise that would prevent any measurable hearing loss over a lifetime. An Ldn of 55 dBA outdoors and an Ldn of 45 dBA indoors were identified as noise thresholds that would prevent activity interference or annoyance. These levels are not "peak" levels but are 24-hour averages over several years. Occasional high levels of noise may occur. An Ldn of 55 dBA is equivalent to a continuous noise level of 48.6 dBA. Typical noise levels are as follows:

- Quiet room: 28–33 dBA
- Computer: 37–45 dBA
- Refrigerator: 40–43 dBA
- Forced hot air heating system: 42–52 dBA
- Microwave: 55–59 dBA
- Clothes dryer: 56–58 dBA

With regard to increases in decibels measured on the A-weighted noise level scale, the following relationships occur:

- A change of 1 dBA cannot be perceived by humans, except in carefully controlled laboratory environments;
- Outside of the laboratory, a 3-dBA change is considered a just-perceivable difference by humans;
- A change in level of at least 5 dBA is required before any noticeable change in human response would be expected; and
- A 10-dBA change is subjectively heard as approximately a doubling in loudness and can cause an adverse response.

None of the states that would be traversed by the proposed Project have a different regulatory noise limit, although many have local ordinances governing noise from construction or industrial activities.

3.12.2.3 Potential Impacts and Mitigation

Construction Impacts

Construction of the proposed Project would be similar to other pipeline projects in terms of schedule, equipment used, and types of activities. Construction would increase noise levels in the vicinity of project activities, and the noise levels would vary during the construction period, depending on the construction phase. Construction noise levels are rarely steady in nature, but instead fluctuate depending on the number and type of equipment in use at any given time. There would be times when no large equipment is operating and noise would be at or near ambient levels. In addition, construction-related sound levels experienced by a noise sensitive receptor in the vicinity of construction activity would be a function of distance.

Pipeline construction generally proceeds at a rate of approximately 20 completed miles per calendar month per spread. However, due to the assembly-line method of construction, pipeline construction activities in any one area could last from 7 weeks to 30 days. Construction of all pump stations would take approximately 18 to 24 months complete, and construction of the Cushing tank farm would take approximately 15 to 18 months. Construction related noise impacts typically would be localized, intermittent, and short term since construction spreads move relatively quickly (several hundred feet to 1.5 miles or more per day).

Residential, agricultural, and commercial areas within 500 feet of the ROW would experience temporary inconvenience from the construction equipment noise (Table 3.12.2-3).

TABLE 3.12.2-3
Typical Noise Levels for Construction Equipment

Equipment	Typical Noise Levels (dBA, at 50 feet)
Front loaders	85
Backhoes, excavators	80
Tractors, dozers	85
Graders, scrapers	85–89
Trucks	88
Concrete pumps, mixers	82–85
Cranes (movable)	83
Cranes (derrick)	88
Pumps	76
Generators	81
Compressors	81
Pneumatic tools	85
Jack hammers, rock drills	88–98
Pavers	89
Compactors	82

Source: Adapted from DOT 2006.

There are approximately 29 residences within 25 feet of the proposed ROW, and 788 residences within 25 to 500 feet of the proposed ROW (Table 3.12-2.1). Depending on actual distances between construction activity and receptors, construction noise levels could reach over 100 dBA. However, the exact value would depend on the number of sources operating at this close distance. These noise levels could be perceived as moderately loud with a significant to serious effect over existing levels, however, any peak noise levels would be temporary and intermittent, generally limited to daylight hours, and would be attenuated with distance.

Although individuals and livestock in the immediate vicinity of the construction activities may be temporarily disturbed, the impact on the noise environment at any specific location along the proposed pipeline route would be short term. Similarly, noise associated with construction of the proposed aboveground facilities would be intermittent during the construction period, but the overall impact would be temporary and is not expected to be significant. Further, nighttime noise levels would normally be unaffected because most construction activities would be limited to daylight hours. Potential exceptions

include completion of critical tie-ins on the ROW; HDD operations if determined by the contractor to be necessary; and other work if determined necessary based on weather conditions, safety, or other project requirements. HDD activities would be conducted consistent with any applicable local noise ordinances.

Noise impacts from construction would be mitigated in accordance with the proposed Project CMR Plan (Appendix B) to minimize effects on individuals, sensitive areas, and livestock. If local noise regulations exist, site-specific noise mitigation plans would be developed to comply with any specific regulations and any applicable authorizations or variances would be obtained. Noise mitigation plans would be provided to the construction contractors for implementation and would be enforced by construction inspectors using portable sound meters.

To ensure that residential and commercial areas within 500 feet of construction activities are not affected by noise levels, advanced notice would be provided to landowners prior to construction activities with high-decibel noise levels would be limited to specified hours, and work schedules would be coordinated so that construction proceeds quickly. In the event that the contractor expects noise levels to exceed regulated noise standards—based on the types of construction equipment used or construction procedures, immediate noise attenuation would be implemented. To further reduce noise impacts to residential and commercial areas a toll-free telephone number would be provided for landowners to report any construction noise-related issues.

It is understood that during occasional, short-term intervals, noise levels would exceed 55 dBa. There are no regulations in rural areas along the pipeline route applicable to construction noise, including noise from construction camps. In municipal areas, pipeline construction noise levels would comply with any applicable municipal regulations. In areas near residences and businesses where construction activities or noise levels may be considered disruptive, work schedules would be coordinated to minimize disruption.

Operations Impacts

Noise impacts from operation of the pipeline would be from the pump stations. Crude oil traveling through the buried pipeline would not emit audible noise above the surface nor would there be perceptible levels of vibration associated with crude oil movement through the pipeline. MLVs would have back-up generators for emergencies and upsets; however, noise impacts would be infrequent and negligible.

Concern was expressed during the comment period on the draft EIS relative to the potential for noise generation by proposed Project pump stations, particularly given the generally rural nature of the area within which the pump stations would be constructed and operated. During operation of the pipeline, the noise associated with the electrically-driven pump stations would be limited to the vicinity of the facilities. A preliminary noise assessment survey for a typical pump station was conducted (Table 3.12.2-4). The assessment assumed wind speeds of 8 miles per hour, a temperature of 75 ˚F, and three pumps operating at 3,000 kW cumulative (proposed installation is 2 to 6 pumps rated at 6,500 hp each per pump station).

TABLE 3.12.2-4 Sound Attenuation from Proposed Project Pump Stations	
Distance (feet)	**Sound Level (dBA)**
Background	35
300	55
700	49
1,000	46
1,300	43
1,600	42
2,000	41
2,300	40
2,600	39
3,000	38
3,300	38
3,600	38
3,900	37
4,200	37
4,600	37
5,000	37

Source: Keystone 2009a.

The study indicated that sound levels would attenuate to nearly ambient noise levels (40 to 45 dBA) within 2,300 feet of the facility (Table 3.12.2-4). There are approximately 197 structures within 0.5 mile (2,640 feet) of proposed Project pump stations (Table 3.12-2.2). Prior to construction, the presence of structures in proximity to the proposed Project pump stations would be verified and residential occupancy would be determined. Although noise impacts from the electrically-powered pump stations are projected to be minor, noise assessment surveys would be performed during operations in locations where nearby residents express concerns about pump station noise. These surveys would indicate operational noise levels and would be used to determine any necessary noise abatement measures to reduce noise to acceptable levels. Mitigation measures could include construction of berms or vegetation screens around specific pump stations that would serve as noise barriers.

3.12.2.4 Connected Actions

Power Distribution Lines and Substations

The following measures, and other BMPs, would be implemented by servicing electric cooperatives or their contractors in the modification or construction of electric transmission lines:

- Mitigation measures to reduce noise during construction as required by local, state, or federal regulations which may include 1) locating construction equipment as far from sensitive receptors as possible, 2) turning off equipment when not in use and reducing idling time, 3) use of temporary equipment enclosures and noise barriers, 4) limit haul trips and construction to

daylight hours where feasible, and 5) use of best available noise control techniques such as mufflers, intake silencers, ducts, engine closures, and acoustically attenuating shields or shrouds for all construction equipment and trucks.

- Mitigation measures to reduce noise during operation, including but not limited to siting of power lines 500 feet or further from residences and the use of C-filters on communication systems. Additional mitigation, such as the use of lightning arrestors and assuring all hardware has a tight fit, are used to reduce Radio Frequency Interference (RFI), which also contributes to a reduction in corona noise.

Big Bend to Witten 230-kV Transmission Line

The following measures, and other BMPs, would be implemented by servicing electric cooperatives or their contractors in the construction of Big Bend to Witten 230-kV transmission line:

- Mitigation measures to reduce noise during construction as required by local, state, or federal regulations which may include 1) locating construction equipment as far from sensitive receptors as possible, 2) turning off equipment when not in use and reducing idling time, 3) use of temporary equipment enclosures and noise barriers, 4) limit haul trips and construction to daylight hours where feasible, and 5) use of best available noise control techniques such as mufflers, intake silencers, ducts, engine closures, and acoustically attenuating shields or shrouds for all construction equipment and trucks.
- Mitigation measures to reduce noise during operation, including but not limited to siting of power lines 500 feet or further from residences and the use of C-filters on communication systems. Additional mitigation, such as the use of lightning arrestors and assuring all hardware has a tight fit, are used to reduce Radio Frequency Interference (RFI), which also contributes to a reduction in corona noise.

Bakken Marketlink Project

Construction and operation of the Bakken Marketlink Project would include metering systems, three new storage tanks near Baker, Montana, and two new storage tanks within the boundaries of the proposed Cushing tank farm. The Bakken Marketlink project would result in noise during operations and construction, but the extent of noise effects is unknown at this time. Consequently, federal, state, and local regulations would be followed to achieve compliance with applicable noise requirements.

Cushing Marketlink Project

The Cushing Marketlink project would be located within the boundaries of the proposed Cushing tank farm of the Keystone XL Project and would include metering systems and two storage tanks. The Cushing Marketlink project would result in noise during operations and construction, but the extent of noise effects is unknown at this time. However, the increase in sound levels over the sound levels produced by the proposed Cushing tank farm and Pump Station 32 is not expected to be substantial. Federal, state, and local regulations would be followed to achieve compliance with applicable noise requirements.

3.12.3 References

DOT. See U.S. Department of Transportation.

EPA. See U.S. Environmental Protection Agency.

FTA. See Federal Transit Administration.

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3.13 POTENTIAL RELEASES FROM PROJECT CONSTRUCTION AND OPERATION AND ENVIRONMENTAL CONSEQUENCE ANALYSIS

This section addresses the potential for and consequences of oil products or crude oil releases that could occur during construction and operation of the proposed Project. The analyses presented in the draft EIS were revised based on comments on the draft EIS and updated information or information unavailable at the time the draft EIS was issued. This information includes the most recent PHMSA incident databases for hazardous liquid pipelines.

Safety regulatory requirements and standards, the risk of crude oil and oil product releases, and the environmental consequences of those potential releases are addressed in the following subsections:

- Pipeline Safety Considerations (Section 3.13.1);
- Potential Types of Releases and Volumes from Project Construction and Operation (Section 3.13.2);
- Potential Releases During Project Construction (Section 3.13.3);
- Potential Releases from Project Operations (Section 3.13.4);
- Impacts Related to Oil Spills (Section 3.13.5); and
- Resource-Specific Impacts (Section 3.13.6).

3.13.1 Pipeline Safety Considerations

3.13.1.1 Pipeline Safety Standards and Regulations

U.S. Department of Transportation Regulations

USDOT is mandated to regulate pipeline safety under Title 49, USC Chapter 601. PHMSA is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation‘s pipelines. Through PHMSA, the USDOT develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation‘s 2.3-million-mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air. PHMSA administers the national regulatory program to ensure the safe transportation of hazardous liquids, including crude oil, by pipeline. PHMSA develops regulations that address safety in the design, construction, testing, operation, maintenance, and emergency response for hazardous liquid pipelines and related facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operators to use various technologies to achieve the required level of safety. PHMSA is responsible for regulations that require safe operations of hazardous liquid pipelines to protect human health and the environment from unplanned pipeline incidents.

The regulations governing pipeline safety are included in 49 CFR Parts 190 through 199. Parts 190, 194, 195, 198, and 199 are relevant to hazardous liquid (including crude oil) pipelines. Individual states are permitted to adopt additional or more stringent safety regulations for intrastate pipelines. Parts 190, 198, and 199 address issues that are tangential to pipeline system integrity. The regulations at 49 CFR 190 (Pipeline Safety Programs and Rulemaking Procedures) describe the pipeline safety programs and rulemaking procedures used by PHMSA in carrying out its regulatory duties, authorize PHMSA to inspect pipelines, describe the procedures by which PHMSA can enforce the regulations, and describe the

legal rights and options of the operating companies in response to PHMSA enforcement actions. The regulations at 49 CFR 198 (Regulations for Grants to Aid State Pipeline Safety Programs) prescribe regulations for grants to aid state pipeline safety compliance programs. The regulations at 49 CFR 199 (Drug and Alcohol Testing) require operators of natural gas, liquefied natural gas, and hazardous liquid pipeline facilities to establish programs for preventing alcohol misuse and to test employees for the presence of alcohol and prohibited drugs.

Regulations that are more directly related to pipeline system integrity and the associated oil spill risk assessment and environmental consequences analyses are addressed in the following paragraphs. The regulations at 49 CFR 194 (Response Plans for Onshore Oil Pipelines) contain requirements for onshore oil spill response plans (the PSRP described in Section 2.4.2.2) that are intended to reduce the environmental impact of oil unintentionally discharged from onshore oil pipelines. Additional information on the requirements of 49 CFR 194 is presented later in this section.

The regulations at 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) include the design, construction, operation, and maintenance safety standards and reporting requirements for pipelines that transport hazardous liquids, including crude oil. Subparts of 49 CFR 195 include:

- Subpart A: General;
- Subpart B: Annual Accident and Safety-Related Condition Reporting;
- Subpart C: Design Requirements;
- Subpart D: Construction;
- Subpart E: Pressure Testing;
- Subpart F: Operation and Maintenance;
- Subpart G: Qualification of Pipeline Personnel; and
- Subpart H: Corrosion Control.

The regulations at Subpart A, Section 195.6 define unusually sensitive areas (USAs) as public drinking water or ecological resource areas.

The regulations at Subpart C include specifications for determination of the internal pressure acceptable in relationship to other design parameters (Part 195.106).

The regulations at Subpart F include requirements for marking, inspecting, and maintaining pipelines and the regulations at Subpart F, 49 CFR 195.260 (e) require a valve on either side of water crossings that are more than 100 feet across (as measured from high water marks). The regulations at Subpart F, Section 195.452 specify pipeline integrity management requirements in high-consequence areas (HCAs). An HCA is defined as:

- A commercially navigable waterway, which means a waterway where a substantive likelihood of commercial navigation exists;
- A high population area, which means an urbanized area—as defined and delineated by the U.S. Census Bureau—that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

- Any other populated area, which means a place—as defined and delineated by the U.S. Census Bureau—that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; or
- An unusually sensitive area (USA) — defined in 49 CFR Part 195.6 as public drinking water or ecological resource areas that are unusually sensitive to environmental effects from hazardous liquid pipeline releases.

Drinking water USAs are a subset of all surface water intakes and groundwater-based drinking water supplies, including public water systems, public water supplies from source water protection areas/wellhead protection areas, and sole-source aquifers. Specifically, drinking water USAs include:

- The surface water intakes for community water systems and non-transient non-community water systems that do not have an adequate alternative drinking water source;
- The source water protection areas for community water systems and non-transient, non-community water systems that obtain their water supply from a Class I or Class IIA aquifer and do not have an adequate alternative drinking water source. If the source water protection area is not available, the wellhead protection areas become the USA; and
- The aquifer recharge area for sole-source aquifers within karst terrains.

For a new hazardous liquid pipeline, the regulations at 49 CFR 195.452 require that HCAs be identified prior to operation and that a written Integrity Management Plan (IMP) be in place within 1 year of the start of operation. The HCA regulation also requires that operators of new hazardous liquid pipelines complete baseline assessments by the start date for pipeline operation. Keystone would conduct a baseline assessment consisting of hydrostatic testing and a caliper/geometry pig inspection prior to the proposed pipeline‘s operation. Keystone also prepared a pipeline risk assessment that comprises incident frequencies and potential spill volumes and fulfills the risk analysis requirements for HCAs (see Appendix P). The pipeline risk assessment summarizes Keystone‘s estimate of pipeline miles within various types of HCAs. More detailed analyses would be conducted by Keystone as part of the IMP process that would occur prior to proposed Project operation. PHMSA would review the proposed pipeline‘s IMP and would conduct periodic inspections of the pipeline during operation. Keystone must implement preventive and mitigating measures to protect each HCA from the consequences of a pipeline failure and release of oil.

Additional actions that may be required include the following:

- Implementing damage prevention Best Management Practices (BMPs);
- Implementing more thorough programs to monitor cathodic protection where corrosion is a concern;
- Establishing shorter inspection intervals;
- Installing emergency flow restriction devices on the pipeline segment;
- Modifying systems that monitor pressure and detect leaks; and
- Providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

The regulations at 49 CFR 195 Subpart G include minimum operator qualification requirements for individuals performing tasks required by the regulations, and Subpart H specifies corrosion control requirements.

As described in Section 2.4.2.2, 49 CFR 195.40 requires that an operations manual be developed that addresses abnormal operations for the proposed Project. Keystone developed an ERP for the Keystone Oil Pipeline Project that addresses these requirements (see Appendix C). Keystone has stated that this ERP would serve as the template for an ERP for the proposed Project and Project-specific information would be inserted into that plan as it becomes available (see Section 2.4.2.2).

PHMSA Special Conditions

At the time of publication of the draft EIS, Keystone had applied to PHMSA for consideration of a Special Permit request that if approved, would have allowed Keystone to operate the proposed Project at a slightly higher pressure than would be allowed using the standard design factor (maximum pressure not to exceed 72 percent of the pipe specified minimum yield strength [SMYS]) specified in 49 CFR 195.106. As a part of consideration of the application for a Special Permit, PHMSA initiated development of Special Conditions that, if the permit were granted, would have allowed Keystone to operate the Project at a maximum operating pressure higher than that specified in 49 CFR 195.106. However, on August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit.

After the application was withdrawn, DOS continued to work with PHMSA and Keystone to develop Special Conditions that could be applied to the proposed Project in response to comments received about pipeline construction, operation, and maintenance. Ultimately, a set of 57 Special Conditions was established (presented in Appendix U) and Keystone agreed that if the Presidential Permit is granted, it would incorporate those conditions into the proposed Project and in its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402. PHMSA has the legal authority to inspect and enforce any items contained in a pipeline operator‘s operations, maintenance, and emergencies manual, and would therefore have the legal authority to inspect and enforce the 57 Special Conditions if the proposed Project is approved. DOS, in consultation with PHMSA, has determined that incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450.

Standards and Regulations for Affected States

Oversight and inspections of interstate hazardous liquid pipelines are carried out by PHMSA with the assistance of state agencies in the states where PHMSA and the state have a cooperative agreement. In all states that would be crossed by the proposed pipeline, PHMSA regulates, inspects, and enforces interstate liquid pipeline safety requirements. States may adopt regulations with requirements that supplement or exceed federal requirements for intrastate pipelines only.

All states that would be crossed by the proposed Project have adopted state one-call systems to reduce the potential for third-party damage to utilities, including pipelines, during activities that involve excavation or soil boring. During construction and operation, contractors and the operator would be required to use the one-call system in each state to reduce the risk of damage to existing subsurface utilities.

Industry Standards

The proposed Project pipeline design would comply with pertinent industry standards. These industry standards could change if PHMSA adopts updated versions of the standards referenced in 49 CFR 195.3. Standards that would be complied with include the following:

- American Society of Mechanical Engineers (ASME)/American National Standards Institute (ANSI) Code B31.4, "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols." This standard addresses requirements for materials of construction welds, inspection, and testing for cross-country hazardous liquid pipelines. ASME B31.4 434.15.2 (a) requires mainline block valves on the upstream side of major river crossings and public water supply reservoirs, and either a block valve or a check valve on the downstream side. 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipelines," has incorporated ASME/ANSI B31.4 code by reference.
- ANSI Standards CSA Z662-03 and Z662.1-03. This standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey various fluids, including crude oil.
- American Petroleum Institute (API) 570, "Piping Inspection Code–Inspection, Repair, Alteration, and Re-Rating of In-Service Piping Systems." This code was developed for the petroleum refining and chemical processing industries but may be used for any piping system.
- API RP 1102, "Recommended Practices for Liquid Petroleum Pipelines Crossing Railroads and Highways." This recommended practice is a requirement of ASME/ANSI B31.4.
- API RP 1109, "Recommended Practice for Marking Liquid Petroleum Pipeline Facilities." ASME/ANSI B31.4 advises that this API RP 1109 shall be used as a guide.
- NACE RP 0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." ASME/ANSI B31.4 refers to sections of this recommended practice as a guide for an adequate level of cathodic protection.
- Other documents or portions thereof pertaining to transportation of hazardous liquids and incorporated by reference in 49 CFR 195.3.

Storage tanks associated with the proposed Project or the Bakken Marketlink and Cushing Marketlink connected actions, as well as surge tanks at delivery points in Texas would be designed and constructed in accordance with relevant standards listed in 49 CFR 195. Additionally, Keystone has agreed to incorporate into the proposed Project specifications a set of Project-specific conditions developed by PHMSA (Appendix U). These Special Conditions incorporate the requirements of the following industry standards:

- API Specification 5L, Specification for Line Pipe, 44th Edition. API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture;
- ASTM International A578/A578M Level B or equivalent. Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications;
- API 1104, *"Welding of Pipelines and Related Facilities."* API 1104 covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the compression, pumping, and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, nitrogen and, where applicable, covers welding on distribution systems. It applies to both new construction and in-service welding. This standard also covers the procedures for radiographic, magnetic particle, liquid penetrant, and ultrasonic testing, as well as the acceptance standards to be applied to production welds tested to destruction or inspected by radiographic, magnetic particle, liquid penetrant, ultrasonic, and visual testing methods;
- API Recommended Practice 1165 *(First Edition)*, *Recommended Practice for Pipeline SCADA Displays;*

- API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines,* (API RP 1130, 1st Edition 2007);
- ASME Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006;
- API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators,* (API RP 1162 (1st edition, December 2003) or the most recent version incorporated in 195.3);
- Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual;
- NACE International RP 0169 (2002 or the latest version incorporated by reference in 195.3) and 0177 (2007 or the latest version referenced through the appropriate NACE standard incorporated by reference in 195.3) (NACE RP 0169 and NACE RP 0177) for interference current levels. NACE RP 0169 was described earlier. NACE RP 0177 addresses mitigation of alternating current and lightning effects on metallic structures and corrosion control systems;
- NACE International RP 0502-2002 (NACE RP 0502-2002) Pipeline External Corrosion Direct Assessment Methodology, or the latest version incorporated by reference in 195.3;
- PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Liquid Pipelines" dated October 6, 2009; and
- The Common Ground Alliance's damage prevention best practices applicable to pipelines.

Summary

As a result of incorporation of the current PHMSA regulations, current industry standards, and the set of 57 Project-specific Special Conditions developed by PHMSA and agreed to by Keystone, the proposed Project would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

3.13.1.2 U.S. Pipeline Spill Incident History

PHMSA Pipeline Incident Statistics

Incidents that result in unintentional releases from hazardous liquid pipelines, which includes crude oil pipelines, are reported to PHMSA on standard forms in accordance with 49 CFR 195.50. PHMSA maintains a database of pipeline incident reports (available online at: http://primis.phmsa.dot.gov/comm/reports/safety/psi.html). Pipeline incident reports encompass onshore and offshore natural gas and hazardous liquid pipelines. In addition to crude oil pipelines, hazardous liquid pipelines include pipelines that transport oil products, liquefied petroleum gas (LPG), anhydrous ammonia, and other hazardous liquids.

The PHMSA database of hazardous liquid pipeline incidents includes incidents categorized as "significant." Significant hazardous liquid pipeline safety incidents include those that meet one or more of the following criteria:

- Spills releasing 2,100 gallons (50 barrels [bbl])[1] or more;
- Spills of 210 gallons (5 bbl) of highly volatile liquid[2];

[1] 1 bbl equals 42 U.S. gallons. Oil volumes are provided in gallons followed by bbl in this EIS.

- Spills resulting in total costs of $50,000 or more (1984 dollars);
- Spills that result in unintentional fire or explosion; or
- Incidents involving a fatality or an injury requiring in-patient hospitalization.

PHMSA defines a ―serious" pipeline incident as one that involves a fatality or an injury requiring in-patient hospitalization. As noted above, significant incidents include all serious incidents.

The PHMSA incident database includes summary tables that provide overviews of serious and significant incidents reported over the last 20 years, ending in 2010. Prior to 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 2,100 gallons (50 bbl). As of 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 5 gallons (0.1 bbl). Therefore PHMSA data prior to 2002 likely understate the actual number of incidents and lead to over estimates of average spill volumes.

Table 3.13.1-1 presents the average number of serious incidents in a year for hazardous liquid pipeline operators (combined onshore and offshore pipeline incidents). The summary data indicate a decreasing temporal trend in the annual average number of serious pipeline incidents. These data include 93 serious incidents reported for 20 years, from 1991 to 2010.

TABLE 3.13.1-1
Nationwide Onshore and Offshore Hazardous Liquid Pipeline Systems, Annual Averages for Serious Incidents[a]

Time Period	Annual Average Serious Incidents per Period
5-year average (2006–2010)	3
10-year average (2001–2010)	3
20-year average (1991–2010)	5

[a] Incidents involving a fatality or an injury requiring in-patient hospitalization.
Source: PHMSA 2011.

The average number of significant incidents per year for onshore hazardous liquid pipelines from 1991 through 2010 is presented in Table 3.13.1-2 along with other data related to the reported incidents. These summary data indicate a generally decreasing trend in annual incident frequency and injuries. The average gross spill volume for the 20-year period was higher than that of the other periods, likely reflecting the higher level of integrity for newer pipelines and the effects of increasingly stringent regulatory requirements.

A summary of PHMSA significant pipeline safety incidents by cause for the period from 2008 through 2010 for onshore hazardous liquid pipelines is presented in Table 3.13.1-3.

[2] The statistics include incidents related to highly volatile liquids; however, crude oil is not a highly volatile liquid. Therefore, incident statistics are somewhat overstated when considering incidents involving crude oil pipeline transport.

TABLE 3.13.1-2
Nationwide Onshore Hazardous Liquid Pipeline Systems, Annual Averages for Significant Incidents

Period	Number of Incidents[a]	Fatalities	Injuries	Property Damage[b,c]	Gross Barrels Lost	Barrels Recovered	Net Barrels Lost
3-year average (2008 – 2010)	107	2	3	$244,301,451	108,201	33,279	74,922
5-year average (2006–2010)	106	2	4	$171,257,826	110,921	41,665	69,256
10-year average (2001-2010)	115	2	6	$143,814,380	104,065	38,647	65,418
20-year average (1991-2010)	134	2	9	$111,080,000	125,532	55,695	69,837

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] For years 2002 and later, property damage is estimated as the sum of all public and private costs reported in the 30-day incident report. For years prior to 2002, accident report forms did not include a breakdown of public and private costs so property damage for these years is the reported total property damage field in the report.

Note: Totals for the period from 1991 through 2010: 2,672 incidents; 40 fatalities; 178 injuries; $2,221,600,007 property damage; 2,510,639 barrels lost; 1,113,894 barrels recovered, and 1,396,745 net barrels lost.

Source: PHMSA 2011.

TABLE 3.13.1-3
Nationwide Onshore Hazardous Liquid Pipeline Systems, Causes of Significant Incidents (2008-2010)

Cause	Number of Incidents[a]	Percent of Total Incidents (%)	Fatalities	Injuries	Property Damage[b, c]	Percent of Property Damage[c] (%)
All other causes	22	6.7	4	1	$526,062,146	69.6
Corrosion	69	21.0	0	0	$38,672,895	5.1
Excavation damage	42	12.8	1	2	$27,382,678	3.6
Incorrect operation	34	10.3	1	6	$7,352,773	0.9
Material or equipment failure	125	38.1	0	0	$104,184,945	13.8
Natural force damage	20	6.1	0	0	$24,049,849	3.1
Other outside force damage	8	2.4	1	1	$5,199,064	0.6
Total[d]	**320**	**97.5**	**7**	**10**	**$732,904,353**	**97.0**

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] Property damage was estimated as the sum of all public and private costs reported in the 30-day incident report, adjusted to 2010 dollars.

[d] Totals presented as reported by PHMSA.

Source: PHMSA 2011.

Outside forces incidents listed in Table 3.13.1-3 include: excavation damage from mechanical equipment, such as bulldozers and backhoes (12.8 percent); natural force damage, including earth movements due to soil settlement, washouts, or geologic hazards and weather effects such as winds, storms, and thermal strains (6.1 percent); and other outside force damage (2.4 percent). Older pipelines have a higher frequency of outside force incidents partly because their location may be less well known and less well marked than it is for newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipes with reduced wall thicknesses, and have a greater rate of incidents related to outside forces. These pipelines are more easily crushed or broken by mechanical equipment or earth movements than larger diameter pipelines such as that of the proposed Project.

Corrosion was the reported cause of 21 percent of all hazardous liquid pipeline incidents from 2008 through 2010 (Table 3.13.1-3). The frequency of incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, because corrosion is a time-dependent process. Also, new pipe generally uses more advanced coatings and cathodic protection to reduce corrosion potential. Significant improvements in corrosion control technology applied to pipelines installed since the 1950s have resulted in reduced corrosion-related incident frequencies. Accordingly, the oldest pipelines (pre-1950) experience a disproportionate frequency of corrosion-related failures (Keifner and Trench 2001). In contrast, the proposed Project would incorporate state-of-the-practice corrosion control methods based on current industry standards, current PHMSA requirements, and the set of Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project plan (see Sections 2.3 and 3.13.1.1).

It is important to consider pipeline age when assessing risk based on records of incident frequencies. In 2004, the Transportation Research Board (TRB 2004) published a review of pipelines that included "Pipeline Safety Data and Trends" as an appendix. Appendix B of that report summarizes a detailed analysis of API and USDOT hazardous liquid pipeline incident data, and relies heavily on previous work done for API (Keifner and Trench 2001). The API work confirms that hazardous liquid pipeline age is a significant spill risk factor, for various reasons. The study grouped pipelines by decade of construction. The work shows that older pipelines not only experienced a higher frequency of spill incidents in general, but they also experienced a higher frequency of spill incidents due to third-party damage.

Many industry standards and practices, PHMSA regulatory requirements, and the set of Project-specific Special Conditions developed by PHMSA that would be incorporated into the proposed Project would likely reduce the potential for spill incidents associated with the proposed Project as compared to PHMSAs incident data summaries (see Sections 2.3 and 3.13.1, and Appendix U for additional details).

TransCanada and Keystone Operating History

For much of its history, TransCanada's business operations focused on natural gas transportation systems in Canada and the United States. In February 1996, the firm initiated its oil transportation business with a 50/50 joint venture with Alberta Energy Company (now EnCana Corporation) to purchase the Platte pipeline and to construct the Express pipeline later that year. Together, the Express and Platte pipelines constitute a 1,700-mile system between Hardesty, Alberta and Wood River, Illinois. The system became operational in February 1997, with commercial deliveries beginning in April 1997. Alberta Energy Company operated the Express and Platte systems on behalf of the joint venture partnership until October 2000, when TransCanada divested its 50 percent interest to EnCana Corporation.

Keystone Oil Pipeline Project

Keystone, a TransCanada subsidiary, constructed the Keystone Oil Pipeline Project (Keystone Mainline Pipeline and Cushing Extension) and the mainline portion of that system initiated operation in 2010. As a

result, TransCanada's limited operating history with crude oil pipelines precludes a direct comparison of accident and oil spill incident rates specific to TransCanada with the industry average rates.

Since the beginning of pre-startup testing and the inception of operations of the Keystone Oil Pipeline Project, there have been 14 unintentional releases of crude oil. None of the releases involved the pipeline itself but rather occurred at pump stations and MLVs. The reported incidents through May 29, 2011, their release volumes, report tracking numbers and incident causes are presented in Table 3.13.1-4. According to Keystone ~~I~~n each of these incidents, the oil was discovered early, in most cases the leaks were limited to the ground surface, the oil was minimal and was cleaned immediately and no environmental damage was reported. In one case (Ludden Pump Station), low level residual offsite oil spray impacts are being treated in-place in accordance with North Dakota Department of Health in-situ land treatment guidelines." (Keystone 2011). According to PHMSA technical staff (2011), the incidents experienced on the existing Keystone pipeline are not unusual start-up issues that occur on pipelines and are not unique. However, the number of incidents that has occurred prompted PHMSA to take action by issuing a temporary Corrective Action Order that has subsequently been lifted. According to PHMSA technical staff, there is no evidence that any of these incidents resulted from internal corrosion or erosion issues (PHMSA Pers. Comm. 2011).

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
CARPENTER PUMP STATION – NRC REPORT 05/21/2010 19051 415th Avenue, Carpenter, SD 57322, Clark County Time of incident: 13:45 CST	Spill contained on site: Amount of release reported ~5 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #941193. South Dakota Department of Environment and Natural Resources File #2010.083 closure received 7/9/10.	Failure of a 1½" below ground fitting connected to the mainline isolation valve. Investigation employed identifying isolated event due to defective fitting.
ROSWELL PUMP STATION – NRC REPORT 06/23/2010 MP 358.3, South Dakota 42592 236th Street, Howard SD 57349, Miner County Time of incident 12:00PM CST	Spill contained on site: Amount of release reported ~100 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #945213. South Dakota Department of Environment and Natural Resources File #2010.126 closure received 9/8/10.	Leak occurred at PS site during maintenance from a small fitting attached to the sump pump. Investigation identified as isolated event as a result of a failed fitting during on-site maintenance activities.
FREEMAN PUMP STATION – NRC REPORT 08/10/2010 MP406.8 South Dakota 282 6th Avenue, Freeman, SD 57029 Hutchinson County Time of incident 11:30CST	Spill contained on site: Amount of release reported ~2 gallons. *Release withdrawal letter sent to PHMSA, leak was determined non-reportable as NRC reporting threshold 5 gallons.*	NRC Case number #950516. South Dakota Department of Environment and Natural Resources File #2010.169 closure received 11/12/10.	Failure of a 1" fitting attached to the pig trap receiver. Investigation identified the fitting to have been improperly installed. Other similar installations were immediately checked for any similar problem, but none were discovered.
HARTINGTON PUMP STATION – NRC REPORT 08/19/2010 Cedar County Nebraska MP454.9 55953 883rd Road, Hartington, NE 68739 Time of incident 08:30CST	Spill contained on site: Amount of release reported 10 gallons. *NE Reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number #951480, Nebraska Department of Environmental Quality Report Case Number #081910-JB-1140. 11/1/10 NDEQ correspondence indicated case closed.	Failure of ½" above ground fitting. Investigation determined the source of the spill to be from an improperly installed cap on the ½" fitting. Similar installations were checked and remediated.

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
FERNEY PUMP STATION – NRC REPORT 01/05/2011 MP263.4 41461 144th Street, Andover, SD 57442, Day County Time of incident: 09:57 CST	Spill contained on site: Amount of release reported <2 gallons *S. Dakota reporting threshold 25 gallons.* *NRC reporting threshold 5 gallons.*	NRC Case number 963799. The NRC report is in the process of being rescinded due to not meeting the reporting threshold, South Dakota Department of Environment and Natural Resources File #2011.004, closure received 3/9/2011.	The leak occurred when a station pump seal bearing started seeping oil. This
SEVERANCE +2_1 VALVE SITE – KDHE REPORT 01/08/2011 Severance +2_1 Valve Site, MP744.3 Doniphan County, Kansas Time of incident: 14:40 CST	Spill contained on site: Amount of release reported <3 gallons. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	Kansas Department of Health and Environment (KDHE) File #32936, closure received 4/4/2011.	Source of the leak was a seal (packing) on a 6" valve. This is an isolated incident.
TURNEY PUMP STATION – NRC REPORT 01/31/2011 MP 787.1 3490 NE A Hwy., Turney, MO 64493, Clinton County Time of incident: 20:00 CST 1/30/11	Spill contained on site: Amount of release reported <10 gallons. *MO reporting threshold >50 gallons. NRC reporting threshold 5 gallons.*	NRC Case number 966126. Spill cleanup completed 1/31/2011.	Source of the leak was a seal failure on Pump #2.
CUSHING STATION – NRC REPORT 2/3/2011 350953 East 750th Rd., Cushing, OK 74023, Lincoln County Time of incident: 14:10 CST	Spill contained on site: Amount of release reported <15 gallons. *OK reporting threshold 25 gallons. NRC reporting threshold 5 gallons.*	NRC Case number 966497. Oklahoma Department of Environmental Quality File #300-00-00-75078, closure received 2/15/2011.	Source of the release was a temporary vent gas separator.
DAVID CITY PUMP STATION – NDEQ REPORT 2/11/2011 MP 552.9 1016 36th Rd., David City, NE 68632, Butler County Time of incident: 16:37 CST	Spill contained on site: Amount of release reported <100 gallons. *NE reporting threshold 25 gallons. NRC reporting threshold for maintenance related activities 5 barrels.*	Nebraska Department of Environmental Quality (NDEQ) File #021111-NH-1730, closure received 4/21/2011.	Source of release was seal failure during maintenance activity on pump seal.
ROCK PUMP STATION – NRC REPORT 2/23/2011 6347 82nd Rd., Udall, KS 67146, Cowely County Time of incident: 15:10 CST, 2/17/11	Spill contained on site: Amount of release reported 10 gallons. Following cleanup completion, estimated spill volume revised to 30 gallons. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	NRC Case number 968357. KDHE File #33000, closure report submittal pending.	Source of the leak was a valve seal on a drain line of a pump suction line.
LUDDEN PUMP STATION – NRC REPORT 3/8/2011 10075 119th Ave. SE, Brampton, ND 58017, Sargent County Time of incident: 10:30 CST	Spill contained on site: Amount of release reported <5 gallons. *ND requires reporting any spill, minimum quantities for mandatory reporting have not been established. NRC reporting threshold 5 gallons.*	NRC Case number 969483. NDDoH verbally provided no further action direction after report that spill was contained to pump unit concrete pad and immediately cleaned up.	Source of the leak was a pump unit bearing housing.

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
SENECA PUMP STATION – NRC REPORT 3/16/2011 2189 State Hwy. 63, Seneca, KS 66538, Nemaha County Time of incident: 10:00 CST	Spill contained on site: Amount of release reported 3 barrels. Following cleanup completion, estimated spill volume revised to 12 barrels. *KS reporting threshold not volumetric based rather "Impacts to soil or water resources." NRC reporting threshold 5 gallons.*	NRC Case number 970232. KDHE File #33038, closure report submittal pending.	Source of the leak was a pump seal failure.
LUDDEN PUMP STATION – NRC REPORT 5/7/2011 10075 119th Ave. SE, Brampton, ND 58017, Sargent County Time of incident: 06:26 CST	Amount of release reported 100 barrels. Subsequently revised to 450-500 barrels. Earthen berming around the perimeter of the facility contained most of the released oil within the facility. An estimated 5 barrels of oil sprayed offsite impacting neighboring properties to the south. Approximately 385 barrels of free phase oil has been collected and will be transported offsite for recycling. Approximately 800 yd^3 of oil coated site surface gravel and offsite surface soil have been excavated and stockpiled onsite pending offsite disposal. Low level residual offsite oil spray impacts are being treated in-place in accordance with NDDoH in-situ land treatment guidelines. *ND Requires reporting any spill, minimum quantities for mandatory reporting have not been established. NRC reporting threshold 5 gallons.*	NRC Case number 975573.	Source of the leak was a ¾" diameter pipe nipple failure.

TABLE 3.13.1-4
Reported Incidents for Existing Keystone Oil Pipeline

Location of Release	Release Volume	Report Tracking Number	Cause of Incident
SEVERANCE PUMP STATION – NRC REPORT 05/29/2011 Time of incident: 00:20 CST	Oil was contained on site (with the exception of a slight trace of oil vapor droplets observed on blades of grass in an area immediately adjacent to the site). Amount of release reported 40 bbl. Later revised to <10 bbl. Approximately 5 barrels of free phase oil has recovered and approximately 395 yd3 of oil coated site surface gravel have been excavated and stockpiled onsite pending offsite disposal. Offsite vegetation impacted by residual oil spray were mowed and containerized for disposal. *KS Reporting threshold not volumetric based rather "Impacts to soil or water resources."* *NRC reporting threshold 5 gallons.*	NRC Case number 977695. KDHE File # 33211.	Source of the leak was a 1/2" nipple located on a pressure transmitter

Source: Keystone 2011.

TransCanada Gas Transmission Pipelines

To evaluate TransCanada's experience in operating gas transmission pipelines, a review of PHMSA enforcement actions was conducted on all of the natural gas pipelines it operated in the U.S. The pipelines reviewed, with dates TransCanada assumed control of the assets, are listed below:

- Gas Transmission Northwest Corp. – Operator ID # 15014 – November 2, 2004;
- ANR Pipeline Co. – Operator ID # 405 – February 22, 2007;
- Great Lakes Gas Transmission Co. – Operator ID # 6660 – February 22, 2007;
- Northern Border Pipeline Company – Operator ID # 13769 – April 1, 2007;
- Tuscarora Gas Transmission Co. – Operator ID # 30838 – December 19, 2006;
- Portland Natural Gas Transmission – Operator ID # 31145 – August 3, 2004; and
- North Baja Pipeline – Operator ID # 31891 – November 2, 2004.

For these pipelines, PHMSA identified two 49 CFR Part 192 compliance issues (natural gas) from time of pipeline ownership to December 31, 2009. There were no civil penalties imposed, and all past compliance issues have been resolved with TransCanada and closed by PHMSA.

In addition, TransCanada's Bison Pipeline (natural gas) experienced a rupture and explosion on July 20, 2011 in Campbell County, Wyoming. An official determination of the cause of the incident was not available at the time the EIS was prepared. There were no reported injuries or private party property damages associated with this event.

3.13.2 Spill Volume Categories and Potential Types of Releases

3.13.2.1 Spill Volume Categories

To address potential spills from the proposed Project in this EIS, the following categories of spill volumes were used:

- Very small spills: less than 210 gallons (less than 5 bbl);
- Small spills: 210 to 2,100 gallons (5 to 49.9 bbl);
- Substantive spills: 2,100 to 21,000 gallons (50 to 499.9 bbl);
- Large spills: 21,000 to 210,000 gallons (500 to 5,000 bbl); and
- Very large spills: greater than 210,000 gallons (5,000 bbl).

This size classification is generally similar to the unofficial categories used by PHMSA for spill reporting. The very small spill and very large spill categories were added to facilitate discussion of the majority of spills (less than 210 gallons [5 bbl]) and very rare spills (greater than 210,000 gallons [5,000 bbl]). A range of spill scenarios was assessed to facilitate the impact assessment. Spill scenarios were based on these spill volume categories. Over the past 20 years (from 1990 through 2010), the average spill size in the PHMSA significant incident database for onshore hazardous liquid pipelines was less than 42,000 gallons (1,000 bbl).

Very Small and Small Spills

The most common scenarios are the very small (less than 210 gallons [5 bbl]) and small (210 to 2,100 gallons [5 to 49.9 bbl]) spills of material—usually diesel, hydraulic fluid, transmission oil, or antifreeze—on work pads, roads, and facility parking or work areas. Some of these small spills may result from slow and small (pin hole) leaks of crude oil from the proposed pipeline, or spills during maintenance activities on the pipeline and its facilities (e.g., pump station valves).

Substantive and Large Spills

Substantive (2,100 to 21,000 gallons [50 to 499.9 bbl]) and large (21,000 to 210,000 gallons [500 to 5,000 bbl]) spills would be much less likely to occur than smaller sized spills (see Sections 3.13.2, 3.13.3, and 3.13.4). Large spills would more likely be crude oil releases from the proposed pipeline and would likely occur in the ROW. Both Substantive and large spills could result from tanker truck accidents (during construction), major failure of the fuel storage tanks at construction sites, outside forces such as excavators and major earth movement, or corrosion of the pipe.

Very Large Spills

A very large spill (greater than 210,000 gallons [5,000 bbl]) could occur during operation and could result from either (1) a major rupture or a complete break in the proposed pipeline, or (2) from a failure of one or more of the three, 350,000-bbl crude oil storage tanks at the Cushing tank farm and the concurrent failure of the containment berms surrounding the tanks. As discussed in Section 3.13.4.2, a very large spill from the pipeline would likely require the occurrence of an event that would shear the pipeline such as major earth movement resulting from slides, major earth movement resulting from an earthquake, major flood flows eroding river banks at non-HDD crossings, mechanical damage from third-party excavation or drilling work, or vandalism, sabotage, or terrorist actions.

3.13.2.2 Potential Types of Releases

The following sub sections provide summary information on the types of materials that may be released from the proposed Project during construction and operation. More detailed information, particularly on crude oil, is presented in Section 3.13.5.1.

Refined Oil Products

Release volumes of refined oil products (e.g., gasoline, diesel, and lubricating and hydraulic fluids) during proposed Project construction or operations would typically be very small to small, although larger release volumes are possible. The small to very small releases would typically be associated with equipment fueling and hydraulic fluid line ruptures. These spills would most likely occur at the construction or operation/maintenance sites, at fueling stations, on the roadways, within the ROW, and at similar managed locations where they would be readily contained and remediated. Refined product releases could also result from accidents (e.g., tank truck rollover); excess fuel or lubricants during vehicle, equipment, and machinery maintenance; failure of fuel storage tanks and the surrounding containment berms; and incorrect operation of equipment or fueling procedures.

Hazardous Materials

The volume of hazardous materials that would be used during proposed Project construction and operations would be small and therefore any spills would likely be very small to small with little likelihood of a Substantive spill. Any hazardous material spills would most likely occur at the construction or operation/maintenance sites where materials would be stored in containers that define maximum spill quantities. Implementation of the ERP, SPCC plans, and hazardous materials location restrictions (see the CMR Plan in Appendix B) would reduce the risk that a hazardous material release could affect surface waters.

Crude Oil

Crude oil releases could occur during proposed Project operation and maintenance activities, as discussed in Section 3.13.4. Estimates of potential crude oil spill volumes are presented in those sections and in Appendix P. The characteristics of the crude oil that would be transported by the proposed Project are discussed in Sections 3.13.5.1 and 3.13.5.3.

3.13.3 Potential Releases during Project Construction

Most construction-related spills would likely release minor quantities of refined products (e.g., gasoline, diesel, and lubricating and hydraulic fluids). These releases would be subject to the reporting requirements of 40 CFR Part 110, and would typically result from vehicle and construction equipment fueling and maintenance. Contractor construction staging and pipe storage areas would typically include skid-mounted, aboveground gasoline storage tanks (9,500-gallon [226-bbl] capacity) and diesel storage tanks (10,000-gallon [238-bbl] storage capacity). These fuel tanks would be installed within impermeable containment areas to prevent spilled material from reaching adjacent natural habitats. According to the Pipeline Risk Assessment (Appendix P) and consistent with one of the requirements of 40 CFR Part 112 for each staging area, oil storage tanks would have secondary means of containment (berms) for 110 percent of the capacity of the largest tank. In addition, portable oil storage containers would have berms that hold 110 percent of the total capacity of the containers inside the berm. Lubricating oil may also be stored in tanks in these areas. Construction would also involve fuel delivery by tanker trucks to operating equipment along the construction ROW. The potential maximum spill volume from the failure of the maximum size fuel tank truck would be about 9,000 gallons (214 bbl) for diesel or gasoline. Lubricating

or hydraulic fluid would be stored in 55-gallon (1.3-bbl) drums, with up to six drums on a pallet. Thus, the potential maximum spill volume of lubricating oil or hydraulic fluid would be equal to the volume of six drums, or approximately 330 gallons (7.9 bbl). Hydrostatic testing of the pipeline prior to operation would not result in release of oil to the environment as the water used in the testing does not contain oil. Also, the discharged water would be required to meet NPDES discharge permit conditions (see Section 2.3.2.6).

Potential spills from construction activities would be addressed by specific preventive and mitigating measures included in the SPCC Plan described in more detail in section 2.3 and Appendix C.

3.13.4 Potential Spills from Project Operations (Including Maintenance)

3.13.4.1 Operational Spills

Operational spills from the proposed Project could originate from the pipeline, pump stations, MLVs, delivery points, or the Cushing tank farm. Additionally, spills similar to those described for construction could occur as a result of ongoing maintenance activities. As described in Appendix P, releases from the proposed Project could result from the effects of corrosion (external or internal), excavation or other subsurface equipment disturbance damage, defects in materials or defects related to proposed Project construction, hydraulic over-pressuring related to incorrect operating procedures, or geologic hazards (e.g., ground movement, washouts, and flooding). Although leak detection systems (see Section 3.13.5.5 and Appendix P) would be in place, some leaks might not be detected by the system for an extended period of time. A pinhole leak could be undetected for days or a few weeks if the release volume rate were small and in a remote area. However, although the total volume of a release from a pin hole leak could be relatively large (e.g., up to a substantive spill), in most cases the oil would likely remain within or near the pipeline trench where it could be contained and cleaned up after discovery. Detection would likely occur through visual or olfactory identification, either during regular pipeline aerial inspections, ground patrols, or landowner or citizen observation, in most cases before the release of a substantive volume of oil to surface habitats and environment.

Larger spills would most likely be associated with leak sources other than pinhole leaks (e.g., excavation damage and geologic hazards). In larger spills, some of the released oil could be contained in the immediate vicinity of the release point, although the released oil would likely migrate from the release source. However, experience gained from previous large pipeline oil releases suggests that the distance the oil would likely migrate is limited (see Section 3.13.6.4). Prior to PHMSA granting permission to operate the proposed Project, Keystone would be required to prepare and implement an ERP that would guide response actions in the event of an oil release to facilitate rapid response. Nonetheless, actual response with containment equipment and cleanup crews could be delayed due to one or more of the following factors:

- If the leak is at a remote location, visual leak detection could be difficult and reporting could be delayed;
- Locating the leak could require time searching the release area to determine where the leak originates;
- Snow, darkness, or other natural factors could hinder visual detection;
- Weather conditions, natural disasters (e.g., floods, landslides, excessive snow fall, or drifting) could delay access to the spill location, especially for larger equipment and supply vehicles; and

- Depending on spill volume, proximity, and season, the oil could reach wetlands, freshwater ponds and lakes, streams, or larger rivers thus necessitating additional time to mobilize response (see Section 3.13.5.1).

3.13.4.2 Operational Spills Risk Assessments

To assess the likelihood of operational releases from the proposed Project, spill risk assessments were conducted. These risk assessments addressed both the potential frequency of operational pipeline releases and the potential volumes of crude oil associated with the releases. The risk analyses for the proposed Project used data derived from the PHMSA database for hazardous liquid pipelines and crude oil pipelines, and the National Response Center (NRC) database for releases and spills of hazardous substances and oil, as described below.

Oil Spill Frequency

Three separate approaches were used to estimate oil spill frequency and potential spill volume:

- DOS utilized the PHMSA spill databases for both significant spill incidents (for conservatism, DOS assumed that all significant spill events were greater than 50 bbl) and all reported incidents for onshore hazardous liquid pipelines to determine the 10-year average spill frequencies and average spill volumes both nationally and within the specific states (for significant incidents only) that would be traversed by the proposed Project (PHMSA 2011).
- DOS also utilized the NRC database to assess the frequency of transmission pipeline spills of both hazardous liquids and crude oil of any size and of spills less than or equal to 50 bbl to determine the national average spill frequencies in the time period 2002 to 2010.
- DOS also estimated the incident frequency of crude oil spills of any size by combining relevant information from the PHMSA and NRC databases.
- As part of its Presidential Permit application, Keystone submitted a risk analysis performed by Keystone and its consultants (Appendix P). The Keystone risk analysis contained an estimate of spill frequency. Keystone related the spill incident frequency to historic pipeline releases attributed to specific causative mechanisms, and adjusted the frequency for Project-specific design, construction, and operational procedures as well as specific terrain conditions that would be crossed by the proposed Project, excluding the pre-existing Cushing Extension (Appendix P). Baseline incident frequencies were adjusted to account for improved technologies, specific pipeline design considerations, and standard PHMSA regulatory requirements for the proposed Project.

DOS Significant Incident Frequency Projections

A significant incident is defined by PHMSA as any incident reported by a pipeline operator where one or more of the following specifically defined consequences occur:

- Fatality or injury requiring in-patient hospitalization;
- $50,000 or more in total costs, measured in 1984 dollars;
- Highly volatile liquid releases of 5 bbl or more or other liquid releases of 50 bbl or more; and
- Liquid releases resulting in an unintentional fire or explosion.

For conservatism in this analysis, DOS assumed that any incident recorded as significant by PHMSA involved a release of 50 bbl or more. As of July 2011, PHMSA reported that there were approximately 171,000 miles of onshore hazardous liquid pipelines in the U.S. That pipeline mileage was divided into the 10-year average (2001 to 2010) of 115 significant incidents per year for onshore hazardous liquid pipelines (PHMSA 2011; see Table 3.13.1-2) to calculate the significant incident frequency factor of 0.0007 incidents per pipeline mile per year for nationwide pipelines.

PHMSA's state-by-state hazardous liquid pipeline incident database was used to generate a Project-specific state-by-state subset of the data. The state-by-state PHMSA data summaries (dated June 6, 2011) provide the total miles of hazardous liquid pipelines within each state and the number of significant incidents that occurred therein for onshore hazardous liquid pipelines during the 10-year period from 2001 through 2010. Analysis of these data also resulted in a frequency of 0.0007 incidents per mile per year for the six states evaluated in spite of the fact that there were relatively small numbers of incidents reported in most of the states that would be crossed by the proposed pipeline.

There are approximately 55,000 miles of crude oil transmission lines in the U.S. (Tribal Energy and Environmental Clearing House 2011, Pipeline 101 2011). The detailed PHMSA incident report database was used to obtain the number of incidents of crude oil spills from onshore hazardous liquid pipelines during the reporting period from 1997 through 2008. There were approximately 600 reported incidents during that 10-year period, which equates to a frequency of 0.00109 crude oil incidents per mile per year.

The results of these three analyses were used to project the number of significant incidents per year for each segment of the proposed Project. The calculated numbers of significant incidents by proposed segment and for the entire proposed pipeline are provided in Table 3.13.4-1.

TABLE 3.13.4-1
Projected Significant Spill Incidents (>50 bbl) per Year for the Proposed Project Pipeline

Characteristic	PHMSA Hazardous Liquids Dataset [a]	PHMSA Data for States Crossed by the Proposed Pipeline [b]	PHMSA Data–Crude Oil [c]
Incidents per mile per year	0.0007	0.0007	0.00109
Proposed Project Segment	**Spill Incidents Per Year**		
Steele City Segment (852 miles)	0.60	0.60	0.93
Cushing Extension (298 miles)	0.21	0.21	0.32
Gulf Coast Segment and Houston Lateral (532 miles)	0.37	0.37	0.58
Project Total Incidents per Year (1,682 miles) [d]	**1.18**	**1.18**	**1.83**

[a] Includes all onshore hazardous liquid pipelines in the U.S.
[b] Includes data only for onshore hazardous liquid pipelines in the states that would be crossed by the proposed pipeline.
[c] "Crude oil" includes data just for onshore crude oil pipeline incidents, all states.
[d] Includes existing Cushing Extension.
Source: PHMSA 2010.

DOS Incident Frequency Based on National Response Center (NRC) Database

The above analysis of spill frequency addresses significant spills (i.e., those assumed to be greater than 50 bbl) in the PHMSA database. In its comments on the draft and supplemental EISs, EPA requested that

the spill frequency analysis address hazardous liquid and crude oil spills, including those less than 50 bbl, using information from the NRC database. The NRC is the federal government's national communication center for reporting releases involving hazardous substances and oil spills. As a result, DOS conducted the spill frequency analysis described below.

The NRC database listed 1,067 spill incidents from hazardous liquid transmission pipeline from 2002 to 2010. Of that total, 546 incidents involved spills of up to 50 bbl in volume and approximately 407 incidents involved crude oil, of which 200 incidents were up to 50 bbl (see Table 3.13.4-2).

As of 2009, PHMSA reported that there were approximately 171,000 miles of onshore hazardous liquid pipelines in the U.S. The total U.S. hazardous liquid pipeline mileage was divided into the 9-year average of 119 incidents per year involving hazardous liquid spills, including crude oil spills, from hazardous liquid transmission pipelines to calculate the incident frequency factor of 0.0007 incidents per pipeline mile per year for nationwide pipelines. That equates to an estimated spill frequency of 1.16 incidents per year for the entire proposed Project corridor. For hazardous liquid spills up to 50 bbl, the estimated incident frequency factor was 0.0004 incidents per pipeline mile per year, resulting in an estimated frequency of 0.6 incidents along the proposed Project corridor per year.

There are approximately 55,000 miles of crude oil transmission lines in the U.S. (Tribal Energy and Environmental Clearing House 2011, Pipeline 101 2011). Approximately 407 crude oil incidents were reported during the 9-year period, which equates to a frequency of 0.0008 crude oil incidents per mile per year. That equates to an estimated spill frequency of 1.38 incidents per year for the entire proposed Project corridor. For those crude oil transmission pipeline incidents less than or equal to 50 bbl, the incident frequency factor was 0.0004, resulting in an estimated frequency of 0.68 crude oil spills along the proposed Project corridor per year.

TABLE 3.13.4-2
NRC Reported Hazardous Liquid and Crude Oil Transmission Pipeline Spill Incidents per Year from 2002 to 2010

Characteristic	Hazardous Liquids Dataset[a]	Hazardous Liquids Dataset Less than or Equal to 50 Barrels[a]	Crude Oil Dataset[b]	Crude Oil Dataset Less than or Equal to 50 Barrels[b]
Total Number of Spill Incidents	1,067	546	407	200
Average Number of Incidents per Year	119	61	45	22
Incidents per mile per Year	0.0007	0.0004	0.0008	0.0004
Project Total Incidents per Year (1,682 miles)[c]	**1.16**	**0.60**	**1.38**	**0.68**

[a] Includes all onshore hazardous liquid transmission pipeline incidents in the U.S. from 2002 to 2010.
[b] "Crude oil" includes onshore crude oil transmission pipeline incidents in the U.S. from 2002 to 2010.
[c] Includes existing Cushing Extension.
Source: NRC 2011.

DOS Estimated Incident Frequency for Hazardous Liquid and Crude Oil Spills of Any Size

An estimate of incident frequency for hazardous liquid and crude oil spills of any size along the proposed 1,682 mile pipeline corridor can be derived by adding the significant incident frequency from the PHMSA dataset (spills greater than or equal to 50 bbl – see Table 3.13.4-1) to the NRC dataset (restricted to spills

less than or equal to 50 bbl – see Table 3.13.4-2). This approach results in an estimated frequency of 1.78 hazardous liquid spills and 2.51 crude oil spills of any size from the proposed Project per year.

Keystone Incident Frequency Analysis

Keystone conducted a threat assessment that identified primary threats that could result in an accidental release of crude oil. These identified threats are materials and construction (e.g., pipe steel flaws, defective welds), corrosion (external, internal and stress corrosion cracking), incorrect pipeline operations (hydraulic surge), accidental damage from third party excavation, and natural hazards (ground movement resulting from seismic and landslide events, flooding and washout). Keystone converted incident frequencies determined using the PHMSA database (2008) to estimated occurrence intervals for the six categories of incident causes specific to the proposed Project (Table 3.13.4-3).

TABLE 3.13.4-3
Corridor Spill Frequency Estimated by Keystone

Threat	Occurrence Interval of One Spill Per Mile	Number of Spills per Mile per Year	Spill per Corridor per Year
Materials and construction	3,300 years	1/3300 = 0.0003	1682 x 0.0003 = 0.50
Corrosion	3,400 years	1/3400 = 0.0003	1682 x 0.0003 = 0.50
Hydraulic surge	6,800 years	1/6800 = 0.0001	1682 x 0.0001 = 0.17
Excavation damage	8,200 years	1/8200 = 0.0001	1682 x 0.0001 = 0.17
Ground movement	81,500 years	1/81500 = 0.00001	1682 x 0.00001= 0.02
Flooding and washout	87,800 years	1/87800 = 0.00001	1682 x 0.00001 = 0.02
Total Estimated Spill Frequency per Year from all Threats for Corridor			**1.38**

It should be noted that the Keystone estimate focused on reported spill incidents from pipelines and pump station facilities in the PHMSA database (2008) for which a cause was reported and only on those causes attributable to the threats included in Table 3.13.4-3.

Keystone modified the above baseline failure frequencies determined from the PHMSA historic database associated with each of the identified threats to reflect reductions in projected failure frequencies for the proposed Project that would result from factors included within the proposed Project design and operations and within the regulatory requirements applicable to the proposed Project, including:

- Standard PHMSA regulatory requirements in 2008, the time the analysis was conducted;
- Pipeline industry best practices incorporated into the proposed Project design;
- The 51 conditions in PHMSA Special Permit #2006-26617 that were known to apply to the existing Keystone Oil Pipeline Project;
- Specific terrain conditions along the proposed Project corridor;
- Specific fault hazard conditions along the proposed Project corridor;
- Specific flood and hurricane threats along the proposed Project corridor;
- Strike and puncture probabilities for the proposed Project resulting from third-party excavation impacts considering pipeline strength, wall thickness, and depth of cover; and
- Technological advances incorporated by Keystone into the proposed Project design, construction, operations, and maintenance plan.

As a result of these threat specific spill frequency reductions, Keystone calculated a Project-specific overall spill frequency of 0.22 spills per year along the entire pipeline corridor. The adjusted Keystone spill frequencies by pipeline segment are shown in Table 3.13.4-4. The adjusted Project-specific spill frequency of 0.22 spills per year includes several layers of conservatism. While the threat analysis is confined to threats to the mainline pipe, the PHMSA (2008) database from which the baseline spill frequency was calculated included all reported spills, not only spills resulting from a mainline pipeline breach. Additionally, the threat analysis did not consider additional safety requirements included within the 57 Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project that were more restrictive than those applied to the existing Keystone Oil Pipeline Project. For security reasons, the detailed threat specific spill frequency analysis is considered proprietary and confidential. A summary of the threat analysis is provided in Appendix P. A commenter prepared a report (Stansbury 2011) critical of this Keystone spill frequency analysis. Consideration was given to the report in the environmental analysis, and a response to issues raised in the report can be found in Appendix V.

TABLE 3.13.4-4
Projected Spill Occurrence for the Proposed Project over a 10-Year Interval

Proposed Pipeline Segment	Spills per Segment (rounded)
Steele City Segment (852 miles)	1.1
Keystone Cushing Extension (298 miles)	0.4
Gulf Coast Segment and Houston Lateral (532 miles)	0.6
Project Total (1,682 miles)	**2.2**

Source: Keystone 2009a.

Summary of Spill Frequency Projections

Relevant DOS estimates of spill frequency based on the PHMSA database for significant spills range from 1.18 incidents per year for hazardous liquid spills to 1.83 incidents per year for crude oil spills greater than 50 bbl (Table 3.13.4-1). Using the NRC database, DOS estimates of hazardous liquid spill frequencies range from 1.16 incidents per year for spills of any size to 0.6 incidents per year for spills up to 50 bbl. In addition, for crude oil spills, the NRC database estimates range from 1.38 incidents per year to 0.68 incidents per year for spills up to 50 bbl (Table 3.13.4-2). The estimate of incident frequencies for hazardous liquid and crude oil spills of any size using both the PHMSA significant spill database for spills greater than 50 bbl and the NRC database for spills up to 50 bbl ranged from 1.78 hazardous liquid spills to 2.51 crude oil spills of any size.

Keystone initially calculated a baseline spill frequency using the PHMSA (2008) database of 1.38. In addition, Keystone separately estimated a proposed-Project-specific spill frequency for the entire pipeline of 0.22 spills per year (Table 3.13.4-4). That estimate was derived from reductions to spill frequencies by threat category resulting from specific terrain and environmental conditions along the proposed Project corridor, required regulatory controls, depth of cover, strength of materials, and technological advances.

Several commenters have expressed concern with the spill frequency analysis results based on the spill history of the existing Keystone Oil Pipeline Project (See Table 3.13.1-4). While the number of spills to date on the existing Keystone Oil Pipeline Project is higher than the annual estimates of spill frequency for the lifetime of the proposed Project, according to PHMSA (PHMSA pers. comm. 2011), the type and number of spills that have occurred during the start up and initial operations of the Keystone Oil Pipeline Project (see Section 3.13.1.2) are typical of this phase of pipeline operations. While the number of

incidents was a concern and prompted PHMSA to take action by issuing a Corrective Action Order, the number of incidents in the start up phase is not indicative of the likely number of spills over time. Therefore, the use of the PHMSA and NRC databases is appropriate to develop estimates of spill frequency throughout the lifetime of the proposed Project. Additionally, the intent of the 57 Project-specific Special Conditions developed by PHMSA and incorporated into the design, construction, operations, and maintenance plans for the proposed Project is to reduce the likelihood of certain types of spills that have occurred in older pipeline systems built and maintained under less stringent requirements.

Oil Spill Volume

Historical Spill Volumes

PHMSA Significant Incident Spill Volumes

The 10-year average of PHMSA onshore hazardous liquid pipeline significant incident data (PHMSA 2011) indicates that the average reported gross volume of fluid lost per year from 2001 through 2010 was 4,376,652 gallons (104,206 bbl) per year. Given an onshore hazardous liquid pipeline mileage of approximately 171,000 miles, this equates to an average fluid loss per pipeline mile per year of approximately 25.6 gallons (0.6 bbl). Using data for onshore hazardous liquid pipelines for each state that would be crossed by the proposed pipeline, the average loss would be 24.8 gallons (0.6 bbl) per mile per year for the full length of the proposed pipeline. Using the PHMSA database for crude oil spills, the loss rate would be approximately 43.7 gallons (1.04 bbl) per mile per year. The average volume for crude oil spills is likely higher than that for all hazardous liquid pipelines due to the fact that larger crude oil volumes are typically transported by pipeline than volumes of other materials. Using these historical spill volume values applied to the pipeline mileage of the proposed Project, the estimates of spill volumes obtained are:

- 42,050 gallons (1,002 bbl) based on the PHMSA significant incident database for onshore hazardous liquid pipelines;
- 41,738 gallons (994 bbl) based on the state-by-state PHMSA significant incident database for onshore hazardous liquid pipelines; and
- 73,503 gallons (1,750 bbl) based on the PHMSA database specific to onshore crude oil pipelines.

PHMSA data for incidents from 2002 through 2010 indicate that 50 percent of the releases over that time period were 126 gallons (3 bbl) or less and that less than 0.3 percent of those releases were 420,000 gallons (10,000 bbl) or greater (PHMSA 2011). However, PHMSA data also indicate that large to very large pipeline spills do occur.

PHMSA All Reported Incidents Spill Volumes (Onshore Hazardous Liquid Pipelines)

The 10-year national average of PHMSA all reported incidents (an average of 344 incidents per year) for onshore hazardous liquid pipelines (PHMSA 2011) indicates that the average reported gross volume of fluid lost per year from 2001 through 2010 was 4,419,836 gallons (105,234 bbl) per year. This equates to a national average fluid loss per pipeline mile per year of approximately 25.8 gallons (0.6 bbl). PHMSA does not provide summary incident reports for all reported incidents by state.

Maximum Spill Volumes

In response to a data request from PHMSA, Keystone conducted a maximum potential pipeline spill volume assessment. A very large (greater than 210,000 gallons [5,000 bbl]) spill would be a very unlikely event (see Appendix P) and would likely result from a major rupture or a complete break in the

proposed Project pipeline that releases crude oil somewhere along the ROW. The actual volumes spilled would vary depending on a number of factors, including:

- MLV locations, activation methods, and activation delay times;
- Operating pressure within the pipeline;
- Location of the structural failure;
- Extent to which the proposed pipeline follows topographic contours, and the location of low spots in the pipeline relative to the structural failure; and
- Nature of the structural failure.

A complete structural failure of a high strength 36-inch outer diameter pipeline with the wall thicknesses of the proposed Project pipeline (see Section 2.3.1, Table 2.3.1-1) would be a highly unlikely event. To cause such a failure, the proposed pipeline would likely need to experience a direct shear event. Such events could be caused by:

- A strike-slip fault movement across the proposed pipeline – however, the proposed pipeline corridor does not cross any known active faults;
- An anchor drag event or a collision event within a navigable river that experiences large to very large ship or barge traffic – however, all such river crossings along the proposed corridor would be crossed using HDD and the pipeline would therefore be installed well below the maximum anchor depth and outside any potential collision hazard;
- A major construction-related accidental equipment interaction with the buried pipeline – however, the proposed pipeline would be buried under a minimum of 4 feet of cover, would be clearly marked, would include warning tape (ribbons) as required by the Project-specific Special Conditions developed by PHMSA, would be predominantly routed through rural areas where such large equipment construction impacts would be rare, and Keystone would implement public awareness and damage prevention programs in accordance with 49 CFR 195.440 and API RP 1162. Additionally, the probability of puncture of the X-70 strength steel pipe of the proposed Project would be very low as its puncture resistance is in excess of 65 tons and approximately 98 percent of all excavators in North America have a maximum digging force of less than 35 tons and no excavator has a digging force greater than 40 tons;
- An intentional act of sabotage, vandalism, or terrorism – however, the pipeline would be buried with a minimum of 4 feet of cover and all aboveground facilities would include security fencing, thus reducing facility accessibility to these potential threats;
- A major flood event with the potential to cause deep scour and debris impact to the proposed pipeline – however, at major river crossings, the proposed pipeline would be installed using HDD and would therefore be below the maximum scour depth, and at all stream crossings, the proposed pipeline would be installed below the calculated scour depth;
- A major slide event could be possible in steep slope areas along the proposed pipeline corridor – however, Keystone has considered landslide potential in the routing of the proposed pipeline and has selected crossings of steeper slope areas where the landslide potential is considered minimal, and the potential for landslide activity would be monitored during operations through regular aerial and intermittent ground patrols and through landowner awareness programs; or
- A combination of a high level of corrosion with some external force on the proposed pipeline – however, the proposed pipeline would be designed, constructed and operated consistent with the

requirements of 49 CFR 195 and the Project-specific Special Conditions developed by PHMSA (see Appendix U), many of which address requirements to reduce and monitor corrosion throughout the lifetime of the proposed Project. As described in Section 2.3.1.2, to protect against corrosion, an external coating (fusion-bonded epoxy, or FBE) would be applied to the pipeline and all buried facilities, and cathodic protection (CP) would be applied to the pipeline by impressed current. These measures would be provided in compliance with 49 CFR Part 195, Subpart H (Corrosion Control) and the requirements of 14 of the PHMSA 57 Special Conditions (see Appendix U). The primary impressed current CP systems would be rectifiers coupled to semi-deep vertical anode beds at each pump station, as well as rectifiers coupled to deep-well anode beds at selected intermediate mainline valve sites. The rectifiers would be variable output transformers which would convert incoming AC power to DC voltage and current to provide the necessary current density to the CP design structures. The rectifiers would have a negative cable connection to the design structure and a positive cable connection to the anode beds. The anode beds would consist of high silicon cast iron anodes backfilled with a highly conductive coke powder to allow for an expected anode minimum life of 20 years. During operation, the CP system would be monitored and remediation performed to prolong the anode bed and systems. The semi-deep anode beds would be 12-inch-diameter vertical holes spaced 15 feet apart with a bottom hole depth of approximately 45 feet. The deep-well anode bed would be a single 12-inch-diameter vertical hole with a bottom hole depth of approximately 300 feet.

Some commenters have expressed concern that the experience of backfill settling on TransCanada's Bison natural gas pipeline may indicate that 4 feet of cover would not occur in all locations along the proposed Project corridor. DOS issued a data request to Keystone asking that Keystone provide information on the Bison backfill settlement event. The following information is taken from Keystone's response:

–Abnormal trench settlement was experienced on the Bison pipeline during the spring of 2011. Correspondence from PHMSA with respect to this issue is attached. Keystone's response to PHMSA will follow.

There appears to be a strong correlation between ditch subsidence on the Bison Pipeline right-of-way and locations that were backfilled during severe winter conditions. Review of air photos and inspection reports and field review by geotechnical specialists and environmental inspectors suggests that the following causative factors were in play:

Initial ditch subsidence may have been caused by one or several factors. If the backfill contained a relatively high volume of snow, the melting snow would have left voids in the backfill. Similarly, if spoil was frozen at the time of backfill, larger voids between frozen angular peds would have been created. Consequently, what appeared to be well-compacted backfill may have actually further consolidated upon thawing. Another contributing factor may have been the high shrink-swell potential in some of the more clay-rich soil types.

In some areas, ditch subsidence appears to be occurring in conjunction with water migration within the relatively loose backfill. This loss of material can create further surface subsidence. Initial drainage pathways enlarge and increase as voids within the backfill are exploited and expanded by further drainage. If either surface runoff or subsurface water intersected a segment of trench with relatively loose backfill or significant voids, it would have exploited this pathway in which to flow on or beneath the trench surface, creating erosion and/or subsidence. Once subsidence begins, surface runoff seeking the topographic low further contributes to saturation of trench backfill and in some locations creates associated surface erosion.

The Keystone XL project is not proposed to work under frozen soil conditions. However, if unseasonal or early winter conditions appear prematurely TransCanada would employ the following measures:

- Substantial amounts of snow would be removed from the ditch and backfill material to manage excessive moisture thus increasing risks of excessive settling.
- Frozen subsoils placed within the trench would require pronounced "over-ploughing" (pile subsoil material over trench and suspend topsoil replacement until the following summer. Deferring this activity until the following summer would ensure all frozen subsoils are thawed and settled and would be followed up with "over-working" or evening out the subsoil horizon within the trench, ensuring a compacted and evenly distributed subsoil horizon. Following this, topsoil replacement would be conducted over the entire pipeline right-of-way in the affected area.
- Breaking up/ pulverizing subsoils into smaller clods may be necessary if subsoil materials are too large to obtain reasonable subsoil backfilling.

Surface diversion berms would be placed along the right-of-way in specific locations to redirect spring run-off to avoid excessive erosion or scouring of the un-compacted trenchline. Additional bentonite ditch plugs or foam breakers may also need to be installed within the pipeline ditch depending on slope, soil types and active subsurface springs and/or seeps."

Additionally, PHMSA Special Condition 19 requires that Keystone maintain the depth of cover at a minimum of 4 feet, so should any settlement of the backfill occur along the proposed Project for any reason, PHMSA would require Keystone to repair the situation.

To ascertain what the maximum volume release could be at any location along the proposed pipeline corridor as requested by PHMSA, an analysis was conducted by Keystone that assessed maximum leak volume from a complete pipeline structural failure using a spill model that is populated with elevation data points occurring at every point of inflection (PI) in the pipeline or every 100 feet, whatever distance is smaller (in most cases it is the PI). The model evaluated over 100,000 data points detailing the profile of the pipeline. The elevation points were acquired through physical survey of the land (accuracy: 2-3 inches) and supplemented with LiDAR (Light Distancing and Ranging system with a vertical accuracy of approximately 6 inches). The model generated spill volume results at each of these data points. This analysis used the following response times:

- Stop pumping units at all pump station locations: approximately 9 minutes.
- Close remotely operated isolation valves: approximately 3 minutes.
- Total time: approximately 12 minutes.

The analysis also assumed a complete pipeline shear and draindown, a highly unlikely event for the reasons stated above. The analysis considered the configuration of the pipeline and the location of MLVs and pump stations from the Canadian border to delivery terminals. Based on this analysis, the approximate maximum spill volume was estimated to be approximately 2.8 million gallons (66,500 bbl), and it was determined that this size release was only theoretically possible along less than 0.1 percent of the proposed pipeline route (less than 1.7 miles). It is important to note that this approximate maximum spill volume could not occur at all locations along the proposed pipeline corridor. It represents the release that would occur under a structural failure scenario where the distance between MLVs and the terrain gradient in the vicinity of the failure, in combination with other factors, would lead to a maximum draindown condition. At all other locations along the pipeline corridor, the maximum draindown volume would be lower. For approximately 50 percent of the proposed pipeline corridor (approximately 842

miles), the modeled maximum spill volume would be less than 672,000 gallons (16,000 bbl) due to a complete structural failure of the pipeline. For the rest of the pipeline, the maximum release would be less due to topography and MLV placement. Areas where maximum spill volumes would be much lower include river crossings and pump stations where MLVs occur on each side of the river or the pump station.

In summary, the estimates of maximum spill volume were based on an analysis that included the following assumptions:

- Complete structural failure of the pipeline;
- Maximum assumed time between the failure incident and the time of detection;
- Maximum time for shutdown to be initiated and completed;
- Maximum flow rate; and
- Largest potential line drainage volume between the closest MLV on each side of the structural failure given site conditions at each 3-foot segment.

To put the size of these maximum spill estimates into perspective, they can be compared to the size of major historical pipeline oil spills. The largest major historical pipeline spills in the U.S. from 1979 through 2010 ranged from about 300,000 to 1.3 million gallons (7,143 to 30,950 bbl). In this time period, there were less than 10 spills within this range of magnitudes. These spills were all lower in volume than the potential largest spill from the proposed pipeline and they appear to confirm the conservatism in the maximum spill estimates, given that they occurred in pipeline systems much older and designed to less stringent requirements than the proposed Project, although none of the pipelines involved with these spills were of the same pipeline diameter and operating pressure as those of the proposed Project.

A very large spill could occur at the proposed Cushing tank farm. However, each of the three 350,000-bbl tanks would be surrounded by a secondary containment berm (Section 2.2.6) that would hold 110 percent of the contents of the tank plus freeboard for precipitation. Therefore, a very large release to the environment could only occur in the unlikely event of a major failure of a tank and a concurrent failure of the secondary containment berm. All other releases from tank failure would be contained within the bermed areas.

A commenter prepared a report (Stansbury 2011) critical of the Keystone maximum spill analysis. Consideration was given to the report in the environmental analysis, and a response to issues raised in the report can be found in Appendix V.

3.13.5 Impacts Related to Oil Spills

Crude oil released from the proposed pipeline during operations or refined oil released during construction or operations into the environment may affect natural resources, protected areas, human uses and services, and aesthetics to varying degrees, depending on the cause, size, type, volume, location, season, environmental conditions, and depending on the timing and degree of response actions. Small oil spills (e.g., minor intermittent leaks and drips from construction machinery and operating equipment) would be almost certain to occur during construction and operation of the proposed Project, although in aggregate these spills could be of sufficient magnitude to substantively affect natural resources and human uses of the environment.

Most oil spills are only broadly predictable in cause, location, time of occurrence, size, and duration (J.L. Mach et al., Hart Associates, Inc. 2000). For example, it is more likely that:

- A pipeline spill would occur in a populated area where excavation is a frequent activity than in a remote wilderness area;
- A pipeline washout would occur in a major river bed than in a small creek;
- A fueling spill would occur on a fueling station pad than on the ROW; or
- A tanker truck would overturn on a winding mountain road than on the prairie.

When an oil spill occurs, the resulting environmental impact depends on a number of factors, including:

- Amount and duration of oil release, and location with respect to topography, infrastructure, and sensitive receptors;
- Fate and behavior of the spilled oil (i.e., the potential for a spill reaching an environmental receptor and its persistence in the environment);
- Chemical composition and physical characteristics of the oil; and
- Toxicity and other adverse effects of the oil to the receptors.

The oil spill literature is diverse, extensive, and often presents conflicting results and conclusions regarding acute and chronic impacts from oil spills. Much of the literature is not published in the peer-reviewed literature but consists of technical reports prepared by the potentially responsible parties (PRPs), natural resource trustees (e.g., state, federal, and tribal managers for the natural resources), consultants and academics retained by the PRPs and/or Trustees, and other interested parties including NGOs. Nevertheless, the body of literature and information taken together provides a basis for evaluating the potential range of impacts that may result from an oil spill from the construction, operation, maintenance and demobilization of the proposed pipeline. Some of the sources of the information utilized for this analysis include the following:

- NOAA DARP website where the Damage Assessment and Restoration Plans provide a description of oil spill impacts as well as planned restoration actions (www.darrp.noaa.gov);
- USFWS website where impact assessment and restoration plans are provided for a limited number of sites (www.fws.gov/contaminants/restorationplans/plans.cfm);
- Oil and Nature Bulletin by USFWS (www.fws.gov/contaminants/Documents/OilAndNature.pdf);
- Resources on Oil Spills, Response, and Restoration: A Selected Bibliography by Anna Fiolek, Linda Pikula, and Brian Voss. June 2010. National Oceanic and Atmospheric Administration, Library and Information Services Division. (http://docs.lib.noaa.gov/noaa_documents/NESDIS/NODC/LISD/Central_Library/current_references/current_references_2010-2.pdf);
- Damage Assessment and Restoration Plan/Environmental Assessment (DARP/EA) listing by California for several Natural Resource Damage Assessments (NRDAs) (www.dfg.ca.gov/ospr/NRDA);
- Oil spill response in freshwater: Assessment of the impact of cleanup as a management tool by John H. Vandermeulen and Cal W. Ross in Journal of Environmental Management 44(4):297-308, 1995;

- Environment Canada's website (www.ec.gc.ca/scitech/) that provides access to 34 years of publications on oil spill impacts and response (mostly in temperate to cold environments) that have been presented at the annual AMOP Technical Seminar on Environmental Contamination and Response;
- Archived Proceedings of the International Oil Spill Conference (www.iosc.org/papers/search.asp) wherein many papers and posters deal with the fate of oil in freshwater systems as well as the impacts to natural resources; and
- Additional papers, technical reports, Natural Resource Damage Assessments (NRDAs) books, and bibliographies related to freshwater oil spill impacts that provide detailed (and sometimes contradictory) assessments of impacts as well as the recovery of natural resources from oil spills, including many catalogued and/or prepared by EPA, USFWS, NOAA, USCG, and many state agencies.

A discussion of oil spill impacts requires a depiction of typical potential spill scenarios and environmental variables that might affect spilled oil fate and behavior. These depictions are necessarily simplified and do not represent the entire spectrum of events that might be realized in actual spills. However, many of these factors and assumptions have been used in previous similar assessments, and all are based on the peer-reviewed literature, technical reports, and empirical experience of oil spill experts worldwide. The following key factors are addressed below:

- Physical, Temporal and Environmental Factors Affecting Hazardous Liquid Spill Impacts (Section 3.13.5.1);
- Keystone Response Time and Actions (Section 3.13.5.2);
- Factors Affecting the Behavior and Fate of Spilled Oil (Section 3.13.5.3);
- Summary of Environmental Factors Affecting Fate of Spilled Oil (Section 3.13.5.4);
- Keystone Actions to Prevent, Detect, and Mitigate Oil Spills (Section 3.13.5.5); and
- Types of spill impacts (Section 3.13.5.6).

3.13.5.1 Physical, Temporal, and Environmental Factors Affecting Hazardous Liquid Spill Impacts

Impacts related to hazardous liquid spills could be affected by the release location, type and volume of material released, nearby receptors and resource uses, seasonal variations, weather, water levels, and other factors that are described below.

Location of Spill

Most spills would occur and be contained within or in close association with the proposed pipeline ROW or associated infrastructure, including construction yards, pump stations, and maintenance yards. These spills would typically be very small (less than 42 gallons [1 bbl]) and would likely be promptly cleaned up as required by federal, state, and local regulations. During construction, some refined product spills may occur from tank truck accidents along roads leading to the construction sites. Some of these spills may result in much or all of a load being spilled to the land, wetlands, ponds and lakes, or flowing waterbodies adjacent to the road or pad. The maximum volume of gasoline or diesel from a tank trunk would be about 9,000 gallons (214 bbl) for diesel or gasoline and approximately 330 gallons (7.9 bbl) for lubricating or hydraulic fluid (i.e., six 55-gallon drums on a pallet). These spills would likely have limited areal extent unless they occurred at or very near an open water body.

Spills during operation and maintenance of the proposed pipeline would for the most part involve crude oil. Based on experience, spills resulting from excavation damage would likely occur in urban/suburban areas and some agricultural areas where water-conveying canal excavation activities below four feet of depth are common. The locations of greatest concern for potential oil spills would be those that are up-gradient of HCAs, especially water intakes for public drinking water or commercial/industrial users and USAs, especially wetlands, flowing streams and rivers, and similar critical habitats.

Crude Oil Composition

The following section of the EIS addresses the composition of WCSB oil sands derived crude oils relative to other crude oils because of the potential for large-to very large volume releases of crude oil from the proposed Project and because the crude oil transported would ultimately be refined in PADD III.

General Description of WCSB Oil Sands Derived Crude Oils

Crude oil transported by the proposed Project would, for the most part, originate within the Alberta oil sands. The material extracted from the oil sands is typically a very viscous material called bitumen. Bitumen and the types of crude oils produced through either processing or diluting the bitumen are defined as follows:

- *Raw bitumen* – Raw bitumen is solid under ambient conditions and therefore must be diluted or converted prior to transport via pipeline.
- *Upgraded bitumen (SCO or syncrude)* – SCO (synthetic crude oil) is produced from bitumen through a refinery conversion that turns heavy hydrocarbons into lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude without heavy fractions.
- *Diluted bitumen (dilbit)* – Dilbit is bitumen mixed with a diluent, usually a natural gas liquid such as gas condensate. This is done to make the mixed product "lighter," reducing its viscosity so that the dilbit can be transported in a pipeline.
- *Synthetic bitumen (synbit)* – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than either SCO or dilbit.
- *Diluted synthetic bitumen (dilsynbit)* – Dilsynbit is a combination of bitumen and heavy conventional crude oils blended with condensate and SCO, producing a product more similar to conventional crude oil than either SCO or dilbit (IHS CERA 2010).

The types of WCSB crude oil that would be transported by the proposed Project would primarily consist of SCO and dilbit. The upgrading process for SCO and the addition of diluent in dilbit would occur before the oil would be delivered to the proposed pipeline at Hardisty, Alberta. The precise composition of SCO and dilbit would vary by shipper and is considered by the shippers to be proprietary information. In general, these crude oils would be similar to Western Canada Select (WCS - a heavy crude oil) and Suncor Synthetic A (a lighter crude oil). The physical and chemical characteristics of these two types of crude oil, as well as most of the other crude oils derived from the oil sands, are available at http://www.crudemonitor.ca/assays.html and are further described below. The diluents mixed with bitumen are generally similar to kerosene, natural gas condensate or synthetic crude oil. The diluents are composed of hydrocarbon molecules that generally have five carbon atoms (pentanes) or more but they can also contain molecules with four carbon atoms (butane) and may contain trace amounts of molecules with one to three carbon atoms (methane, ethane, and propane, respectively).

Crude oils may differ in their solubility, toxicity, persistence, and other properties that affect their impact on the environment. The effects of a specific crude oil are a function of its composition and physical properties. Of particular importance are:

- Specific gravity, which determines whether the unweathered oil would sink or float upon release to an aquatic environment. A specific gravity of less than 1.0 means the unweathered oil will float on fresh water. In the discussions of crude oil within this section of the EIS, API gravity is used rather than specific gravity. If a crude oil has an API gravity greater than 10, it is lighter and would float on water. If a crude oil has an API gravity less than 10, it would sink in water;
- Viscosity, which determines how readily the oil would flow when released. Typically, viscosity increases as temperature decreases. This may be an important consideration, as air temperatures along the length of the proposed pipeline corridor may range from well below freezing in winter to in excess of 100˚F in summer;
- Pour point, an indicator of the temperature at which the oil changes from liquid to a –solid" material that does not flow;
- Proportion of volatile and semi-volatile fractions, an indicator of (1) the amount of oil that would evaporate or volatilize; (2) the amount of oil that would likely physically persist in the environment as it weathers; and (3) the amount of potentially toxic material that could dissolve or disperse into an aquatic environment and cause toxicological impacts;
- Proportion and amount of polycyclic aromatic hydrocarbons (PAHs), many of which are considered key toxic components of crude oils; and
- Proportion of other elements and compounds including sulfur and metals.

Information on example crude oils expected to be transported by the proposed Project (see Tables 3.13.5-1 and 3.13.5-2) indicates that the transported crude oil would likely have the following general characteristics:

- Average specific gravity of approximately 0.846 for Suncor Synthetic A oil and approximately 0.924 for WCS crude oil which means that both types of crude oil would float on fresh water;
- Pour point for heavy crude oil less than approximately -30˚C (-22˚F);
- Pour point for synthetic crude oil less than approximately -21˚C (-5.8˚F);
- PAH concentrations which are considered proprietary by the shippers and unknown to Keystone at this time;
- Benzene, toluene, ethyl benzene, and xylene (BTEX) concentrations are approximately 1 percent by volume of the crude oil volume;
- Sulfur concentrations less than 0.25 percent and 3.6 percent by weight for synthetic and diluted bitumen respectively;
- Nickel concentrations less than 2.5 and 66 parts per million (ppm) for synthetic oil and diluted bitumen respectively, and vanadium concentrations less than 160 and 4 ppm respectively; and
- Average mercury concentrations lower than comparable values for Mexican Maya and Venezuelan heavy sour crude oils (see Table 3.13.5-7).

TABLE 3.13.5-1
Constituents and Properties of Western Canadian Select Crude Oil

Characteristic	Observed	Past Average	Standard Deviations [a]
Basic Properties			
Relative Density	0.924	0.931	0.005
API Density	21.6	20.6	0.8
Absolute Density (kg/m^3)	923.6	929.6	4.8
Total Sulphur (wt %)	3.37	3.33	0.17
MCR (mass %)	8.93	9.38	0.39
SW (vol %)	- [b]	-	-
Sediment (ppmw)	301	374	97
TAN	1.03	0.86	0.11
Salt in Crude (ptb)	-	40.3	12.6
Iron (mg/L)	-	-	-
Nickel (mg/L)	53.6	53.7	6.1
Vanadium (mg/L)	129.9	130.1	13.2
Molybdenum (mg/L)	-	-	-
Constituent			
Methane	-	-	-
Ethane	-	0.03	0.00
Propane	0.07	0.07	0.02
isoButane	0.57	0.59	0.13
nButane	1.54	1.45	0.26
Total Butanes	2.11	2.04	0.38
Total C4 minus	2.18	2.14	0.40
isoPentane	2.14	1.93	0.29
n-Pentane	2.22	2.01	0.30
Hexanes	4.04	3.58	0.54
C7 Paraffins	0.73	0.64	0.10
C7 Naphthenes	1.16	1.10	0.13
C7 Aromatics	0.40	0.34	0.05
nHeptane	0.62	0.56	0.07
Total Heptanes	2.90	2.65	0.30
C8 Paraffins	0.76	0.74	0.09
C8 Naphthenes	0.61	0.63	0.09
C8 Aromatics	0.48	0.44	0.07
nOctane	0.39	0.38	0.05
Total Octanes	2.25	2.79	0.27
C9 Paraffins	0.35	0.36	0.06
C9 Naphthenes	0.38	0.39	0.06
C9 Aromatics	0.68	0.66	0.10
nNonane	0.26	0.23	0.04
Total Nonanes	1.33	1.64	0.23
C10 Paraffins	0.53	0.49	0.07
C10 Naphthenes	0.05	0.06	0.03
C10 Aromatics	-	-	-
nDecane	0.26	0.24	0.05
Total Decanes	0.84	0.78	0.13

TABLE 3.13.5-1
Constituents and Properties of Western Canadian Select Crude Oil

Characteristic	Observed	Past Average	Standard Deviations [a]
Distillation Information (°C), % Off			
IBP	-	34.1	1.2
1%	-	35.0	1.7
5%	-	77.2	24.2
10%	-	157.6	35.5
15%	-	222.4	29.2
20%	-	267.5	21.7
25%	-	302.7	18.9
30%	-	333.8	18.3
35%	-	363.9	19.2
40%	-	394.1	20.7
45%	-	423.2	21.5
50%	-	452.3	23.8
55%	-	483.6	26.9
60%	-	518.1	31.1
65%	-	555.7	35.4
70%	-	594.6	37.4
75%	-	633.0	37.8
80%	-	665.7	35.1
85%	-	682.9	28.9
90%	-	698.2	22.1
95%	-	706.6	10.2
98%	-	-	-
99%	-	-	-
100%	-	-	-
FBP	-	716.8	2.5
Residue (%)	-	13.72	4.93
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	2.1	0.4
Naphtha (C5; 190°C)	-	9.1	2.8
Kerosene (190°C – 227°C)	-	10.9	1.2
Distillate (277°C – 343°C)	-	9.7	1.2
Gas Oil (343°C – 565°C)	-	34.7	2.7
Residue (565°C +)	-	33.4	4.8
BTEX (Vol %)			
Benzene	0.18	0.15	0.02
Toluene	0.32	0.27	0.04
EthylBenzene	0.06	0.06	0.01
Xylenes	0.33	0.30	0.05

[a] Past Average and Standard Deviations include 156 records.
[b] - (dash) indicates a tested value below the instrument threshold.
kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter
Source: Crude Quality Inc. 2010.

TABLE 3.13.5-2
Constituents and Properties of Suncor Synthetic A Crude Oil

Characteristic	Observed	Past Average	Standard Deviations [a]
Basic Analysis Information			
Relative Density	0.846	0.860	0.006
API Density	35.8	33.1	1.2
Absolute Density (kg/m^3)	844.9	858.7	6.0
Total Sulphur (wt %)	0.19	0.19	0.03
MCR (mass %)	- [b]	0.02	0.06
SW (Vol %)	-	-	-
Sediment (ppmw)	-	-	-
TAN	-	-	-
Salt in Crude (ptb)	-	-	-
Iron (mg/L)	-	-	-
Nickel (mg/L)	-	0.6	1.0
Vanadium (mg/L)	-	1.5	1.4
Molybdenum (mg/L)	-	-	-
Light Ends (Vol %)			
Methane	-	-	-
Ethane	-	-	-
Propane	0.03	0.02	0.01
isoButane	0.37	0.28	0.11
nButane	1.81	1.51	0.32
Total Butanes	2.18	1.80	0.43
Total C4 minus	2.21	1.82	0.45
isoPentane	1.73	1.10	0.19
n-Pentane	2.49	1.88	0.31
Hexanes	5.09	3.96	0.65
C7 Paraffins	1.28	1.01	0.23
C7 Naphthenes	1.29	1.09	0.17
C7 Aromatics	0.38	0.29	0.06
nHeptane	1.48	1.23	0.19
Total Heptanes	4.43	3.62	0.52
C8 Paraffins	1.63	1.56	0.21
C8 Naphthenes	1.35	1.35	0.18
C8 Aromatics	0.89	0.82	0.12
nOctane	0.93	0.91	0.13
Total Octanes	4.80	4.64	0.60
C9 Paraffins	0.93	0.97	0.13
C9 Naphthenes	0.76	0.79	0.13
C9 Aromatics	1.36	1.47	0.21
nNonane	0.78	0.75	0.10
Total Nonanes	3.83	3.98	0.50
C10 Paraffins	1.35	1.25	0.19
C10 Naphthenes	0.07	0.13	0.11
C10 Aromatics	-	0.00	-
nDecane	0.75	0.77	0.13
Total Decanes	0.17	2.17	0.32

TABLE 3.13.5-2
Constituents and Properties of Suncor Synthetic A Crude Oil

Characteristic	Observed	Past Average	Standard Deviations [a]
Distillation Information (°C) % Off			
IBP	-	34.5	1.6
1%	-	37.5	3.3
5%	-	92.2	14.3
10%	-	132.9	12.4
15%	-	167.0	12.2
20%	-	196.1	12.4
25%	-	223.5	12.3
30%	-	247.7	11.5
35%	-	267.9	10.4
40%	-	285.6	9.7
45%	-	300.9	8.6
50%	-	314.6	8.0
55%	-	327.8	7.7
Distillation Information (°C) % Off (Cont.)			
60%	-	341.0	7.4
65%	-	354.1	7.2
70%	-	367.3	7.1
75%	-	381.3	7.1
80%	-	396.9	7.1
85%	-	414.3	6.8
90%	-	434.3	7.2
95%	-	464.8	8.4
98%	-	502.2	13.8
99%	-	533.5	21.9
100%	-	-	-
FBP	-	572.5	31.3
Residue (%)	-	0.0	-
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	1.8	0.4
Naphtha (C5; 190°C)	-	16.3	2.2
Kerosene (190°C – 277°C)		20.2	1.9
Distillate (277°C – 343°C)	-	22.1	1.0
Gas Oil (343°C – 565°C)	-	23.2	10.9
Residue (565°C +)	-	-	-
BTEX (Vol %)			
Benzene	0.09	0.05	0.03
Toluene	0.30	0.23	0.05
EthylBenzene	0.15	0.15	0.03
Xylenes	0.57	0.52	0.08

[a] Past Average and Standard Deviations include 100 records.
[b] - (dash) indicates a tested value below the instrument threshold.
kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter
Source: Crude Quality Inc. 2010.

Additional characteristics of these crude oils are reported in copyrighted assays by Crude Quality, Inc. (http://www.crudemonitor.ca/current.html). The crude oils reported in this website represent approximately 85 percent of the current crude oil production in the WCSB (Bill Lywood Pers. Comm. 2011). Some crude oil characteristics is not included in the assay data for the reference crude oils described in the EIS, including viscosity profiles, proportion of volatile and semi-volatiles compounds, the amount or proportion of PAHs, and toxicity to aquatic organisms based on bioassays. Information on these characteristics is therefore drawn from the available literature in the public record.

Several commenters on the draft EIS expressed concerns relating to the chemical composition of the WCSB crude oil, in particular the dilbit crude oil, that would be transported through the proposed Project in relationship to other crude oils. Many commenters on the draft and supplemental draft EIS also expressed concern relative to the potential that WCSB crude oil delivered to PADD III through the proposed Project would create new air quality concerns resulting from refining due to the composition of the WCSB crude oil relative to crude oils currently refined in PADD III. In response to these and other concerns relative to the composition of crude oils that would be transported through the proposed Project, DOS has compared the chemical composition of WCSB oil sands derived crude oils with conventional (i.e., non-oil sands derived) WCSB crude oils that have been transported through pipelines into the U.S. in large quantities for several decades. DOS has also compared the composition of WCSB heavy crude oils likely to be transported through the proposed Project to other heavy crude oils currently refined in PADD III.

Characteristics of WCSB Oil Sands Derived Crude Oils (Dilbits) Compared to Conventional WCSB Heavy Crude Oils

This section of the EIS focuses on comparisons of crude oil characteristics of dilbits relative to reference conventional crude oils that have been imported from Canada for several decades. The categories of crude oils examined and the specific characteristics of these crude oils were obtained primarily from information provided on the website www.crudemonitor.ca. These categories are:

- Light crude oils (both sweet and sour), which generally have an API gravity equal to or greater than 35;
- Medium sour crude oils, which generally have an API gravity between 24 and 35 and sulfur content greater than 0.5 percent;
- Heavy conventional crude oils, which generally have an API gravity equal to or less than 24; and
- Dilbits, which generally have an API gravity less than 24.

As presented in Table 3.13.5-3, since at least 1986 Canadian heavy crude oils (which are all sour) and medium sour crude oils have generally comprised 60 to70 percent of total Canadian imports to the U.S. The import statistics do not distinguish between conventional heavy crude oils and dilbits, but comparing the import statistics with historic production figures provided by CAPP (CAPP 2006), it is reasonable to infer that before 2000 the majority of Canadian heavy crude oil imports were likely from conventional production, and further to infer that since 2000 dilbits have comprised an increasingly large percentage of these heavy crude oil imports. Dilbits are not the only example of crude oils produced by mixing a heavy crude oil (or bitumen) with a lighter hydrocarbon diluent to facilitate transport through pipelines. For example, the heavy crude oil produced for decades in the Lloydminster area of Canada exhibits an API gravity ranging between 10 and 25 at the wellhead (Wong and Ogrodnick 1998). This Lloydminster heavy crude oil is mixed with diluents to create the former benchmark WCSB Lloyd Blend that comprises 80 percent crude oil and 20 percent diluent.

TABLE 3.13.5-3
Historic U.S. Imports of Canadian Crude Oil by Category (thousands of barrels of oil per day)

Year	Heavy[a]	Medium Sweet[b]	Medium Sour[c]	Light Sweet and Sour[d]	Total
1986	181	14	205	169	570
1990	242	43	104	254	643
1995	237	53	436	295	1039
2000	433	154	512	252	1351
2005	705	257	500	173	1635
2010	1039	314	344	267	1964

[a] =<24 API
[b] Between 24 and 35 API <.5%
[c] Between 24 and 35 API >.5% sulfur
[d] >=35 sulfur
Source: EIA 2011.

Commenters on the draft EIS and supplemental draft EIS expressed concerns that the characteristics of oil sands derived crude oils, particularly dilbit, make them more corrosive to steel pipelines as compared to conventional crude oils. These corrosivity concerns are discussed in a report (NRDC 2010) produced by several non-profit organizations. Public concern has lead to the possibility that Congress could direct PHMSA to conduct a specific study of dilbit corrosivity in comparison to other crude oils. Additional comments on the supplemental draft EIS regarding WCSB crude oil composition and characteristic were received from the Canadian Association of Petroleum Producers (CAPP), including a report from Crude Quality, Inc. (2011).

To address commenter concerns relative to WCSB crude oil, the following discussion has been clarified, updated, supplemented and reorganized into two subsections addressing crude oil corrosivity/erosivity and volatility/instability, respectively. In preparation of this discussion, DOS reviewed the relevant comments and stakeholder submittals, technical publications referenced in this section, and input from technical experts including corrosion engineers, petroleum engineers, pipeline engineers, chemists, environmental and natural resource scientists, PHMSA personnel, private industry, and academia.

Corrosivity/Erosivity

Some commenters expressed concern that WCSB crude oil pipeline statistics from Canada suggest that corrosion rates for WCSB crude oil pipelines are higher than for other crude oil pipelines. In consultation with ERCB, PHMSA made adjustments to the data ERCB regarding internal corrosion incidents on oil pipelines, to ensure that similar types of pipelines were being compared. When the comparison is made between similar pipelines carrying processed crude oils, the Albertan and U.S. pipeline statistics indicate similar rates of internal corrosion.

Other reports (NRDC 2011) that have suggested a substantially higher percentage of internal corrosion incidents in Albertan crude oil pipelines included statistics not only from crude oil pipelines, but also oil effluent, or multiphase, pipelines. DOS consulted with ERCB regarding the Albertan system for classifying pipelines. According to ERCB, the oil effluent category pipelines are delivering the production of individual oil wells to nearby satellites or batteries. This production is a blend of gases, oil, condensates, and water, in varying compositions (Dave Grzyb, Pers. Comm. 2011). These types of pipelines in the U. S. are not regulated by PHMSA and not included in the PHMSAS statistics. Therefore, it is appropriate to eliminate them from a comparison between PHMSA and Albertan incident statistics.

According to the ERCB, the higher rate of internal corrosion incidents in oil effluent pipelines is likely attributable to the elevated water and content of the oil effluent resulting from the age and production capability of conventional Alberta oil fields. These older oil fields carry high amounts of water and dissolved gases that are very corrosive to steel. The ERCB statement is consistent with the literature regarding causes of internal corrosion in crude oil pipelines, which identifies water and certain gases such as carbon dioxide and hydrogen sulfide as indicators of internal corrosion potential (Baker 2008). It is also consistent with a California study that concluded that crude oil gathering lines carry a higher percentage of water and other impurities which tend to increase the internal corrosion rate (CSFM 1997).

Direct comparisons between spill frequencies in the Canadian NEB/ERCB incident database and the PHMSA spill frequency database are complicated by differences in spill reporting requirements in the two jurisdictions. In Canada, spills of any size are reported. In the U.S., spills of 5 gallons or more are reported at this time. PHMSA reports that in the U.S. from 2002 to 2009, internal corrosion accounted for approximately 26.5 percent of spill incidents (PHMSA 2011). The NEB/ERCB reported that in Alberta from 1990 to 2005, internal corrosion accounted for approximately 24.8 percent of spill incidents (Alberta Energy and Utilities Board 2007). In a briefing to the U.S. Senate on June 8, 2011, PHMSA presented statistics comparing total failures, internal corrosion related failures, and external corrosion related failures in the U.S. crude oil pipeline transmission system from 2002 to 2010 with similar failures in the Alberta crude oil pipeline transmission system over the same time period (see Table 3.13.5-4). The quantity of oil sands derived crude oil in the Alberta system over this time period was likely much higher on a percentage basis than the quantity of oil sands derived crude oil in the entire U.S. system. Nonetheless, the internal corrosion related failures in the Alberta system over this time period (per 1,000 pipeline miles per year) were approximately 24 percent lower than in the U.S. system. The combined internal and external corrosion related failures in the Alberta system over this time period (per 1,000 pipeline miles per year) were approximately 13 percent lower than in the U.S. system. Therefore, there is no evidence that the transportation of oil sands derived crude oil in Alberta has resulted in a higher corrosion related failure rate than occurs in the transportation of the variable-sourced crude oils in the U.S. system.

TABLE 3.13.5-4
Crude Oil Pipeline Failures U.S. and Alberta (2002-2010)

U.S. Crude Oil Pipeline Incident History[a]		
Incident/Failure Case	**Failures/Year**	**Failures per 1,000 Pipeline Miles per Year**
Corrosion - External	9.8	0.19
Corrosion - Internal	22.1	0.42
All Failures	89.3	1.70
Alberta Crude Oil Pipeline Incident History[b]		
Corrosion - External	2.3	0.21
Corrosion - Internal	3.6	0.32
All Failures	22.0	1.97

[a] PHMSA includes spill incidents greater than 5 gallons. U.S. has 52,475 miles of crude oil pipelines in 2008.
[b] Alberta Energy and Utility Board Report, includes spills less than 5 bbls. Alberta has 11,187 miles of crude oil pipelines in 2006.
Source: PHMSA 2011.

Several commenters have expressed concern that dilbits could be more corrosive to pipeline steel because of their total acid numbers (TAN), sulfur content, chloride salts content, and the entrained sediment composition. As explained below, these characteristics are generally either not indicative of the

corrosivity of a crude oil to pipeline steel, and/or the available information does not indicate that dilbits are substantially different than conventional crude oils produced in the WCSB, particularly the conventional heavy and the medium sour crude oils that have comprised the majority of Canadian imports into the U.S. since at least 1986.

The TAN of a crude oil does not indicate the corrosion potential of the crude oil to steel piping at temperatures below approximately 450 degrees Fahrenheit (PHMSA 2011). This is because the primary acids being measured by TAN are naphthenic acids which are not active below those elevated temperatures (Norman Kittrell Merichem Company 2006). The maximum operating temperature of the proposed Project pipeline would not exceed 150 degrees Fahrenheit. In light of the above, it appears that a relatively higher TAN number is not indicative of increased corrosion potential in a crude oil transmission pipeline. In addition, while the TAN for WCSB dilbits is higher than for most conventional Canadian crude oils, the dilbit TANs are generally in the midrange of heavy crude oils that are transported to and refined in PADD III, as presented in Table 3.13.5-7. Also, several California crude oils are noted for TANs that are more than double the TANs of the majority of the WCSB dilbits (Sheridan 2006). These California crude oils have been produced and transported by pipeline throughout California for several decades.

The dilbits have a sulfur content that is at the higher end of the range for crude oils produced in the WCSB. The two largest production dilbits, WCS and Cold Lake Blend (CLB), have similar sulfur contents to some of the heavy conventional Canadian crude oils, but other dilbits have a higher sulfur content. The sulfur content of a crude oil, however, is not itself indicative of potential increased risk of corrosion. This is because the sulfur may exist in the crude oil either as elemental sulfur or in a variety of compounds (e.g., hydrogen sulfide) that may or may not be corrosive. A report prepared for PHMSA addressing corrosion issues states that "For internal corrosion, the environment [potentially causing corrosion] would be water containing sodium chloride (salt), hydrogen sulfide, and or carbon dioxide." (Michael Baker Jr., Inc. 2008).

The hydrogen sulfide content of different crude oils is not typically reported in publicly available information. Hydrogen sulfide is present in some amount in most crude oils, particularly in sour crude oils, but can also be present in sweet crude oils in very small amounts. Total sulfur content of a crude oil, however, does not necessarily correlate with hydrogen sulfide content of that crude oil. For example, Mexican Maya is a heavy crude oil that typically has a total sulfur content of approximately 3.4 percent but reportedly has a hydrogen sulfide content of 100 parts per million (ppm); whereas Mexican Olmeca crude oil is a light crude oil that typically has a sulfur content of approximately 0.9 percent but has a hydrogen sulfide content higher than Mexican Maya crude oil at 116 ppm. Also, the Strategic Petroleum Reserve has four sour crude oil streams that have total sulfur contents of 1.41 to 1.46 percent, but hydrogen sulfide contents ranging from 17 to 82 ppm. Based on the available information, it does not appear that dilbits have elevated hydrogen sulfide levels compared to other crude oils, nor that a higher total sulfur content for a crude oil directly correlates to higher hydrogen sulfide content in the crude oil.

Some commenters have expressed concerns that WCSB oil sands derived crude oils would lead to a higher incidence of stress corrosion cracking (SCC). However, the composition of the crude oil is not a major factor in determining the potential for SCC. According to a report prepared for PHMSA (Michael Baker Jr., Inc. 2005),

> "...the single most important recommendation in the prevention of SCC is an emphasis on coatings that remain bonded to the pipeline, but allow the passage of cathodic protection current in the event of disbondment. Emphasis should also be placed on the quality assurance/quality control of the surface preparation and field application. These considerations would apply to both new pipeline installations as well as to coating replacement projects. Apart from this

consideration, there are limited practical recommendations for pipeline operation processes that can prevent SCC initiation. However, the emphasis must be such that procedures, especially the collection and integration of data specific to SCC development from in-line inspection and direct examinations, are identified and implemented to refine and update this model over time, which will help operators gain a better understanding of the SCC susceptibility. Therefore, it is recommended that operator plans reflect this need for continued data and knowledge development and sharing."

These findings and recommendations are consistent with the approaches included within the 57 Project-specific Special Conditions. Further, it is PHMSA's opinion that relative to SCC, key influencing factors include temperature, pipe coating, and external environment (particularly moisture). According to PHMSA, the coating system for the proposed Project is not conducive to SCC, and the limits on operating temperature included in Special Condition 15 would further reduce the risk of SCC. Therefore, PHMSA does not consider SCC to be a significant potential risk for the proposed KXL pipeline (PHMSA Pers. Comm. 2011).

One type of stress corrosion cracking is chloride stress corrosion cracking. Concern has been expressed that the dilbits have higher salt contents than many conventional crudes, and that this elevated salt content could lead to increased risk of chloride stress corrosion cracking. However, chloride stress corrosion cracking is not a mechanism of corrosion that affects carbon steel pipelines (A. I. [Sandy] Williamson Pers. Comm. 2011). Nonetheless, high salt/chloride content in a crude oil can contribute to internal corrosion, because the chloride ions may increase the conductivity of any water present in the crude (Michael Baker Jr., Inc. 2008). The WCS heavy crude oil salt content (40 pounds per thousand barrels [ptb]), is higher than that of other heavy crude oils shown in Table 3.13.5-7, but data available at the Crude Monitor website (www.crudemonitor.ca) indicates that salt content of the dilbits is in a similar range to the medium sour and heavy crude oils imported from Canada over the past 25 years. The five-year average salt content for the medium sour crude oils ranged from 15 to 65 ptb, for the heavy conventional crude oils ranged from 11.5-68 ptb, and for the dilbits ranged from 6.9 to 46.3 ptb (www.crudemonitor.ca).

Some commenters have expressed concerns that the sediment content of dilbits, particularly portions of the sediment that may be comprised of relatively harder quartz particles, could present increased risk of internal erosion of the proposed Project pipeline.

Relative to the basic sediment and water (BS&W) content of oil sands derived crude oil, bitumen produced by the original naphtha solvent-based process (dilution centrifuge as practiced by Suncor and Syncrude) has approximately 0.3 to 0.5 percent solids and 1 to 2 percent water. This makes it unsuitable for pipelining and direct sale to traditional refineries. However, a paraffinic solvent process commercialized in the Shell-led Albian Sands project has provided the means to produce bitumens that are lower in asphaltenes, substantively lower in BS&W, and more easily blended with other refinery feed stocks (Oil Sands Technology Roadmap: Unlocking the Potential Mining Based Bitumen Extraction). This product meets the necessary 0.5 percent BS&W limit for pipeline transport.

A substantive amount of water and inorganic particulate material is entrained in heavy crude oil during extraction and production. However, as indicated in Table 3.13.5-5, the WCSB medium conventional crude oils, WCSB heavy conventional crude oils, and WCSB dilbits have similar ranges of total sediment content.

TABLE 3.13.5-5
API Gravity and Total Sediment Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils

Crude Name (Origin)	API Gravity	Total Sediment (ppmw)[a]
WCSB Conventional		
Midale (MSM)	30.3 ± 0.6	380 ± 185
Mixed Sour Blend (SO)	31.3 ± 2.2	335 ± 71
SHE (SHE)	35.2 ± 2.2	285 ± 191
Bow River North (BRN)	21.5 ± 1.2	360 ± 136
Bow River South (BRS)	23.3 ± 0.6	219 ± 73
Fosterton (F)	20.4 ± 0.6	224 ± 53
Lloyd Blend (LLB)	20.9 ± 0.8	364 ± 95
Lloyd Kerrobert (LLK)	20.6 ± 0.8	324 ± 84
Western Canadian Blend (WCB)	20.7 ± 0.8	288 ± 104
WCSB Dilbit, Synbit, Dilsynbit, Heavy Synthetic		
Access Western Blend (AWB)	21.9 ± 0.9	231 ± 211
Cold Lake (CL)	20.8 ± 0.8	176 ± 103
Peace River Heavy (PH)	20.7 ± 0.7	179 ± 101
Seal Heavy (SH)	20.6 ± 0.8	215 ± 118
Smiley-Coleville (SC)	20.0 ± 0.7	238 ± 69
Wabasca Heavy (WH)	20.3 ± 0.7	183 ± 110
Western Canadian Select (WCS)	20.6 ± 0.8	392 ± 95
Long Lake Heavy (PSH)	20.7 ± 1.1	217 ± 248
Surmont Heavy Blend (SHB)	19.6 ± 0.6	187 ± 166
Suncor Synthetic H (OSH)	19.8 ± 0.3	187 ± 133
Albian Heavy Synthetic (AHS)	19.2 ± 0.3	714 ± 274

[a] ppmw = parts per million by weight.
Source: Crude Quality Inc. 2010.

It is noted that these sediment data do not include the specific composition of the type of sediment in the crude oils. Commenters have expressed concern that the level of internal erosion resulting from dilbit transportation could be related to the sediment composition and specific sediment characteristics, including particle hardness and size distribution. There are anecdotal industry reports suggesting that the sediment in oil sands crude oils may contain from 7 to 25 percent of harder sediments, such as silicates (quartz/sand) and iron sulfide (pyrite). However, based on the production method used for the majority of WCSB conventional heavy crude oils (Cold Heavy Oil Production with Sand, or CHOPS) (Government of Alberta. n.d.) it appears likely that those crude oils also contain quartz sand. The CHOPS method of production uses large amounts of sand to open up channels in the oil reservoir to enhance crude oil production. The amount of sand produced when employing CHOPS can range from 5 percent to as high as 40 percent in initial production stages at the wellhead. In 2000, it was estimated that 460,000 barrels of conventional heavy crude oil were produced using CHOPS and, historically, approximately 60-70 percent of the conventional heavy crude oil produced in the WCSB has been diluted and shipped to the U. S.

To mitigate against any pipeline wall thinning resulting from either corrosion or erosion, Special Condition 33 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and accepted by Keystone includes a requirement that Keystone build the Project to allow internal inline inspection (pigging) throughout and that it prepares and implements a corrosion mitigation and integrity management plan for segments that for any reason do not allow the passage of the inline inspection device. Special Condition 34 requires Keystone to limit basic sediment and water to 0.5 percent by volume and to annually report testing results to PHMSA. Additional measures include requirements to conduct cleaning runs twice in the first year of operation, and at least annually thereafter, and to test the liquids collected during those cleaning runs, including basic sediment and water. Special Condition 34 also requires that Keystone develop internal corrosion mitigation plans based on the results of those tests. This means that if the crude oil transported through the pipeline (whether produced conventionally or from the oil sands) did contain higher amounts of relatively hard sediments that might pose additional internal corrosion risk, Keystone would be required to develop a corrosion mitigation plan specifically to address that risk.

Special Condition 34 is more stringent than the existing regulatory requirements, and more stringent than the tariff specifications that would be in place for the proposed Project. The tariff that would need to be approved by U.S. Federal Energy Regulatory Commission (FERC) specifies that crude oils that exceed a combined bottom (or basic) sediment and water (BS&W) content of 0.5 percent by volume can be rejected. Specifically, Article 4 (Quality) of the FERC tariff would set forth the following specifications to govern the quality of the crude oil that shippers may tender for transportation in the proposed pipeline:

> —4.1 Permitted Petroleum.
>
> Only that Petroleum having properties that conform to the specifications of Petroleum described in Sections 4.2, 4.3 and 4.4 following will be permitted in the Pipeline System. Shipper will not Tender to Carrier (Keystone XL), and Carrier will have no obligation to accept, transport or deliver Petroleum which does not meet said specifications.
>
> 4.2 Specifications of Petroleum.
>
> For the purposes of Section 4.1, the specifications of the Petroleum shall be as follows: (i) Reid Vapor Pressure shall not exceed one hundred and three kilopascals (103kPa); (ii) sediment and water shall not exceed one-half of one percent (0.5%) of volume, as determined by the centrifuge method in accordance with ASTM D4007 standards (most current version) or by any other test that is generally accepted in the petroleum industry as may be implemented from time to time; (iii) the temperature at the Receipt Point shall not exceed thirty-eight degrees Celsius (38°C); (iv) the density at the Receipt Point shall not exceed nine hundred and forty kilograms per Cubic Meter (940 kg/m3); (v) the kinematic viscosity shall not exceed three hundred and fifty (350) square millimeters per second (mm2/s) determined at the Carrier‘s reference line temperature as posted on Carrier‘s electronic bulletin board; and (vi) shall have no physical or chemical characteristics that may render such Petroleum not readily transportable by Carrier or that may materially affect the quality of other Petroleum transported by Carrier or that may otherwise cause disadvantage or harm to Carrier or the Pipeline System, or otherwise impair Carrier‘s ability to provide service on the Pipeline System.
>
> 4.3 Modifications to Specifications.
>
> Notwithstanding Sections 4.1 and 4.2, or any other provision in these Rules and Regulations to the contrary, Carrier shall have the right to make any reasonable changes to the specifications under Section 4.2 from time to time to ensure measurement accuracy and to protect Carrier, the Pipeline System or Carrier‘s personnel, provided that Carrier shall give Shipper reasonable notice of such changes prior to filing.

4.4 Freedom from Objectionable Matter.

Petroleum shall not contain sand, dust, dirt, gums, impurities or other objectionable substances in quantities that may be injurious to Carrier, the Pipeline System or downstream facilities, or which may otherwise interfere with the transportation of Petroleum in the Pipeline System."

Some commenters have expressed concern about corrosion inhibiting agents that could be added to the crude oil prior to acceptance into the proposed pipeline. Corrosion inhibitors may be added to the crude oil stream with concentrations determined based on crude oil composition, supplier recommendations, and laboratory testing. Any heavy metals associated with corrosion inhibiting agents would be assessed and monitored as required by restrictions imposed through tariff specifications on pipeline transportation and other applicable regulations and requirements related to deleterious crude oil stream constituents.

In summary, while a focused, peer-reviewed study of the potential corrosivity/erosivity of WCSB oil sands derived crude oils relative to other crude oils has not yet been conducted, the existing information and analyses reviewed by DOS in consultation with relevant experts indicate that oil sands derived crude oils do not have unique characteristics that would suggest the potential for higher corrosion rates during pipeline transport of these crude oils.

Volatility/Instability

Concerns have been expressed about the potential volatility and/or instability of dilbits. The concerns are related to the possibility that dilbits are more volatile or unstable when being transported in a pipeline than crude oils currently transported in the U.S. pipeline system, including the possibility that dilbits would undergo flash volatilization when released into the environment through a breach in the pressurized pipeline.

One measure of the volatility of crude oil and petroleum products is the Reid Vapor Pressure (RVP). RVP is the vapor pressure at equilibrium of a hydrocarbon liquid at 100 degrees Fahrenheit in a closed system. A higher RVP indicates a higher level of crude oil volatility. As indicated in Figure 3.13.5-1, the RVP range for dilbits is comparable to the range for conventional heavy crude oils, and lower than the ranges for medium conventional crude oils, light conventional crude oils, and natural gas condensates. It should be noted that the RVP range for dilbits is lower than the range for condensates, indicating that once a diluent is homogeneously mixed with bitumen to create a dilbit, it exhibits the characteristics of that mixture rather than the characteristics of its individual components.

The RVP values confirm that light crude oils and medium crude oils have more "light ends" in that they have a higher concentration of lighter hydrocarbon molecules with lower boiling points that more readily evaporate. Based on information provided at www.crudemonitor.ca, dilbits have light end concentrations in the range of approximately 16 to 25 percent. The light conventional crude oils have light end concentrations in the range of approximately 29 to 42 percent, the medium conventional crude oils have light end concentrations in the range of approximately 27 to 36 percent, and the heavy crude oils have light end concentrations in the range of approximately 13 to 18 percent. These data are consistent with the conclusion that dilbit volatility is comparable to the volatility of conventional crude oils.

Additionally, crude oil is considered a largely homogeneous mixture of a variety of specific hydrocarbon molecules ranging from methane (one carbon) to asphaltines (hundreds of cross-linked carbons). The diluents used in mixture with bitumen to create dilbits are themselves a homogeneous solution of specific hydrocarbon molecules. When blended together with bitumen the resulting crude oil exhibits properties of the mixture – not the individual component parts that were used to produce the blend – and these properties fall within the range of the properties of other crude oils. Blending bitumen with condensate simply puts back components that evaporated from the rock containing the bitumen over millions of years of exposure. However, the gas condensate used as diluent is stabilized (i.e., contains no

hydrocarbon gases in solution under high pressure). The assertion that the rapid depressurization of a pipeline as a result of a pipeline breach would result in flash volatilization of gases contained in the diluents is therefore unfounded. The dilbit at rest prior to the development of pumping pressure is stable and at equilibrium between its component parts.

To illustrate this point, the publicly available American Petroleum Institute E&P Tank Program (API 4697) was utilized to assess working and standing losses of volatile compounds resulting from natural crude oil evaporation into air. While this program was designed to model emissions from tanks, it can be employed to provide a rough estimate of working and standing losses from a pipeline crude oil spill. It is recognized that there are limitations in the model's ability to simulate actual conditions involved in a specific pipeline oil spill at a specific location. For modeling purposes, a dilbit with an API gravity of 18 was compared to gas condensate (a typical diluent, API gravity 55.5), West Texas Intermediate (WTI) crude oil (API gravity 41.0), and Alaska North Slope (ANS) crude oil (API gravity 27.5) using the API model. It should be noted that actual WTI and ANS hazardous air pollutant (HAP) and volatile organic carbon (VOC) concentrations may vary since the actual mix of a specific WTI or ANS crude oil would depend on the composition of the blend. For the dilbit, a full component chromatograph assay of a proprietary unstabilized condensate was available which was modified to match the initial boiling point and heavy ends with bitumen as represented in a published dilbit boiling curve (TIAX 2009). The modeling indicates that the dilbit would produce evaporation (i.e., standing and working) total emissions of VOC and HAP about half the emissions of Alaska North Slope crude oil, and 5 to 20 percent of West Texas Intermediate, respectively. This is because the WTI and ANS crude oils are pipelined straight out of the ground and field stock tank, where the gases under pressure in the deep underground reservoir (i.e. methane, ethane, carbon dioxide) have flashed off but the whole crudes stored at atmospheric pressure are not stabilized by further removing residual light hydrocarbon gases such as propane and butane. In comparison with straight condensate, the bitumen in the dilbit blend acts to reduce the partial pressure of light hydrocarbons in the condensate, slowing evaporation. These results clearly show that the behavior of the dilbit is substantially different than the behavior of the unmixed diluent and bitumen taken separately.

Commenters have also expressed concern about the potential for gas pocket formation within the pipeline due to dilbit volatility. According to PHMSA, the potential for gas pocket formations exists during the transport of any crude oil and there are no technical studies that suggest that the potential for gas pocket formation would be any different for crude oils likely to be transported by the proposed Project compared to conventional crude oils. However, regarding the volatility of crude oils, the above comparisons of RVP and light ends content indicate that dilbits are generally less volatile than WCSB light and medium crude oils.

As with any petroleum pipeline, gas pocket formation could occur during a slack-line condition. A slack-line condition can occur in any crude oil pipeline when line flow is insufficient to keep the entire pipe volume filled with liquid, leading to sporadic non-liquid volume pockets. Gas pocket formation is related to local topography and crude oil flow rates. Real time transient modeling addresses this concern, although leak detection sensitivity can be affected. Special Conditions 25 through 32 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and incorporated into the proposed Project design, construction, and maintenance plan by Keystone specifically address the requirements of the SCADA system and its ability to detect leaks within the limitations of current technology. These conditions also address the requirement for SCADA operator training, including training to address transient flow conditions, and the need for the SCADA system to assess flow characteristics upstream and downstream of valve locations. Further, in response to a data request from DOS concerning design approach to address slack flow conditions, Keystone provided the following:

—Slack flow is defined as a condition where the pressure of the crude oil inside the pipeline is reduced such that the pipeline pressure is less than the vapor pressure of the crude oil itself. The Keystone XL pipeline, under design operating conditions, will not operate in slack flow. Keystone has ensured the operating regime allows for adequate pressure on the crude oil such that a slack flow condition will not arise. The pipeline's controls philosophy (inclusive of valve controls) accomplishes this by regulation of the suction and discharge pressures at the pump stations so they don't drop below the vapor pressure of the crude oil. Further, the pressure in the pipeline is continuously monitored by the Operations Control Center where pressure readings from transmitters placed no more than 20 miles apart along the pipeline are reported back through the SCADA system. Additionally, as Keystone has avoided extreme elevation changes along the route, natural causes for slack flow are eliminated."

Similar concerns relative to gas pocket formation during transport were raised as a result of an interpretation (NRDC 2011) of studies conducted at the University of Alberta on the complex phase behavior of heavy crude oils and bitumen in reservoirs. DOS contacted the author of the original studies to address this concern and determined that it would not be valid to infer from this research that dilbits are any more or less stable than other crude oils, or that they are more likely to cause pressure spikes during transport in pipelines or otherwise pose an increased risk to pipeline safety (John Shaw Pers. Comm. 2011).

Some commenters have expressed concern that air emissions in the event of a dilbit release from the pipeline would be very high and further that the emissions would contain unusually high levels of the volatile aromatic BTEX compounds. However, the total BTEX content of WCSB conventional medium to heavy crude oils is similar to and in a few cases substantially higher than the BTEX content of oil sands derived dilbit crude oils that would be transported by the proposed Project and less than the BTEX content of oil sands derived synthetic crude oils (see Table 3.13.5-6).

TABLE 3.13.5-6
API Gravity and Total BTEX Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils

Crude Name (Origin)	API Gravity	Total BTEX[a] (ppm)
Western Canadian Select (DilSynBit)	21.3	7,700 – 9,100
Midale (Conventional)	30.3	26,700
Mixed Sour Blend (Conventional)	31.2	10,300
Sour High Edmonton	35.0	29,100
Suncor Synthetic A	35.8	11,100
Cold Lake Blend (DilBit)	21.6	9,800
SynCrude Synthetic (Canada)	31.7	13,100
CNRL Light Sweet Synthetic (Canada)	35	9,500
Bow River South (BRS) – Conventional	23.3	9,300
Lloyd Blend (LLB) – Conventional	20.9	9,700
Western Canadian Blend (WCB) – Conventional	20.7	5,800

[a] BTEX = benzene, toluene, ethylbenzene, xylenes.
Source: Crude Quality Inc. 2010.

Characteristics of WCSB Heavy Crude Oils Compared to Other Heavy Crude Oils Currently Refined in PADD III

Several commenters have expressed concern that the composition of WCSB crude oils that would be transported to refineries in PADD III by the proposed Project would be substantially different from crude oils currently refined in PADD III. To address this concern, DOS has assessed the chemical composition of WCSB oil sands derived crude oils and compared them to other heavy crude oils, in particular those currently refined in PADD III.

Mexican Maya, Venezuelan Bachaquero, and Venezuelan Petrozuata crude oils are examples of heavy crude oils currently refined in PADD III. Maya is the "marker" heavy crude oil in the U.S. Gulf Coast with an API gravity ranging from approximately 22 to 25, with a sulfur content of approximately 3 to 3.7 percent by weight. Maya has greater than 35 percent vacuum residue by weight that is approximately 5 percent sulfur by weight, and high in vanadium and nickel with a combined concentration greater than 300 ppm. The two Venezuelan heavy crude oils have a sulfur content ranging from 2.4 to 2.7 percent by weight and a combined nickel and vanadium content of approximately 400 ppm. The vacuum residue for these two crude oils is approximately 59 percent by weight, and some Venezuelan crude oils (such as those from the Orinoco region) have a vacuum distillation residue of 60 percent by weight with a combined vanadium and nickel content in the range of 500 to 600 ppm.

A summary of the range of properties for heavy crude oils currently refined in the PADD III area is provided in Table 3.14.3-7. For comparison purposes, the table also includes properties for two heavy sour crude oils from the Middle East (Dubai Fateh and Arabian Safaniya) and a Canadian dilbit (Cold Lake Blend, a mixture consisting of approximately 70 percent bitumen and 30 percent gas condensate) that may or may not be transported by the proposed Project based on current Project planning. As discussed in more detail below, the WCSB crude oils that would be transported by the proposed Project have characteristics that make them of similar quality to heavy crude oils currently refined in PADD III.

The chemical characteristics of a selection of crude oils are presented in Table 3.13.5-7. These selected crude oils include:

- Western Canadian Select and Suncor Synthetic crudes, representative of WCSB crude oils that would be transported by the proposed Project. (The typical chemical composition of the WCSB crude oil that would be transported by the proposed Project was provided in the May 1, 2009 Response to DOS Data Request #1 and updated with additional details in the July 15, 2010 Response to DOS Data Request #4);
- Crude oils that are currently refined in PADD III and that would be partially or wholly replaced by crude oils that would be transported by the proposed project;
- Two reference heavy crude oils from the Middle East; and
- Another representative WCSB crude oil, the Canadian Cold Lake Blend.

It is apparent from the data provided in Table 3.13.5-7 that the heavy crude oils that would be transported by the proposed Project are comparable to the existing heavy crude oils refined in PADD III. The sulfur content is similar to Mexican Maya, but slightly higher than the other heavy crude oils such as Venezuelan Bachaquero. The nickel and vanadium content would be higher than the Middle Eastern crude oils, but lower than Mexican Maya and the Venezuelan crude oils. Overall, the nickel and vanadium content of the WCSB crude oils is within the expected range for crude oils with an API gravity less than 28 (API 2011). Additionally, mercury content, although not typically reported in crude oil assays, would likely be lower, since Canadian crude oils, and WCSB crude oils in particular, have lower

concentrations of total mercury than oils from foreign sources such as Mexico and South America (Hollebone and Yang 2007). Heavy crude oil from Mexico has not been frequently tested for mercury but estimates suggest that those levels may be two to nearly 10 times the average for WCSB crude oils and from 1.5 to 6 times higher than synthetic crude oils produced from the Alberta oil sands. The average mercury level across all grades of Venezuelan crude oils is three times the average in WCSB crude oils and two times the average for synthetic crude oils from the Alberta oil sands. Finally, the total BTEX content of the WCSB crude oils is higher than the Mexican Maya and Venezuelan crude oils, but considerably lower than Arabian Heavy crude oil. Also, the BTEX content of heavy crude oils is generally lower than lighter crude oils (e.g., West Texas Sour and Brent Blend), many of which have twice the BTEX content of the heavy crude oils (Environment Canada 2011).

Additionally, the quality of Maya crude oil imported to PADD III has recently declined. In early 2010, the Maya crude oil had a higher than normal salt and metals content, which led to increased downtime at Mexican refineries (Reuters, June 8, 2010 –Poor Maya crude quality hampers Mexico refineries"). Reportedly, the viscosity of Maya crude oil processed in Mexico has also risen sharply in recent years due to a greater proportion of extra-heavy crude oil from the Ku Maloob Zaap field being added to the domestic Maya blend leading to increased viscosity and the likelihood that the potential corrosivity of the Maya crude oil has also been adversely affected. It should be noted, however, that Maya crude oil has been received for many years at the Louisiana offshore oil port (LOOP) at three offshore single-point moorings and transported to shore through a 56-inch external diameter submarine pipeline.

In summary, the DOS analysis of these crude oils indicates that the WCSB heavy crude oils that would be transported by the proposed Project are not substantially different than the heavy crude oils currently refined in PADD III.

TABLE 3.13.5-7
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian[a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A[a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya[b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata)[c]	Cold Lake Blend[d] (Dilbit; Hardisty)	Dubai Heavy[b] (Fateh)	Arabian Heavy[e, b] (Safaniya)
Density (kg/m^3)	929.4 ± 4.8	858.6 ± 6.6	935.9 @15°C	967.9 @15°C	928.4 ± 5 @15.5°C	873.5 @15°C	0.889
Gravity (°API)	20.6 ± 0.8	33.2 ± 1.3	1.3 - 25.1	16.8 / 19.5	19.7 – 21.2	30.4 - 31.1	27 – 28
Vacuum Residue (wt%)	32[f]	0.3[f]	35 -- 45	59[g]	45 -- 50	20 – 22	19
Sulphur (wt%)	3.40 ± 0.14	0.19 ± 0.03	3.0 – 3.7	2.40 / 2.69	3.66 – 3.95	2 – 2.13	2.9 – 3
Hydrogen Sulphide or Mercaptan Sulphur (wt%)	Alberta Canadian L&M Crudes[h] 0.0020% - 0.0058%	0.0100%	0.0100%	--	0.0034%	< 0.0001%[i]	
MCR (wt%)	9.46 ± 0.40	ND	--	17.3	10.48 ± 0.36	--	--
Bottom Sediment & Water (out) (%v)	0.38% ± 0.095%v	<<0.5%	0.7%-1.5%[j,k]	--	--	--	0.29%[j,k]
TAN (mgKOH/g)	0.88 ± 0.11	--	0.40	1.20	0.94 ± 0.1	0.05	0.4[d]
Salt (ptb)	40.0 ± 13.6		--	6[l]	--	11.9 ± 3.2	--
Mercury (mg/Kg)	1.4 ± 0.3 ; 2.2 ± 0.4[m]	3.5; 13.5[n]	4.2[o,n]	--	--	--	
Nickel (mg/L)	55.9 ± 3.4	ND	45.8 ± 7 (n=3)	55 – 84	65.2 ± 3.6	14 – 19	22 – 25
Vanadium (mg/L)	134.1 ± 10.3	0.1 ± 3.8	267 ± 23 (n=4)	324 – 303	169 ± 11.2	42 – 58	70
Olefins (wt%)	ND	ND	--	--	--	--	--
Naphtha (wt%)	8.9	--	15	2 – 8	16	11.5 – 16	14.7
S:A:R:A (wt%)	11% S: --: --: 33% A	--: --: --: --	23 : 35 : 15 : 27	4 : 4 : 59 : 33	--: --: --: --	--: --: --: 2% A	--: --: --: 9.6% A 5%S: --: --: 11% A
Benzene	0.14	0.15 ± 0.02	0.05 ± 0.03	0.05	0.24 ± 0.03	6.5	0.99

TABLE 3.13.5-7
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian[a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A[a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya[b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata)[c]	Cold Lake Blend[d] (Dilbit; Hardisty)	Dubai Heavy[b] (Fateh)	Arabian Heavy[e, b] (Safaniya)
Toluene	0.25	0.27 ± 0.04	0.24 ± 0.05	0.13	0.37 ± 0.05	--	3.98
Ethyl Benzene	0.05	0.06 ± 0.01	0.15 ± 0.02	0.07	0.05 ± 0.01	--	2.18

Notes:

"—" No Information obtained as of the date of this report.
ND = Not Detected
S:A:R:A Percent Saturates : Aromatics : Resins : Asphaltenes in whole oil

%BS&W Out: Percent Bottom Sediment and Water after a dehydration process. For example, Maya crude has ~15% BS&W In; pre-dehydration; and 0.7-1.5% BS&W Out; post dehydration (Warren 2002)

[a] Western Canadian Select and Suncor Synthetic A crude data generally from the Canadian crudemonotor: http://www.crudemonitor.ca/crude.php?acr=WCS and http://www.crudemonitor.ca/crude.php?acr=OSH, respectively.

[b] Maya and Dubai (Fateh) data from:

http://www.etc-cte.ec.gc.ca/databases/Oilproperties/; Jacobs Consultancy and Life Cycle Associates. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes. File No. AERI 1747. Prepared for Alberta Energy Research Institute. July 2009

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[c] Bachaquero http://www.etc-cte.ec.gc.ca/databases/Oilproperties/;and Petrozuata.

[d] Cold Lake Blend from:

www.exxonmobil.com/apps/crude_oil/crudes/mn_cold.html; http://www.crudemonitor.ca/report.php?acr=CL
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http://www.oildrop.org/Info/Centre/Lib/7thConf/19980094.pdf

[e] Arabian heavy crude data from:
Al Darouich, T. F. Béhar, C. Largeau, and H. Budzinski. 2005. Separation and Characterisation of the C15- Aromatic Fraction of Safaniya Crude Oil. *Oil & Gas Sci. Technol.Rev. IFP. 60*:681-695;

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http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Arabian_Heavy.pdf

[f] Swafford, P. 2009. Understanding the quality of Canadian bitumen and synthetic crudes. Crude Oil Quality Group Meeting. February 26, 2009. 32 pp.

[g] Ancheyta, J. and J.G. Speight. 2007. Hydroprocessing of heavy oils and residua. CRC Press. 345 pp.

[h] Oil & Gas Journal Data Book, 2006. p. 240. Data for light and medium Alberta crudes; H_2S data not obtained for Western Select or Suncor Synthetic crudes but the content would likely be comparable to the listed range.
http://books.google.com/books?id=YmLik9YY4uUC&pg=PA240&dq=canadian+crude+h2s&hl=en&ei=fcJoTc36HYSusAO1qJT9Cw&sa=X&oi=book_result&ct=result&resnum=2&ved=0CEUQ6AEwAQ#v=onepage&q=canadian%20crude%20h2s&f=false (last accessed 26 Feb 2011)

[i] Capline Systen Crude Oil Properties and Quality Indicators. 7 Jan 2004. http://www.caplinepipeline.com/documents/CaplineCrudeListq_4_qtr_2003.pdf (last accessed 26 Feb 2011).

[j] Warren, K.W. 2002. New tools for heavy oil dehydration. SPE Internl Thermal Ops and Heavy Oil Symposium & Internl Horizontal Well Technol Conf., Calgary, Alberta, CAN, 4-7 Nov. 6 pp.

[k] Sams G.W. and Warren K. 2006. New electrostatic technology for desalting crude oil. National Petrochemical & Refiners Association, Spring National Conference, March 2006.

[l] White, S. and T. Barletta. 2002. Refiners processing heavy crudes can experience crude distillation problems. *Oil & Gas J*. Nov 18, 2002

[m] Average for WCSB crude oils per Hollebone, B.P. and C.X. Yang, 2007, including the higher average of 2.2 mg/kg volume-weighted concentration in synthetic crude oils produced from Alberta oil sands. Mercury in Crude Oil Refined in Canada, *Environment Canada*, Ottawa, ON. 82 pp.

[n] Two estimates for mercury in Maya crude by Acosta y Asociados (2001) and EPA (1997) as cited by Acosta y Asociados (2001). Acosta y Asociados Preliminary atmospheric emissions inventory of mercury in Mexico. Project CEC-01. Prepared for Commission for Environmental Cooperation (No. 3.2.1.04). May 30, 2001. P. 18-19.

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[o] Average for all Venezuelan oil types (Wilelm et al. 2007)

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Habitat, Natural Resources, and Human Use Receptors

The impact of an oil spill would be heavily influenced by the types of receptors (i.e., habitats, natural resources, and human uses) that might be exposed to the oil. For this EIS, these receptors are generally categorized and described in the following bulleted list, in increasing order of likely environmental impacts and concern to the spectrum of potential stakeholders:[3]

- Terrestrial–agricultural land. Includes grazing, field and row crops, fallow fields, and similar land uses.
- Terrestrial–natural habitat. Includes native and second-growth forests, naturally restoring grasslands, and similar areas that are not being used directly by people for commercial purposes.
- Groundwater. Emphasis is on areas where a public drinking groundwater aquifer is close to the ground surface and/or is overlain by soils permeable to oil or by karst formations.
- Aquatic–wetland habitat. Includes all areas that meet the definition of wetlands.
- Aquatic–lake/pond habitat. Includes agricultural stock ponds, irrigation and drainage ditches, small and large lakes, reservoirs, and similar non-flowing waterbodies.
- Aquatic–stream/small river habitat. Includes smaller flowing waterbodies as well as those that are intermittent or ephemeral. These generally do not support commercial boat traffic and are not restricted with dams or major reservoirs. Some may support important recreational resources and activities or may be limited in beneficial uses.
- Aquatic–large river habitat. Includes large flowing waterbodies (e.g., Yellowstone River, White River, Niobrara River, Platte River, Missouri River, Loup River, Red River, and Canadian River) that are perennial, may support commercial traffic, and/or may be restricted by dams and major reservoirs.
- Threatened and endangered species and their critical habitat. Most are USAs and are a special case of resources that may be found in any of the habitats but are limited in population size or spatial distribution.
- Human use–residential. Areas where the proposed pipeline ROW is near rural, suburban, or urban populations. Towns and cities generally have population densities that qualify the area as an HCA. Areas of special concern include any concentrations of low-income or minority populations that could represent environmental justice issues.
- Human use–recreational. Areas, especially lakes, small and large rivers, and reservoirs and associated parks used by people for various recreational activities.
- Human use–commercial. Areas that may be closed to normal use during a spill response action and result in substantive economic impacts.
- Human use–surface water intakes. Many public water intakes are located in reservoirs, and large rivers. Human uses include drinking water, industrial cooling water, and/or agricultural water.

[3] The directly impacted stakeholders (e.g., ranchers, farmers, homeowners) would likely consider the impacts to their resources as very high concern regardless of the overall impact in an ecosystem context. Also, USAs and HCAs would be considered sensitive receptors due to their designation and their ecological or human use significance.

Season

The season in which a spill occurs could dramatically influence spill behavior, fate, impacts, and cleanup response actions. Seasonal variations in potential spill behavior are addressed in this section.

Spring-Fall

The length and timing of the spring-fall season depends on location along the proposed pipeline route and the ambient weather regime. For this EIS, this time period is generally defined as the period when the ground is mostly free of snow and access to the proposed pipeline ROW is not restricted by snow and ice. Most of the rivers and creeks are flowing; ponds, lakes, and reservoirs exhibit open water; land is mostly snow-free; and biological use of land and waterbodies is high. Currents, winds, and passive spreading forces would disperse spills that reach the waterbodies. Spills to land would directly affect the vegetation, although dispersal of the spilled material is likely to be impeded by the vegetation. Spills to wetlands may float on the water or be dispersed over a larger area than would spills to dry land or to ice and/or snow-covered land and waterbodies associated with the wetlands.

Winter

Winter is the period when waterbodies may be covered with ice and possibly snow, and the land surface may be partially to completely covered with snow. Dispersal of oil spilled to the land generally would be slowed, although not necessarily stopped, by the snow cover. Depending on the depth of snow cover as well as the temperature and volume of spilled material, the spill may reach the underlying dormant vegetation or wetlands, ponds, and lakes. Similarly, spills to flowing rivers and creeks generally would be restricted in area by the snow and ice covering the waterbody, compared to seasons with little or no snow and ice cover. Spills under the ice to creeks, rivers, and ponds/lakes might disperse slowly as the currents are generally slow to non-existent in winter. However, because of snow and ice, winter spills may be harder to detect and, when found, more difficult to contain and clean up.

Freeze-up and Breakup in Aquatic Environments

Freeze-up is the transition time in the fall when the lakes and rivers begin to freeze over in the northern regions of the pipeline route. Breakup or spring melt is the short transition period between winter and spring when thawing begins, ice thins and/or breaks up, and river flows increase substantively and quickly, often to flood stages. Major floods may cause bank erosion and ultimately pipeline failure, with the oil entering the river and likely being widely dispersed and difficult to contain or clean up.

An oil spill that results in oil reaching waterbodies during either freeze-up or breakup may be difficult to contain, remove and cleanup. The ice may not be strong enough to support people or equipment. In rivers, the oil may be transported several miles under the ice or in broken ice before it can be contained. Once the ice is strong enough to support people and equipment, it may be more difficult to detect the oil under the ice and to implement measures to affect rapid containment/cleanup at and near the spill site.

Weather and Water Levels

Weather, especially rapid warming periods and heavy rainfall, may cause rapid ice melt in rivers, snowmelt and runoff. These could result in major flood flows that breach levees along larger rivers, erode river banks, alter channels, and expose the proposed pipeline to forces that may break or rupture it. This scenario, although a very low-likelihood event especially at HDD crossings, could occur at large or

small stream or river crossings not spanned by HDD[4]. If spilled oil is released to the flooded area, especially to flowing waters, oil could be distributed to adjacent terrestrial, wetland, and aquatic habitats that normally would not be exposed. These habitats and natural resources, as well as human uses of the habitats and resources, may be exposed to the spilled material.

Concern was expressed in comments on the draft EIS relative to potential spray zones associated with operational leaks from the proposed pipeline. Winds, especially high-velocity sustained winds, could spread material released under pressure from hole(s) in the top hemisphere of an exposed portion of the pipeline to create a "spray zone." To generate a spray zone a potential leak would need to occur on the upper hemisphere of the proposed pipeline. If corrosion related leaks occurred, they would typically occur on the lower hemisphere of the pipeline and would likely be associated with entrained water. The implementation of the Project-specific Special Conditions developed in consultation with PHMSA would make such leaks highly unlikely. Potential leaks on the upper hemisphere of the proposed pipeline would likely be associated with accidental equipment impact. However, the likelihood of such events is significantly reduced by the 4-foot minimum cover requirement in most areas and the implementation of public awareness and damage prevention programs. However, if such a release were to occur, ejected material could form a cloud of mist and fine particles, and could be carried downwind. The extent of distribution would depend on wind velocity, direction of the released spray (e.g., downward into the ground, horizontal, or skyward), and characteristics of the release (e.g., pressure in the pipeline, type of oil, size of hole). Under most scenarios, the pressure in the pipeline would drop quickly, the release would be highly visible, and immediate pipeline spill control and shutdown actions would be taken[5] by the CMP and SCADA as well as the onsite personnel. If a leak would occur on the upper hemisphere of the pipeline, Keystone has estimated that the maximum spray zone for an exposed portion of the pipeline would be in the range of 75 to 400 feet (i.e., the areal extent of the release to land would be limited to a few acres or less in the immediate area of the release point and downwind of the release point).

Major flooding or adverse weather conditions (e.g., high winds, tornados, blizzards, and extreme cold) could limit Keystone's ability to detect small releases and/or hinder the spill response contractors from implementing timely and effective oil spill containment and cleanup operations. Response actions appropriate for these conditions would be addressed in the ERP and the PSRP (see Section 2.4.2.2).

3.13.5.2 Keystone Response Time and Actions

For spills ranging in magnitude from very small to substantive, response time and actions by responders would most likely prevent the oil from reaching sensitive receptors or would contain and clean up the spills before significant environmental impacts occurred. Most spills in this category are likely to occur on construction sites or at operations and maintenance facilities, and would not be released to the environment outside of these Project-related areas.

For large spills, very large spills and potentially some substantive spills, especially those that reach aquatic habitats, the response time between initiation of the spill event[6] and arrival of the response contractors would influence the magnitude of impacts to the environmental resources and human uses. This would be particularly true if the oil reaches flowing waters in major rivers. Once the responders are

[4] These type of events account for less than 4 percent of spills (see Table 3.13.1-3) and Keystone has a proactive, preventative plan to shut down the pipeline if severe weather or any other natural event poses a threat to the pipeline integrity.

[5] The SCADA system would shut down the pipeline within 12 minutes of detection of the release (Sections2.4.2.1 and 3.13.5.5).

[6] "Initiation of the event" means when the oil began to leak or spill to the environment, not when it is detected by either the SCADA or other means. There may be a substantive delay between initiation and detection, particularly for slow or pinhole leaks under snow or below ground.

at the spill scene, the efficiency, effectiveness, and environmental sensitivity of the response actions (e.g., containment and clean up of oil, and protection of resources and human uses from further oiling) would substantively influence the type and magnitude of additional environmental impacts.

In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two spill scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight that would be in place relative to potential spills from the proposed Project.

The first hypothetical spill occurs in the summer in an area with deep groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone describes the following:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;
- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline (see Section 2.4.2.2 for additional information on the Keystone ERP). Based on its review of the hypothetical spill response scenarios, DOS considers Keystone‘s response planning appropriate and consistent with accepted industry practice.

3.13.5.3 Factors Affecting the Behavior and Fate of Spilled Oil

The primary and shorter-term processes that affect the fate of spilled oil are spreading, evaporation, dispersion, dissolution, and emulsification (Payne et al. 1987, Boehm 1987, Boehm et al. 1987, Overstreet and Galt 1995). These processes are called weathering. Weathering dominates during the first few days to weeks of a spill. A number of longer term processes also occur, including photo-degradation and biodegradation, auto-oxidation, and sedimentation. These longer-term processes are more important in the later stages of weathering and usually determine the ultimate fate of the spilled oil that is not recovered by the cleanup program.

The chemical and physical composition of oil changes with weathering. Some oils weather rapidly and undergo extensive changes in character, whereas others remain relatively unchanged over long periods. Because of evaporation, the effects of weathering are generally rapid (one to a few days) for hydrocarbons with lower molecular weights (e.g., gasoline, aviation gas, and diesel). Degradation of the higher weight fractions (e.g., crude oil, transmission and lube oil, and hydraulic fluid) is slower and occurs primarily through microbial degradation and chemical oxidation. The weathering or fate of spilled oil depends on the oil properties and on environmental conditions, both of which can change over time.

Spreading

Spreading reduces the bulk quantity of oil present in the vicinity of the spill but increases the spatial area over which adverse effects could occur. Thus, oil in flowing systems (e.g., rivers and creeks) rather than contained systems (e.g., wetlands, ponds, and lakes) would be less concentrated in any given location but could cause impacts, albeit reduced in intensity, over a larger area. Spreading and thinning of spilled oil also increases the surface area of the slick; enhancing surface-dependent fate processes such as evaporation, biodegradation and photo-degradation (see below), and dissolution. However, experience on previous oil spills suggests that the degree of spreading of an oil spill from the spill source is constrained by natural conditions in the vicinity of the release site. For example, in a crude oil release from a pipeline system on August 20, 1979 near Bemidji, Minnesota, approximately 10,700 barrels of crude oil was released onto a glacial outwash deposit consisting primarily of sand and gravel. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient. Spreading in subsurface water is discussed further in 3.13.6.3.

Adsorption

Crude or refined oil dispersed in soil would adsorb or adhere to soil particles. Crude oil would usually bind most strongly with soil particles in organic soils and less strongly with soil particles in sandy soils. In water, heavy molecular weight hydrocarbons may bind to suspended particulates, and this process can be significant in highly turbid or eutrophic waters. Organic particles (e.g., biogenic material) in soils or suspended in water tend to be more effective at adsorbing oils than inorganic particles (e.g., clays). Sorption processes and sedimentation reduce the quantity of heavy hydrocarbons present in the water column and available to aquatic organisms. However, these processes also render hydrocarbons less susceptible to degradation. Oil in sediment tends to be highly persistent and can cause chronic impacts.

Evaporation

Evaporation is the primary mechanism for loss of low-molecular-weight constituents and light oil products. However, recent studies related to the MC-252 oil spill in the Gulf of Mexico (Deepwater Horizon incident) indicate that higher molecular weight constituents from spilled oil also volatilize over time and distance from the spill source (De Gouw 2011). As lighter components evaporate, remaining petroleum hydrocarbons become denser and more viscous. Evaporation tends to reduce oil toxicity but enhance persistence. Hydrocarbons that volatilize into the atmosphere are broken down by sunlight into smaller compounds. This process, referred to as "photo-degradation," occurs rapidly in air; the rate of photo-degradation decreases as molecular weight increases.

Dispersion

Dispersion of oil is the spreading of oil in water and dispersion increases when water surface turbulence increases. Wind, gravity, tidal currents, or broken ice movement could cause the turbulence. Dispersion of oil into water increases the surface area of oil susceptible to dissolution and degradation processes, and

thereby limits the potential for physical impacts. However, some of the oil could become dispersed in the water column or on the bottom as it adheres to particulate matter suspended in the water column. The presence of particulates, including organic matter, silt and clay, and larger sediment particles, is likely to be greatest during spring ice breakup, flood flows, and wind storms.

Dissolution

Dissolution of oil involves soluble oil components dissolving in a water column. Dissolution in water is not the primary process controlling the fate of the oil in the environment (i.e., oil generally floats on rather than dissolves into water). Despite the characterization of crude oil that would be transported by the proposed Project as heavy crude oil, it would still be lighter than water based on its characteristic specific gravity. Some crude oil components are water-soluble and to the extent that dissolution does occur, it is one of the primary processes affecting the toxic effects of a spill, especially in confined waterbodies. Dissolution increases with decreasing hydrocarbon molecular weight, increasing water temperature, decreasing water hardness or "salinity," and increasing concentration of dissolved organic matter. Under the same environmental conditions, lighter weight petroleum hydrocarbons (e.g., BTEX) would dissolve more readily than the heavier fractions such as PAHs.

Emulsification

Emulsification is the incorporation of oil in water in a colloidal suspension. During emulsification, small drops of water become surrounded by oil. External energy from wave or strong current action is needed to naturally emulsify oil. In general, heavier oils emulsify more readily than lighter oils. The oil could remain in a slick, which could contain as much as 70 percent water by weight and could have a viscosity of a hundred to a thousand times greater than the original oil. Water-in-oil emulsions often are referred to as "mousse." Emulsifications are more common in large water bodies (e.g., large lakes, major rivers, and the ocean) where waves and/or currents mix the surface waters than in smaller water bodies where this mixing energy is usually much less.

Some commenters on the draft EIS were concerned that the bitumen component of WCSB crude oil that would be transported by the proposed Project (specifically dilbits), if released to a waterbody, would be expected to sink and accumulate on the underlying bed of the waterbody leading to difficult cleanup during spill response. This concern is apparently based on the characteristics of a bitumen-based product called Orimulsion. This product is a combination of bitumen (about 70 percent), water (about 30 percent), and surfactants (less than 1 percent) and forms an emulsion (colloidal suspension) that is materially different from the crude oils that would be transported by the proposed Project. Since the ingredients of Orimulsion do not form a solution when combined, they separate into bitumen particles, water, and surfactant when released into water. Additionally, since the specific gravity of the bitumen is either equal to or greater than the specific gravity of water, it can sink after de-emulsification. This does not occur in dilbits, such as the Western Canadian Select crude oil, because the bitumen blended with diluents forms a solution with a specific gravity less than water that would not separate when released and that would initially tend to form a lenticular mass that would float on the water column. However, given sufficient time for volatilization and biodegradation, any crude oil residuum can become more dense than water and sink.

Photo-degradation

Photo-degradation of oil increases with greater solar intensity. It can be a significant factor controlling the disappearance of a slick, especially of lighter constituents, but it would be less important during cloudy days and in winter months. Photo-degraded petroleum constituents tend to be more soluble and

more toxic than parent compounds. Extensive photo-degradation leading to increased dissolution could increase the biological impacts of a spill event.

Biodegradation

Biodegradation is the breakdown of compounds by native or introduced microorganisms. Biodegradation of oil by native microorganisms, in the immediate aftermath of a spill, would likely not be a significant process controlling the fate of oil in waterbodies previously unexposed to oil. Although oil-degrading microbial populations are ubiquitous at low densities, a sufficiently large population must become established before biodegradation can proceed at any appreciable rate. Biodegradation is typically a long-term (weeks to years) process that reduces both the toxicity and volume of spilled oil.

3.13.5.4 Summary of Environmental Factors Affecting the Fate of Spilled Oil

The environmental fate of released oil and oil products is controlled by many factors. Major factors affecting environmental fate include the spill volume, spill rate, oil temperature, terrain, receiving environment, time of year, and weather. Crude oil would weather differently than diesel or refined products in that both diesel and refined products would evaporate faster and dissolve to a greater degree into water than crude oil.

The characteristics of the receiving environment, such as the type of land cover, soil porosity, land surface topography and gradient, type of freshwater body, presence of ice and/or snow cover on water or land, and flowing water current velocity, would affect how the spill behaves. In ice-covered waters, many of the same weathering processes occur as in open water. However, ice changes the rates and relative importance of these processes (Payne et al. 1991).

The time of year when a spill occurs has a major effect on the fate of crude oil. The time of year controls climatic factors such as temperature of the air, water, or soil; depth of snow cover; presence of ice; and the depth of the active (soil frost) layer. During winter, colder air temperatures can modify the viscosity of oil so that it would spread less and potentially solidify. Temperature also affects the rate of evaporation of the volatile fraction of hydrocarbons. Frozen ground would limit the depth of penetration of any spill. Weather could also affect the ability to detect, contain, or clean up a spill.

3.13.5.5 Actions to Prevent, Detect, and Mitigate Oil Spills

The proposed Project would include processes, procedures, and systems to prevent, detect, and mitigate potential oil spills that could occur during operation of the proposed pipeline. These are summarized below. The final ERP would contain further detail on response procedures and would be completed and reviewed by PHMSA prior to granting permission to operate the proposed pipeline.

Oil Spill Prevention

Immediate control, containment, and cleanup of released oil are important factors in limiting the spatial and temporal effects of a spill. Keystone conducted a pipeline threat analysis using the pipeline industry-published list of threats under ASME B31.8S to determine the applicable threats to the proposed pipeline (see Appendix P). Safeguards were then developed to protect against these potential threats, which have been identified as follows:

- Incorrect pipeline operations (e.g., overpressure of the pipeline);
- Materials and construction damage (e.g., flaws such as defective welds, dents, cracks, nicks in the coating that are a result of transport or construction, and flaws in the seam of the pipeline created during the manufacturing process);
- Corrosion (e.g., internal, external, and stress-corrosion cracking) including defects that develop over time during operation;
- Accidental damage such as external contact with the pipeline (e.g., third-party backhoes, excavators, and drills); and
- Facility damage from natural hazards (e.g., landslides, floods, and earthquakes).

Some commenters expressed concern regarding the threat of terrorism. In the aftermath of the terrorist attacks that occurred on September 11, 2001, terrorism has become a very real issue for infrastructure throughout the country. Since that date, there has been an increase in security awareness throughout the pipeline industry and the nation. The Office of Homeland Security was established with the mission of coordinating the efforts of all executive departments and agencies to detect, prepare for, prevent, and protect against, respond to, and recover from terrorist attacks within the U.S.

There are currently about 500,000 miles of interstate oil and gas transmissions lines, and hundreds of thousands of miles of oil and gas gathering lines and distribution lines throughout the country. Although safety and security are important considerations for those facilities, the number, lengths, and locations of the pipelines precludes having guards, cameras, and other types of continuous surveillance and protection measures. However, to reduce the vulnerability of the proposed Project to terrorism, the pipeline would be buried to a minimum depth of 4 feet, and mainline valves, pump stations, and the Cushing tank farm would be surrounded by locked security fencing. The pipeline route would be routinely inspected by air and ground patrols as required by PHMSA, and the aboveground facilities would routinely be visited by maintenance and monitoring crews.

The likelihood of future attacks of terrorism or sabotage occurring along the proposed Project route, or at any of the many crude oil pipelines, refined product pipelines, natural gas pipelines, or other energy facilities throughout the U.S. is unpredictable given the disparate motives and abilities of terrorist groups. Despite the ongoing potential for terrorist acts along any of the nation‘s crude oil, product, and natural gas pipelines, the continuing need for the construction of these facilities is not eliminated.

Safeguards were included in the proposed Project‘s design and would be implemented during construction and operations. These include:

- Pipe specifications that meet or exceed applicable regulations;
- Use of the highest quality external pipe coatings (fusion bond epoxy or FBE) to prevent corrosion;
- Providing 4 feet of soil cover over the buried pipeline in most locations, which exceeds federal standards;
- Public awareness and damage prevention programs in accordance with 49 CFR 195.440 and RP 1162;
- Implementing a variety of pipeline system inspection and testing programs prior to operation, to prevent leaks. Examples of these programs include: an extensive pipeline quality assurance program for pipe manufacturing and coating; non-destructive testing of 100 percent of girth welds; hydrostatic testing in conformance with Special Conditions 8 and 22, that require the pipe

to be subjected to a mill hydrostatic test pressure of 95 percent SMYS or greater for 10 seconds and the pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100 percent SMYS for mainline pipe and 1.39 times MOP for pump stations for 8 continuous hours;

- An operational pipeline monitoring system (Supervisory Control and Data Acquisition [SCADA]) that remotely measures changes in pressure and volume every 5 seconds on a constant basis. These data would be immediately analyzed to determine potential product releases anywhere on the pipeline system;
- Periodic pipeline integrity inspection and cleaning programs using internal inspection tools (pigs) to detect pipeline anomalies indicating excavation damage, and loss of wall thickness from corrosion;
- Aboveground aerial and ground surveillance inspections (ground-level patrols would be undertaken in the event of a suspected leak but would not be routinely undertaken). The aerial inspections would be conducted 26 times per year (not to exceed 3 weeks apart) to detect leaks and spills as early as possible, and to identify potential third-party activities that could damage the proposed pipeline; and
- Installing MLVs along the proposed pipeline route in accordance with PHMSA regulatory requirements and PHMSA Special Condition 32 (see Appendix U) to reduce or avoid spill effects to PHMSA-defined HCAs.

In addition to the regulatory requirements and industry standards to be incorporated into the design, PHMSA developed a set of Project-specific Special Conditions (see Appendix U) that have been agreed to by Keystone and would be incorporated into the proposed Project. Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

Oil Spill Detection

In addition to the integrity systems and measures that would be implemented as described in Section 2.4.2.1 to maintain pipeline integrity and minimize spills, the proposed Project would utilize a SCADA system that would alert the Operations Control Center (OCC) operator of an abnormal operating condition, indicating a possible spill or leak. SCADA would be installed in accordance with the requirements of 49 CFR 195.446 and the Project-specific Special Conditions (see Appendix U).

SCADA facilities would be used to remotely monitor and control the pipeline system. This would include a redundant fully functional backup system available and ready for service at all times. Automatic features would be installed as integral components within the SCADA system to ensure operation within prescribed pressure limits. Additional automatic features would be installed at the local pump station level and would provide pipeline pressure protection in the event communications with the SCADA host are interrupted.

Software associated with the SCADA monitoring system and volumetric balancing would be utilized to assist in leak detection during pipeline operations. If pressure indications change, the pipeline controller would immediately evaluate the situation. If a leak is suspected, the ERP would be initiated, as described in Section 2.4.2.2. In the event of a pipeline segment shutdown due to a suspected leak, operation of the affected segment would not be resumed until the cause of the alarm (e.g., false alarm by instrumentation, or leak) is identified and repaired. In the case of a reportable leak, USDOT approval would be required to resume operation of the affected segment.

A number of complementary leak detection methods and systems would be available within the OCC and would be linked to the SCADA system. Remote monitoring would consist primarily of monitoring pressure and flow data received from pump stations and valve sites that would be fed back to the OCC by the SCADA system. Software based volume balance systems would monitor receipt and delivery volumes and would detect leaks down to approximately 5 percent of pipeline flow rate. Computational Pipeline Monitoring or model based leak detection systems would monitor small pipeline segments on a mass balance basis. These systems would detect leaks down to approximately 1.5 to 2 percent of pipeline flow rate. Computer based, non-real-time, accumulated gain/loss volume trending would assist in identifying seepage releases below the 1.5 to 2 percent by volume detection thresholds. If any of the software-based leak detection methods indicate that a predetermined loss threshold has been exceeded, an alarm would be sent through SCADA and the Controller would take corrective action. The SCADA system would continuously poll all data on the proposed pipeline at an interval of approximately 5 seconds.

In the event of a leak, the operator would shut down operating pumping units and close the isolation valves. It would take approximately 9 minutes to complete the emergency shut-down procedure (shut down operating pumping units) and an additional 3 minutes to close the isolation valves. Some commenters have expressed concern that the Ludden spill on the existing Keystone Oil Pipeline Project (see Table 3.13.1-4) took longer than 12 minutes to shut down. In the case of the May 7, 2011 Ludden spill, the time from 3:51 to 4:26 pm MST was used to verify flow imbalance trends detected by the SCADA system. At 4:26 pm the Keystone Oil Control Center (OCC) received visual verification of a leak from a local farmer, thus confirming that a leak had occurred and system shutdown was immediately initiated. Shutdown was completed by 4:35 pm MST. The elapsed time from leak confirmation through visual verification to complete system shutdown was 9 minutes. The incident emphasizes the importance and difficulty of leak verification in some instances. The incident confirms that the uncertainty in time to shut down for any leak is primarily a function of the time required to verify that a leak has occurred.

In addition to the SCADA and complimentary leak detection systems, direct observation methods including aerial patrols, intermittent maintenance patrols, and public and landowner awareness programs would be implemented to encourage and facilitate the reporting of suspected leaks and events that could suggest a threat to the integrity of the pipeline.

EPA expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology addressed included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. In that report PHMSA concludes that while external leak detection systems have proven results for underground storage tank systems there are limitations to their applicability to pipeline systems and they are better suited to shorter pipeline segments. Their performance even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. While it is acknowledged that some external detection methods are more sensitive to small leaks than the SCADA computational approach, the costs are extremely high and the stability and robustness of the systems are highly variable. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable.

Relative to additional ground patrols, Keystone responded to a data request from DOS concerning the feasibility of more ground-level inspections. Keystone responded that based on land owner concerns, additional ground-level inspections are not feasible due to potential disruption of normal land use activities (e.g., farming, animal grazing). However, it should be noted that in the normal course of maintenance Keystone would have crews at various places along the proposed Project corridor (e.g.,

maintenance inspections of cathodic protection system rectifiers, MLVs, and pump stations). These crews would be trained and experienced in the identification of crude oil releases.

Oil Spill Response Procedures

Prior to the proposed Project construction, an SPCC plan consistent with EPA requirements is required to guide Keystone response in the event of unintended releases of petroleum products and hazardous materials during construction. SPCC requirements are addressed in Section 2.3 and in the CMR Plan in Appendix B; a draft SPCC plan is presented in Appendix C.

Prior to initiation of operation of the proposed Project, an ERP approved by PHMSA is required. The ERP is applicable to the pipeline operations and maintenance activities. The ERP would not be finalized until final definition of proposed Project elements included in all applicable permits. As noted in Section 2.4.2.2, an ERP was previously developed by Keystone for the existing Keystone Mainline and Cushing Extension project and approved by PHMSA. The ERP for the proposed Project would have the same general approach as presented in the Keystone ERP but would have many specific differences, such as the names and contact information for responders along the Project route and the differing environmental and public health vulnerabilities along the pipeline corridor. The publically available portion of the Keystone Oil Pipeline System ERP is included as Appendix C (some of the ERP is considered confidential by PHMSA and the U.S. Department of Homeland Security). The Keystone ERP would be used as a template for the ERP for the proposed Project and would include Project-specific information as it becomes available. In addition, as required by 49 CFR 194.107, the response plan submitted to PHMSA would include ~~"p~~procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantive threat of such a discharge." Once the Project route is finalized, field work would commence in collecting relevant information to be incorporated into the Project ERP which would then be submitted to PHMSA for review and approval.

Spill response procedures incorporated in the ERP would be followed in the event of a spill. Procedures that are likely to be included in the final, approved, ERP are summarized in this section. Additionally, in response to a DOS data request, Keystone provided its response procedures for two hypothetical release scenarios in areas overlying aquifers. These release scenarios are included in Appendix C and further discussed in Section 3.13.6.4.

The ERP standard operating and response procedures would be utilized by the OCC operator in responding to abnormal pipeline conditions, including leak alarms. The OCC operator would have the full and complete authority to execute a pipeline shutdown. Keystone's OCC operator would follow prescribed procedures in responding to possible spills that may be reported from sources such as:

- Abnormal pipeline condition observed by the OCC operator;
- Leak detection system alarm;
- Employee reported abnormal conditions; and
- Third party reported abnormal conditions.

Upon receipt of an abnormal condition report, leak report, or leak alarm, the OCC operator would implement the following procedures:

- Follow prescribed OCC operating and response procedures for specific directions on abnormal pipeline condition or alarm response;
- Dispatch First Responders;

- Shut down the proposed pipeline within a predetermined time threshold if abnormal conditions or leak alarm cannot be positively ruled out as a leak;
- Complete internal notifications; and
- Report identified spill to federal (including National Response Center [NRC]), state and local responders as required by all applicable reporting regulations.

All Keystone employees are authorized to communicate directly with the OCC should they observe conditions that may signify a possible spill.

Commenters have expressed concern that special procedures would be required to clean up the type of oil that would be transported by the proposed Project in the event of a spill. The proposed Project would transport heavy crude oil similar to heavy crude oils currently transported by pipeline in the U.S. as well as lighter crude oils. As noted in Section 3.13.5.1, the composition of dilbits is not different from other heavy crude oils, including the WCSB conventional heavy crude oils that have been imported into the U.S. for over two decades. As a result, response to a spill from the proposed pipeline would not require unique clean up procedures. As noted by the EPA Office of Emergency and Remedial Response (EPA 1999):

> —Lighter oils tend to evaporate and degrade (break down) very quickly; therefore, they do not tend to be deposited in large quantities on banks and shorelines. Heavier oils, however, tend to form a thick oil-and-water mixture called *mousse*, which clings to rocks and sand. Heavier oils exposed to sunlight and wave action also tend to form dense, sticky substances known as *tar balls* and *asphalt* that are very difficult to remove from rocks and sediments. Therefore, deposits from heavy oils generally require more aggressive cleanup than those from lighter ones."

Therefore, although the cleanup of heavy crude oils that would be transported by the proposed Project would be a difficult task, the spill response procedures currently used by EPA, the U.S. Coast Guard, and cleanup contractors could be effectively used for a spill of heavy crude oil from the proposed Project.

Response Time

In the event of a potential pipeline leak or spill, the estimated time to complete an emergency pipeline shutdown and close remotely operated isolation valves is as follows:

- Stop pumping units at all pump station locations: approximately 9 minutes.
- Close remotely operated isolation valves: approximately 3 minutes.
- Total time: approximately 12 minutes.

Consistent with industry practice and in accordance with regulations, Keystone's response time to transfer the necessary resources to a potential leak site would follow an escalating or tier system as required by 49 CFR 194.115 (Table 3.13.5.8). Dependent on the nature of site-specific conditions and resource requirements, Keystone would meet or exceed the requirements along the entire length of the proposed pipeline system.

TABLE 3.13.5-8 Response Time Requirements of 49 CFR 194.115 along the Proposed Pipeline			
Area	**Tier 1 Resources**	**Tier 2 Resources**	**Tier 3 Resources**
High-volume area[a]	6 hours	30 hours	54 hours
All other areas	12 hours	36 hours	60 hours

[a] "High-volume area" indicates an area where an oil pipeline with a nominal outside diameter of 20 inches or more crosses a major river or other navigable waters; because of the velocity of the river flow and vessel traffic on the river, this area would require a more rapid response in the case of a worst-case discharge or the substantive threat of such a discharge.

Spill Response Equipment

In general, Tier 1 emergency response equipment would be pre-positioned for access by Keystone including: pick-up and vacuum trucks, containment boom, skimmers, pumps, hoses, fittings, and valves, communications equipment including cell phones, two-way radios, and satellite phones, containment tanks and rubber bladders, expendable supplies, including absorbent boom and pads, assorted hand and power tools, including shovels, manure forks, sledge hammers, rakes, hand saws, wire cutters, cable cutters, bolt cutters, pliers, and chain saws, personnel protective equipment, including rubber gloves, chest and hip waders, and air monitoring equipment to detect H2S, O2, Lower Explosive Level, and benzene concentrations.

Additional equipment, including helicopters, fixed-wing aircraft, all-terrain vehicles, snowmobiles, backhoes, dump trucks, watercraft, bull dozers, and front-end loaders also may be accessed depending on site-specific circumstances. Other types, numbers, and locations of equipment would be determined upon concluding the detailed design of the proposed pipeline and completing Keystone's final ERP. This plan would be completed and submitted to PHMSA for review prior to commencing operations as described above.

The primary task of the Tier 1 response team is to reduce the spread of the spill on the ground surface or water in order to protect the public and USAs, including ecological, historical, and archeological resources and drinking water locations. The Emergency Site Manager (also known as the Qualified Individual or —QI) would perform an initial assessment of the site for specific conditions, including the following:

- The nature and amount of the spilled material;
- The source, status, and release rate of the spill;
- Direction(s) of spill migration;
- Known or apparent impact of subsurface geophysical features that may be affected;
- Overhead and buried utility lines and pipelines;
- Nearby population, property, or environmental features and land or water use that may be affected;
- Location of HCAs including USAs downcurrent or down gradient from the spill site; and
- Concentration of wildlife and breeding areas.

The QI would request additional resources in terms of personnel, equipment, and materials from the Tier 2 and if necessary, the Tier 3 response teams. Once containment activities have been successfully

concluded, efforts would then be directed toward the recovery and transfer of free product. Site cleanup and restoration activities would then follow, all of which would be conducted in accordance with the ERP and in conjunction with authorities having jurisdiction.

Spill Response Personnel and Training

The number of emergency responders comprising specific response teams would be determined upon completion of the proposed Project ERP. Emergency responders would meet or exceed the requirements of 49 CFR Part 194.115, and would typically be comprised of Hazardous Waste Operations and Emergency Response (—HAZWOPER") trained personnel. The response organization would follow the industry-accepted Incident Command System (ICS) and would typically consist of personnel both onsite and within an established remote or Regional Emergency Operations Center (EOC).

Locations of Spill Responders

Emergency responders would be based consistent with industry practice and consistent with applicable regulations, including 49 CFR 194 and 49 CFR 195. Consequently, emergency responders would be based in close proximity to the following areas:

- Commercially navigable waterways and other water crossings;
- Populated and urbanized areas; and
- USAs, including ecological, historical, and archeological resources and drinking water locations.

The specific locations of other emergency responders would be determined upon conclusion of the detailed location and design of the proposed pipeline, and completion of the ERP.

Spill Training Exercises and Drills

The spill training exercise and drill program would be designed to meet the requirements of the National Preparedness for Response Exercise Program Guidelines developed by the USCG and required by the Oil Pollution Act of 1990 (OPA 90). The primary elements of the exercise program are notification exercises, tabletop exercises, equipment deployment exercises, contractor exercises, unannounced exercises by government agencies, and area-wide exercises up to and including actual field drills conducted by industry and government agencies.

Operating personnel would participate in exercises or responses on an annual basis in order to ensure that they remain trained and qualified to operate the equipment in the operating environment and to ensure that the ERP is effective. However, personnel and equipment that are assigned to multiple Response Zones would participate in only one deployment exercise per year.

Local Emergency Planning Committees (LEPC)

As discussed in Section 3.10.2, LEPCs were established pursuant to the Emergency Planning and Community Right-to-Know Act (EPCRA) of (1986). Keystone has committed to a communication program that would reach out to LEPCs along the proposed pipeline corridor during development of the PSRP and the Emergency Response Plan included within the proposed Project Operations and Maintenance Plan. The LEPCs would participate in emergency response consistent with their authority under EPCRA, their local emergency response plan, and the proposed Project specific response plans addressed previously.

At the suggestion of EPA, DOS reached out to LEPCs along the proposed pipeline corridor to determine the following information:

- LEPC contact information (phone, fax, email, website);
- Counties/cities included in the LEPC plan;
- Date of last LEPC plan update;
- Regularity of LEPC meetings;
- LEPC funding status;
- Last LEPC emergency response training exercise; and
- Components of emergency plan, including potential pipeline releases, railroad or truck transport releases, and potential dangers and/or responses specifically affecting low-income or minority populations in LEPC area.

The information gained from the DOS LEPC survey is presented in Table 3.13.5-9. This information would be used in the development of required emergency and response plans should the proposed Project be implemented.

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Greg Spears	P.O. Box 360, Malta, MT 59538	(406) 263-7437	des@phillipscounty.mt.gov	Phillips County	20-May-08	Quarterly	No	1-Jun-11	no	Yes	yes	Yes
Richard Seiler	501 Court Square #10, Glasgow, MT 59230	(406) 228-6224 No answer	rseiler@co.valley.mt.us	Valley County	20-May-08							
Alan Stempel and Ryan Grigg	493 Stoney Rd, Circle, MT 59215	(406) 485-2347 Left a message for Ryan Grigg	mcondes@midrivers.com	McCone County	20-May-08							
George Lane Tim Mort: County Fire Chief; 406.989.1015.	300 S Merrill Ave, Glendive, MT 59330	(406) 377-2361	laneg@midrivers.com	Dawson County	20-May-08	Monthly	No	11-Feb-11	no	Yes. Currently updating plan and planning pipeline spill	Yes	Not sure
John Pisk	P.O. Box 126, Terry, MT 59349	(406) 635-5738	jpisk@co.prairie.mt.us	Prairie County	20-May-08	Quarterly	No	23-Jun-11	no	Yes	Yes	No (there is a general basic needs plan that applies to everyone)
Sam Thielen	P.O. Box 846, Baker, MT 59313	(406) 778-3223 No answer	fcdes@midrivers.com	Fallon County	20-May-08							
Candy Loehding	P.O. Box 42, Ekalaka, MT 59324	(406) 975-6416	cloehding@midrivers.com	Carter County	20-May-08	as needed	No	1-May-11	no	no	yes	yes
Don Thompson	P.O. Box 26, Buffalo, SD 57720	(605) 256-7611	kathy.glines@state.sd.us	Harding County	20-May-08	Quarterly (more as needed)	all volunteer-small grant from EPS	July, 2011	no	yes	yes	yes (everyone gets the same information)
Robert Fines	3200 E Highway 34 Ste 17, Pierre, SD 57501	(605) 723-0900 Left a message	rob.fines@co.hughes.sd.us	Butte County	20-May-08							
Kelly Serr	P.O. Box 234, Bison, SD 57620	(605) 244-5243	perkinscoso@sdplains.com	Perkins County	17-May-08	Quarterly	Yes; no idea	10-Jun-01	no	not sure	yes	yes
Kathie Grant	1400 Main St, Sturgis, SD 57785	(605) 347-4222	emgmgmt@meadecounty.org	Meade County	17-May-08	not active, as needed	No	6/2010, 9/26/11 is planned	no	yes	yes	no for minorities but yes for special needs individuals.
Donald Opie (Part time, retired and a volunteer)	P.O. Box 411, Mobridge, SD 57601	(605) 845-2800 Left a message	warhawk@westriv.com	Ziebach County, SD	17-May-08							
Anthony Carbajal	315 Saint Joe St B-31, Rapid City, SD 57701	(605) 394-2185	pamb@co.pennington.sd.us	Pennington County	20-May-08	Quarterly	Yes, $8500/yr	11-Jun-11	no	not yet, updating now	yes	no
Lola Roseth	20115 Manilla Rd, Midland, SD 57552	(605) 567-3515	lolaroseth@gwtc.net	Haakon County	20-May-08	no	No	28-Jun-11	no	no	yes	no
John Brunskill	P.O. Box 302, Murdo, SD 57559	(605) 669-7100	jamoore29@hotmail.com	Jones County	1-Jul-10	no	No	1-Apr-09	no	no	yes	yes
Steve Manger	P.O. Box 97, Kennebec, SD 57544	(605) 869-2200 Left a message	deputy.manger@lymancoso.org	Lyman County	17-May-08							

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Shawn Pettit	200 E 3rd St, Winner, SD 57580	605-842-1890	ritatrco@gwtc.net	Tripp County	17-May-08	Quarterly, more if needed)	Funded through the state, around $1,000/yr	October 2010	No	No	Yes	Partial component, for evacuation
Damon Wolf	P.O. Box 431, Burke, SD 57523	(605) 775-2626	gregorycoso@gwtc.net	Gregory County	17-May-08	Annually	No	1-Aug-10	no	no	yes	yes
Douglas Fox	365 N Main, Valentine, NE 69201	(402) 684-2424	ccema@inebraska.com	Kay-Paha County	20-May-08 (waiting to see what other counties are developing before making any new additions)	In the process setting one up, not now	No	1-Jul-11	www.nema.ne.gov/leops/nebraskamap.htm	no	yes	yes
Douglas Fox	P.O. Box 178, Bassett, NE 68714	(402) 376-2420	region24@huntel.net	Rock County	20-May-08	In the process setting one up, not now	No	2-Jul-11	www.nema.ne.gov/leops/nebraskamap.htm	no	yes	yes
No Contact provided	P.O. Box 544, O'Neill, NE 68763	(402)340-5664 Left a message	holtcountyema@telebeep.com	Holt County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Alma Beland	404 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Garfield County	20-May-08	no	No	1-Apr-10	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Alma Beland	405 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Wheeler County	20-May-08	no	No	2 0 0 9	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Alma Beland	406 4th St, Taylor, NE 68879	(308) 942-3461	region26@cornhusker.net	Greeley County	20-May-08	no	No	2 0 0 9	www.nema.ne.gov/leops/nebraskamap.htm	no	no	no
Dave Speigel	222 S 4th, Albion, NE 68620	(402) 395-2144 Left a message	bcbcarey@frontiernet.net	Boone County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Davis Moore	Rt 1 Box 133, Genoa, NE 68640	(308) 536-2452	nancecivildefence@hamilton.net	Nance County	20-May-08	no	No	1-May-11	no	no	no	no (a list of emergency resources is available, but without specific details on what low income/ minorities should do)
Kevin Cambpell	1821 16th Ave, Central City, NE 68826	(308) 946-2345 Left a message	merikso@cconline.net	Merrick County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Kirt Smith	916 13th St, Aurora, NE 68818	(402) 694-5126 Left a message	hcems@hamilton.net	Merrick County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Rick Schnedier	451 5th St, David City, NE 68632	(402) 367-7400 Left a message	bcema@neb.rr.com	Polk County	20-May-08				www.nema.ne.gov/leops/nebraskamap.htm			
Gary Petersen	16 Eastridge Dr N, York, NE 68467	(402) 362-7744 Cell: 402-643-5761	hlheiden@alltel.net	York County (and Seward Co)	20-May-08	Quarterly	Yes $500/year	March, 2011	www.nema.ne.gov/leops/nebraskamap.htm	No	No	No, working on an "Access and developmental needs" registry. Will be voluntary for citizens.
Donna Mainwaring	P.O. Box 266, Geneva, NE 68361	(402) 759-4914	emergencymanagement@fillmorecounty.org	Fillmore County	20-May-08	Quarterly, in the process of setting up regular meetings	No	May, 2011	www.nema.ne.gov/leops/nebraskamap.htm	No	No	In the evacuation portion of EMP
B.J. Fictum	P.O. Box 865, Wilber, NE 68465. (Under public health annex)	(402) 821-3010	scema@diodecom.net	Saline County	17-May-08	Quarterly	Yes, each county puts in about $500/yr	18-Jun-11	www.nema.ne.gov/leops/nebraskamap.htm	Yes	yes	Yes
John McKee	803 4th St, Fairbury, NE 68352	(402) 729-3602	don@kbsi.us	Jefferson County	20-May-08	Quarterly	Funded through County budget; around $2,000/yr	June 1, 2011	www.nema.ne.gov/leops/nebraskamap.htm	Generally, not specifically	Yes	Special needs registry for evacuations; (GIS database). No mention of minorities
Pam Kemp	603 4th St, Clay Center, KS 67432	(785) 632-5802	kemp@kansas.net	Clay County	26-Jan-11	Monthly	No	2-Jul-11	no	no	no	no
Pam Dunham	2100 N Ohio Ste B, Augusta, KS 67010	(316) 733-9796	pdunham@bucoks.com	Butler County	26-Jan-11	Quarterly	No	10-Jun-11	www.butlercoema.org	no	no	no
Charlie Lawson (started recently)	315 W 6th, Ste 203, Stillwater, OK 74074	(405) 533-6875	ghessier@paynecounty.org	Payne County	20-May-08	Quarterly	Yes, grants for training	not sure	no	yes	yes	not sure
Don Sweger	1008 E Tejon, Bristow, OK 74010	(918) 367-2252 Left a message	bristowcd27@sbcglobal.net	Creek County	20-May-08							
Joey Whitefield	811 Manvel # 4, Chandler, OK 74834	(405) 258-4100 Out through July	lincoln.county@oem.ok.gov	Lincoln County	20-May-08							
Bill Elliot	P.O. Box 26, Okemah, OK 74859	(918) 623-6766	okfuskeeem@onalot.com	Okfuskee County	20-May-08	Quarterly	No	1-Jun-11	no	yes	yes	no

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
Ernie Willis (no active county manager)	820 Jefferson St, Seminole, OK 74818	(405) 382-3702	semem@armmediapro.com	Seminole County	20-May-08	Monthly	Limited funding	4-May-11	no, thinking about updating	yes	yes	not sure
Robert Nolan	7892 Highway 9 Building B, Wetumka, OK 74883	(405) 379-2203 Busy signal	pnutfarm@netscape.net	Hughes County	20-May-08							
Gene Linton	231 S Townsend, Ada, OK 74820	(580) 436-8015 Left a message	pontotocem@adaok.com	Pontotoc County	20-May-08							
Aaron Blue	9 North Jerome St, Coalgate, OK 74538	(580) 927-0107	burns308@yahoo.com	Coal County	20-May-08	Quarterly	State grants $2K-$4K annually, no actual budget	1-Apr-11	no, will be up by the end of the year	yes	yes	no
Mike Aidaire	P.O. Box 1243, Atoka, OK 74525	(580) 889-4038 Left a message	eddycooke@totalnet.us	Atoka County	20-May-08							
James Dalton	224 W Evergreen Ste 100, Durant, OK 74701	(580) 924-3661	jdalton@durant.org	Bryan County, OK	20-May-08. The next training is July 23 2011, updating now	Monthly	No	1-Apr-11	no	yes	yes	no
Pat Collins* just started July 1	403 E Highland, Hugo, OK 74743	(580) 326-2000	athelta@aol.com	Choctaw County	20-May-03* being updated now	No	No, but applying for grants	July 2010	No	No	Yes	Yes
Darrel Brewer	210 S Main, Bonham, TX 75418	(903) 640-8484	fcmcem@cableone.net	Fannin County	17-May-08	Annually	No	1-Sep-10	no	yes	yes	no
Heath Thomas Heath just started June 1, 2011	125 Brown Ave, Paris, TX 75460	(903) 739-0824	countyjudge_lamar_tx@yahoo.com	Lamar County	17-May-08	not active, as needed	No	1-Sep-10	no	no	yes	not yet, but being constructed now
Joe Matilla	200 W Bonham St, Cooper, TX 75432	(903) 243-1247	N/A	Delta County	20-May-08	Twice a year	Grant driven	1-Apr-11	no	yes	yes	yes
Carl Nix	P.O. Box 288, Sulphur Springs, TX 75483	(903) 439-6217 Left a message	fireadmin@hopkinscountytx.org	Hopkins County	17-May-08							
Gary Allen	P.O. Box 718, Mt. Vernon, TX 75457	(903) 537-2342 Left a message	fcdm@mt-vernon.com	Franklin County	17-May-08	Quarterly	No	June 2011	No	Yes	Yes	No
Randy Sellman	261 Drifting Cloud, Holly Lake, TX 75755	(903) 569-7327 (cell)	mclanton@co.wood.tx.us	Wood County	17-May-08	Annually	No	4-May-11	no, but a hazard plan available on line, but not full EMP.	yes	yes	no
Gary Roberts	P.O. Box 790, Gilmer, TX 75644	(903) 843-2541 Left a message	dean.fowler@countyofupshur.com	Upshur County	17-May-08							
Jim Seaton	11325 Spur 248, Tyler, TX 75707	(903) 590-2653	jseaton@smith-county.com	Smith County	2-Apr-10	No	No	9-Jun-10	no	yes	yes	no
Patty Sullivan	115 N Main # 500-A,	(903) 657-0326	patricia.sullivan@co.rusk.tx.us	Rusk County	17-May-08	Quarterly	No	March 2011	No	No	No	No

TABLE 3.13.5-9
LEPC Telephone Survey[a]

Contact Person	Address	Phone/Fax	E-Mail	Counties/ Cities included in the Emergency Plan	Date Emergency Plan was Last Updated	LEPC Meetings (no; or mthly, qrtly, twice yr, yearly, other)	LEPC Funded[b] (no/yes; $ amt)	Date of Last Emergency Exercise	Emergency Plan Website Link[c]	Emergency Plan Addresses Pipelines (yes/no)	Emergency Plan Addresses Railroads/ Trucks (yes/no)	Emergency Plan Addresses Low-income/ Minorities (yes/no)
	Henderson, TX 75652	Left a message										
Sidney Riley	135 S Main, Rusk, TX 75785	(903) 683-5947 Busy signal	emc@cocherokee.org	Cherokee County	9-Mar-10	Quarterly	No	May 4, 2011	No	Yes	Yes	No
Joe English	101 W Main # 130, Nacogdoches, TX 75961	(409) 560-7793 Wrong number	jenglish@co.nacogdoches.tx.us	Nacogdoches County	17-May-08							
Ricky Connor	P.O. Box 908, Lufkin, TX 75901	(936) 671-4054 Left a message	acem@lcc.net	Angelina County	17-May-08							
Judge Page	P.O. Box 457, Groveton, TX 75845	(936) 642-1746	tcjudge@consolidated.net	Trinity County	17-May-08	working on schedule, new judge	Not sure	Jul-11	www.co.trinity.tx.us	yes	yes	no
Kenneth Hambrick	602 E Church # 400, Livingston, TX 77351	(936) 327-6810 Left a message	emcpolk@livingston.net	Polk County	17-May-08							
Fritz Faulkner	1 State Highway 150 # 5, Cold Spring, TX 77331	(936) 653-4367 Wrong number	fritz.faulkner@co.san-jacinto.tx.us	San Jacinto County	17-May-08							
Debbie Scott	2103 Cos St, Liberty, TX 77575	(936) 334-3219	ken.defoor@co.liberty.tx.us	Liberty County	17-May-08	Quarterly (but not recently)	No	1-Jun-11	no	yes	yes	no
Dennis Gifford	300 Monroe St, Kountze, TX 77625	(409) 755-6031 Left a message	dgifford@lumbertonfirerescue.org	Hardin County	17-May-08		All volunteer					
Greg Fountain	7933 Viterbo Rd Ste 6, Beaumont, TX 77705	(409) 835-8757	corey.cricchio@christushealth.org	Jefferson County	17-May-08	Bi-monthly	Funded by industry, member-ship based so budget fluctuates	1-May-11		yes	yes	no
Lori Ordwin	2520 South Highway 87, Orange, TX 77630	(409) 883-2612 Left a message	nellaij@cpchem.com	Orange County	17-May-08							
Ryan Holzaepfel	P.O. Box 957, Anahuac, TX 77514	(409) 267-2445	rholzaepfel@co.chambers.tx.us	Chambers County	17-May-08	Monthly	No	November, 2009	no	yes	yes	yes
Larry Mousseau	P.O. Box 1847, Channelview, TX 77530	(713) 881-3100	jcchief@pdq.net	Harris County/ Channelview	17-May-08	Daily	Yes, but no idea how much money	July, 2011	hcoem.org	yes	yes	yes[d]
Larry Mousseau	P.O. Box 10817, Houston, TX 77262	(713) 884-3786	nicholas.guillen@cityofhouston.net	Harris County/ City of Houston	17-May-08	Larry handles all of Harris Co, Houston and Channelview						yes[d]

[a] Note: this telephone survey occurred in June and July, 2011. At least four attempts were made to connect with the listed contact persons during this time period.
[b] Note: most grant funding reported in this table is for training purposes only, not for salaries.
[c] Note: some LEPC contact personnel reported that the department of Homeland Security recommends against posting their emergency management plan on a public website.
[d] Specific transportation evacuation options are provided for low income residents who do not have access to transportation. An entire section of government (Harris Co Homeland Security) deals with this.

Mitigation and Liability

Mitigation

Federal, state, and local agencies would participate in response activities and soil, surface water, and groundwater cleanup consistent with their authorities and duties under applicable regulations and consistent with the requirements of the ERP. A list of applicable regulations relative to remediation of crude oil spill contamination at the federal and state level is provided in Table 3.13.5-10. Required mitigation for crude oil or oil products spill impacts would be determined by these agencies. In addition, the state, tribal, and federal natural resource trustee agencies could require a NRDA under either OPA 90 or the Comprehensive Environmental Restoration Compensation and Liability Act (CERCLA), depending on the types of materials spilled, to assess the magnitude of the impacts and the type/amount of suitable restoration actions to offset the loss of natural resource services resulting from the spill.

TABLE 3.13.5.10
Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
Resource Conservation and Recovery Act, 42 U.S.C. § 6973.	EPA may issue an order or bring a suit in district court against any person who has contributed or who is contributing to the handling, treatment, storage, transportation or disposal of solid or hazardous waste which may present an imminent and substantial endangerment to health or the environment. Persons who violate an order are subject to civil penalties of up to $7,500 per day. Section 7003(a) of RCRA, 42 USC 6973(a), authorizes EPA "upon receipt of evidence that the past or present handling, storage, treatment, transportation or disposal of any solid waste or hazardous waste may present an imminent and substantial endangerment to health or the environment," to bring suit in district court or to issue an administrative order to any person who contributed or is contributing to that handling, storage, treatment, transportation" to restrain or take any other action in response. Oil released from a pipeline would constitute solid or hazardous waste, and the authority allows EPA to require action even if the spill "may present an imminent and substantial endangerment."
Safe Drinking Water Act, 42 U.S.C. §§ 300f, et seq.	EPA may issue orders to any person in circumstances where "contaminant" is present in or is likely to enter a public water system or an underground source of drinking water (defined broadly to include virtually almost all groundwater) which may present an imminent and substantial endangerment to the heal of persons and states (to whom primary responsibility is granted under the SDWA) are not acting. The orders may require that person to take such actions as EPA deems necessary to protect health. 42 U.S.C. § 300i (a). Civil penalties are available for failure to comply with such an order. Section 1431(a) of SDWA, 42 USC 300i(a), authorizes EPA "upon receipt of information that a contaminant which is present in or is likely to enter a public water system or an underground source of drinking water . . . which may present an imminent and substantial endangerment to the health of persons," to take "such actions as [it] deems necessary," including issuance of orders and civil judicial actions. Again, this authority is quite broad. An underground source of drinking water is virtually any underground water that has the potential to be used for drinking water, and a "contaminant" is any biological, chemical or physical substance in water.

TABLE 3.13.5.10
Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
Pipeline Safety Act, 49 U.S.C. §§ 60101, et. seq.	PSA provides authority for PHMSA to establish minimum safety standards for interstate hazardous liquid pipelines, including petroleum pipelines. The standards may apply to the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement and maintenance of pipeline facilities. § 60102(a)(2). Penalties Violations of PHMSA requirements are subject to civil judicial enforcement actions, with varying penalty amounts depending on the nature of the violation (generally, $100,000 for each violation, with a maximum of $1,000,000 for a related series of violations). Written Procedures Regulations require that a pipeline operator prepare and implement a manual for operations, maintenance and emergencies. 49 C.F.R. § 195.402. For emergencies, the manual must include procedures for (a) receiving, identifying and classifying notices of events which need immediate response and (b) responding promptly to the emergency, including fire or explosion near or involving a pipeline, accidental release of materials from a pipeline, operational failures and natural disasters. 49 C.F.R. § 195.402(e). Notification Regulations require that a pipeline operator make an accident report, including telephonic report, for pipeline failures which result in (a) explosion or fire, (b) release of 5 gallons or more of petroleum (with certain exceptions), (c) death, (d) personal injury necessitating hospitalization, or (e) property damage (including cleanup) in excess of $50,000. 49 C.F.R. §§ 195.50-195.54.
Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. §§ 9601, et. seq.	Similar to the Oil Pollution Act, but addresses releases of hazardous substances and specifically *excludes* oil and petroleum. Provides for liability for response costs and natural resource damages against owners or operators of a vessel or facility and persons who arranged for disposal of hazardous substances. The act contains similar defenses as for the OPA, as well as contribution rights. Also provides EPA authority to issue administrative orders requiring response actions.
Montana	There is no single statutory scheme under Montana law governing liability for pipeline spills on land and in groundwater, but one or more of the following provisions could apply depending on the circumstances: MCA 75-10-705 et seq., Montana's "Comprehensive Environmental Cleanup and Responsibility Act" ("CECRA" - Montana's version of CERCLA) MCA 75-10-401 et seq., the "Montana Hazardous Waste Act" – while crude oil is not specifically listed in the definition of 'hazardous waste' the definition may be broad enough to apply to a crude oil spill MCA 75-5-101 et seq., Montana's water quality statutes – applicable to both surface water and groundwater MCA 75-20-101 et seq., the "Montana Major Facility Siting Act" – applicable to "facilities," including pipelines, that fall under MFSA. Keystone XL falls under MFSA. The regulations that relate to the statutes and may apply are: ARM 17.55.101 et seq. dealing with CECRA ARM 17.53.101 et seq. dealing with hazardous waste ARM 17.30.101 et seq. dealing with water quality

TABLE 3.13.5.10
Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
	ARM 17.20.101 et seq. dealing with MFSA There are also various common law grounds under Montana law for asserting liability for pipeline spills, and Montana also has "clean and healthful environment" constitutional provisions that could be used to assert liability.
South Dakota	First, South Dakota Public Utilities Commission permit HP09-001 authorizing the project in the State, issued in final form June 29, 2010, provides at Condition 48: "No person will be held responsible for a pipeline leak that occurs as a result of his/her normal farming practices over the top of or near the pipeline." The permit provides further at Condition 49: "Keystone shall pay commercially reasonable costs and indemnify and hold the landowner harmless for any loss, damage, claim or action resulting from Keystone's use of the easement, including any resulting from any release of regulated substances . . . except to the extent such loss, damage claim or action results from the gross negligence or wilful misconduct of the landowner or its agents." Second, statutes contained in SDCL Chapter § 34A-12, which create the regulated substance response fund, provide for corrective action in case of a spill or leak from a "tank." The definition of "tank" includes "pipeline facilities which transport and store regulated substances." SDCL § 34A-12-1(12). A "regulated substance" is defined to include crude oil. SDCL § 34A-12-1(8). Under the chapter, the Department of Environment and Natural Resources is directed to take corrective action to clean up any unauthorized discharge of a regulated substance, but only after first ordering the responsible person to take corrective action. A "responsible person" is as a person who has caused a discharge of a regulated substance, or a person who is an owner or operator of a tank at any time during or after a discharge. SDCL § 34A-12-1(10). If the responsible person fails to act, then the department may seek injunctive relief to compel corrective action. SDCL § 34A-12-10. If a responsible person cannot be identified or refuses to undertake corrective action, or if emergency action is needed to prevent an imminent threat to public health or safety, then the department may undertake correction action with funds from the response fund. SDCL § 34A-12-4(2), (3). The department may recover corrective action costs from either the responsible person, SDCL § 34A-12-6, or from "any person who has caused a discharge of a regulated substance." SDCL § 34A-12-12. That statute also provides that the person causing a discharge "is strictly liable for the corrective action costs expended by the department. . ." Third, SDCL Chapter § 34A-2 addresses the discharge of petroleum substances into state waters. SDCL § 34A-2-96 imposes liability on the owner or operator of a facility that stores or transports petroleum substances for the costs of containment and recovery of discharges into the waters of the state. SDCL § 34A-2-96. This section also provides that "any person causing the discharge shall be strictly liable to the owner or operator for all costs and proximate damages resulting from the discharge." A violation of an order issued pursuant to the statute is a class 1 misdemeanor. SDCL §§ 34A-2-96, 34A-2-75. Finally, landowners who experience a discharge have civil court remedies for damage to their property, including loss of use and loss of future productivity. Clean up costs incurred by the landowner are a recoverable element of damage.
Nebraska	The Nebraska Environmental Protection Act, Nebraska RRS § 81-1501, et seq. (Act) and the Nebraska Administrative Code (NAC) Title 126, Chapter 18, provide for liability in the event a pipeline spills oil or a hazardous substance in

TABLE 3.13.5.10
Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations

Statute/Regulation	Description
	or on land or waters of the State. Waters of the State include both surface waters and groundwater. In the event of a release, the person responsible for the release has various responsibilities. "Responsible person" means any person producing, handling, storing, transporting, refining, disposing of an oil or hazardous substance when a release occurs, either by accident or otherwise. This includes carriers or any other person in control of an oil or hazardous substance when a release occurs, whether they own the oil or hazardous substances or are operating under a lease, contract, or other agreement with the legal owner thereof. NAC Title 126, Chapter 18-038. The responsible person must: (1) notify the Nebraska Department of Environmental Quality (NDEQ) if the release exceeds threshold quantities, or, regardless of quantity, if the release occurs beneath the surface of the land or impacts or threatens waters of the State or threatens the public health and welfare, (2) must take all necessary steps to stop the release and contain all released material, and take action to preclude continued or future releases, (3) investigate the release, to determine its impact, and the investigation must be reported to NDEQ, (4) take remedial action, which remedial action is subject to the review and approval of NDEQ, (5) properly dispose of any waste generated from the cleanup. Compliance with these requirements does not relieve the responsible person from liabilities, damages or penalties resulting from the release, cleanup and disposal. The Act also has civil and criminal penalties that may be assessed in the event of a release. The Act further provides for reimbursement to the State for any loss of fish or wildlife as a result of a release.
Oklahoma	For releases on Oklahoma jurisdictional lands, the Oklahoma Corporation Commission (OCC) is the regulatory agency that has jurisdiction over pollution resulting from pipeline releases. Under OCC's rules (OAC 165:10-7-5), releases to soil, surface waters or groundwater must be reported to the OCC [OAC 165:10-7-5(c)(1)(A)]. These rules also require remediation/cleanup and provide a framework for enforcement albeit the potential penalties levied are typically nominal sums. [OAC 165:10-7-5(c)(1)(B) and OAC 165:10-7-5(c)(2)]. Supplementing the regulatory requirements noted above are common law based landowner/water user rights. These actions are commonplace and are filed by those individuals whose property or health is impacted by the release. These actions are based on theories including but not limited to nuisance, trespass and negligence. Remedies for these claims can include orders to abate the nuisance along with monetary damages awarded by the court. Releases occurring on or threatening Indian tribal land (trust land or otherwise), presents a more complex analysis. Oklahoma has numerous recognized Indian tribes with lands (trust or otherwise) held throughout the state. Federal laws typically apply to these releases, including but not limited to the CWA and OPA and possibly RCRA. In addition, several Indian tribes have passed their own environmental statutes that can address these releases therefore a detailed analysis depends on the exact location of the release and identification of the tribes involved.
Texas	Crude oil spills on land and in groundwater in Texas are regulated by the Texas Railroad Commission. The pertinent regulations are as follows: Spills that contaminate groundwater: Pollution of groundwater is prohibited by Rule 3.8 of the Texas Administrative Code. Rule 3.8 imposes reporting

TABLE 3.13.5.10 Potentially Applicable Federal and State Soil, Surface Water, and Groundwater Cleanup Regulations	
Statute/Regulation	**Description**
	requirements and immediate corrective action when pollution occurs. The Rule makes an operator responsible for immediately removing oil or other pollution materials from the water where it is found, and imposes liability for the cleanup expense on the operator. Additionally, Rule 3.8 subjects violators to the penalties and remedies specified in the Texas Natural Resources Code, Title 3, which include penalties of up to $10,000 per day for each violation, and any other statutes administered by the Commission. Spills that contaminate soil: Rule 3.91 of the Texas Administrative Code establishes guidelines for the cleanup of soil contaminated by a crude oil spill. Under these guidelines, operators must remediate the soil to a final cleanup level of 1.0% by weight total petroleum hydrocarbons, and must comply with notification and reporting requirements regarding the scope of the spill and the progress of the cleanup. In addition to these standard guidelines, Rule 3.91 specifies that cleanup requirements for crude oil spills in sensitive areas will be determined on a case-by-case basis. "Sensitive areas" are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. The Railroad Commission is authorized to assess civil penalties for violations that pertain to the prevention or control of pollution, including penalties of up to $10,000 a day for each violation. Additional reporting requirements: Texas law requires pipeline owners who observe or detect any petroleum-based contamination of soil or water in proximity to the pipeline to report the contamination to the Railroad Commission and the owner of the land on which the pipeline is located no later than 24 hours after observing or detecting the contamination. Texas Natural Resource Code § 81.056.

Liability

Many commenters requested information regarding what Keystone's liability would be in the event of an accidental release of crude oil from the Project. Section 1001(32)(B) of the OPA 90 states that in the case of an onshore facility, any person owning or operating the facility is the responsible party. Additionally, under Section 1002 of OPA 90, Keystone would be liable for any discharge of oil (or threat of discharge) to the navigable waters of the United States and their adjoining shorelines. The term ~~"n~~avigable waters" is defined in OPA 90 as ~~"th~~e waters of the United States, including the territorial sea" (OPA 90). In Rice v. Harken Exploration Co. (2001) the Fifth Circuit confirmed a lower court ruling that groundwater is not within the scope of the OPA unless a direct connection to surface waters can be affirmed. Otherwise it is likely that any spill with the potential to contaminate surface waters of the United States would fall within the purview of OPA 90.

Therefore, if there is an accidental release that could affect surface water, no matter what the reason, Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations, up to a maximum of $350,000,000. However this statutory liability limit does not apply where the incident was proximately caused by (1) gross negligence or willful misconduct of, or (2) the violation of an applicable federal safety construction or operating regulation by Keystone or a person acting pursuant to a contractual relationship with Keystone. Additionally, under the CWA, Keystone would be liable for up to $50,000,000 for United States removal costs for harmful quantities of oil discharged from a Keystone-owned or operated facility unless the discharge was caused solely by an act of God, an act of war, negligence by the United States, or the act or omission of a third party. The limit

does not apply if the discharge resulted from Keystone's willful negligence or willful misconduct. Keystone would also be liable for damages to natural resources, to real or personal property for the loss of subsistence use of natural resources, for the net loss of taxes, royalties, rents, fees or net profit shares from injuries to real or personal property or natural resources, for loss of profits or impairment of earning capacity by any claimant, or for net cost of providing increased or additional public services. There are no limits to these liabilities. Keystone would also be subject to the civil and criminal penalty provisions of the CWA. Keystone would also be subject to penalty provisions of the Rivers and Harbors Act and the Pipeline Safety Act.

In addition to the provisions described above, in the event that a release of crude oil contaminates groundwater, Keystone has agreed that it would be responsible for clean-up and restoration, and for providing an appropriate alternative water supply for groundwater that was used as a source of potable water, or for irrigation or industrial purposes.

However, if a release is caused by negligent or willful acts of others, Keystone may ultimately recover costs from those committing the acts since individuals are not automatically protected from liability associated with negligent acts or willful misconduct leading to property destruction and environmental damage. Specific liability warrants and indemnifications are included within individual easement agreements. DOS has no regulatory authority to intervene in the negotiation of those agreements. In addition, consideration of liability is beyond the scope of NEPA environmental reviews and is therefore not addressed in this EIS.

In addition to the various provisions described above, Keystone has agreed that it would be responsible for providing appropriate alternative water supply, and for clean-up and restoration in the event of a release of crude oil into groundwater.

3.13.5.6 Types of Oil Spill Impacts

This section summarizes the types and magnitudes of physical, chemical and biological impacts that may occur to a variety of resources and activities due to spills that occur during either construction or operation of the proposed Project. However, due to the potentially greater magnitude of spill size from an accidental release from the pipeline during operation, this section focuses primarily on crude oil spills from the pipeline. The descriptions are necessarily somewhat general because of the large number of independent spill-related variables listed below, most of which have a wide range of values in magnitude, duration, and range of effects depending upon the exposed resource, and many of which are unpredictable in spatial and temporal distribution as well as frequency of occurrence. In addition, there is a wide range of values and variability of values for those variables, for the numerous human and natural resources encountered along the proposed pipeline route.

Physical Impacts

Physical impacts of spills of crude oil or petroleum products to natural resources and human uses typically result from physical coating of soils, sediments, plants, animals, or areas used by people. Physical impacts include, but are not limited to:

- Smothering living organisms so they cannot feed or obtain oxygen;
- Coating feathers or fur, which reduces their insulating efficiency and results in hypothermia;
- Adding weight to the organism so that it cannot move naturally or maintain balance;

- Coating sediments and soils, which reduces water and gas (e.g., oxygen and carbon dioxide) exchange and affects subterranean organisms; and
- Coating beaches, water surfaces, wetlands, and other resources used by people which may result in offensive odors, visual impacts, as well as soiled livestock, crops, clothes, recreational equipment, pets, and hands/feet.

In aquatic areas with high energy (e.g., waves, turbulent river flows, and/or high sediment deposition), the oil may become buried under or mixed into the substratum where it may remain for extended periods of time and may be slowly released to the environment to re-oil downstream habitats and resources. In some cases, the buried oil would be in an anoxic environment and would resist weathering by physical or biological processes. Upon release to the environment, this ~~"u~~nweathered" oil may result in additional but delayed impacts.

Potential for Explosion and Fire

Several commenters on the draft EIS expressed concern about the potential for explosion and fire associated with the operation of the proposed Project. Crude oil releases are very unlikely to result in an explosion because crude oil contains a relatively small proportion of volatile hydrocarbons and most spills do not occur in confined spaces which allow the buildup of vapors to potentially explosive levels. Almost all ~~"p~~etroleum or hydrocarbon pipeline explosions" occur in pipelines that are transporting highly flammable, highly volatile hydrocarbons such as natural gas, LPG, propane, LNG, gasoline, naphtha, and similar products. The released material from these product and natural gas pipelines could rapidly form a flammable vapor cloud that could explode if exposed to an ignition source in a confined area at an explosive concentration. A release of diesel, gas condensate, kerosene, or similar refined liquid hydrocarbon will ignite and burn rapidly and seem to ~~"e~~xplode" if the vapors are exposed to a fire or similar high temperature heat source, usually a fire caused by some other accident.

The PHMSA database for significant onshore hazardous liquid incidents (PHMSA 2010) indicates that only 6 of 2,706 (0.2 percent) reported incidents were attributed to ~~"f~~ire/explosion as a primary cause." Those 6 incidents were related to the release of flammable hydrocarbons, such as gasoline or liquid propane, and did not involve releases of crude oil.

The pump stations for the proposed Project would be powered by electricity. As a result, there would not be natural gas or other flammable fuel at the facilities that could ignite explosively. A crude oil spill at a pump station would likely result in the emission of some hydrocarbon vapors, but the vapors would not be emitted into confined spaces and therefore an explosion would be unlikely.

Other commenters have expressed concern that diluents would flash volatilize from the homogenous mixture dilbits in the event of a pressurized pipeline breach and subsequent crude oil release leading to a severe fire and explosion risk. As discussed previously in this section, dilbits would not experience flash volatilization in the event of a pipeline rupture. Additional concerns related to a hypothetical flash volatilization event included the potential release of hydrogen sulfide. Not only is flash volatilization from crude oil that would be transported by the proposed Project physically not possible, the hydrogen sulfide concentration of crude oils that could be transported on the proposed Project is very low and in the very unlikely event of a fire from any cause, any small concentration of hydrogen sulfide released would combust with oxygen to produce sulfur dioxide and water.

Chemical and Toxicological Impacts

Toxicological impacts are a function of the chemical composition of the oil, the solubility of each class of compounds, and the sensitivity of the receptor. The primary classes of compounds found in crude oil are

alkanes (hydrocarbon chains), cycloalkanes (hydrocarbons containing saturated carbon rings), and aromatics (hydrocarbons with unsaturated carbon rings). Most crude oils are more than 95 percent carbon and hydrogen, with small amounts of sulfur, nitrogen, oxygen, and traces of other elements. Crude oils contain lightweight straight-chained alkanes (e.g., hexane, heptane); cycloalkanes (e.g., cyclyohexane); aromatics (e.g., benzene, toluene); cycloalkanes; and heavy aromatic hydrocarbons (e.g., PAHs, asphaltines). Straight-chained alkanes are more easily degraded in the environment than branched alkanes. Cycloalkanes are extremely resistant to biodegradation. Aromatics (i.e., benzene, toluene, ethylbenzene, xylenes compounds) pose the most potential for toxic impacts because of their lower molecular weight making them more soluble in water than alkanes and cycloalkanes.

Toxicological impacts are the result of chemical and biochemical actions of petrogenic compounds on biological processes of individual organisms (e.g., API 1997, Muller 1987, Neff 1979, Neff and Anderson 1981, Neff 1991, Stubblefield et al 1995, Sharp 1990, Taylor and Stubblefield 1997). Impacts may include: various toxic effects to animals and birds as they try to remove the oil from their fur or feathers; direct and acute mortality; sub-acute interference with feeding or reproductive capacity; disorientation; narcosis; reduced resistance to disease; tumors; reduction or loss of various sensory perceptions; interference with metabolic, biochemical, and genetic processes; and a host of other acute or chronic effects. A description of toxicological effects of petroleum to both human and natural environment receptors is presented in Appendix P.

For most construction spills, the volume and areal extent of the oil spill would be limited and generally confined to the construction ROW, construction yards, and roadways. Livestock would typically be restricted from these areas until construction activities are completed. Wild animals, especially birds and mammals, also would tend to avoid these areas during construction. If a spill does occur and impacts a substantive amount of habitat, the response personnel would encourage and assist farmers and ranchers to move livestock if necessary.

Oil spills are not likely to have toxic effects on the general public because of the numerous restrictions that local, state and federal agencies would impose to restrict environmental exposure. A 2003 report to EPA prepared by the American Petroleum Institute (API) compared the health effects of synthetic crude oil with those of conventional crude oil and included the following statement (API 2003, page 9):

> "Synthetic crude oil, from upgraded tar sands, is compositionally similar to high quality conventional crude oil (>33º API). The conventional technologies such as delayed and fluid coking, hydrotreating, and hydrocracking, used to upgrade heavy crude oils and bitumens, are used to convert tar sands into an essentially 'bottomless' crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to EPA . . . to support the position that tar sands-derived synthetic crude oil is comparable to conventional crude oils for health effects and environmental testing, a position with which EPA concurred."

However, it should be noted that based on current production projections and the market demand at Gulf Coast refineries, the majority of crude oil that would likely be transported by the proposed Project would be dilbit crude oils (EnSys 2010).

Fumes from spilled oil could lead to human health effects depending on the intensity and duration of exposure. The reported range of hydrogen sulfide or mercaptan sulfur in WCSB crude oils typical of those that would be transported on the proposed Project is from 20 to 100 ppm (Table 3.13.5-7). In the event of an oil release, the potential human exposure risk would relate to the inhalation of any hydrogen sulfide emitted into the air column in the vicinity of the oil spill. The hydrogen sulfide volatilized into the air column would be at concentrations much lower than the concentration in the crude oil. Olfactory

perception of hydrogen sulfide occurs for most people at concentrations in the air of approximately 0.2 ppm. Human health effects of exposure to hydrogen sulfide, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of hydrogen sulfide in urban areas reportedly range from 0.11 to 0.33 parts per billion (ppb), while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb (Skrtic 2006). A rotten egg odor characterizes hydrogen sulfide at low concentrations, and some people can detect the gas by its odor at concentrations as low as 0.5 ppb (Skrtic 2006). In an assessment of risk to first responders at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of hydrogen sulfide from crude oil spills using three different crude oil hydrogen sulfide concentrations (1 ppm, 20 ppm, and 350 ppm). The results of their analysis indicate that hydrogen sulfide levels in the immediate aftermath of a crude oil spill at the two higher levels of hydrogen sulfide concentration (20 ppm and 350 ppm) could pose short-term health risks (respiratory paralysis) to first responders at the spill site. However, since initial responders do not typically arrive at spill sites immediately and model results indicate that even under worst-case conditions (no wind), modeled exposures drop to non-toxic levels in less than 4 minutes, hydrogen sulfide exposures would not be expected to create substantive health hazards. The rapid atmospheric dissipation of hydrogen sulfide levels indicated by these model results also suggests that risks to the general public would be very small to negligible in the event of an oil spill. Additionally, some commenters have expressed concern that in the event of a fire or explosion involving crude oil that would be transported by the proposed Project, hydrogen sulfide could be released. However, hydrogen sulfide would not be a likely by-product in the unlikely event of an explosion or fire involving the proposed Project because hydrogen sulfide itself is highly flammable and any hydrogen sulfide involved in an explosion or fire would rapidly combine with oxygen to form sulfur dioxide and water.

Oil spilled into surface or groundwater supplies that serve as human drinking water sources would be detected and monitored until the levels return to safe drinking water levels and the appropriate agencies authorize resumption of use of these water supplies. Water-related activities would be restricted in any area where there is oil present at levels that the health agencies and the Incident Commander consider unsafe for human exposure. Private landowners could choose to undertake activities that would increase exposure at their own risk.

Birds typically are the most affected wildlife if exposed to the chemical and toxicological effects of an oil spill, whether it is on land or on water (e.g., Holmes 1985, Sharp 1990, White et al 1995). In addition to the potential for external oiling of the feathers and hypothermia or drowning due to loss of flotation, birds may suffer both acute and chronic toxicological effects. Birds are likely to ingest oil as they preen their feathers in an attempt to remove the oil. The ingested oil may cause acute hepatic, gastrointestinal, and other systemic impacts resulting in mortality, reduced reproductive capacity, loss of weight, inability to feed, and similar effects. Oiled birds that are nesting or incubating eggs may coat the eggs or young with oil and injure or kill them. Dead oiled birds may be scavenged by other birds as well as mammals.

Fish and aquatic invertebrates could also experience toxic impacts of spilled oil, and the potential impacts would generally be greater in standing water habitats (e.g., wetlands, lakes and ponds) than in flowing rivers and creeks. Also, in general, the impacts would be lower in larger rivers and lakes and much lower under flood conditions since the toxic hydrocarbon concentrations would likely be relatively rapidly diluted.

The concentration of crude oil constituents in a spill would vary both temporally and spatially in surface water; however, localized toxicity could occur from virtually any size of crude oil spill. Acute toxicity values of various crude oil hydrocarbons to a broad range of freshwater species are presented in Table 3.13.5-11. Acute toxicity refers to the death or complete immobility of an organism within a short period of exposure. The LC50 is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms. For aquatic biota, most acute LC50 for monoaromatics range between 10 and

100 ppm. LC50 for polyaromatic naphthalene was generally between 1 and 10 ppm, while LC50 values for anthracene were generally less than 1 ppm.

In aquatic environments, toxicity is a function of the concentration of a compound necessary to cause toxic effects combined with the compound‘s water solubility. For example, a compound may be highly toxic, but if it is not very soluble in water then its toxicity to aquatic biota is relatively low. The toxicity of crude oil is dependent on the toxicity of its constituents. As an example, Table 3.13.5-12 summarizes the toxicity of various crude oil hydrocarbons to the water flea, Daphnia magna. This species of water flea is used as a standard test organism to determine acute and chronic responses to toxicants. The relative toxicity of decane is much lower than for benzene or ethylbenzene because of the comparatively low solubility of decane. Most investigators have concluded that the acute toxicity of crude oil is related to the concentrations of relatively lightweight aromatic constituents, particularly benzene. Because the diluted bitumen crude oils have a significant amount of lighter hydrocarbons added, they tend to have higher benzene concentrations than many other heavy oils (such as Mexican Maya and Venezuelan Bachaquero), but lower than many light crude oils (such as Brent Blend or Alaska North Slope) (Environment Canada 2011).

While lightweight aromatics such as benzene tend to be water soluble and relatively toxic, they are also highly volatile. Thus, most or all of the lightweight hydrocarbons accidentally released into the environment evaporate, and the environmental persistence of this crude oil fraction tends to be low. High molecular weight aromatic compounds, including PAHs, are not very water-soluble and have a high affinity for organic material. Consequently, these compounds, if present, have limited bioavailability, which render them substantively less toxic than more water-soluble compounds (Neff 1979). Additionally, these compounds generally do not accumulate to any great extent because these compounds are rapidly metabolized (Lawrence and Weber 1984; West et al.1984). There are some indications, however, that prolonged exposure to elevated concentrations of these compounds may result in a higher incidence of growth abnormalities and hyperplastic diseases in aquatic organisms (Couch and Harshbarger 1985).

Significantly, some constituents in crude oil may have greater environmental persistence than lightweight compounds (e.g., benzene), but their limited bioavailability renders them substantively less toxic than other more soluble compounds. For example, aromatics with four or more rings are not acutely toxic at their limits of solubility (Muller 1987). Based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills.

Chronic toxicity values (most frequently measured as reduced reproduction, growth, or weight) of benzene to freshwater biota are summarized in Table 3.13.5-13. Chronic toxicity from other oil constituents may occur, however, if sufficient quantities of crude oil are continually released into the water to maintain elevated concentrations. However, that condition would not result from an accidental release from the proposed Project since the release would be a one-time occurrence and would not be continuous, and the release would be followed by the required response and repair activities.

TABLE 3.13.5-11
Acute Toxicity of Aromatic Hydrocarbons to Freshwater Organisms

Species	Toxicity Values (ppm)				
	Benzene	**Toluene**	**Xylenes**	**Naphthalene**	**Anthracene**
Carp (*Cyprinus carpio*)	40.4	---	780	---	---
Channel catfish (*Kctalurus*)	--[a]	240	---	---	---
Clarias catfish (*Clarias* sp.)	425	26	---	---	---
Coho salmon (*Oncorhyncus kisutch*)	100	---	---	2.6	---
Fathead minnow *(Pimephales*)	---	36	25	4.9	25
Goldfish (*Carassius auratus*)	34.4	23	24	---	---
Guppy (*Poecilia reticulate*)	56.8	41	---	---	---
Largemouth bass (*Micropterus*)	--	--	--	0.59	---
Medaka (*Oryzias* sp.)	82.3	54	---	---	---
Mosquito fish (*Gambusia affinis*)	---	1,200	---	150	---
Rainbow trout (*Oncorhyncus mykis)*	7.4	8.9	8.2	3.4	---
Zebra fish (*Therapon iarbua*)	--	25	20	--	---
Rotifer *(Brachionus calyciflorus)*	>1,000	110	250	---	---
Midge *(Chironomus attenuatus)*	--	--	--	15	--
Midge *(Chironomus tentans)*	--	--	--	2.8	--
Zooplankton *(Daphnia magna)*	30	41	---	6.3	0.43
Zooplankton *(Daphnia pulex)*	111	---	---	9.2	---
Zooplankton *(Diaptomus forbesi)*	---	450	100	68	---
Amphipod *(Gammarus lacustris)*	--	--	0.35	--	---
Amphipod *(Gammarus minus)*	--	--	--	3.9	--
Snail *(Physa gyrina)*	--	--	--	5.0	--
Insect *(Somatochloa cingulata)*	--	--	--	1.0	---
Chlorella vulgaris	---	230	---	25	---
Microcystis aeruginosa	--	--	--	0.85	---
Nitzschia palea	--	--	--	2.8	---
Scenedesmus subspicatus	---	130	---	---	---
Selenastrum capricornutum	70	25	72	7.5	---

[a] -- Indicates no value was available in the database; ppm = parts per million.

Note: Data summarize conventional acute toxicity endpoints from USEPA's ECOTOX database. When several results were available for a given species, the geometric mean of the reported LC_{50} values was calculated.

TABLE 3.13.5-12
Acute Toxicity of Crude Oil Hydrocarbons to *Daphnia magna*

Compound	48-hr LC_{50} (ppm)[a]	Optimum Solubility (ppm)	Relative Toxicity[b]
Hexane	3.9	9.5	2.4
Octane	0.37	0.66	1.8
Decane	0.028	0.052	1.9
Cyclohexane	3.8	55	14.5
methyl cyclohexane	1.5	14	9.3
Benzene	9.2	1,800	195.6
Toluene	11.5	515	44.8
Ethylbenzene	2.1	152	72.4
p-xylene	8.5	185	21.8
m-xylene	9.6	162	16.9
o-xylene	3.2	175	54.7
1,2,4-trimethylbenzene	3.6	57	15.8
1,3,5-trimethylbenzene	6	97	16.2
Cumene	0.6	50	83.3
1,2,4,5-tetramethylbenzene	0.47	3.5	7.4
1-methylnaphthalene	1.4	28	20.0
2-methylnaphthalene	1.8	32	17.8
Biphenyl	3.1	21	6.8
Phenanthrene	1.2	6.6	5.5
Anthracene	3	5.9	2.0
9-methylanthracene	0.44	0.88	2.0
Pyrene	1.8	2.8	1.6

[a] The LC_{50} is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms within a predetermined time period (e.g., 48 hours) (USEPA 2000).

[b] Relative toxicity = optimum solubility/LC_{50}

ppm = parts per million.

Source: USEPA 2000.

TABLE 3.13.5-13
Chronic Toxicity of Benzene to Freshwater Biota

Taxa	Test Species	Chronic Value (ppm)
Fish	Fathead minnow (*Pimephales promelas*)	17.2 *
	Guppy (*Poecilia reticulata*)	63
	Coho salmon (*Oncorhynchus kitsutch*)	1.4
Amphibian	Leopard frog (*Rana pipens*)	3.7
Invertebrate	Zooplankton (*Daphnia* spp.)	>98
Algae	Green algae (*Selenastrum capricornutum*)	4.8 *

Note: Test endpoint was mortality unless denoted with an asterisk (*). The test endpoint for these studies was growth.

Biological (Ecological) Impacts

The physical and chemical impact processes described previously are manifested at the organism level. Additional biological and ecological impacts may manifest in local populations, communities, or entire ecosystems depending on the location, size, type, season, duration, and persistence of the spill, as well as the type of habitats and biological resources exposed to spilled oil. Except for some endangered, threatened, or protected species, loss of a small fraction of a population of organisms would result in a minimal impact at a community to ecosystem level. Loss or reproductive impairment of a significant portion of a population or biological community from an oil spill could result in a significant environmental impact. The impact is likely to be greater if the species affected have long recovery times (e.g., low reproductive rates); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers; or are otherwise a critical component of the local biological community or ecosystem. Furthermore, if the species or community is a key recreational or commercial resource, biological impacts manifested at the population or community level may constitute a significant impact to human uses of the resource.

Assessment of Impact Magnitude

The magnitude of oil spill impact is primarily a function of size of the spill, type of oil, and sensitivity of the receptors affected (API 1992, API 1997, National Research Council 1985, 2003a, 2003b). The crude oil that would be transported by the proposed Project would primarily consist of diluted bitumen (dilbit) and syncrude. Information on the chemical characteristics of these crude oils is provided in Section 3.13.5.1. Variations in spill size and receptor type are key variables for estimating the magnitude of environmental impacts of oil spills from the proposed Project. Spill volume categories used in this impact assessment are presented in Section 3.13.2.1. Receptor sensitivity is subjective and is influenced by the perspectives and biases of evaluators and the actual sensitivity of the receptors to the oil. For example, a farmer whose grain field is oiled could consider impacts to a crop more significant than spill related impacts on a wetland that supports threatened and endangered species, recreational hunting, and other recreational opportunities. Conversely, a national wildlife refuge manager could evaluate relative impacts very differently. The relative sensitivities of receptors are presented in Table 3.13.5-11, based on historical spill sensitivity assessments and input from a typical range of stakeholders.

The magnitude of environmental impacts generally increases within a receptor type as spill size increases (i.e., from left to right in Table 3.13.5-11). Within a spill size, the magnitude of impact increases with increasing sensitivity of the receptors (i.e., from top to bottom in the table). Combining size and sensitivity, the magnitude of impacts generally increases from top left to bottom right in the table. In many oil spills, there are clear differences in the way that stakeholders (e.g., general public, non-governmental organizations, natural resource management agencies, regulatory agencies, enforcement agencies, private businesses, municipal agencies, and others) value spill related impacts on natural resources and habitats compared to spill related impacts on human uses. Table 3.13.5-11 reflects a ranking of these values, recognizing that the concept of ~~"i~~mpact assessment and magnitude" is anthropogenic and not a component of ecosystem function.

For this EIS, five levels of environmental impact were considered and entered into the table to indicate the generally expected magnitude of impacts from oil spills. The magnitude of impact may vary from these general trends depending on a number of site-specific variables described previously.

TABLE 3.13.5-11
Typical Ranges of Potential Crude Oil Spill Environmental Impacts[a,b]

Type of Receptor[c]	Very Small (<210 gal [5 bbl])	Small (210 – 2,100 gal [5-49.9 bbl])	Substantive (2,100 – 21,000 gal [50-499.9 bbl])	Large (21,000 – 210,000 gal [500-5,000 bbl])	Very Large (>210,000 gal [5,000 bbl])
Terrestrial–agricultural land	Negligible	Negligible to minor	Minor to substantive	Minor to substantive	Substantive
Terrestrial–natural habitat	Negligible	Minor	Minor to substantive	Substantive	Substantive
Groundwater	Negligible	Negligible	Negligible to minor	Minor to substantive	Substantive
Aquatic–wetlands	Negligible	Minor	Minor to substantive	Substantive	Major to catastrophic
Aquatic–lakes and ponds	Negligible	Negligible to minor	Minor to substantive	Substantive	Major
Aquatic–streams and small rivers	Negligible	Negligible to minor	Substantive	Major	Major to catastrophic
Aquatic–large rivers	Negligible	Negligible	Minor	Substantive to major	Major to catastrophic
Threatened and endangered species and habitat	Negligible to minor	Minor to substantive	Substantive	Substantive to major	Major to catastrophic
Human use–commercial	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–residential	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–recreational	Negligible	Negligible to minor	Minor to substantive	Substantive to major	Major to catastrophic

[a] Magnitude of impact is defined as follows:

[b] Spill size categories are described in Section 3.13.2.1.

[c] Receptor sensitivity subjective and based on experience from previous oil spill responses and analyses.

Negligible Impact – Little to no detectable impact on most resources; may be some visible presence of oil on land, vegetation, or water. Zero to few organisms apparently killed or injured. Impacts are temporary (measured in days) and spatial distribution localized to spill site. There are no detectable effects on HCAs including USAs.

Minor Impact – Measurable presence of oil and limited impacts on local habitats and organisms. Impacts are temporary (measured in days to weeks) and local (measured in acres). Some organisms, likely birds, fish, and aquatic macroinvertebrates, may be killed or injured in the immediate area. There may be limited effects on HCAs including USAs.

Substantive Impact – Patchy to continuous presence of oil on terrestrial and aquatic habitats near the spill site. Impacts may be present for weeks to a few months and affect tens of acres or a few miles of stream/river habitat. There may be impacts to the local biological community and population-level effects on organisms and human uses of the area. There may be detectable effects on HCAs including USAs.

Major Impact – Patchy to continuous and heavy presence of oil on terrestrial and aquatic habitats near the spill site and for substantive distances down gradient from the spill site. Impacts may be present for weeks to months and potentially for a year or more. The impacted area may include many acres to sections of land or wetlands, and several miles of riverine habitat. There may be effects on the local biological community and population-level impacts on organisms and habitats, as well as disruption of human uses in local oiled areas. There may be substantive effects on HCAs including USAs.

Catastrophic Impact – Mostly continuous or nearly continuous presence of oil on all habitats near and/or for substantive distances down gradient of the spill site. Impacts may be present for months to years. The impacted area may include many acres to sections of land or wetlands, and several to numerous miles of river or other aquatic habitat. There may be both local and regional disruption of human uses. There may be both local and regional impacts to biological populations and communities. There may be significant to catastrophic effects on HCAs including USAs.

3.13.6 Resource-Specific Impacts

This section addresses potential impacts related to the resources described in Sections 3.1 through 3.12 that may result from very small spills to very large spills. Additional or corroborative information on the potential impacts of oil spills is presented in Appendix P.

3.13.6.1 Geology

Potential impacts from oil spills would not involve geological features that have received state or federal protection, nor would they involve any geological features of known tribal significance along the proposed route, although concerns related to paleontological resources have been identified. Potential impacts to geologic resources due to a spill from either construction or operation of the proposed Project are addressed in the following sections.

Paleontological Resources

Most spills would be confined to a construction yard, access roadway, or pipeline ROW, or to an adjacent area. The primary exceptions would be large to very large spills from pipelines that affect areas beyond the ROW. Paleontological resources exposed to a spill could be affected. Cleanup activities could also damage paleontological resources. However, a Paleontological Mitigation Plan would be developed in South Dakota and a Memorandum of Understanding (MOU) in Montana to protect significant fossil resources that may be encountered during construction or damaged as the result of an oil spill. Locations with the potential for significant paleontological fossils occur infrequently in limited areas along the proposed route.

Mineral and Fossil Fuel Resources

For surface and near-surface resources such as sand, gravel, clay and stone, small to substantive spills may result in localized reduction in resource availability and value depending on actions involved in the incident response and subsequent remedial activities. For large and very large spills, the impacts may be proportionally greater. However, the distribution of these mineral resources and their relatively undeveloped state along the ROW indicate that the overall potential for impacts to the resources and their associated industries would be small.

The proposed route would cross deposits of sand, gravel, clay, and stone, but the acreage of deposits covered by the proposed ROW is insignificant compared to the total acreage of deposits present in each state. The proposed route would not cross any currently active aggregate mining operations. Thus, impacts from spills in the vicinity of these resources would be negligible for small or even substantive spills that are rapidly contained. Even large spills would result in minor impact because of the wide spatial distribution of these resources and their current state of development.

The proposed Project route would not cross the well pads of any active or proposed oil or gas wells, although active oil and gas wells are located near the proposed ROW along some portions of the proposed route. Spills of any size would not likely result in more than minor impacts to these oil and gas resources due to the proposed pipeline‘s location and the depth and containment afforded by the extraction equipment, operations, and sites.

3.13.6.2 Soils and Sediments

Soils

The impact of oil spills on soil is a function of several variables, including the type of material spilled. Once oil reaches the soil surface, the depth of penetration into the soil would depend on the porosity of the soil and the extent to which it is frozen or water saturated. The area affected would be limited to that area immediately adjacent to and covered by the spill. Porous soils (e.g., sand, gravel, and moraines) are more permeable than clays and silts. Karst areas, especially where the karst formations are close to the surface and the overlying soils are porous, may be especially vulnerable to impacts from a spill, if the oil reaches and moves through the karst. Most soils along the route have low to moderate permeability providing sufficient time to control and cleanup the oil prior to extensive movement through soils.

Spills could affect soils indirectly by affecting the vegetation, which in turn could die and expose the soil to water and wind erosion or solar heating, even if the soil itself was not directly affected by the spilled material. Spill cleanup is more likely to affect the soils than the presence of the spilled material itself, unless the cleanup is well controlled and heavy traffic and digging are minimized (especially for summer spills). Oil that adsorbs to or is retained between soil grains may weather only slowly over one to several years.

Soil productivity could be negatively impacted by oil contamination particularly in the event of large to very large spills. If long-term remediation is required, beneficial uses of the soil could be restricted for the length of the remediation period or longer.

Sediments

Sediments (defined here as submerged soils in wetlands and aquatic habitats) are typically fine grained and saturated with water. They may be covered by or integrated with a substantive amount of organic material, primarily from riparian and aquatic vegetation. The sediment may be more coarse-grained in fast-flowing streams and rivers, and in areas where glacial moraines dominate the parent soil materials. Crude or refined oils typically do not penetrate beyond the surface layer in sediments unless (1) there is a substantive amount of turbulence that mixes the oil and sediments, followed by deposition of the mixture in low energy areas; (2) the interstitial spaces are large enough (e.g., in gravel and coarse sand) to allow for penetration of the oil as it sinks; or (3) physical activities associated with spill response actions mix the surface-deposited oil-sediment mixture into deeper subsurface levels of the sediment profile. Refined products also typically would not penetrate sediments because of the water content but may penetrate or be mixed further into the sediments under the same turbulent conditions or cleanup actions as for crude oil. The oil deposited on and remaining in the top sediment layer, especially in aerobic environments may be subject to biodegradation by microbes, which would reduce or eliminate long-term impacts. Oil that is incorporated into sediments, especially in the anaerobic subsurface levels, may weather very slowly. Sediments of exposed shores can retain oil for extended periods of time, even in higher energy areas (Short et al. 2007).

3.13.6.3 Water Resources

Surface Water

Spills could affect surface freshwater quality if spilled material reaches waterbodies directly or from flowing over the land. However, the vast majority of spills would likely be confined to construction yards, areas in or adjacent to the proposed pipeline ROW, or along access roads. The volumes of most spills would likely be very small to small (see spill size categories in Section 3.13.2.1). In addition, for

some portion of the winter months each year, in the northernmost portions of the route, spill responders could remove much of the spilled material from frozen ground or ice-covered waterbodies prior to snowmelt. During the rest of the year, spills could reach and affect wetlands, ponds and lakes, as well as creeks and rivers before spill response is initiated or completed.

Released oil that reaches a water body directly or indirectly would float in a lenticular layer on the water surface. In some cases, oil could be physically mixed into upper portions of the water column or incorporated into bottom sediments in high energy aquatic environments.

An oil spill that reaches a freshwater body could cause reduced dissolved oxygen (DO) concentrations and increased toxicity to aquatic organisms, particularly from dissolved phase hydrocarbons (e.g., BTEX). Because oil slicks are less permeable to oxygen than water, spilled material that reaches wetlands, ponds, or small lakes could lower DO concentrations due to a decreased influx of atmospheric oxygen and the relatively high rate of natural sediment respiration in many shallow waterbodies. In small, shallow waterbodies with limited water movement and high organic loading (e.g., small lakes, farm reservoirs, and stock ponds), increased biodegradation resulting from the addition of oil to the water column may further reduce oxygen levels.

In winter, however, a small spill would not likely contribute substantively to an oxygen deficit in most waters because biological abundance and activity are depressed and water column respiration rates at that time would be low to negligible. Furthermore, sediment respiration has less relative effect in lakes that are too deep to freeze to the bottom. Such lakes tend to be supersaturated with DO in winter (BLM and MMS 1998). An exception to such conditions could occur if spilled material were introduced to a waterbody beneath the ice cover, in very restricted waters with depleted oxygen levels and a concentrated population of overwintering fish. During open water periods in most waterbodies, especially larger lakes, rivers, and streams, spilled materials would likely result in little detectable decrease in DO levels. The high water volume (relative to the volume of oil) or the high rate of water flow would disperse oil before it affected DO concentrations.

Long-term aquatic toxicity would be less likely to occur in larger lakes and rivers because oil would be diluted or dispersed within the sediment over large areas by currents and wind and wave action. Spills into larger rivers and creeks, especially during open water periods, might result in some toxicity within the water column itself. However, in larger rivers, because of the large and rapid dilution of the oil relative to the flow volumes, these impacts would likely be limited to the first few back eddies, calm water regions and reservoir pools down current of where the spill enters the river. In smaller flowing streams, an oil spill could create direct aquatic toxicity in the water column because of the lower relative volume and rate of water flow, and thus there would be a higher likelihood of direct contact between the biota and the dispersed oil. Some toxicity might persist in these streams for a few weeks to months, until toxic compounds trapped in the sediment were washed out or until oiled sediment was covered by cleaner sediment.

Since the majority of oil spills are small in volume, these smaller spills if reaching larger lakes, would result in minimal effects on overall water quality, assuming the lake volume is substantially larger than the volume of spilled oil. Decreases in DO levels would be negligible in most cases but may be greater in large to very large spills that cover much of the water surface for a day or more. Direct toxicity would be short-term because of the high dilution volume in these lakes and the rapid evaporation of most of the potentially toxic lighter hydrocarbons. Spreading of a spill over a lake surface may have a minor to major effect on water aesthetics and recreational use. This effect could exist for days to a few weeks until the oil was removed.

Minor temporary to short-term surface water quality degradation is possible from smaller maintenance equipment and vehicle spills or leaks. Longer term water quality degradation could be associated with large to very large spills. A larger spill could also affect potable surface water sources and irrigation water supplies. As mentioned previously, the crude oils transported by the proposed Project would tend to float on the surface water column. However, as with any crude oil, over time volatilization of the aromatic fraction and biodegradation could lead to an oil residuum that would sink.

Groundwater

During construction and operation of the proposed Project, potential minor, short- to longer-term groundwater quality degradation is possible from equipment and vehicle spills or leaks. Substantive spills of refined products, especially diesel or gasoline, and substantive to very large spills of crude oil may reach groundwater where the overlying soils are porous and the upper boundary of the water table is relatively near the surface. Areas near major wetlands and meandering streams or rivers as well as the Sand Hills topographic region of Nebraska are key examples of locations where the water table may be close to the surface. In some of these areas, it may be difficult to distinguish between groundwater and surface water. A summary of locations where shallow aquifers are present and a description of the NHPAQ system in Nebraska are provided in Section 3.3.1.

Subsurface Crude Oil Migration and Groundwater Flow

The potential for crude oil or oil products migration into subsurface groundwater is determined by several factors. These factors include the areal extent of the oil spill, the viscosity and density of the material, the characteristics of the environment into which the material is released (particularly the characteristics of the underlying soils), and the depth to first groundwater. In most cases, given that vertical migration is controlled by the infiltration rate of the oil into the underlying soil, the extent of vertical migration can be mitigated by quick emergency response measures that include rapid source control (containment and collection of the oil released) (see Appendix C). An evaluation of these factors is presented below.

The crude oil that would primarily be transported by the proposed Project is classified as heavy crude oil. All heavy crude oils are more viscous than lighter crude oils. Most of the crude oil transported by the proposed Project would originate from bitumen, and would either be pre-processed into a heavy synthetic crude oil or pre-processed and blended with petroleum diluents (typically a light aromatic hydrocarbon) to produce an acceptable viscosity for pipeline transport (see Section 3.13.5). These types of crude oil would become more viscous when released into the environment as the lighter aromatic fraction volatilizes. Increasing viscosity tends to reduce vertical crude oil migration rates in soil profiles. Crude oil vertical migration would be further restricted by the cooling of the crude oil after its release (a decrease in temperature will increase the viscosity of oil), particularly in the cooler months of the year.

Heavy crude oils likely to be transported by the proposed Project are less dense than water and would form a lenticular layer that floats on surface waterbodies. If crude oil infiltrates into soil formations, it would tend to form a distended lens above and slightly below the water table when groundwater is encountered, largely based on the amount of the spill and the associated vertical hydraulic head pressure. The crude oil plume would then spread horizontally, in an ellipsoid in the down-gradient direction, until it reaches a steady state based on the crude oil head pressure, groundwater flow rate, and soil characteristics. Plume expansion can also be affected by the rate of water being pumped out of an aquifer.

Studies related to oil and oil products releases from over 600 underground storage tank leaks indicate that potential surface and groundwater impacts from these releases are typically limited to several hundred feet or less from the release site (API 1998). The median length of groundwater plumes comprised of

these soluble components (BTEX) was 132 feet and approximately 75 percent of these plumes were under 200 feet (API 1998). These studies indicate that the size of the oil release is the key factor influencing the ultimate oil plume dimensions (including the dissolved phase plume). While there are differences in the rate of oil movement through different soil types, hydrogeologic factors such as hydraulic conductivity and gradient are not as significant in determining ultimate plume length (API, 1998). However, on a localized basis, it is acknowledged that water withdrawals through extensive pumping can influence the hydraulic gradient.

An example of a crude oil release from a pipeline system into an environment similar to the NHPAQ system and Sand Hills topographic region occurred on August 20, 1979 near Bemidji, Minnesota. Approximately 449,400 gallons (10,700 bbl) of crude oil were released onto a glacial outwash deposit consisting primarily of sand and gravel. The water table in the spill area ranged from near the surface to about 35 feet below ground surface. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site, and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient.

Estimates of the hydraulic conductivity (the rate that water moves through soil) of soils at the Bemidji site ranged from 1.59 feet per day (ft/d) to 99.23 ft/d. These hydraulic conductivity estimates were provided in an oral communication with a USGS scientist with extensive experience evaluating impacts from the Bemidji spill (Delin, pers. comm. 2011). The following specific hydraulic conductivity estimates were provided (converted from meters per second to ft/d):

- 1.59 ft/d estimated from particle-size distributions (Dillard et al. 1997);
- 19.85 ft/d based on a calibrated estimate (Essaid et al. 2003);
- 20.70 ft/d based on aquifer (slug) tests (Strobel et al. 1998); and
- 99.23 ft/d based on permeameter tests (Bilir 1992).

As described in Section 3.3, the High Plains Aquifer system (which includes the NHPAQ system), exhibits hydraulic conductivities estimated to range from 25 to 100 ft/d in 68 percent of the aquifer, with an average hydraulic conductivity estimated at 60 ft/d (Weeks et al. 1988). In general, groundwater velocity (which also takes into account the porosity and the hydraulic gradient [slope of the water table]) in the High Plains Aquifer system is 1 ft/d and flows from west to east (Luckey et al. 1986).

Estimates of the hydraulic conductivity of the Sand Hills Unit of the NHPAQ system are variable, with a high end estimate of 50 ft/d (Gutentag et al. 1984) and a lower range estimate of 13 to 40 ft/d (Lappala 1978). Hydraulic conductivity values for surficial dune sands (8 inches in depth) in the Sand Hills Unit range from 16.4 to 23.0 ft/d (Wang et al. 2006). At intermediate depths within the root zone, hydraulic conductivity values range from 26.3 to 32.8 ft/d in lowland areas and from 32.8 to 49.2 ft/d in higher elevation areas. In the lower boundary of the root zone, at approximately 6.5 feet bgs, hydraulic conductivities ranged from 42.7 to 49.2 ft/d (Wang et al. 2006). These values were based on direct in-situ measurements by a constant head permeameter.

These referenced estimates for hydraulic conductivity in the NHPAQ system and the Sand Hills Unit are within the range of values estimated for the Bemidji spill site. Although the subsurface conditions in the Sand Hills Unit, the NHPAQ system, and at the Bemidji spill site are not identical, the soils exhibit similar hydraulic conductivities and flow characteristics. However, three dimensional transmissivity may differ. For instance, hydraulic conductivity in the Sand Hills topographic region near the top of a dune may be higher than in nearby lowlands or lakes. Other differences between the two sites likely include saturated thickness and potential influence of well pumping on hydraulic gradient. While the two sites

are not completely analogous, the Bemidji site provides the best physical model for response to an oil release in the NHPAQ system and studies of the Bemidji site suggest that a spill of similar magnitude in the Sand Hills would remain localized and the dimensions of the liquid plume and associated dissolved plumes would be similar in extent to the plumes at the Bemidji site.

Other shallow groundwater resources along the proposed pipeline corridor may occur within soil profiles somewhat dissimilar from the Bemidji site (see Section 3.3). In many areas, shallow unconfined aquifers occur within alluvium in flood plains near streams and rivers. Shallow aquifers can also occur under confined conditions. Under confined conditions, the confining layer (e.g., silt or clay) would impede or prevent vertical migration of the crude oil into the aquifer. Unconfined alluvial soils are comprised of a range of soil constituents, including gravels, sands, silts, and clays in various percentages. As a result, these alluvial soils exhibit a range of hydraulic conductivities, but it is expected that in general vertical and lateral oil migration would follow similar patterns.

EPA expressed concern relative to risks of contamination in aquifer recharge areas. Aquifer recharge occurs when overlying permeable materials connect to an aquifer unit. Shallow unconfined aquifers are overlain by such permeable materials and therefore are at risk if contamination of the overlying soils occurs. Where surface expressions of deeper bedrock aquifers outcrop, they could also be at risk if they lie within an oil spill zone. Section 3.3 provides information on the locations of known recharge areas along the proposed Project corridor based on available information. Recharge areas are also addressed in comparisons between the I-90 Corridor Alternatives, the Keystone Corridor Alternatives, and the proposed Project in Section 4.3.3. It should also be noted that research by the USGS at the Bemidji site suggests that downward migration of nutrients to an oil spill in unconfined shallow aquifer recharge areas may actually increase the rate of natural biodegradation by microbes (Bekins et. al, 2005) in the event of an oil spill.

Response Time, Source Control, Cleanup and Remediation

Relative to reducing potential groundwater impacts, DOS recognizes the importance of rapid response leading to source control, containment, and cleanup in the event of an oil spill in shallow aquifer areas. The ability to respond in a timely and appropriate manner to an unanticipated oil release is of critical importance. In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight currently in place relative to potential spills in relatively shallow groundwater areas.

The first hypothetical spill occurs in the summer in an area with deeper groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone described the following in detail:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;

- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

In the first scenario, a low likelihood of groundwater contamination was determined. For the second scenario, it was determined that emergency response teams would respond prior to the time the subsurface oil plume reaches groundwater. This would allow rapid cleanup of the surface plume to reduce the downward head pressure on the oil plume. However, groundwater would likely be impacted. Impacted groundwater would be remediated by short-term mechanical approaches (excavation and vacuum methods), medium-term chemical methods (chemical oxidation), biological methods (bioremediation), and long-term natural attenuation.

In most real-world spills, a combination of methods would be used to accomplish the highest degree of remediation practicable in the shortest amount of time. However, DOS acknowledges that in areas such as the Sand Hills region, where groundwater may be very shallow (less than 10 feet bgs), some level of groundwater impact would likely occur even with very rapid and efficient spill response. Although cleanup and remediation efforts would be more complicated and potentially of longer duration if groundwater were affected, the extent of aerial contamination would be limited primarily depending on the size of the release.

Wetlands

Impacts of crude oil spills or refined product spills on wetlands are influenced by the type of oil or oil product, the amount and proportion of water surface area covered, the type of vegetation present in the wetland, and cleanup response actions. Refined products tend to be more toxic than crude oil, while crude oil tends to cause more physical impacts (e.g., smothering). Any refined or crude oil release would tend to remain on the water surface, and would therefore affect oxygen exchange between water and air, potentially affecting the water column DO content. Toxic components of a refined product release may dissolve and disperse over the affected area. In the event of a heavy crude oil release, dense stands of emergent vegetation could act like oil booms and collect oil at the edges of the stands, particularly given the heavy crude oil viscosity. Aggressive and intrusive cleanup methods could mix oil with water and sediments (which are often anoxic below the surface layer) leading to longer lasting impacts. Passive cleanup methods (including natural attenuation) are likely to cause less impact on wetland resources. Physical disruption of wetland resources below the water line during spill response could be reduced in some cases through ignition of the oil floating on the water surface[7].

Spills of refined product (e.g., diesel or gasoline) would be more likely to occur during construction. The majority of these spills would be very small to small spills from construction pads or access roads. If the spills occur in winter, the wetland may be covered in ice and spilled product may be contained by snow or

[7] Burning of oil and oiled emergent vegetation in wetlands with an overlying water layer has been used several times in Texas and Louisiana. The vegetation above the waterline along with the floating oil is burned but the submerged vegetation including the roots is generally unharmed. Regrowth occurs rapidly. This technique reduces the chances of oil exposure to birds and other wildlife, and reduces the physical impact of cleanup crews disrupting the marsh during manual removal methods.

remain on top of the ice. In either case, the spilled oil would likely be recovered before it directly affected wetland habitat and associated organisms. For spills occurring during the rest of the year, most of the product would float on the water or wet soil surface, although some of the volatile fraction may dissolve or disperse in water. Although gasoline spills evaporate quickly, there may be short-term acute effects on wetland wildlife and vegetation. Diesel spills tend to be more persistent, and diesel may infiltrate sediments as well as adhere to emergent vegetation.

Crude oil spills that occur during operation of the proposed Project could affect wetlands either where the proposed pipeline would cross wetlands or waterbodies (e.g., ponds, lakes, reservoirs, streams, rivers, or adjacent riparian habitats) or where the spill site is on land but upgradient of the wetland. Due to the viscosity of heavy crude oils, spills would likely be restricted in areal extent, particularly in colder months. Snow could serve as a sorbent to further restrict the spill migration. Larger spills in open water seasons could flow into wetlands, cover the water surface, coat wetland wildlife and vegetation, and restrict oxygen exchange between air and water. Some spilled crude oil could sink through the water into underlying sediments and remain there for years, depending on the amount of biodegradation and chemical or physical weathering that takes place.

Smaller refined product or crude oil spills would generally produce minor impacts on wetlands unless the wetland is small and isolated from other waterbodies. In these cases, impacts could be substantive if the majority of the wetland is exposed to the oil. Substantive and large to very large crude oil spills could result in substantive impacts on wetlands due to the size of the spill and the proportion of the wetlands that would be affected. Impacts could approach a catastrophic level in areas where the wetlands are heavily used by migratory waterfowl and the spill occurs during the spring or fall migration.

3.13.6.4 Biological Resources

Vegetation

Smaller spills during construction could occur within contractor yards, along access roads, at above-ground facilities and along the proposed pipeline construction ROW, and the spilled fuel or oil would generally remain localized near the release site. These spills would typically produce minor impacts on crops, native vegetation and associated wildlife. However, substantive and large to very large spills during operation would likely result in greater impacts.

Along the Steele City Segment of the proposed pipeline, winter snow cover may occasionally be sufficient to slow and limit the surficial flow of spilled oil, thus limiting the extent of damage to vegetation and habitat. On other pipeline segments and on the Steele City Segment in other seasons, the spilled oil may flow farther on the land surface. Spill response activities could cause impacts on vegetation and habitat if activities are not implemented carefully and with regard for minimal disturbance of the surface soils and vegetation.

The majority of spills would likely be very small to small (see Section 3.13.2.1 for spill volumes within spill categories) and would typically cover less than 1 acre, but large to very large spills could be extensive, with the areal extent partially dependent on topography and the density, rigidity, and structural complexity of grass/forb/shrub vegetation on the surface of the land. Overall, most past spills on terrestrial habitats have caused minor ecological damage, and ecosystems have shown a good potential for recovery, with wetter areas recovering more quickly (Jorgenson and Martin 1997, McKendrick 2000). The length of time that a spill persists depends on several factors, including oil and soil temperature, availability of oleophilic (oil-loving) microorganisms, soil moisture, and the concentration of the product spilled. For the most part, effects of land oil spills would be localized and are not expected to impact vegetation and associated habitat outside the immediate spill area. Spills that occur within or near

streams, rivers, and lakes could indirectly affect riparian vegetation and habitat along these waterbodies. Affects on vegetation from subsurface leaks that reach the root zones of surface vegetation could assist in leak detection as a result of visible patches of affected vegetation along the pipeline ROW resulting from oil interference with water and nutrient uptake by plant root systems.

A large to very large spill could spread over larger areas and coat vegetation, including row crops, wild lands, seasonal wetlands, and range lands, especially down slope from the spill site. The vegetation within the spill zone could be injured, killed or coated with oil, although population level vegetation effects are unlikely. Affected vegetation may not be suitable for grazing animals and any commercial row or field crops would not be marketable.

Birds

Very small or small spills on or near the roads, construction yards, pump stations, or MLV sites would not generally affect birds, although a few individual shorebirds, waterfowl, raptors and passerine birds could be exposed to the spilled oil. Exposed individuals could die from hypothermia or from the toxic effects of ingesting the oil during preening, or from ingestion of oiled food and water. Potential impacts would likely be limited to a few individual birds, especially waterfowl and shorebirds that use small ponds and creeks affected by very small to small spills. If a very small to small size spill occurred during migration periods, greater numbers of birds could be affected. There could also be an associated impact to a few individual scavenging birds and mammals if they feed on oiled carcasses. Very small to small spills would not be expected to cause population-level impacts.

A substantive to very large spill in terrestrial habitats could cause mortality of birds that spend time foraging or nesting on the ground, such as shorebirds, grassland nesting songbirds (passerines), and upland game birds, where they would come into direct contact with oil and oiled prey or forage. If the spilled material entered wetlands or waters, water-dependent birds such as waders, seabirds, shorebirds, and waterfowl could be exposed. The numbers of individuals oiled would depend primarily on wind conditions and the numbers of birds within and proximate to the area affected by the spill. Impacts may be detectable at the local population level, especially for resident species with limited geographic distribution, if the spill affected important breeding habitat for migratory birds, or if the spill occurred within migration staging habitats during active migration periods. The North Valley Grasslands, crossed by the proposed pipeline in Valley County, Montana (Montana Audubon 2008), is a designated globally Important Bird Area (IBA) supporting resident and migrant grassland nesting birds. Although not designated as an IBA along the route of the proposed pipeline, the Platte River and associated wetlands in central Nebraska are used for migration staging from mid-February to early April by more than 500,000 sandhill cranes during their northward migration (Audubon 2010).

If raptors, eagles, owls, ravens, crows, magpies, vultures, and other predatory or scavenging birds are present in the spill vicinity, they could become secondarily oiled by eating oiled prey. Mortality of breeding raptors likely would represent a minor loss for local populations but would not likely affect regional populations. Mortality of migrant or winter roosting aggregations of bald eagles attracted to waterfowl aggregations at migration staging and winter open water locations, could result in more significant losses for regional bald eagle populations from exposure to oiled prey.

If a large spill moved into wetlands, adjacent riparian habitats, or open water habitats of major rivers along the ROW, waterfowl species that breed, stage, or congregate in these areas during migration could be at risk. A spill entering a major river in spring, especially at flood stage, could significantly affect waterfowl in the short term by contaminating overflow areas or open water where spring migrants of waterfowl and shorebird species concentrate before occupying nesting areas or continuing their migration.

Lethal effects would be expected to result from moderate to heavy oiling of birds. Light to moderate exposure could reduce future reproductive success because of pathological effects on liver or endocrine systems (Holmes 1985) caused by oil ingested by adults during preening or feeding that interfere with the reproductive process. Oiled individuals could lose the water repellency and insulative capacity of feathers and subsequently die from drowning or hypothermia. Stress from ingested oil can be additive to ordinary environmental stresses, such as low temperatures and metabolic costs of migration. Oiled females could transfer oil to their eggs, which at this stage could cause mortality, reduced hatching success, or possibly deformities in young. Oil could adversely affect food resources, causing indirect, sub-lethal effects that decrease survival, future reproduction, and growth of the affected individuals.

In addition to the expected mortality due to direct oiling of adult and fledged birds, potential effects include: mortality of eggs due to secondary exposure by oiled brooding adults; loss of ducklings, goslings, and other non-fledged birds due to direct exposure; and lethal or sub-lethal effects due to direct ingestion of oil or ingestion of contaminated foods (e.g., insect larvae, mollusks, other invertebrates, or fish). Taken together, the effects of a large spill may be significant for individual waterfowl and their post-spill brood. Population depression at the local or regional scale would be greater than for smaller spills. However, the effects of even a large spill would be attenuated with time as habitats are naturally or artificially remediated and populations recover to again utilize them. In general, losses from substantive to very large spills would likely result in negligible to minor impacts to regional bird population levels but may result in significant impacts to local population levels.

Mammals

Most oil spills, including large to very large spills, would result in a limited impact on most of the terrestrial mammals utilizing the area affected by the spill. The extent of impacts would depend on the type and amount of oil spilled; the location and terrain of the spill; the type of habitat affected; mammal distribution, abundance, and behavior at the time of the spill; and the effectiveness of the spill response. Typically, the proportion of habitat affected would be very small relative to the area of habitat available for most mammals.

A large to very large spill could affect terrestrial mammals directly or indirectly through impacts to their habitat, prey, or forage. For example, a large spill likely would affect vegetation, the principal food of the larger herbivorous mammals, both wild (e.g., ungulates) and domestic (e.g., cattle, sheep, and horses). Some to most of these animals probably would not ingest oiled vegetation, because they tend to be selective grazers and are particular about the plants they consume. Many predators and scavengers (e.g., bears, foxes, and raccoons) could experience toxic effects through feeding on birds, other mammals, reptiles, and fish killed or injured by the oil spill. However, these effects would not generally be life threatening or long term for the predator or scavenger (White et al. 1995). Spill response activities would typically frighten most large mammals away from the spill, thus reducing the possibility of mammal ingestion of oiled vegetation. As noted previously, vegetation could be affected by the spilled oil, thus temporarily reducing local forage availability, although it is unlikely that the overall abundance of food for large herbivorous mammals would be substantively reduced.

For large spills that are not immediately or successfully cleaned up, the potential for contamination would persist for a longer time and the likelihood of animals being exposed to the weathered oil would be greater. Over time, any remaining oil would gradually degrade. Although oiling of animals would not likely remain a threat after cleanup efforts, some toxic products could remain in soil, aquatic sediments, or in or on plant tissues, potentially up to 5 years or longer. To the extent that residual oil leads to further contact or ingestion by mammals, effects to individual mammals would continue.

Small mammals and furbearers could be affected directly by spills due to oiling or indirectly through ingestion of contaminated forage or prey items. Furbearers, especially river otters, mink, muskrat, raccoons, and beavers that are dependent on or frequently use aquatic habitats would likely be exposed to oil if spills reached aquatic habitats within their range. Oiled furbearers would be susceptible to hypothermia and oil toxicity from ingestion during grooming. Impacts to small mammals and furbearers would likely be localized around the spill area and would not cause population-level impacts.

Fish and Other Aquatic Species

Spills within aquatic habitats could affect fish, macroinvertebrates (e.g., mussels, crustaceans, insects, and worms), algae and other aquatic plants, amphibians, and reptiles; many of which are prey for mammals and birds. Aquatic habitats include wetlands, ponds, lakes, reservoirs, drainage ditches, streams and rivers.

The effects of oil spills on freshwater fish, macroinvertebrates, and other aquatic organisms have been documented and discussed in reports of assessments of many previous spills (Poulton et al. 1997, Taylor and Stubblefield 1997, Vandermulen et al. 1992, API 1992a, 1992b, and 1997). Specific effects would depend on the concentration of spilled crude oil or oil product present, the length of exposure, and the stage of development (larvae and juveniles are generally most sensitive) of affected individuals. If lethal concentrations of spilled material are encountered (or sub-lethal concentrations over a long enough period), mortality of aquatic organisms would likely occur. However, extensive mortality from exposure to oil spills is typically observed in small, enclosed waterbodies and in the laboratory environment. Most acute-toxicity values (96-hour lethal concentration for 50 percent of test organisms [LC50]) for fish are generally from 1 to 10 ppm of toxic hydrocarbons. Concentrations observed within the water column beneath surface oil slicks have usually been less than the acute values for fish, macro invertebrates, and plankton. For example, extensive sampling following the Exxon Valdez oil spill (approximately 11 million gallons [262,000 bbl] in size) revealed that hydrocarbon levels were well below those known to be toxic or to cause sub-lethal effects in fish and plankton (Neff 1991). The low concentration of hydrocarbons in the water column following a large oil spill appears to be the primary reason for the lack of lethal effects on fish and plankton. Should a substantive to very large crude oil spill occur during proposed Project operation, the hydrocarbon concentration in flowing rivers and creeks within the affected area would likely be relatively low based on the observations made following the Exxon Valdez spill.

If an oil spill of sufficient size occurred in a small water body that contained fish or other sensitive aquatic species and that exhibits restricted water exchange (e.g., ponds and small, slow-flowing creeks), lethal and sub-lethal effects could occur for the fish and food resources in that water body. Toxic concentrations of oil in a confined area would result in greater lethal impacts on larval/juvenile fish than adults. Larval/juvenile fish are generally more sensitive than adults (Hose et al. 1996, Heintz et al. 1999). Sub-lethal effects include changes in overwintering and spawning behavior, reduction in food resources, consumption of contaminated prey, and temporary displacement (Morrow 1974, Brannon et al. 1986, Purdy 1989). If a large to very large spill reached a slow-flowing, small to moderate size river in summer, the impacts due to toxic exposures could be greater than in the same river when flows are higher and water temperatures are cooler.

McKim (1977) reviewed results from 56 toxicity tests and found that, in most instances, larval and juvenile stages were more sensitive than adults or eggs. Increased mortality of larval fish would be expected because they are relatively immobile and often found at the water‘s surface, where contact with oil would be more likely. Adult fish would be able to avoid contact with oiled waters during a spill in the open water season, but survival would be expected to decrease if oil were to reach an isolated pool of ice-covered water.

An example of potential impacts on fish food resources is provided by Barsdate et al. (1980), who studied the limnology of an arctic pond near Barrow, Alaska, with no outlet, after an experimental oil spill. The study concluded that half of the experimental spill was biodegraded or naturally attenuated during the first year. The remaining oil was trapped along the edge of the pond; most of it sank to the bottom by the end of summer. Researchers found no change in pH, alkalinity, or nutrient concentrations. Photosynthesis was briefly reduced and then returned to normal levels after several months. Carex aquatilis, a vascular plant, was affected after the first year due to emerging leaves encountering oil. Certain aquatic insects and invertebrates that lived in these plant beds were reduced in numbers, presumably from entrapment in the oil on plant stems. Some of the insects were still absent six years after the spill. There were no fish in this pond; therefore, the impact of the loss of a prey base to the fish could not be measured. Reducing food resources in a closed lake or pond, as described above, would decrease fitness and potentially reduce reproduction until prey species recovered.

Another potential impact could occur if oil that spilled before or during the spring floods from spring snowmelt or extremely high rainfall dispersed into some of the adjacent wetlands or lakes with continuous or ephemeral connection to rivers and large creeks. This oil could be left stranded when the water recedes and the oil could cause limited toxic or physical smothering effects to riparian, terrestrial and aquatic plants and animals in the flooded area. Lethal effects to fish in streams and some lakes would be unlikely during high-water events such as floods, because toxic concentrations of hydrocarbons would be unlikely. However, toxic levels could be reached in lakes that are normally not connected to the river/creek system except during the high-water periods. If hydrocarbon concentrations in the water column reach toxic levels, these fish could suffer mortality or injury.

Although lethal effects of oil on fish have been established in laboratory studies (Rice et al. 1979, Moles et al. 1979), large kills following oil spills are not well documented, likely because toxic hydrocarbon concentrations in the water column seldom occur. In instances where oil does reach the water, sub-lethal effects are more likely to occur, including changes in growth, feeding, fecundity, survival rates, and temporary displacement. Other possibilities include interference with movements to feeding, overwintering, or spawning areas; localized reduction in food resources; and consumption of contaminated prey.

Most oil spills from the proposed Project would not be expected to measurably affect fish populations in the vicinity of the proposed route. Oil spills occurring in a small body of water containing fish with restricted water exchange would be expected to kill a small number of individual fish but would not be expected to measurably affect fish populations. The same assessment would generally apply to many macroinvertebrates, amphibians, and reptiles because they are motile and generally have a wide geographic distribution. However, sessile freshwater mussels with limited geographic distribution could be affected at a population level in large to very large spills that affect a substantive segment of a stream or river.

Although very unlikely, a large to very large spill under or adjacent to a river could affect water quality, aquatic resources, and other water-associated resources, as well as subsistence and recreational fisheries in downstream areas. In the winter season, an undetected spill, especially under ice, depending on the length of time until spill detection and the volume of released oil, could affect aquatic resources downstream of the spill source. Mortality could result for fish and macroinvertebrates in deeper pools within the spill migration zone. Early-arriving birds could be exposed in any open water pools and cracks in the river ice. Depending on the season of occurrence, however, containment and cleanup of a large or very large oil spill could be difficult.

Sensitive, Threatened and Endangered Species

Most of the potential impacts to the habitats used by threatened, endangered, and protected species are included in the previous discussions of impacts on biological resources. The important additional consideration for these species is that, by definition, they have limited distribution and/or population sizes. Although exposure to oil may adversely affect only a few individuals or a small, localized population of individuals, such a loss could represent a significant portion of the population and its gene pool. Consequently, even a very small or small spill could substantively affect a threatened or endangered species. The likelihood of impacts on threatened, endangered, and protected species would be low because the majority of spills would likely occur at construction yards, on roads, at pump stations, or at MLV sites that have been sited to avoid or minimize any impacts on these habitats and species.

Spilled oil is more likely to affect species that heavily use or completely depend on aquatic and wetland habitats than those in terrestrial habitats. The oil could be transported into flowing streams and rivers, especially with substantive to very large spills, and thus affect a substantive portion of some populations of aquatic species (i.e., freshwater mussels, fish, herptiles, and water birds).

Based on the results of formal consultation between DOS and USFWS, any oil spill in designated habitat for the American Burying Beetle would require initiation of additional consultation to determine appropriate response actions and follow-up. In the event of a spill sufficiently large or coincident with occupied habitat or individuals of any sensitive, threatened or endangered species, Keystone would implement provisions of the ERP to protect potentially affected habitats and species from oiling and would conduct response actions as required by local, state, and federal agencies to return impacted areas to an agreed-upon condition.

3.13.6.5 Land Use, Recreation and Special Interest Areas, and Visual Resources

Agricultural land and rangeland is the predominant land use along the proposed pipeline corridor, comprising about 78 percent of land crossed by the proposed Project. A large to very large spill could affect agricultural activities, including irrigation water supplies.

Most very small to small spills would be confined to construction yards, roads, pump stations, MLVs, or the immediate vicinity of the proposed pipeline ROW. Substantive to very large spills would likely extend beyond the proposed ROW, although the overall extent of terrestrial releases would likely be limited unless the spilled material reaches flowing rivers or streams. Impacts from spills on recreational uses and wilderness-type values of scenic quality, solitude, naturalness, or primitive/unconfined recreation would vary depending on the overall extent of spill migration. Since the majority of releases would likely be small to very small and confined within the proposed Project ROW, their effects on these uses would be negligible to minor.

For some substantive to very large spills, particularly those that reach a stream or river, land use impacts could be substantive. Spilled oil could be visible and result in impacts to agricultural uses and recreational uses for weeks or years depending on the extent and duration of the spill. Agricultural production and crop yields within the spill zone could be reduced until remediation of affected soils and groundwater is accomplished. Rangeland forage in the spill zone could be negatively affected although livestock could likely find sufficient forage in unaffected areas. Fishing, boating, kayaking, tubing, camping, scenic values, and other recreational pursuits could be affected if spilled crude oil reaches lakes and rivers used by recreationists.

3.13.6.6 Cultural Resources

Most known cultural resources which have been previously identified would be avoided by the proposed Project alignment. Any cultural resources that are eligible for listing on the National Register of Historic Places impacted by a crude oil or oil products release would be mitigated through documentation and/or data recovery excavations consistent with the requirements of the Programmatic Agreement (PA). An Unanticipated Discoveries Plan is included within the PA. Proposed Project facilities, including the proposed pipeline, were located to minimize proximity to and potential adverse effects on identified cultural and historical resources.

Large to very large spills could impact cultural resources already identified within the Area of Potential Effect (APE) or cultural resources that are outside of the APE and are currently unidentified. Measures to avoid potential harm to historic properties would be undertaken as part of the spill response efforts. If necessary, identification and mitigation of potentially eligible cultural resources would occur during response efforts consistent with the requirements of the PA.

The proposed pipeline corridor crosses National Historic Trails administered by the NPS. If these areas were impacted by an oil or oil products spill, special care would be required during spill response actions to limit damage to the historic values of the trail systems.

3.13.6.7 Socioeconomics

Oil spills, especially large or very large spills, could affect components of the socioeconomic environment, including:

- Populated areas, especially residential areas, and other HCAs;
- Agricultural activities including farming, ranching, and livestock grazing on wild land;
- Water intakes and water supplies (e.g., drinking water and agricultural irrigation water);
- Other commercial activities; and
- Single-family home sales and property value.

Economic affects related to potential impacts to drinking water supplies could occur in the event of a large to very large oil spill. However, the proposed Project was sited to avoid water supply intakes and nearby potable groundwater well heads. Nonetheless, as discussed in Section 3.3, numerous water wells exist within a mile on either side of the proposed pipeline centerline along its route. Since all of these water wells are over 100 feet from the proposed Project centerline, the impact to these users would likely be minor for small to very small spills and could be substantive if a large to very large spill affects nearby water wells or intakes for a substantive period of time. In the event of oil spill impacts to water supplies for residential, agricultural, commercial, or public uses, Keystone would provide alternate sources of water for essential uses such as drinking water, irrigation, industrial cooling water, and water for fire fighting and similar public safety services. Economic affects related to short-term disruption in local agricultural production could result from a spill that enters agricultural lands or wild lands used by grazing livestock. The extent and duration (e.g., short term or long term) of the economic impacts would depend on the number of productive acres affected, the response time, the remedial method selected and implemented by the response team, and the length of time required to return land services to conditions similar to those prior to the spill.

Some commenters expressed concern about spilled oil reaching surface water supply intakes and affecting fire fighting capability. As stated previously, the proposed pipeline was sited to avoid water supply

intakes. Additionally, most surface water supply intakes draw water well below the water surface and would therefore draw water from below the lenticular floating spill mass in the unlikely event it moved over a water intake.

If a spill affected recreational lands and/or waterways, businesses relying on hunting, fishing, sightseeing, and other recreational activities could experience a short-term negative economic impact. During response and restoration actions, access to oil-impacted areas would generally be limited or prohibited to anyone except the cleanup and monitoring crews, thus limiting recreational access. Adverse publicity about the impacts of large to very large spills could reduce use by recreationists from the local and regional areas, or even from other areas in the U.S. for an extended period of time. For small to very small spills, there would likely be negligible economic impacts to businesses relying on recreational uses. In some cases, response to oil spills could generate positive local economic activity for the limited duration of the spill response activities as a result of the need for lodging, meals, equipment, and other facilities, materials, and logistic support for the cleanup crews and the incident command team.

Economic impacts to land and residence values in areas affected by oil spills could occur. Simons et al. (2001) conducted a study of 2,300 single-family home sales before and after an oil pipeline rupture that spilled 120,000 gallons of mostly number 2 fuel oil into 10 miles of the Patuxent River in Prince George County, Maryland, in the spring of 2000. The study determined that a statistically significant reduction in sales prices of over 10 percent occurred for properties located off of the river (i.e., ~~in~~terior" properties) for the first sales season after the spill (i.e., about 6 months), and further determined that there was also a reduction in sales volumes during that period.

Hansen et al. (2006) evaluated the impacts to properties in Bellingham, Washington as a result of a June 1999 rupture of a 19-inch-diameter gasoline pipeline that spilled 229,000 gallons of gasoline into Whatcom Creek and led to an explosion and fire. Due to associated fatalities and injuries, this incident received significant national media coverage and led to a temporary halt to pipeline development and the passage of the Pipeline Safety Improvement Act of 2002. The Hansen study evaluated single-family home sales within 1 mile of the affected Olympic Pipeline, and also the Trans Mountain crude oil pipeline located less than 1,500 feet away, for 5.5 years prior to and 5 years after the incident. An analysis of 3,765 sales showed the following statistically significant reductions in the mean sale price (slightly more than $209,000) depending on distance from the pipeline:

- A reduction of $9,613 for property located 50 feet from the pipeline;
- A reduction of $4,863 for property located 100 feet from the pipeline;
- A reduction of $2,446 for property located 200 feet from the pipeline; and
- A reduction of $491 for property located 1,000 feet from the pipeline.

Over time after the spill and explosion, changes in mean sale prices within 100 feet of the pipeline varied as follows:

- A reduction of $5,813 after 6 months;
- A reduction of $4,784 after 12 months;
- A reduction of $4,267 after 24 months; and
- A reduction of $4,008 in price 48 months.

Thus, the impacts of the pipeline incident decreased somewhat over time. These data suggest that the economic consequences of an oil spill could include a temporary reduction in housing prices that would likely decrease over time.

Environmental Justice Considerations

Information on minority and low-income populations within the proposed Project environmental justice analysis area, including locations along the proposed Project corridor that are designated as HPSA and/or MUA/P areas are presented in Section 3.10. Depending on the location and volume of an accidental crude oil release from the proposed Project, it is possible that minority or low-income populations could be affected by the release. Minority and low-income populations could be more vulnerable to health impacts associated with the crude oil release, particularly if access to health care is less available in the release area. Exposure pathways could include direct contact with the crude oil, inhalation of airborne emissions from the crude oil, or consumption of food or water contaminated by either the crude oil or components of the crude oil. However, as discussed previously in Section 3.13.5.5, Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations, up to a maximum of $350,000,000 for any release that could affect surface water, no matter what the reason. Therefore potential impacts to minority or low-income populations would be mitigated by the operator's liability for the release. Additionally, Keystone has committed to provide an alternative water supply if an accidental release from the proposed Project contaminates groundwater or surface water used as a source of potable water or for irrigation or industrial purposes, which includes water uses by minority and low-income populations. Given the potential vulnerability of these populations to health impacts, it is essential that spill response planning considers appropriate communications directed to these populations in the unlikely event of an accidental crude oil release. Emergency communications should be provided in languages appropriate for identified populations at risk. As a measure to avoid or minimize impacts to minority or low-income populations, response planning should include outreach to Local Emergency Planning Committees (LEPCs) (see Sections 3.10.2 and 3.13.5.5) to ensure due consideration of the potential issues involved in emergency response in areas where minority and low-income populations have been identified along the proposed Project corridor (see Section 3.10.1).

3.13.6.8 Air Quality

Impacts on air quality from an oil spill would be localized and transient, even for very large spills. Evaporation of the lighter hydrocarbon fractions typically occurs within one to a few days, and the vapors are usually dissipated below risk levels within a short distance of the source. Additional evaporation of the heavier compounds would take place over a longer period of time and could be an important source of organic aerosol pollution (De Gouw 2011). The oil spill response personnel would monitor air for hydrocarbon vapors. Public access to areas exceeding specified risk levels would be restricted and authorized personnel within the restricted areas would be equipped with appropriate personal protective equipment. Nearby farmers and ranchers would be informed of potential hazards to livestock and other farm animals, and assistance would be provided in moving livestock if necessary.

Based on models by Hanna and Drivas (1993), the majority of volatile organic compounds (VOCs) from crude oil spills would likely evaporate almost completely within a few hours after the spill occurred, especially during late spring/early fall when air and soil surface temperatures are higher. Emissions of VOCs, such as BTEX, would peak within the first several hours after the spill and likely drop by two orders of magnitude after approximately 12 hours. The heavier compounds would take longer to evaporate, particularly at the colder temperatures typical of the winter season, and might not peak until more than 24 hours after the spill. In the event of an oil spill on land, the air quality effects would be less severe than those for a spill on water because some of the oil could be absorbed by vegetation or into the

ground. However, some effects might last longer on land before the VOC compounds are completely dissipated.

During construction, diesel fuel oil, kerosene and similar hydrocarbons could be spilled during refueling, from a broken diesel refueling line, or from accidents involving vehicles or equipment. A diesel spill would evaporate faster than a crude oil spill. Ambient hydrocarbon concentrations would be higher than for a crude oil spill but would persist for a shorter time.

Gasoline and solvents would typically evaporate and disperse very rapidly. Almost all the released volume would evaporate, except for small amounts that may seep into the upper soil and vegetation layers from which it would be released over 1 day to several days. Gasoline vapors are generally not toxic at the concentrations experienced in spills but they may lead to flammable or explosive vapor concentrations. Public and response personnel access to fire and explosion hazards would be restricted.

In general, impacts on air quality related to oil spills would be localized and short term. The associated VOC air emissions would result in little impact to the biological or physical resources in the vicinity of the spill.

3.13.7 Potential Additional Mitigation Measures

The following potential mitigation measures have been suggested by regulatory agencies:

- As a potential mitigation for concerns relative to environmental justice, the information gathered by phone survey of LEPCs along the proposed Project corridor shown in Table 3.13.5-8 can be used during development of the PSRP and the ERP within the onsite O&M Plan to determine whether additional considerations should be included within these Project-specific plans. Response planning should also consider the potential vulnerability of HPSA and/or MUA/P designated areas when assessing potential response times for any exposed populations. In response to a DOS request, Keystone provided information relative to the level of environmental justice community involvement that it intends to incorporate into proposed Project emergency planning. With regard to emergency response, tribal officials associated with the Integrated Public Awareness (IPA) Program were identified and updated in the Keystone IPA database. A protocol for Keystone‘s Emergency Management process was developed at an emergency planning scenario on the Fort Peck Reservation in Montana with Keystone personnel, the local municipalities and tribal emergency entities. Should the proposed Project be implemented, Keystone would reach out to LEPCs during and after the development of its Emergency Response Plan (ERP) and public awareness materials with special emphasis on considerations of low income and minority communities in those preparedness efforts. As described in Section 2.4.2.2, Keystone would be required to develop a PSRP for review and approval by PHMSA and an ERP for review by PHMSA for the proposed Project. PHMSA may request EPA and U.S. Coast Guard consultation on the response elements of the PSRP. Keystone would share on its own volition portions of the PSRP with community emergency responders along the proposed pipeline corridor to ensure an appropriate level of collaborative emergency response planning. However, based on a PHMSA advisory bulletin issued on November 3, 2010, Keystone would be required to share the ERP with local emergency responders in relevant jurisdictions along the proposed Project corridor.
- EPA suggested considering the placement of additional intermediate mainline valves, particularly in areas of shallow groundwater and at river crossings of less than 100 feet where sensitive aquatic resources may exist. Project-specific Special Condition 32 developed in consultation with PHMSA that Keystone agreed to incorporate into the proposed Project plan states:

> —Keystone shall locate valves in accordance with 49 CFR § 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations, to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than twenty (20) miles apart, whichever is smaller."

The requirement to take into consideration elevation, population, and environmentally sensitive locations to minimize consequences of a release, and the maximum valve spacing of 20 miles exceed what is currently required in 49 CFR § 195.260. Based on Special Condition 32, the proposed Project was redesigned to increase the number of intermediate mainline valves from 76 to 112 and some previously planned valve locations were moved. As per standard code requirements, there would also be two valves at each of the 30 pump stations. Section 2.2.2 has been updated to include information on the additional intermediate valves and valve locations.

EPA also expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks, such as external leak detection systems. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology assessed in that report included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. The report concluded that while external leak detection systems have proven results for underground storage tank systems, there are limitations to their applicability to long pipeline systems and they are better suited to shorter pipeline segments. The performance of external leak detection systems even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. Some external detection methods are more sensitive to small leaks than the SCADA computational approach, but the stability and robustness of the systems are highly variable, particularly over long pipeline segments, and the costs are extremely high. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable. It may be possible, however, to incorporate external leak detection methods along discrete segments of pipeline where particularly sensitive resources may exist. For example, in the development of the original Keystone pipeline, specific analysis was commissioned at the request of the North Dakota Public Utilities Commission to examine the possibility of using external leak detection in the area of the Fordville aquifer. That analysis was performed by Accufacts, Inc., a widely recognized expert on pipeline safety that has authored a report for the Pipeline Safety Trust on leak detection technology. The Accufacts, Inc. report (2007) on the Fordville aquifer noted:

> —Such real-time external systems should be considered as complementing CPM [computational pipeline monitoring] leak detection in those few ultra-sensitive areas where the environment can quickly spread low rate releases. These systems may be justified in a few areas that can have high consequences because of the number of sensitive receptors (i.e., people) or the potential to critically impact the environment."

The author of the report defined —ultra-sensitive" areas as those areas where low rate or seepage pipeline release could —reach a sensitive area, have serious consequences, and could not be actively remediated." (Accufacts, Inc. 2007).

DOS in consultation with PHMSA and EPA determined that Keystone should commission an engineering analysis by an independent consultant that would review the proposed Project risk assessment and proposed valve placement. The engineering analysis would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. The scope of the analysis and the selection of the independent consultant would be approved by DOS with concurrence from

PHMSA and EPA. After completion and review of the engineering analysis, DOS with concurrence from PHMSA and EPA would determine the need for any additional mitigation measures.

- EPA and other commenters on the draft and supplemental draft EIS recommended consideration of ground-level inspections as an additional method to detect leaks. The PHMSA report (2007) on leak detection presented to Congress noted that there are limitations to visual leak detection, whether the visual inspection is done aerially or at ground-level. A limitation of ground-level visual inspections as a method of leak detection is that pipeline leaks may not come to the surface on the right of way and patrolling at ground level may not provide an adequate view of the surrounding terrain. A leak detection study prepared for the Pipeline Safety Trust noted: ―A prudent monitor of a pipeline ROW will look for secondary signs of releases such as vegetation discoloration or oil sheens on nearby land and waterways on and off the ROW" (Accufacts 2007). PHMSA technical staff concurred with this general statement, and noted that aerial inspections can provide a more complete view of the surrounding area that may actually enhance detection capabilities. Also, Keystone responded to a data request from DOS concerning additional ground-level inspections and expressed concerns that frequent ground-level inspection may not be acceptable to landowners because of the potential disruption of normal land use activities (e.g., farming, animal grazing). PHMSA technical staff indicated that such concerns about landowner acceptance of more frequent ground-level inspections were consistent with their experience with managing pipelines in the region. Although widespread use of ground-level inspections may not be warranted, in the start-up year it is not uncommon for pipelines to experience a higher frequency of spills from valves, fittings, and seals. Such incidences are often related to improper installation, or defects in materials. In light of this fact, DOS in consultation with PHMSA and EPA determined that if the proposed Project were permitted, it would be advisable for the applicant to conduct inspections of all intermediate valves, and unmanned pump stations during the first year of operation to facilitate identification of small leaks or potential failures in fittings and seals. It should be noted however, that the 14 leaks from fittings and seals that have occurred to date on the existing Keystone Oil Pipeline were identified from the SCADA leak detection system and landowner reports.
- EPA requested that language be added to address Keystone's commitment to cleanup and restoration, even in groundwater areas that are not linked to navigable waters of the U.S. In response, Keystone has agreed that it would be responsible for providing appropriate alternative water supply, and for clean-up and restoration in the event of a release of crude oil into groundwater, even in areas that are not linked to navigable waters of the U.S.
- EPA requested the following to be included in the PSRP and/or ERP:
    - Develop a contingency plan before commencement of operation for emergency response and remedial efforts to control contamination from a release in order to avoid and minimize potential impacts through all media (i.e., surface and ground water, soil, and air) to minority, low-income and Tribal populations rather than relying solely on after-the-fact compensation measures. Provide translation of emergency information to linguistically isolated communities. Provide bottled water to Environmental Justice communities in the event the drinking water supply becomes contaminated.
    - Provide notification to individuals affected by soil or groundwater contamination, ensuring the public is knowledgeable and aware of emergency procedures and contingency plans (including posting procedures in high traffic visibility areas), and providing addition monitoring of air emissions and conducting medical monitoring and/or treatment responses where necessary.

- Designate staging and deployment areas for oil spill equipment, and dedicated oil spill-contingency-plan buildings and equipment at each of the pump stations.
- Develop spill scenarios that cover a variety of terrains, oil products, spill volumes, and seasonal conditions.
- Have aerial photographs of the pipeline to aid in spill response planning.

- The risks of spills or leaks could be assessed using 3-dimensional modeling of a spill of a particular magnitude in the Sand Hills. The modeling could assess fate and transport, including routes of exposure to human and ecosystem receptors (Professor Gates and Professor Woldt, UNL).

3.13.8 References

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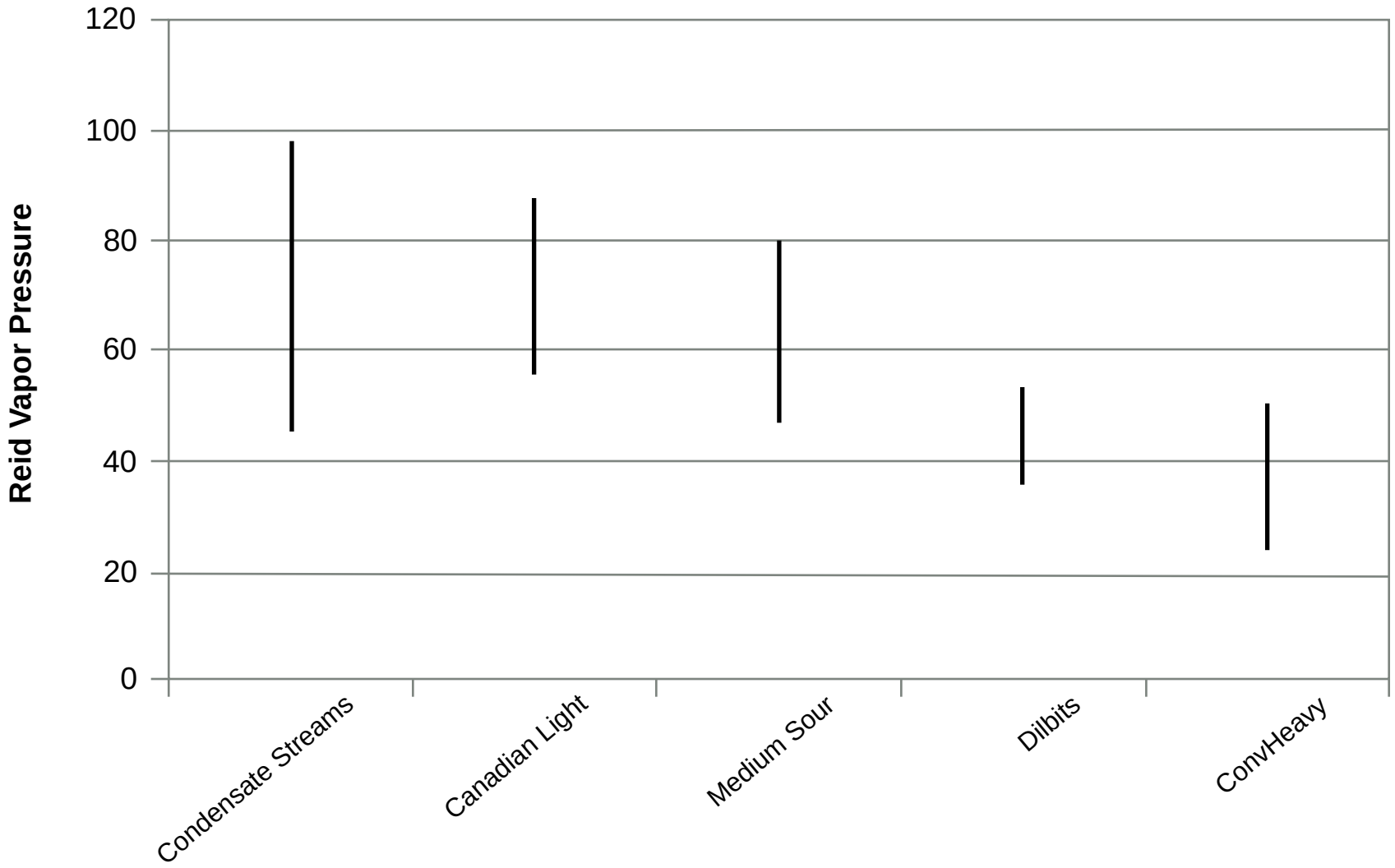

Source: http://www.enbridge.com/DeliveringEnergy/Shippers/CrudeOilCharacteristics.aspx

KEYSTONE XL PROJECT

Figure 3.13.5-1

Range of Reid Vapor Pressures by Crude Oil or Condensate Type

3.14 CUMULATIVE IMPACTS

The analysis of cumulative impacts in this EIS employs the definition of cumulative impacts found in the Council on Environmental Quality (CEQ) regulations implementing NEPA: "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such actions" (40 CFR 1508.7). Not all actions identified in this section would have cumulative impacts in all resource areas.

Although rare in occurrence, it is plausible that accidental or emergency events may arise due to an unforeseen chain of events during the proposed Project's operational life. For an assessment of the potential short- and long-term effects of oil releases to the environment, see Section 3.13 (Potential Releases from Project Construction and Operation and Environmental Consequences Analysis).

3.14.1 Methods and Scope of the Cumulative Impacts Analysis

Cumulative impacts were assessed by combining the potential environmental impacts of the proposed Project with the impacts of substantial projects that have occurred in the past, are currently occurring, or are proposed or planned in the future within the proposed Project cumulative impact corridor. In general, the proposed Project cumulative impact corridor extends from 1 to 2 miles from the proposed Project pipeline centerline depending on the resource considered. The potential cumulative impact corridor for the proposed Project encompasses the area of physical disturbance along the proposed Project construction ROW and adjacent areas that could have localized impacts associated with temporary access roads and aboveground facilities. The actions considered in the cumulative impact analysis may vary from the proposed Project in nature, magnitude, and duration. These actions are included based on their likelihood of occurrence, and only projects with either ongoing or reasonably foreseeable impacts are identified. While it is not clear that an analysis of extraterritorial cumulative impacts (cumulative impacts resulting from activities under the jurisdiction of another nation or affecting the territory of another nation) is required by DOS regulations (22 CFR 161.12) or by EO 12114 (Environmental Affects Abroad of Major Federal Actions), DOS has included a discussion of these potential cumulative impacts in Section 13.14.4 (Extraterritorial Concerns).

The anticipated cumulative impacts of the proposed Project and these other actions are discussed below, along with any pertinent mitigation actions. In general, the analysis of cumulative impacts in this section follows the processes recommended by CEQ (1997 and 2005) and the regulations at 40 CFR 1508.7. The process includes the identification of federal, non-federal, and private actions with possible effects that could be coincident with those of the proposed Project on resources, ecosystems, and human communities. Coincident effects would be possible if the geographic and time boundaries for the effects of the proposed Project and past, present, and reasonably foreseeable future actions overlap.

The temporal boundaries for this analysis reflect the nature and timing of Project activities and the availability of information on future projects that have a high probability of proceeding. The proposed Project schedule includes target timeframes for construction and operation (see Section 2.4). Fifty years of proposed Project operation was assumed for the purpose of this analysis, although the proposed Project could be operational beyond 50 years. As noted in Section 2.7, there are no plans for abandonment of the proposed Project at this time. Reasonably foreseeable future projects were considered if available information suggested that they could be implemented by 2015. For the purpose of this analysis, short-term effects were those that could occur during the construction period, and long-term impacts were those that could occur over the operational lifetime of the proposed Project.

3.14.2 Past, Present, and Reasonably Foreseeable Projects

The proposed Project would occur in locations that include numerous existing, under construction, and planned linear energy transportation systems, including natural gas pipelines, crude oil pipelines, and electric transmission lines. Additionally, the proposed Project would occur in areas that support major existing and planned water delivery projects and a number of energy development projects, including producing oil and natural gas well fields (with associated collection piping systems), coal mines, and existing and planned wind power facilities.

The projects considered in the cumulative impact analysis were identified through scoping and independent research including queries to the PHMSA National Pipeline Mapping System (https://www.npms.phmsa.dot.gov/) and the FERC natural gas pipeline database. Substantial existing, under construction, proposed, or announced projects that were considered in the cumulative impacts analysis are listed in Table 3.14.2-1. Those projects that are considered to have the greatest potential to contribute to cumulative impacts are discussed in more detail in Sections 3.14.2.1 through 3.14.2.5. A detailed description of potential cumulative impacts by resource category is presented in Section 3.14.3.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Crude Oil Pipelines and Storage Facilities			
Express-Platte Pipeline System (existing)	Approximately 1,700 miles of crude oil pipelines that are 20 and 24 inches in diameter.	Montana, Wyoming, Nebraska, Missouri, and Illinois	The Express-Platte system would be within the proposed Project's cumulative impact corridor (PCIC)[b] near Steele City, Nebraska.
Keystone Mainline Oil Pipeline (existing)	Approximately 1,379-mile-long crude oil pipeline has a design capacity between 435,000 bpd to 591,000 barrels per day (bpd).	North Dakota, South Dakota, Nebraska, Kansas, Missouri, and Illinois.	Portions of the Keystone pipeline would be in the PCIC near Steele City, Nebraska.
Keystone Cushing Extension (existing)	298-mile-long, 36-inch-diameter crude oil pipeline.	Nebraska, Kansas, and Oklahoma.	Portions of the northern and southern ends of the Cushing Extension would be within the PCIC (near Steele City, Nebraska and near Cushing, Oklahoma).
BakkenLink Pipeline (planned)	Approximately 144-mile-long,12-inch-diameter oil gathering system to move Bakken crude within North Dakota to a rail loading station that is being developed near Fryburg, about 30 miles west of Dickinson in southwestern North Dakota.	North Dakota	The BakkenLink Pipeline would be within North Dakota near the PCIC.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Bakken Marketlink Project (planned)	Three crude oil storage tanks and associated facilities near Baker adjacent to the proposed Pump Station 14 and two crude oil storage tanks and associated facilities at the proposed Cushing tank farm in Cushing, Oklahoma pipeline to store and inject Bakken oil production from producers in North Dakota and Montana into the proposed Project pipeline.	Montana and Oklahoma	The Bakken Marketlink Project would be within the PCIC near Baker, Montana and near Cushing, Oklahoma and would be constructed concurrently with the proposed Project.
Cushing Marketlink Project (planned)	Two oil storage tanks and associated equipment at the proposed Cushing tank farm to store and inject oil from producers in Oklahoma into the proposed Project pipeline.	Oklahoma	The Cushing Marketlink project would be within the PCIC near Cushing, Oklahoma and would be constructed concurrently with the proposed Project.
Enterprise Product Onshore Pipeline System (existing and under construction)	A system of approximately 4,400 miles of onshore crude oil pipelines and 10.5 million barrels of crude oil storage. A new crude oil terminal on an industrial site in southeast Houston is under construction and planned to begin operation in 2012.	New Mexico, Texas, and Oklahoma	Portions of the Enterprise Product System would be within the PCIC near Cushing, Oklahoma. Facilities associated with the proposed crude oil terminal in southeast Houston would be near the PCIC.
True Company Pipelines and Crude Oil Storage Facility (existing)	A system of more than 3,400 miles of crude oil gathering and transportation pipelines, including Bridger Pipeline, LLC that owns and operates the Poplar, Little Missouri, Powder River, Belle Fourche, and Bridger pipeline systems. Three collector pipelines to transport production from the north, west and east into the Butte Pipeline near Baker are under construction.	Wyoming, Montana, and North Dakota	Portions of the True Companies pipeline system would be within the PCIC in eastern Montana.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Enbridge Monarch Pipeline (planned)	Planned 24-inch-diameter pipeline that now comprises a northern leg (that would move 200,000 to 300,000 bpd of Bakken and WCSB crude oil from Chicago area to Cushing) and a southern leg (that would move the WCSB and Bakken crude oil and an additional 350,000 bpd light crude oil from Cushing to Gulf Coast refineries).	Illinois, Missouri, Kansas, Oklahoma and Texas	Portions of the Monarch Pipeline would be in the PCIC in the Cushing, Oklahoma area and would likely be in the PCIC in the vicinity of delivery points in Texas. The route of the Monarch pipeline has not been announced, but other portions of the route may also be within the PCIC. It is possible that the Monarch pipeline would be constructed at about the same time as the proposed Gulf Coast Segment and Houston Lateral.
Basin Pipeline System (existing and proposed)	A 519-mile-long interstate crude oil system with a capacity ranging from about 144,000 and 400,000 bpd and about 5.5 million barrels of storage along the system. Basin proposed to increase pumping in the system to increase throughput. Modification began in 2011, with completion expected in early 2012.	New Mexico, Texas, and Oklahoma	Portions of the Basin system would be in the PCIC in the Cushing, Oklahoma area.
Centurion Pipeline (existing)	2,750 miles of oil-gathering pipelines with a throughput capacity of about 350,000 bpd and 5 million barrels of storage capability. The system also has 64four truck unloading facilities along the route.	New Mexico, Oklahoma, and Texas	Portions of the Centurion Pipeline system would be in the PCIC in the Cushing, Oklahoma area.
Seaway Pipeline (existing)	A 530-mile-long, 30-inch-diameter pipeline with a capacity of about 430,000 bpd.	Texas and Oklahoma	Portions of the Seaway Pipeline would be within the PCIC in the Cushing, Oklahoma area.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Double E Pipeline (planned)	A 584-mile long pipeline (with 354 miles of new pipeline) originating at crude oil storage facility in Cushing, Oklahoma and terminate at a crude oil storage and terminal facility in southeast Harris County, Texas.	Texas and Oklahoma	Portions of the Double E Pipeline would be within the PCIC in the Cushing, Oklahoma area.
Magellan Pipeline (planned)	A pipeline from Cushing, Oklahoma, to refineries along the U.S. Gulf Coast with a capacity of between 60,000 and 70,000 bpd.	Texas and Oklahoma	Portions of the Magellan Pipeline would be within the PCIC in the Cushing, Oklahoma area.
Natural Gas Pipelines			
Williston Basin Interstate Pipeline Company System (existing)	A 3,364-mile-long natural gas pipeline transmission system.	Montana, North Dakota, South Dakota, Wyoming, Colorado, and Kansas	Portions of the Williston Basin System would be within the PCIC in eastern Montana and northwestern South Dakota.
Northern Border Pipeline (existing)	A 1,249-mile-long interstate natural gas pipeline with a design capacity of approximately 2.4 billion cubic feet of gas per day (bcfd).	Montana, North Dakota, South Dakota, Minnesota, Iowa, Illinois, and Indiana	Portions of the Northern Border Pipeline would be in the PCIC in northeastern Montana and would be near and parallel to the proposed pipeline for approximately 21.5 miles.
Enterprise Product Onshore Pipeline System (existing)	A natural gas pipeline system that includes approximately 19,200 miles of natural gas pipelines, including about 6,560 miles in Texas.	Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas, and Wyoming	Portions of the Enterprise Product System would be in the PCIC near or within the Beaumont/Orange area and in the area southeast of Houston area
Northern Natural Gas (existing)	A network of approximately 15,141 miles of natural gas pipelines.	Minnesota, Wisconsin, Michigan, Iowa, South Dakota, Illinois, Nebraska, Kansas, Oklahoma, and Texas	Portions of the Northern Natural Gas pipeline system would be within the PCIC in Nebraska, South Dakota, and Montana.
Natural Gas Pipeline of America (Existing)	Approximately 9,800 miles of natural gas transmission system	Illinois, Iowa, Nebraska, Kansas, Oklahoma, Texas, New Mexico, Missouri, and Arkansas	Portions of the Natural Gas Pipeline System of America would be within the PCIC in Texas and Oklahoma.
Oklahoma Natural Gas Company System (existing)	Approximately 2,500 miles of transmission pipeline.	Oklahoma	Portions of the Oklahoma Natural Gas system would be within the PCIC in Oklahoma.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Lone Star Pipeline System (existing)	Approximately 7,746 miles of gathering and transmission pipelines.	Texas	Short distances of the Lone Star system may be within the PCIC.
Transco Pipeline System (existing)	Approximately 10,560 miles of transmission pipeline with a system design capacity of approximately 8.1 bcfd.	Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, New Jersey, and New York	Portions of the Transco system would be within the PCIC in Texas.
Gulf Crossing Pipeline (existing)	Approximately 374-mile-long, 42-inch-diameter, interstate natural gas pipeline with a capacity of approximately 1.73 bcfd.	Oklahoma, Texas, Louisiana, and Mississippi	Portions of the Gulf Crossing Pipeline would be within the PCIC in Oklahoma and Texas and would be parallel and near the proposed Project ROW between Lamar County, Texas, and Bryan County, Oklahoma.
Golden Pass Pipeline (existing)	Approximately 69 miles of 42-inch-diameter pipeline with a transportation capacity of about 2.5 bcfd.	Texas, Louisiana	Portions of the Golden Pass Pipeline would be located within the PCIC along the Gulf Coast Segment in Texas.
Bison Natural Gas Pipeline (under construction)	A 301-mile-long, 30-inch-diameter pipeline with a capacity of 500 million cubic feet per day (mcfd).	Wyoming, Montana, and North Dakota	Portions of the Bison pipeline would be located within the PCIC in Fallon County, Montana.
Mid-Continent Express Pipeline (MEP; existing)	A 506-mile-long, 42-inch-diameter interstate natural gas transmission pipeline with a capacity of about 1.8 bcfd in the western portion of the project.	Southeastern Oklahoma, northeaster Texas, Louisiana, and Alabama	Portions of the MEP would be within or adjacent to the PCIC in Bryan County, Oklahoma and Lamar County, Texas.
Rockies Express West (REX-W; existing)	A 713-mile-long 42-inch-diameter interstate natural gas transmission pipeline with a capacity of approximately 1.5 bcfd. The project includes 5 compressor stations.	Colorado, Wyoming, southern Nebraska, northeastern Kansas, and northern Missouri	REX-W would cross a portion of the PCIC in a generally west-to-west direction in the vicinity of Steele City, Nebraska.
Carbon Dioxide Pipelines			
Green Pipeline (under construction)	Approximately 320-mile-long, 24-inch-diameter pipeline. Transport capacity will be 800 mcfd. Anticipated in-service date is mid 2011.	Louisiana, Texas	Portions of this pipeline would be within the PCIC in Texas and would be collocated with the proposed Project for approximately 46 miles between Beaumont, Texas, to the start of the Houston Lateral.

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Water Delivery Systems			
Dry Prairie Rural Water System (under construction)	System to provide drinking water to approximately 27,434 people in eastern Montana. The system will consist of 12- to 15-inch-diameter PVC water delivery pipelines throughout the service area. Planned completion of the overall system is 2011.	Montana	Portions of the water system west of the Fort Peck Indian Reservation may be within the PCIC in northeastern Montana.
Electrical Transmission Lines			
Mountain States Intertie Project (MSTI; proposed)	Approximately 430 miles of 500-kV electrical transmission line from Townsend, Montana to Midpoint, Idaho. Estimated in-service date is 2013.	Montana and Idaho	The MSTI Project would be in western Montana and would not be within the PCIC.
Nebraska Public Power District (proposed)	Upgrades to the existing transmission system, including more than 140 miles of 345-kV and 115-kV transmission lines. Estimated in-service date is mid 2012.	Nebraska, Kansas	Portions of the Nebraska Public Power transmission system would be within the PCIC in Nebraska.
Chinook Project (proposed)	A 500-kV electrical transmission line over 1,000 miles long. Est. in-service date is 2015.	Montana, Idaho, Nevada	The Chinook Project would be located in west central Montana and would not be within the PCIC.
Kansas V-Plan (proposed)	Approximately 180 miles of 765-kV transmission line. Estimated in-service date is 2013.	Kansas	The Kansas V-Plan would be west of Wichita, Kansas and would not be within the PCIC.

[a] This table provides basic information on representative key projects in the vicinity of the proposed Project that are existing, under construction, proposed (applications submitted to agencies with jurisdiction) , planned (announced but not proposed), or reasonably foreseeable. It is not intended to provide a listing of all such projects since there are likely hundreds of existing linear and other projects that have contributed to the cumulative impacts within the area in the vicinity of the proposed Project (see Figures 3.14.2-1 through 3.14.2-4).

[b] The proposed Project cumulative impact corridor (PCIC) is generally defined as a 4-mile-wide corridor centered on the proposed pipeline.

3.14.2.1 Cumulative Impacts from Oil Storage and Transportation Systems

The proposed Project would contribute to regional cumulative impacts associated with currently operating oil pipeline systems, newly constructed and soon to be operating pipeline systems, and proposed or announced future oil storage and transportation systems.

Currently Operating Oil Storage and Transportation Systems

A map of existing and planned crude oil and petroleum products pipeline systems of the U.S. is shown in Figure 3.14.2-1. According to API there are over 165,000 miles of existing crude oil and petroleum pipelines in the U.S. and a large number of pipelines either cross or occur in the vicinity of the proposed Project cumulative impacts corridor. For example, the Express and Platte pipelines deliver WCSB crude oil through central Montana and Wyoming and then travel east-southeast through eastern Wyoming, Nebraska, northeastern Kansas, and Missouri before terminating at the Wood River refinery in western Illinois. These existing pipelines intersect the proposed Project cumulative impacts corridor in southern Nebraska.

Operation of existing oil pipeline systems, such as the Express and Platte Crude Oil Pipelines, have resulted primarily in alterations to land uses, terrestrial vegetation, and wildlife habitat. Cumulative impacts associated with existing oil pipelines would be primarily related to noise emanating from pump stations and the cumulative increases in the width of ROWs in areas where the proposed Project would be adjacent to existing ROWs. In those areas where the proposed Project would not be directly adjacent to existing ROWs there would be a cumulative change in vegetation resources, wildlife habitat, and land uses during proposed Project operation.

A very large existing oil storage and transfer terminal exists in Cushing, Oklahoma. A small existing oil storage facility exists near Baker, Montana. Additionally, there are existing oil storage and transfer facilities in the general vicinity of the proposed Project delivery points at Nederland and Moore Junction, Texas. The impacts of oil storage facilities associated with the proposed Project and its connected actions would occur near Baker, Montana and at Cushing, Oklahoma. Impacts associated with these facilities would primarily include air emissions and land use alterations. The cumulative effects of the new storage facility at Cushing would be very small compared to the impacts associated with the very large terminal already in place. However, the new storage facility near Baker would likely produce impacts similar in nature to the existing storage facilities.

Newly Constructed Oil Pipelines

Newly constructed oil pipelines in the vicinity of the proposed Project cumulative impact corridor contribute to overall cumulative impacts. For example, construction on the Keystone Mainline Pipeline and Cushing Extension has been completed and these pipelines are now in operation. The Keystone Mainline Pipeline crosses North Dakota, South Dakota, Nebraska, Kansas, Missouri, and Illinois and would overlap the proposed Project cumulative impact corridor near Steele City, Nebraska. As part of the proposed Project, two new pump stations would be constructed along the Keystone Cushing Extension to support the increased crude oil flow rates. Cumulative effects from the Keystone Cushing Extension and the proposed Project would primarily be additive and minor relative to the overall environmental resource base in the region. Other relatively new pipeline systems in the vicinity of the proposed Project cumulative impact corridor are presented in Table 3.14.2-1.

Future (Proposed or Announced) Oil Storage and Transportation Systems

Connected Actions to the Proposed Project

Future oil storage and transportation systems in the vicinity of the proposed Project cumulative impact corridor would also contribute to overall cumulative impacts. For example, since publication of the draft EIS, successful open seasons have occurred for two connected actions to the proposed Project. These connected actions are the Bakken Marketlink and Cushing Marketlink Projects. These two proposed projects are addressed as connected actions in Sections 2.5.3 and 2.5.4 and are also considered in this

cumulative impacts analysis to the extent possible based on currently available information. The Bakken Marketlink Project would receive crude oil from the Williston Basin in Montana, North Dakota, and Saskatchewan for shipment to PADD II and PADD III. The Williston Basin is experiencing increased oil production, particularly associated with the development of the Bakken shale formation. The Cushing Marketlink Project would receive crude oil from producers in midwestern U.S. states (e.g., Kansas and Oklahoma) for shipment to PADD III. These two projects would include construction and operation of crude oil storage tanks, connecting pipelines, manifolds, metering stations, and associated facilities, and construction could overlap with construction of the proposed Project. The proposed Bakken Marketlink project would compete in the market with other transport options to move Williston Basin crude to refiners in other areas of the country. The Bakken Marketlink proposal reserves space for a potential 100,000 bpd of Bakken production of which 65,000 bpd has been committed at this date. The Cushing Marketlink proposal reserves space for a potential 150,000 bpd for crude oil reaching the Cushing area.

Contribution to cumulative effects during construction would primarily comprise additional dust and noise generation, loss of vegetation or crop cover, and minor localized traffic disruptions. The primary contribution to cumulative effects during operations would be increased air emissions from storage tanks. However, Keystone Marketlink would be required to obtain air quality permits for the projects and would have to comply with the emissions limitations of those permits. Additional contributions to cumulative effects would include effects on visual resources in the vicinity of the storage tanks and manifolds, cultural resources, changes in land use, increased tax revenues, and increased employment.

Commenters on the supplemental draft EIS suggested that the Bakken Marketlink project could induce accelerated and expanded growth of the Bakken oil field within the Williston Basin. At this time the Bakken formation in the Williston Basin is producing over 400,000 bpd of crude oil (Investors Business Daily 2011). These production levels from the Bakken formation are consistent with EIA (2011) projections. The addition of the Bakken Marketlink transport capacity would not be expected to impact the rate of growth in crude oil production from the Bakken formation in the Williston basin in North Dakota and Montana. A North Dakota Pipeline Authority (NDPA) report (2010) examined projected increases in production in North Dakota and eastern Montana compared to current and planned transportation routes for crude oil. That NDPA forecast indicated that even under high growth projections for crude oil production in the area, there is sufficient existing and planned pipeline transport capacity to accommodate the increased production from the Bakken oil field through at least 2017 without the Bakken Marketlink project.

In the past four months, there have been significant upward adjustments in both the projected potential production in the Williston basin, and in the projected crude oil transport capacity out of the Williston basin. As indicated in Figure 3.14.2-2, the most recent NDPA projections indicate that production in the Williston basin could peak at as much as approximately 900,000 to 1.1 million bpd in the time period shortly after 2020. The same figure indicates that existing, currently under construction, and planned crude oil transport projects would provide between 1.1 and 1.2 million bpd of transport capacity by midyear 2013, without the proposed Bakken Marketlink project. This projection may actually understate the potential transport capacity that could be in place by 2013 by several hundred thousand barrels, as it includes only approximately 450,000 bpd of rail capacity. The more recent EnSys (2011) report indicates that the rail-loading capacity could actually be as high as 750,000 bpd by 2013. The surplus of existing, currently under construction, and planned take-away capacity from the Williston basin, as well as the rapidity and flexibility with which the market for crude oil transport has responded to the sharp increase in Bakken production, reinforce the conclusion that the Bakken Marketlink project is unlikely to have an effect on the rate of production in the Williston basin.

Another potential project, the BakkenLink Pipeline Project, is currently in the assessment stage and may or may not be carried through to construction and operation. The BakkenLink Pipeline Project has

concluded an open season, the results of which are unknown at the time this EIS was prepared. However, North Dakota's Public Service Commission reported on August 3, 2011 that the proposed BakkenLink Pipeline Project now intends to build a pipeline to a rail loading station that is being developed near Fryburg, about 30 miles west of Dickinson in southwestern North Dakota. The length of the proposed line is being reduced from 250 miles to about 144 miles and is no longer routed into Montana. Any indirect or induced effects of the BakkenLink Pipeline Project (e.g., potentially accelerating the development of crude oil resources in Montana and North Dakota) would be assessed in a future environmental review if the project were to seek regulatory approval at some future time.

Other Potential Transportation Systems

As of the time the EIS was written, the following additional potential crude oil transportation systems have been announced.

Portal Link Pipeline

Enbridge, Inc. is implementing a reversal of its existing Portal Link pipeline in North Dakota that would provide an on-ramp for Williston Basin oil production to its existing Enbridge Mainline pipeline in Saskatchewan. The reversal is expected to be completed in 2011.

Monarch Pipeline

In August, 2011, Enbridge announced that its planned 24-inch-diameter Monarch pipeline now comprises a northern leg that would move 200,000 to 300,000 bpd of Bakken and WCSB crude oil from the Chicago, Illinois area to Cushing, Oklahoma through Illinois, Missouri, Kansas and Oklahoma, and a southern leg that would move the WCSB and Bakken crude oil and an additional 350,000 bpd light crude oil from Cushing, Oklahoma to Gulf Coast refineries in Texas.

Double E Pipeline

Enterprise Products Partners L.P. and Energy Transfer Partners, L.P. have formed a joint venture to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. The project would provide up to 450,000 barrels per day of takeaway capacity for crude oil currently stranded at the Cushing storage hub due to a lack of southbound pipeline infrastructure. The project would offer greater access to Gulf Coast refineries, while providing refiners with a reliable, domestic source of crude oil as an alternative to higher priced imported crude oil that currently represents their largest source of supply. The project would utilize existing pipelines and construct 354 miles of new pipeline, to create a 584-mile long pipeline which would originate at crude oil storage facility owned by Enterprise in Cushing, Oklahoma and terminate at the ECHO crude oil storage and terminal facility owned by Enterprise in southeast Harris County, Texas. The ECHO crude oil terminal would offer access to major Texas Gulf Coast refining centers in Texas City, Pasadena/Deer Park, Baytown and on the Houston Ship Channel. The open season for the project ended on August 12, 2011. Subject to shipper commitments during the open season and the required regulatory approvals, the proponents expect the new pipeline to begin service in the fourth quarter of 2012.

Seaway Pipeline

ConocoPhillips owns the 530-mile-long Seaway pipeline system (operated by Enterprise Products Partners LP) which transports crude oil from the Houston area to storage facilities at Cushing. The pipeline has a capacity of approximately 350,000 bpd. The system also supplies crude oil to refineries in the Houston area and has a usable storage capacity of 3.4 million barrels. In 2007, the former operator of the pipeline (Teppco Partners, LP) stated it would consider reversing the line to transport crude oil from Cushing to PADD III. However, Bloomberg (2011) stated that ConocoPhillips had decided that it would

not reverse the pipeline. As a result, the Seaway pipeline was not further considered as a system alternative to the proposed Project.

Magellan Pipeline

Magellan Midstream Partners LP is considering a project to that would connect existing pipelines from Cushing, Oklahoma, to refineries along the U.S. Gulf Coast. This project would be able to carry between 60,000 and 70,000 bpd to PADD III.

Other Pipelines

No other major future proposed oil pipelines have been identified in the vicinity of the proposed Project cumulative impact corridor. However, should additional oil pipelines be constructed within the Project area, they would likely contribute to potential cumulative impacts associated with habitat fragmentation, land use issues, and viewshed degradation.

3.14.2.2 Cumulative Impacts from Natural Gas and Carbon Dioxide Pipelines

A map of existing oil and gas pipeline systems of the U.S. is shown in Figure 3.14.2-1. Several existing pipelines transport natural gas across Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. For example, the Williston Basin Interstate Pipeline System transports natural gas through southeastern Montana and western South Dakota and portions of this system would be within the proposed Project cumulative impact corridor in Montana and South Dakota (see Figure 3.14.2-3).

Portions of the Northern Border Pipeline would also be within the proposed Project cumulative impact corridor in northeastern Montana. The proposed Project ROW would parallel the Northern Border Pipeline for approximately 21.5 miles along the Steele City Segment, beginning at the U.S./Canada border near Morgan, Montana. The Northern Border Pipeline is an existing natural gas pipeline that has been in service since 1982. The Northern Border Pipeline permanent ROW has been reclaimed and routine maintenance and refurbishment activities would continue along the ROW during construction and operation of the proposed Project. Parallel placement of the proposed Project along the Northern Border ROW in this segment would concentrate potential impacts within an already disturbed corridor. However, impacts such as habitat fragmentation and wetlands disruption would potentially be exacerbated with parallel pipeline placement.

The Gulf Crossing Pipeline would parallel the proposed Project ROW along the Gulf Coast Segment between Bryan County, Oklahoma and Lamar County, Texas. The Gulf Crossing Pipeline is a recently completed, 374-mile-long, 42-inch-diameter, interstate natural gas pipeline extending from Grayson County, Texas and Bryan County, Oklahoma to Madison Parish, Louisiana. As construction of the Gulf Crossing Pipeline has been completed, many of the potential short-term cumulative impacts associated with concurrent construction schedules, such as demand for housing and services from the construction workers, construction traffic, and noise, would be avoided. Also, because the construction of the Gulf Crossing Pipeline has been completed, cumulative impacts of the proposed Project and the Gulf Crossing Pipeline would be limited to a cumulative long-term conversion of forested vegetation and land uses to herbaceous, open lands within each project's permanent ROWs.

The proposed Project would parallel the Golden Pass Pipeline in the Beaumont, Texas area. The Golden Pass Pipeline, which was completed in April of 2009, is a 42-inch-diameter pipeline that transports natural gas approximately 69 miles from an LNG receiving terminal near Sabine Pass, Texas, to existing interstate natural gas pipeline interconnections near Starks, Louisiana. Construction of the Golden Pass Pipeline has been completed; therefore, many of the potential short-term cumulative impacts associated with concurrent construction schedules would be avoided. Also, because the construction of the Golden

Pass Pipeline has been completed, cumulative impacts of the proposed Project and the Golden Pass Pipeline would be limited to a cumulative long-term conversion of forested vegetation and land uses to herbaceous, open lands within each project's permanent ROWs.

Multiple natural gas pipelines comprise the Enterprise Product Onshore Pipeline System, which is owned by Enterprise Product, LP. Portions of this pipeline system may parallel the proposed Project ROW in Texas. In Oklahoma, Texas, Nebraska, South Dakota, and Montana, other existing pipeline systems of note are operated by Northern Natural Gas System, NGPL of America, Oklahoma Natural Gas Company System, and the Lone Star Pipeline System. Portions of these pipelines may parallel or cross the proposed Project cumulative impact corridor in some areas, but most are well outside of the proposed Project area, as shown in Figure 3.14.2.-4.

The Texas Intrastate System, which is operated by Enterprise Product LP, is a network of natural gas pipelines in Texas. Portions of these pipelines are within or near the proposed Project cumulative impact corridor in southeastern Texas. The Transco Pipeline System is a 10,560-mile-long natural gas pipeline transportation and distribution system that extends from Texas up the east coast of the U.S. to New York. Portions of the Transco Pipeline System are within the proposed Project cumulative impact corridor in eastern Texas.

The construction and operation of these existing pipeline systems has resulted in impacts to the human and natural environment typical for such linear facilities. Some older pipeline systems may have resulted in greater impacts to the natural environment than those recently constructed due to less stringent environmental regulation in the past. Cumulative impacts associated with existing natural gas pipelines are primarily related to noise emanating from operating compressor stations and loss of vegetative cover and habitat fragmentation to the degree such fragmentation is not mitigated through ROW restoration.

The Steele City Segment of the proposed Project would cross the Bison Pipeline Project in Fallon County, Montana. The Bison Pipeline is a 301-mile-long, 30-inch-diameter, natural gas pipeline extending from Campbell County, Wyoming to Morton County, North Dakota. The Bison Project was constructed before the proposed Project, thereby avoiding concurrent construction impacts. In Fallon County, Montana, there would be sequential impacts to environmental resources where the proposed Project cumulative impact corridor crosses the Bison ROW. In the context of the regional resource base, it is likely that the impacts resulting from the close proximity of these two proposed pipelines would be minor.

The Green Pipeline would parallel the proposed Project area in the Gulf Coast Segment. It is a proposed 320-mile-long, 24-inch-diameter pipeline that would transport carbon dioxide from Donaldsville, Louisiana to the Hastings Field, which is located south of Houston, Texas. The Green Pipeline and the Gulf Coast Segment of the proposed Project would be roughly parallel for a distance of approximately 46 miles from Beaumont, Texas to the connection of the Gulf Coast Segment with the Houston Lateral. Along the Houston Lateral, the proposed Project would roughly parallel the Green Pipeline for a distance of approximately 47 miles from Houston, Texas to the connection of the Houston Lateral with the Gulf Coast Segment. As the in service date for the Green Pipeline is projected for mid 2011, and work on the Houston Lateral would not begin until 2012, cumulative impacts from contemporaneous construction would be avoided. However, successive construction timeframes would increase the time period over which some minor short-term impacts would occur, resulting in short-term cumulative impacts to soils, wetlands, wildlife, vegetation, and land use.

Potential cumulative impacts associated with these proposed pipelines would include habitat fragmentation, land use changes and localized viewshed degradation where above-ground facilities or clearings through forested areas occur. Should these or other unidentified pipelines be under construction

at the same time as the proposed Project, there may also be short-term cumulative impacts to noise and air quality.

3.14.2.3 Cumulative Impacts from Electrical Power Distribution and Transmission Lines

The electrical power distribution and transmission grid in the vicinity of the proposed Project cumulative impact corridor includes many existing interstate and local electric power distribution and transmission lines. These distribution and transmission lines represent existing linear facilities that extend across or within each of the states that the proposed Project would cross if permitted and constructed. Figure 3.14.2-5 is a map of the U.S. electrical power grid.

Due to advances in engineering, construction methods, and environmental regulation, the construction and operation of these existing electrical power lines typically resulted in greater construction and operation impacts than those associated with more recent projects and, therefore, the impacts from older lines may be greater than lines of similar length and energy capacity constructed either in the recent past or in the future.

Connected Actions to the Proposed Project

Power Distribution Lines and Substations

The proposed Project would necessitate the construction and operation of electrical power distribution lines by local power providers that would extend from existing power delivery infrastructure along the route to proposed Project pump stations. In addition, new substations would be required to assure the power is delivered to the pump stations at the appropriate voltage.

The power requirements and line miles of each power distribution line for pump stations and the Cushing tank farm are presented in Section 2.0 (see Table 2.5.1-1). The duration of construction for these lines would be relatively short in any one location. Where possible, power lines would parallel other ROWs (i.e., roadways, pipeline corridors, and existing power lines). Power distribution lines would likely be installed along field edges or section lines to reduce the overall amount of habitat fragmentation and interference with agricultural operations. Limited clearing would be required along existing roads in native and improved grasslands and croplands. Some trees may be removed to provide adequate clearance between the conductors and underlying vegetation. Trimming instead of tree removal could be employed in some locations. Land disturbance and vegetation clearing for the electrical distribution lines and substations would affect only a small fraction of the native vegetation present in the region.

The most notable cumulative impacts associated with electrical power distribution line construction would be the additive effects on land use and visual quality impacts associated with other projects. Proposed power distribution lines would cross a variety of land use types including developed land, agriculture/cropland, rangeland/grassland, forestland, and undeveloped greenfield areas. The largest contribution to cumulative impacts would occur on rangeland/grassland areas, and would be less for agriculture/cropland, forest land, and developed areas. Depending on location, size, and configuration, new electrical power distribution lines could contribute to cumulative effects on visual resources, especially in undeveloped areas with relatively high scenic values. Additional minor cumulative impacts to soils (compaction and erosion), vegetation, wetlands, and wildlife could also be expected. Minor indirect cumulative air quality impacts in the region could be associated with the generation of electricity that would be transmitted through power lines to pump stations and the tank farm.

Big Bend to Witten 230-kV Transmission Line

A major new approximately 70-mile-long 230-kV transmission line would be constructed and operated by Basin Electric Power Cooperative (BEPC) in South Dakota to ensure reliable power delivery in the region when the pipeline reaches full operational capacity (see Section 2.5.2). This new transmission line would create a new power transmission corridor across terrain that is currently relatively undisturbed. The impacts of this transmission line would be additive to the impacts generated by the construction of the proposed Project pipeline and appurtenant facilities, and additive to the impacts associated with existing linear facilities within the proposed Project cumulative impact corridor. Cumulative impacts associated with construction and operation of this transmission line would primarily include effects to land use and visual quality, and other minor impacts to soils, vegetation, wetlands and wildlife (potential impacts to raptors and other avian species would be of particular concern).

Other Projects

Planned electrical power distribution and transmission lines in the vicinity of the proposed Project cumulative impact corridor are presented in Table 3.14.2-1. The proposed Mountain States Intertie (MSTI) Project would extend from Townsend, Montana to Midpoint, Idaho. The proposed Zephyr Project would extend from southeastern Wyoming through Idaho and into Nevada. The Kansas V-Plan is an approximately 180 mile-long 765-kV transmission line situated west of Wichita, Kansas. The Nebraska Public Power District plans to build more than 140 miles of 345-kV and 115-kV power distribution lines in Nebraska and Kansas to connect to the proposed Project pump stations and also to interconnect proposed wind farms and increase system reliability. Of these proposed transmission lines, only portions of the upgrades to the Nebraska Public Power District transmission system would be within the proposed Project cumulative impact corridor. Cumulative impacts which may arise as a result of construction and operation of portions of the Nebraska Public Power District transmission system within the proposed Project cumulative impact corridor could include impacts to avian wildlife and viewshed degradation. In addition, if the construction of future power distribution or transmission lines in the proposed Project cumulative impact corridor overlaps with the proposed Project construction schedule, short-term cumulative impacts associated with noise, dust, and general construction activity could occur.

3.14.2.4 Cumulative Impacts from Wind Power

Wind power is increasing in the United States. Wind power accounted for 42 percent of all new electrical capacity added to the United States electrical system in 2008, although wind continues to account for a relatively small fraction of the total U.S. electrical-generating capacity (25.4 GW of a total of 1,075 GW) (AWEA 2009). The Global Wind Energy Council (2008) projected the possibility of a 17-fold increase in wind-powered generation of electricity globally by 2030.

Wind resources in the contiguous U.S., specifically in the central plains states, could accommodate as much as 16 times total current demand for electricity in the U.S. Potential wind-generated electricity available from onshore facilities on an annually averaged state-by-state basis is provided in Figure 3.14.2-6. As shown in the figure, there is a high concentration of wind resources in the central plains region extending northward from Texas to the Dakotas, westward to Montana and Wyoming, and eastward to Minnesota and Iowa. The wind resources in this region could achieve significantly greater electricity production than current local demand (Lu et al. 2009). Exploitation of these wind resources would require significant extension of the existing power transmission grid. Expansion and upgrading of the grid would be required in any case to meet anticipated future growth in U.S. electricity demand (Lu et al. 2009). It is therefore reasonable to assume that there would be upgrades and extensions to the existing electrical power transmission grid to support wind power development in the vicinity of the proposed Project cumulative impact corridor in the future. The magnitude of impacts from these transmission line

extensions would be dependent upon the extent of new lines required to meet the needs of new and existing wind farms. Cumulative impacts from future construction and operation of transmission lines originating from wind farms could include viewshed degradation and disruption to land uses, vegetation, and avian wildlife. Should the construction of future transmission lines occur concurrent with the proposed Project construction schedule and within the proposed Project cumulative impact corridor, short-term cumulative impacts associated with noise, dust, and general construction activity could occur.

3.14.3 Cumulative Impacts by Resource

Resources potentially sensitive to cumulative effects from existing, proposed, and reasonably foreseeable future projects are addressed in this section.

3.14.3.1 Geology

The proposed Project would cross deposits of sand, gravel, clay, stone, and coal bearing formations in multiple states. Existing oil and natural gas ROWs limit the area available for extraction of mineral resources. In areas where existing ROWs are present within the proposed Project area, there would be a minor cumulative decrease in the access to mineral resources because the proposed Project would limit the extraction of mineral resources in the permanent Project ROW. Extraction of oil and gas resources would not be affected by operation of the proposed Project. Overall, the proposed Project would have a negligible contribution to cumulative impacts on mineral extraction in the proposed Project cumulative impact corridor.

The proposed Project would have a negligible contribution to cumulative impacts on regional topography in the proposed Project cumulative impact corridor since the ROW would be returned to the approximate original topographic contour during restoration activities. Impacts to bedrock are expected to be minimal, and limited to areas where bedrock is within 8 feet of the surface. Some amount of bedrock ripping could be required on approximately 175 miles of the proposed Project route. Blasting is not anticipated during Project construction and pipeline installation activities.

During construction, damage to or destruction of paleontological resources from excavation and grading activities, or from unauthorized collection of fossils by construction personnel or the public may occur. Consultation with appropriate state and federal agencies and landowners during proposed Project planning has minimized the potential for the proposed Project to impact scientifically-significant paleontological resources. Construction and operation of the proposed Project would have a negligible contribution to cumulative impacts on paleontological resources within the proposed Project cumulative impact corridor.

3.14.3.2 Soils and Sediments

Potential cumulative effects to soils and sediments could occur if construction disturbances of the proposed Project overlap with other projects, particularly if the projects are in close proximity. Portions of the proposed Project cumulative impact corridor have already experienced the effects of the construction and operation of previous pipeline and transmission line projects. These areas may have experienced disruption to soils and sediments through clearing, grading, trench excavation, backfilling, heavy equipment traffic and restoration. Most impacts to soils and sediments through construction of oil pipelines and transmission lines would be short-term, with no impacts outside of the construction ROW.

Construction and operation activities associated with the proposed Project could contribute to cumulative impacts within the proposed Project cumulative impact corridor resulting from temporary and short-term soil erosion, loss of topsoil, short-term to long-term soil compaction, permanent increases in the

proportion of large rocks in the topsoil, and short-term to permanent soil contamination from accidental spills. Additional contributions to cumulative impacts could include reduced productivity in disturbed farmland and rangeland areas until soil reclamation efforts are successful. Over the long-term, soil productivity impacts from the proposed Project would be minor and would have a negligible contribution to cumulative impacts within the proposed Project cumulative impact corridor.

3.14.3.3 Surface Water and Groundwater

Cumulative impacts to waterbodies within the proposed Project cumulative impact corridor could occur if one or more projects cross the same waterbody in the same watershed. Some streams that would be crossed by the proposed Project in Montana, South Dakota, and Oklahoma are listed as impaired for siltation, total suspended sediment, and turbidity, respectively. Where conditions warrant the use of the HDD crossing method, waterbody impacts of construction would be minimal since no direct contact would occur with stream banks, channel bed or waters. Where non-HDD crossing methods are used, or in the event that a frac-out were to occur, there would be some short-term contribution to cumulative impacts within the proposed Project cumulative impact corridor. However, the proposed Project would adhere to applicable local, state, and federal regulations and permit conditions that would require the use of best management practices to reduce the short and long-term impacts to waterbodies resulting from the proposed Project. It is possible that in some locations there could be a temporary reduction in channel stability leading to a short-term degradation in localized aquatic habitats. Non-HDD crossings in sensitive systems could contribute to contaminated or impaired conditions. However, the proposed Project includes a set of construction and operating requirements that if implemented would lead to minimal impacts to waterbodies under normal construction and operating conditions and the contribution to cumulative impact within the proposed Project cumulative impact corridor would be negligible.

Some commenters on the draft EIS and supplemental draft EIS expressed concerns that the refining of heavy crude oil that would be transported by the proposed Project to PADDs II and III could contribute to cumulative water quality impacts. However, the contribution to cumulative impacts to water quality resulting from the processing of heavy crude oil transported by the proposed Project would be limited since refinery upgrades to wastewater treatments systems would be required to meet discharge limitations specified in the NPDES permits under which wastewater discharges are permitted. Recent refinery upgrades have required reassessment of NPDES permit requirements including stormwater capacity and water treatment requirements (e.g., installation of water strippers and more efficient final water filters) to ensure that wastewater and stormwater discharges meet NPDES permit limitations and protect the quality of receiving waters.

3.14.3.4 Wetlands

Past and current wetland disturbance in the proposed Project cumulative impact corridor includes wetland drainage and disruption associated with agricultural and rangeland activities. Previous construction activities within the corridor have impacted wetland resources, including wetland functions. In most areas the wetlands have transitioned back to pre-construction vegetation communities, although wetland restoration in arid areas has not always succeeded. Recovery time for herbaceous or scrub-shrub vegetation in wetlands is typically 3 to 5 years. Where vegetation would not be continually affected during proposed Project operations, forested wetlands would have regeneration periods of 20 to 50 years or more to accommodate tree species height potential. Depending on the vegetation types, past effects on wetlands within the proposed Project cumulative impact corridor may still be evident. Also, previously-installed pipeline or transmission projects would have resulted in a permanent conversion of forested wetland vegetation types in their permanent ROWs. Under currently applicable regulations, mitigation for any permanent loss or conversion of forested wetland resources could be required.

The majority of cumulative wetland impacts would occur where the proposed Project and other existing or planned projects impact the same wetland features. Few of the wetlands affected by the proposed Project would likely be permanently filled or drained, and the proposed Project's permanent impact on most wetland resources would likely require compensatory mitigation. Therefore, the contribution of the proposed Project to wetland cumulative impacts within the proposed Project cumulative impact corridor would likely be minor.

3.14.3.5 Terrestrial Vegetation

The degree of cumulative impact from past projects within the proposed Project cumulative impact corridor depends upon the type and amount of vegetation affected, the rate at which the removed vegetation regenerated after construction, and the frequency of vegetation maintenance conducted. The primary contribution to cumulative impacts on vegetation from the proposed Project would be the cutting, clearing, or removal of vegetation within construction work areas, the removal or trimming of herbaceous vegetation during operations in the permanent ROW, and the potential introduction or spread of noxious weeds in cleared areas. The degree of proposed Project contribution to cumulative impacts would depend on the type and amount of vegetation affected, the rate at which removed vegetation would regenerate after construction, and the frequency of vegetation maintenance in the permanent ROW. Construction of the proposed Project would result in some permanent loss of forested and scrub-shrub vegetation, and in a minor increase in native grassland, sagebrush, and forest fragmentation.

Clearing of native grasslands along portions of the proposed Project ROW along the Steele City Segment would contribute to the cumulative decline of native grasslands. Although most native grasslands would be restored, the effects of land clearing on previously untilled native prairies may be irreversible. Short-grass prairie and mixed-grass prairie areas could take 5 to 8 years to become reestablished due to poor soil conditions and low moisture levels. Construction would also involve removal of woody shrubs in sagebrush grasslands. Sagebrush vegetation could require 20 to 50 years to become reestablished and removal of sagebrush vegetation could therefore contribute to long-term cumulative impacts to this habitat.

Cumulative vegetation impacts within the Gulf Coast and Houston Lateral segments of the proposed Project ROW would result from clearing of upland, riparian, and bottomland forests. Removal of trees in upland and riparian forest communities would result in long-term impacts because of the long periods required for forest communities to mature to pre-construction conditions. Contribution to cumulative impacts within the proposed Project cumulative impact corridor would be minor and would result from the clearing of vegetation within the permanent ROW where the reestablishment of cleared vegetation would be prevented.

Contribution to cumulative impacts within the proposed Project cumulative impact corridor on annually tilled croplands would be minor and would generally be limited to the current growing season, provided that topsoil segregation was maintained and soils were not compacted during construction. Similarly, contribution to cumulative impacts within the proposed Project cumulative impact corridor on pastures, rotated croplands, and grasslands would generally be short-term and minor with vegetation typically becoming reestablished within 1 to 5 years after construction is complete. Long-term impacts on these vegetation types would generally be minimal because these areas would be allowed to recover following construction and typically would not require maintenance mowing and therefore the contribution to cumulative impacts within the proposed Project cumulative impact corridor would be minimal.

The total amount of vegetation that may be affected by all of the reasonably foreseeable projects, including the proposed Project, is relatively small compared to the abundance of similar vegetation in the proposed Project cumulative impact corridor. Additionally, future projects would likely implement

mitigation measures designed to minimize the potential for erosion, revegetate disturbed areas, implement site stabilization procedures, and control the spread of noxious weeds, which would minimize the contribution of those projects to the cumulative impacts on vegetation within the proposed Project cumulative impact corridor.

3.14.3.6 Wildlife

The area in the vicinity of the proposed Project contains a diversity of wildlife, including big game animals, small game animals and furbearers, waterfowl and game birds, and other nongame animals. Wildlife habitats in these areas include: grasslands/rangelands, shrublands, croplands/pasturelands, upland forests, and wetlands. These vegetation communities provide a wide variety of foraging, cover, and breeding habitats for wildlife. Migratory birds also use many of these habitat types for nesting, migration stopover, and overwintering. Many birds nest in Montana and South Dakota and winter in Texas. Commenters have suggested that the EIS should consider mitigations for cumulative effects to migratory bird species. In response to these suggestions, DOS requested that Keystone provide a synopsis of activities at the corporate level that TransCanada supports to provide broad scale mitigations for cumulative impacts to migratory species. In response, TransCanada provided the following information.

TransCanada has partnered with Ducks Unlimited to provide assistance for the Oak Hammock Marsh Interpretative Centre, educational laboratories and the Watershed Legacy program all located in Winnipeg, Manitoba. TransCanada has contributed $1 million dollars to Ducks Unlimited as part of a 5-year commitment running from 2009-2013 to launch the Ducks Unlimited / TransCanada Partnership regarding Habitat Conservation in the Missouri Coteau conservation in Saskatchewan and the Grand Bayou Hydrology Restoration project in Louisiana.

The Missouri Coteau is a 25,000 square mile tract stretching across south-central Saskatchewan and is internationally recognized as a critical wildlife habitat area. The region is mainly native grassland and pothole wetlands capable of supporting vast populations of breeding waterfowl and providing prime habitat for other wildlife. This project will focus on retain existing uplands and wetland habitat through conservation easements and land purchases; restore lost habitats through forage conversion programs; and deliver rangeland stewardship programs by working with landowners to improve ecological function and reduce the risk of native habitat loss.

The Grand Bayou project is located on the Pointe-aux-Chenes Wildlife Management area in Louisiana and includes two management units totaling 4,568 acres of coastal marsh habitat. The area is managed for furbearers, waterfowl, alligators and other wildlife as well as being open to the public for recreational purposes. The area has seen significant habitat deterioration due, in part, to damaged levees from Hurricane Rita and to increased salinity levels and excessive tidal fluctuations. Coastal marsh restoration will involve the installation of levees and installation of new water control structures in order to manage salinity and water levels and encourage production of desirable vegetation. This project will focus on restoration of approximately 4,575 acres of coastal marsh; construction of one 24,000 linear feet of earthen levee & one 25,000 linear feet of earthen levee; installation of three new water control structures, and backfilling portions of an abandoned oilfield access canal.

Past disturbances to wildlife and wildlife habitats have contributed to habitat loss, alteration, and fragmentation; direct mortality during construction and operation; indirect mortality and reduced breeding success from stress; reduced feeding due to noise and human activity; and reduced survival or reproduction due to decreased abundance of suitable habitat, prey, or forage. Similar disturbances from the proposed Project would contribute to cumulative impacts on wildlife and wildlife habitats within the proposed Project cumulative impact corridor.

Some areas of native grasslands and sagebrush shrubland habitats and many areas of forestland in the proposed Project cumulative impact corridor have not been previously fragmented by road and/or electrical power line networks. Increased habitat fragmentation from pipeline construction and connected power distribution lines would be most pronounced within large contiguous areas of native grassland/rangeland, sagebrush shrublands, and forested habitats. Prior fragmentation of native grasslands and sagebrush in Montana and South Dakota resulting from clearing may have contributed to minor decreases in abundance and productivity for wildlife that depend on these habitats for breeding, cover, and forage. Many forestlands within the proposed Project cumulative impact corridor along the Gulf Coast Segment and Houston Lateral have been previously fragmented by ROWs and could experience additional fragmentation from the proposed Project which could have minor contributions to cumulative impacts on the abundance and productivity of wildlife that depend on large areas of contiguous forested habitat.

Construction and operation of the proposed Project, along with the reasonably foreseeable projects, could result in short-term disturbance to wildlife and long-term wildlife habitat loss, alteration, and fragmentation. The proposed Project would produce a minor contribution to the cumulative effects on resident and migrant wildlife potentially resulting in somewhat reduced abundance and productivity within the proposed Project cumulative impact corridor. Displacement of wildlife that depends on the carrying capacity of habitats that would be disturbed by the proposed Project could result in reduction of reproductive effort or survival, thus producing a minor contribution to cumulative impacts on wildlife within the proposed Project cumulative impact corridor. This potential is greater for wildlife for which suitable habitat is limited in the Project area or that are otherwise sensitive to disturbance.

3.14.3.7 Fisheries

Riparian vegetation removal and instream disturbance have occurred as a result of previous projects that cross streams within the proposed Project cumulative impact corridor. Potential cumulative effects on fisheries due to instream and riparian disturbance include habitat alterations that result in potential disruption to aquatic species feeding, breeding, and life stages.

The proposed Project would cross streams or rivers that contain known or potential habitat for special-status fish species. Special-status fish species include those listed by a state or listed under the federal ESA as threatened, endangered, or as species of conservation concern. Special-status fish species are known to be present in waterbodies crossed by the proposed Project. Impacts to special-status fish species would be avoided in those streams or rivers where the HDD crossing method is utilized. Prior to implementing open-cut water crossings, surveys would be conducted as required by wildlife resource agencies to determine whether species of special concern are present. These surveys in conjunction with the proposed Project avoidance, minimization, and mitigation measures would reduce the proposed Project's contribution to cumulative impacts on fishery resources.

Current disturbance to fisheries resources from projects in the vicinity of the proposed Project cumulative impact corridor include sediment releases from instream construction and loss of overhead shade and nutrient input. For the proposed Project in non-HDD stream crossings, similar disturbances could cause short-term changes to downstream aquatic life and habitats (Levesque and Dube 2007, Wood and Armitage 1997). Other potential contributions to cumulative impacts from proposed Project construction include alterations to streambed conditions, reductions in the abundance and diversity of benthic invertebrate communities, and reductions in the abundance of fish populations in cases of large-scale sediment releases. Cumulative impacts to fisheries would be greater in areas where important fish spawning or rearing habitat would be altered by construction. Since small-scale effects are typically non-residual, and recovery of streambeds and benthic invertebrate productivity to pre-construction conditions is expected within approximately 1 year (Crabtree et al. 1978, Tsui and McCart 1981, Gowdy et al. 1994,

Anderson et al. 1998), contribution to cumulative impacts from these small-scale effects of the proposed Project would be minor. However, larger scale disturbances that include post-construction impacts and that can take longer to recover (Crabtree et al. 1978), could have larger contributions to cumulative impacts.

Future projects that could be constructed within or in the vicinity of the proposed Project cumulative impact corridor could result in small cumulative impacts to fisheries resources. However, those future projects that occur after these streams have recovered from activities associated with the proposed Project, would have less contribution to cumulative impacts on fisheries.

3.14.3.8 Threatened and Endangered Species

Past cumulative effects for threatened and endangered species present near the proposed Project have included habitat loss , alteration, and fragmentation primarily due to agricultural, silvicultural, industrial, urban and suburban development; reduced water quantity and blockage of fish migrations from impoundment and diversion for agricultural or urban use; and reduced water quality from degradation of riparian habitats and contamination from agricultural, industrial, urban, and suburban runoff. Such cumulative impacts have led to the overall decline and resulting determination of the "protected" or "concern" status for some animals and plants that occur within the vicinity of the proposed Project.

A number of federally-protected threatened, endangered, proposed-for-listing, and candidate-for-listing species potentially occur in the proposed Project vicinity. These species include 3 mammals, 9 birds, 1 amphibian, 6 reptiles, 4 fish, 2 invertebrates, and 6 plants (see Section 3.8). Further review of the 24 federally-protected species indicates that the proposed Project would likely adversely affect 1 species, would not likely adversely affect 11 species with implementation of proposed conservation measures, and would have no effect on 12 species. Of the 7 federal candidate species identified within the proposed Project vicinity, it has been determined that 5 candidate species would not likely be present in the affected area and the habitat for 2 candidate species would likely be disturbed or altered.

Incremental loss or alteration of black-tailed prairie dog colonies through prior project construction and operation in addition to similar effects from the proposed Project could lead to cumulative impacts on the black-footed ferret and the mountain plover in Montana and South Dakota. However, the black-tailed prairie dog colonies that would be crossed by the proposed Project were determined to be too small to support black footed ferrets. Short-, medium-, or long-term loss or alteration of native grassland and sagebrush habitats through the spread of invasive plants in Montana and South Dakota from previous projects in addition to similar impacts from the proposed Project could contribute to cumulative habitat impacts for federal candidate-for-listing birds, including the greater sage-grouse and Sprague's pipit.

The proposed Project could potentially affect 5 migratory birds within their migration range from Texas to Montana and/or within their breeding habitats. Conservation measures proposed for 3 of these birds (i.e., whooping crane, piping plover, and interior least tern) include protection of river and riparian nesting and migration staging habitats through use of HDD crossing methods and site-specific surveys to avoid disturbance to migration staging, nesting, and brood-rearing individuals. Habitat and disturbance impacts at major river crossings from future linear projects would likely incorporate similar conservation measures to avoid and minimize affects to these birds. Future electrical power transmission lines and the distribution lines that would serve pump stations and MLVs of the proposed Project or any other future projects could incrementally increase the collision hazard for 5 protected or candidate migratory birds. Cumulative collision mortality affects would be most detrimental to the whooping crane, interior least tern, and piping plover; while perches provided by towers and poles could increase the cumulative predation mortality for ground nesting birds, including the greater sage-grouse, interior least tern, mountain plover, piping plover, and Sprague's pipit.

Incremental impacts to streams and riparian habitats from future linear project construction and the accidental spread of exotic aquatic invasive plants and animals could increase cumulative impacts to threatened and endangered species habitat. Increased competition from invasive species could contribute to cumulative impacts to native freshwater mollusks and prairie stream fishes which have been increasingly recognized as vulnerable. Multiple stream and wetland crossings, especially those associated with small clear springs and streams or freshwater mussel beds, could result in impacts to habitat quality that could in conjunction with the impacts of the proposed Project affect federally-protected aquatic species of conservation concern.

The USFWS has determined that the proposed Project may adversely affect the American burying beetle through direct mortality resulting from pipeline and associated facility construction and through potential long-term habitat alteration resulting from vegetation changes, soil compaction, and pipeline heat dissipation. Conservation measures designed to reduce direct take of American burying beetles would be implemented, although some mortality would likely occur. Compensatory mitigation in the form of contribution to protection of occupied habitat for this species would offset these affects by preventing future losses through conservation of important habitat and populations, thus reducing cumulative impacts on the species. Construction of new pipelines or other ground disturbing projects through southern South Dakota and north-central Nebraska could contribute to cumulative mortality and loss of habitat. Any additional potential losses within this species would likely require similar conservation methods and mitigations, thus reducing overall cumulative impacts on the American burying beetle.

Implementation of appropriate conservation measures as determined through consultations with federal, state, and local agencies for state-protected sensitive species and federally protected threatened, endangered, or candidate species for the proposed Project and for future projects would include habitat restoration, impact avoidance, and impact minimization which would ameliorate long-term cumulative impacts. Proposed Project reclamation includes restoration of native vegetation and soil conditions and prevention of spread and control of noxious weeds for disturbed areas. Unavoidable alteration and maintenance of vegetation structure to ensure pipeline safety and to allow for visual inspection would result in some conversion of tall shrub and forested habitats to herbaceous habitats. These conversions are not expected to adversely affect or contribute to cumulative impacts for any federally protected threatened or endangered species.

3.14.3.9 Noise

Given the short duration of construction related noise impacts for the proposed Project it is likely that contributions to cumulative noise impacts associated with construction within the proposed Project cumulative impact corridor would be minor to negligible and short-term. Contribution to cumulative noise impacts from proposed Project operation could be important in the immediate vicinity of proposed Project pump stations and less important and variable throughout the rest of the proposed Project corridor. If necessary, noise from pump stations could be mitigated through construction of berms around the facilities or planting of vegetation noise screens. Contribution to cumulative noise impacts from the Cushing tank farm would be negligible given its proximity to both proposed Pump Station 32 and the very large existing tank farm complex at Cushing.

3.14.3.10 Land Use

Construction of the proposed Project could contribute to cumulative impacts in the proposed Project cumulative impact corridor through disruption of agricultural, forest, and rangeland production. Short-term contributions could include potential damage to agricultural infrastructure (e.g., drain tiles or irrigation systems) that would diminish agricultural productivity, and construction-related noise and dust that could temporarily impair other land uses. Most acreage disturbed during construction of the

proposed Project would be returned to preconstruction uses after ROW restoration and would therefore not contribute to long-term alterations in land uses. Generally, disturbed agricultural land would become productive within several planting seasons. However, disturbed pastures and rangelands could require revegetation taking 1 to 5 years to recover to preconstruction levels. Forestland outside the permanent ROW could take 20 or more years to recover and would be eliminated within the permanent ROW and at aboveground facilities for the life of the proposed Project. Aboveground facilities (e.g., pump stations and valves) required for operations would convert the land associated with these facilities to an industrial use for the life of the proposed Project. The aggregate contribution of lands committed to industrial uses during the life of the proposed Project would be small in relation to the number of acres available for these land uses. In addition, some agricultural lands currently enrolled in the CRP or other conservation programs may not qualify for continued participation in these programs, potentially resulting in the land converting back to active agricultural uses, thus contributing to cumulative reductions in land dedicated to conservation withdrawal. Easement restrictions associated with the proposed Project would contribute to land use restrictions within the proposed Project cumulative impact corridor.

3.14.3.11 Visual Resources

Cumulative impacts on visual resources could occur in areas where past and reasonably foreseeable future projects in addition to the proposed Project remove large swaths of vegetation and where permanent aboveground facilities are installed. Within the proposed Project cumulative impact corridor, the additional visual impact from the proposed Project would include ROW clearing through forested areas and aboveground components (e.g., pump stations, tank farm, MLVs) that would contribute to an intensified industrial character.

Within most of the proposed Project cumulative impact corridor, contribution to cumulative visual impacts due to proposed Project construction activities would be limited to removal of existing vegetation, exposure of bare soils, earthwork and grading scars, and minor landform alterations. Along portions of the proposed Project route where concurrent construction activities from other projects occur, temporary contributions to degradation in visual quality could result from the presence of construction crews, equipment, and dust. Over the long term, proposed Project aboveground facilities would contribute, in the presence of similar facilities from past or future projects, to an intensified industrial character within the proposed Project cumulative impact corridor that could adversely affect the visual quality of the area.

3.14.3.12 Socioeconomics

The proposed Project area is predominantly rural and sparsely populated, with the population tending to increase from north to south along the proposed Project corridor. The population density in northern Montana is less than 1 person per square mile. In the southern Oklahoma/northeastern Texas area, population density ranges from 35 to 40 people per square mile. In areas in southern Texas, population densities range from 50 to 280 people per square mile along the Gulf Coast Segment to nearly 2,000 people per mile in the urbanized areas at the western end of the Houston Lateral.

The presence of temporary construction workers requiring housing and other services would be the primary contribution of the proposed Project to cumulative socioeconomic impacts. Construction workers would likely utilize the closest available local rental, motel/hotel, RV and camping facilities during the construction of each spread. Since adequate temporary housing and services appear to be present along the Gulf Coast Segment and the Houston Lateral, the contribution to cumulative socioeconomic impacts in these areas would be short-term and minor. Along the Steele City Segment of the proposed Project, short-term contribution to housing shortages would be mitigated through construction and operation of four temporary construction camps in Montana and South Dakota.

Additional short-term contribution to cumulative socioeconomic impacts would result from increased employment opportunities and related labor income benefits, and increased government revenues associated with sales and payroll taxes. The primary long-term contribution to cumulative socioeconomic impacts in these areas would include limited employment and income benefits resulting from a very small permanent proposed Project operations staff and some local proposed Project expenditures, as well as an increased property tax base and associated tax revenues. Operation of the proposed Project would require relatively few permanent employees; thus, there would be little contribution to long-term cumulative impacts on population, housing, municipal services, or traffic in the proposed Project area. The increased tax revenue paid to the state and local governments over the life of the spectrum of projects in the proposed Project vicinity would result in beneficial long-term cumulative economic impacts. Keystone estimates that $138.4 million in annual property tax revenues would be generated by the proposed Project in the region of influence. This estimate is based on 2006 tax rates and an estimated $7.0 billion of capital costs. It should be noted that these revenues may increase since the current estimate of proposed Project capital cost has been raised to an estimated $9.0 billion.

Environmental Justice Considerations

As described in Section 3.10.1 and summarized below, DOS identified minority and low-income populations within a 4-mile-wide corridor centered on the proposed pipeline centerline to determine potential impacts to these populations.

In the analysis, 287 census block groups were identified either partially or totally within the 4-mile-wide environmental justice analysis area, and the percentage of each census block group's population represented by each U.S. Census Bureau minority classification (i.e., each race, aggregate race minority population, and Hispanic/Latino ethnic origin) was calculated. Towns and cities within and near the analysis area with minority populations and low-income populations meaningfully greater than state-wide averages were also identified (see Figures 3.10.1-1 through 3.10.1-6). In addition, HPSA and/or MUA/P areas were identified in counties with minority and low-income populations along the proposed Project corridor (see Table 3.10.1-18 and Figures 3.10.1-7 through 3.10.1-13). Cumulative impacts to minority and low-income populations related to past and reasonably foreseeable future projects could occur, particularly if future projects place additional demands on medical services in HPSA and/or MUA/P areas. However, the contribution of the proposed Project to these cumulative impacts would be minor since the permanent workforce associated with the proposed Project is very small.

Several commenters on the draft EIS and the supplemental draft EIS expressed concern that there would be indirect cumulative adverse impact to minority and low-income populations due to increased or potentially more toxic air emissions associated with the refining of WCSB crude oil within PADD III. DOS has assessed the composition of heavy WCSB crude oils likely to be transported by the proposed Project and compared these crude oils to the typical crude oils currently refined in PADD III (see Section 3.13.5.1). The heavy WCSB crude oils would either displace or replace the heavy crude oils originating from other sources that are currently refined in PADD III.

The more volatile and toxic aromatic components of crude oil are generally of greatest concern when considering the potential health effects from refinery air emissions. In general, lighter crude oils, such as Alaskan North Slope crude oil, have higher concentrations of these more volatile and toxic aromatic fractions than either the WCSB heavy crude oils or the typical heavy crude oils (e.g., Mexican Maya and Venezuelan Bachaquero) currently refined in PADD III. As discussed in Section 3.13.5.1, the WCSB crude oils that would be transported by the proposed Project have characteristics (e.g., sulphur content and heavy metals content) that make them comparable to and of similar quality to the heavy crude oils currently refined in PADD III. Additionally, each refinery would blend individual feedstock streams to generate an optimized crude oil blend prior to initiating the refining process. The blend would be

optimized based on the types of crude oil stored at the refinery and available for blending, specific refinery configuration, processing equipment, and desired end product mix. For example, blending WCSB dilbit crude oil with a lighter Middle East crude oil or even with SCO crude oil would create a feed blend for refining that would be similar to West Texas Intermediate crude oil. Regardless of the types of oil, the refineries currently optimize the blend prior to refining and their future blends would likely be similar. Therefore, displacement or replacement of the heavy crude oils currently refined in PADD III refineries with heavy WCSB crude oil transported by the proposed Project would not likely change the overall load of toxic or noxious refinery emissions during either normal operation or during shutdown/startup conditions. As a result, incremental contribution to cumulative health risks of minority or low-income populations would not likely result from the displacement or replacement of heavy crude oil currently refined in PADD III with WCSB heavy crude oil transported by the proposed Project.

Additionally, as discussed in this section under PADD III Refineries and in the EnSys (2010) report, construction and operation of the proposed Project would be independent of the level of oil refining in PADD III and would not directly result in increased or significantly changed refinery emissions in Gulf Coast refineries.

3.14.3.13 Cultural Resources

Contribution to cumulative impacts to cultural resources from the proposed Project would include disturbance to aboveground and belowground resources within the designated Project APE. The proposed Project would be constructed in accordance with requirements under Section 106 NHPA and other relevant federal, state and local regulations. Disturbance to these resources from construction of the proposed Project would be limited primarily through avoidance, and through mitigation when avoidance is not achievable.

The contribution to cumulative impacts to cultural resources that could occur from construction and operation of the proposed Project include damage or destruction of historic properties that cannot be avoided; introduction of visual or audible elements that would diminish the integrity of a historic property's significant historic features; changes to the character of the historic property's use; or changes to physical features within the historic property's setting that contribute to its significance. The proposed Project's contribution to cumulative impacts on cultural resources would be primarily limited through avoidance of adverse effects to historic properties that have been found eligible for listing in the NRHP or that are currently unevaluated. Cultural resource avoidance could be achieved through pipeline route variations to avoid NRHP-eligible properties, or through boring underneath the cultural deposits using HDD construction methods. For any historic properties adversely affected by the proposed Project, mitigation measures would be developed as part of a Treatment Plan to be incorporated into the PA.

Contribution to cumulative impacts on cultural resources could result from future linear projects or other future developments within the proposed Project cumulative impact corridor that disturb known or currently unidentified archaeological sites and historic properties or degrade in-place mitigation for previously disturbed historical properties. However, known sites identified during proposed Project studies or in past or future cultural resource studies would likely be avoided or mitigated to the degree practicable as required by Section 106 NHPA during future project implementation.

3.14.3.14 Air Quality

Pipeline Construction & Operation

Contribution to cumulative air quality impacts resulting from construction of the proposed Project would be from activities that generate fugitive dust (e.g., excavation and materials handling) and air emissions (e.g., fueling and operation of construction equipment and open burning). However, contractors would be required to implement dust-minimization practices to control fugitive dust during construction as required by the CMR Plan (Appendix B) and local or state ordinances, including the application of water sprays and surfactant chemicals, and the stabilization of disturbed areas. Contractors would also be required to maintain all fossil-fueled construction equipment in accordance with manufacturer's recommendations to minimize construction-related emissions. The majority of pipeline construction activity would generally pass by a specific location within a 30-day period before final grading, seeding, and mulching takes place, thereby resulting in minor short-term contributions to cumulative air quality impacts. Emissions contributing to cumulative air quality impacts from construction of the proposed Project are provided in Table 3.14.3-1. The construction emissions represent combined total emissions from the 17 construction spreads. There would be no current contribution to cumulative impacts from the construction of past or future projects since the impacts of these projects are short-term and occur at the time of construction only. As a result, contributions to cumulative air quality impacts within the proposed Project cumulative impact corridor from construction of the proposed Project and past or future reasonably foreseeable projects would be negligible.

Contribution to cumulative air quality impacts resulting from operation of the proposed Project would include emissions from vehicles and aircraft used during twice monthly ROW inspection, and regular maintenance of pump stations, tank farms, valves, and other aboveground facilities. Emissions contributing to cumulative air quality impacts from proposed Project operations are also provided in Table 3.14.3-1. Contribution to cumulative air quality impacts from ongoing operations of past projects within the proposed Project cumulative impact corridor, including existing oil and natural gas pipelines, and reasonably foreseeable future projects would likely be limited to emissions from any project facilities and from vehicles and aircraft used during inspection and maintenance of project facilities.

TABLE 3.14.3-1
Estimated Direct Emissions for the Project

Emission Source	NOx (tons)	CO (tons)	VOC (tons)	SO_2 (tons)	PM (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	CO_2-e[a] (tons)
Construction emissions								
Construction camps[b]	494.4	432.6	46.4	33.0	24.7	24.7	24.7	108288.0
On-road vehicles	37.5	232.6	12.9	0.2	1.4	1.4	1.4	16094.3
Non-road equipment	596.4	697.4	51.0	25.2	25.0	25.0	25.0	85162.4
Open burning	19.8	1159.8	85.2	--	185.9	132.6	112.7	27433.0
Fugitive dust	--	--	--	--	1480.9	740.5	111.1	--
Paved road dust	--	--	--	--	117.8	18.5	1.9	--
Total construction emissions	**1148.1**	**2522.4**	**195.5**	**58.4**	**1835.7**	**942.7**	**276.8**	**236977.7**

TABLE 3.14.3-1
Estimated Direct Emissions for the Project

Emission Source	NOx (tons)	CO (tons)	VOC (tons)	SO_2 (tons)	PM (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	CO_2-e[a] (tons)
Operating emissions								
Tank farm	--	--	43.2	--	--	--	--	--
Surge relief tanks	--	--	16.0	--	--	--	--	--
Pump station fugitives[c]	--	--	6.8	--	--	--	--	84.6
On-road vehicles[d]	6.7E-05	1.5E-03	7.2E-05	8.0E-07	3.7E-02	5.8E-03	5.7E-04	4.3E-02
Total operating emissions (annual)	**6.7E-05**	**1.5E-03**	**66.1**	**8.0E-07**	**3.7E-02**	**5.8E-03**	**5.7E-04**	**84.6**

[a] CO_2 equivalent is conservatively estimated by assuming all total organic compounds are methane and multiplying by 21 for the global warming potential (GWP) for methane.
[b] Construction camp emission estimates include four construction camps with four, 400-kW generator engines per camp operating for 2 years.
[c] Pumping station emissions include combined emissions from 30 pumping stations along the Steele City and Gulf Coast Segments.
[d] The operational emissions noted from onroad vehicles include mobile emissions from the Steele City Tank Farm only and do not include the preliminary estimated VOC emissions from the storage tanks.

Notes:
NOx = Oxides of nitrogen.
CO = Carbon monoxide.
VOC = Volatile organic compounds.
SO_2 = Sulfur dioxide.
PM = Particulate matter.
PM_{10} = Particulate matter less than 10 microns in diameter.
$PM_{2.5}$ = Particulate matter less than 2.5 microns in diameter.
CO_2-e = Carbon dioxide equivalents.
Source: Keystone 2009c.

Refineries

While the proposed Project does not include construction, retrofit or operation of any refineries that could receive crude oil transported through the proposed Project, refinery operations could contribute to increased cumulative impacts to air quality in the vicinity of the proposed Project cumulative impact corridor or beyond if changes in the type or quantity of refinery emissions occurred in the future as a direct result of refining crude oil transported by the proposed Project. Such changes could occur if the proposed Project induced construction of a new refinery, induced expansions of capacity in existing refineries, induced existing refineries to add new downstream processing units (such as cokers or fluid catalytic converters), and/or induced the refineries to process a different crude oil slate (e.g., one that was higher in sulfur content and lower in API gravity with different heavy metals content).

As discussed in Sections 1.2 and 1.4, crude oil delivered to PADD II and PADD III refineries would replace domestic crude oil supplies processed at these refineries or supplant existing supplies from overseas that are less stable, more costly, or otherwise less desirable to the refineries.

PADD II Refineries

The proposed Project would supply up to 155,000 bpd to the proposed Cushing tank farm in PADD II. While the specific receiving refineries are not known at this time, there are some refineries or geographic areas proximal to the proposed Project that would be more likely to receive crude oil transported through

the proposed Project. There are 27 refineries in PADD II that have a 2008 capacity to process over 3.9 million bpd of crude oil (Table 3.14.3-12), and heavy crude oil deliveries to these refineries totaled at least 900,000 bpd in 2008. According to EnSys (2010), the WCSB heavy crude oil deliveries to PADD II totaled 1.22 million bpd in 2009. The majority of the heavy crude oil supply to PADD II is provided via pipelines from Canada.

Crude oil deliveries through the proposed Project to the Cushing tank farm would generally serve refineries in PADD II, which includes 15 states in the Midwest from North Dakota to Oklahoma and east to Ohio. Crude oil refineries in those 15 states including the crude oil capacity for each refinery are presented in Table 3.14.3-2.

In PADD II, expansions and upgrades have been proposed or implemented in Oklahoma (Sinclair), Illinois (WRB Refining and ConocoPhillips Refinery), Michigan (Marathon), and Indiana (Whiting). There is no indication that the availability of oil transported via the proposed Project would directly result in specific expansions of existing refineries and development of new refineries (none have been built in the U.S in 30 years).

TABLE 3.14.3-2
PADD II Refinery Crude Capacity: 2008

Refineries	Crude Oil Capacity (thousand bpd)
ExxonMobil, Joliet, IL	250
Marathon, Robinson, IL	214
PDV Midwest Refining, Lemont, IL	171
WRB Refining, Wood River, IL	322
BP Whiting, IN	420
Countrymark, Mount Vernon, IN	27
Coffeyville Resources, Coffeyville, KS	120
Frontier, El Dorado, KS	135
NCRA, McPherson, KS	88
Marathon, Catlettsburg, KY	250
Somerset. Energy, Somerset, KY (idle)	0
Marathon, Detroit, MI	114
Flint Hills, Saint Paul, MN	330
Marathon, Saint Paul, MN	84
Tesoro, Mandan, ND	60
BP-Husky, Toledo, OH	160
Lima Refining, Lima, OH	170
Marathon, Canton, OH	85
Sunoco, Toledo, OH	175
ConocoPhillips, Ponca City, OK	210
Sinclair, Tulsa, OK	75
Sunoco, Tulsa, OK	90
Valero. Ardmore, OK	92

TABLE 3.14.3-2 PADD II Refinery Crude Capacity: 2008	
Refineries	**Crude Oil Capacity (thousand bpd)**
Ventura, Thomas, OK (idle)	0
Wynnewood Refining, Wynnewood, OK	75
Premcor, Memphis, TN	182
Murphy Oil, Superior, WI	35
PADD II GRAND TOTAL	**3,934**

Source: U.S. Energy Information Administration (EIA), Refining Capacity 2009.

PADD III Refineries

The proposed Project would supply up to 830,000 bpd to customers along the Gulf Coast in PADD III, which covers six states from New Mexico to Alabama. Because up to 100,000 barrels per day of capacity is reserved for crude oil from the Williston Basin, and 155,000 barrels per day of capacity is available to pick up crude oil from domestic producers that deliver to Cushing, Oklahoma, the quantity of oil sands crudes is more likely to be closer to 600,000 barrels per day maximum for the next decade or two. There are 58 refineries in PADD III with a 2008 refining capacity of approximately 8.4 million bpd (Table 3.14.3-3). Heavy crude oil accounted for approximately 2.5 million bpd of the crude oil refined in PADD III in 2008 and the proportion of heavy crude oil refined is expected to grow. In 2009 PADD III as a whole imported 2.9 million bpd of heavy crude oil (EnSys 2010).

As identified in Table 3.14.3-3, a total of 15 refineries in PADD III would be connected directly to the hubs to which the proposed Project connects. These 15 refineries are in the Houston, Texas; Port Arthur, Texas; and Lake Charles, Louisiana areas, and have a total crude oil capacity of almost 4 million bpd, including over 1.4 million bpd of heavy crude oil capacity (EIA 2009, Purvin & Gertz 2009). Oil transported via the proposed Project could be delivered to other refineries in PADD III through the existing pipeline network that extends throughout those general areas. The other refineries in PADD III have a total crude oil refining capacity of 4.4 million bpd, including approximately 1.1 million bpd of heavy crude oil. Thus, crude oil deliveries from the proposed Project could be processed at any of the refineries with direct or indirect access to the delivery points of the proposed Project.

The crude oil capacity for each refinery in PADD III, including refineries with direct access to the proposed Project, without direct access to the proposed Project, and with possible pipeline connection to the proposed Project, are identified in Table 3.14.3-3.

TABLE 3.14.3-3
PADD III Refinery Crude Capacity: 2008

Refineries	Crude Oil Capacity (thousand bpd)
Gulf Coast Refineries with Direct Pipeline Access to the Proposed Project	
Motiva Enterprises LLC; Port Arthur, TX	285
Total Petrochemicals; Port Arthur, TX	232
Valero Energy Corp.; Port Arthur, TX	289
Exxon Mobil; Beaumont, TX	349
Pasadena Refining; Pasadena, TX	100
Houston Refining (Lyondell); Houston, TX	271
Valero Energy Corp.; Houston, TX	83
Deer Park Refining; Deer Park, TX	330
Exxon Mobil; Baytown, TX	567
BP; Texas City, TX	478
Marathon Oil; Texas City, TX	76
Valero Energy Corp.; Texas City, TX	200
Calcasieu Refining; Lake Charles, LA	53
CITGO; Lake Charles, LA	430
ConocoPhillips; Lake Charles/Westlake, LA	239
Sub-Total Group I	**3,981**
Gulf Coast Refineries in PADD II Without Direct Pipeline Access to the Proposed Project	
Hunt Refining Co.; Tuscaloosa, AL	35
ConocoPhillips; Belle Chasse, LA	247
Exxon Mobil; Baton Rouge, LA	503
Valero Energy Corp.; Krotz Springs, LA	80
Valero Energy Corp.; St. Charles, LA	185
Marathon Oil; Garyville, LA	256
Chalmette Refining; Chalmette, LA	193
Murphy Oil; Meraux, LA	120
Motiva Enterprises LLC; Norco, LA	236
Motiva Enterprises LLC; Convent, LA	235
Placid Refining; Port Allen, LA	56
Shell Chemical; Saint Rose, LA	55
ChevronTexaco; Pascagoula, MS	330
ConocoPhillips; Sweeny, TX	247
CITGO; Corpus Christi, TX	156
Valero Energy Corp.; Three Rivers, TX	96
Flint Hills Resources; Corpus Christi, TX	288
Valero Energy Corp.; Corpus Christi, TX	142
Sub-Total Group 2	**3,460**

TABLE 3.14.3-3 PADD III Refinery Crude Capacity: 2008	
Refineries	**Crude Oil Capacity (thousand bpd)**
Inland PADD III Refineries with Possible Pipeline Connection to the Proposed Project	
Navajo Refining; Artesia, NM	84
WRB Refining; Borger, TX	416
Valero Energy Corp.; Sunray/McKee, TX	171
Alon USA; Big Spring, TX	67
Delek; Tyler, TX	58
Sub-Total Group 3	**526**
Inland PADD III Refineries without Pipeline Access to the Proposed Project	
Other Refineries without Access	449
Sub-Total Group 4	**449**
PADD III GRAND TOTAL	**8,416**

Source: U.S. Energy Information Administration (EIA), Refining Capacity 2009.

There are ongoing or completed major refinery upgrades at several PADD III refineries that would have direct pipeline access to crude oil transported through the proposed Project (i.e., Motiva, Port Arthur; Valero, Texas City; and Total, Port Arthur) and at several PADD III refineries without direct pipeline access (Borger, Texas; Artesia, New Mexico; and Garyville, Louisiana). There are also continuing plans for upgrades in Port Arthur, revived plans for upgrades in St. Charles and Tuscaloosa, Alabama, and smaller-scale upgrades elsewhere designed to increase heavy crude oil refining capacity in PADD III. There is no information that any of these refinery upgrades are being made specifically as a result of the proposed Project, although at least one refinery (Valero, Texas City) has indicated publicly it would receive crude oil from the proposed Project if it is constructed. The above refineries that have already constructed or are in the process of constructing their upgrades would have significant economic incentive to utilize the upgraded capacity to process a relatively heavier slate of crude oil whether the proposed Project is constructed or not.

Future Projections of Refinery Crude Oil Slates, Expansions and Investments in PADD III

To address the potential that the proposed Project could induce changes in crude oil slates, or induce refinery expansions and capital investments, an independent analysis of various aspects of the proposed Project was commissioned by the DOE Office of Policy and International Affairs (EnSys 2010). This analysis incorporated projections of likely future PADD III refinery operations, including total refinery throughputs and potential refinery expansions and investments (i.e. adding downstream processing units to process a different crude slate) and the average crude slate quality (measured by average API gravity and sulfur content).

The EnSys (2010) report (Appendix V) assessed seven alternative pipeline expansion scenarios for two separate petroleum product demand outlooks, a Reference outlook (the 2010 U.S. EIA Annual Energy Outlook) and a Low Demand outlook (based on a February-March 2010 EPA study assuming ~~"~~more aggressive fuel economy standards and policies to address vehicle miles travelled"). The different scenarios examined resulted in a range of projected WCSB crude oil volume refined in PADD III in 2030

from 0.57 million bpd (No Keystone XL Project [KXL] + Hi Asia[1]) to 1.79 million bpd (KXL no TMX), or 7 to 21 percent of total crude oil refined in PADD III. Three of these scenarios have been selected to highlight the potential impacts in PADD III directly attributable to the proposed Project. These three scenarios are: the KXL Scenario (assumes the proposed Project is built), the no-KXL Scenario (assumes the proposed Project is not built), and the No Expansion Scenario (assumes that the proposed Project is not built but the Trans Mountain TMX2 and TMX3 expansions proceed and additional pipeline capacity is constructed in the near-term between PADDs II and III).

As presented in Table 3.14.3-4, the EnSys (2010) results suggest there could be more WCSB crude oil refined in PADD III by 2020 if the proposed Project is implemented as compared to a scenario without the proposed Project. The volume of WCSB crude oil refined in PADD III in 2030 would remain virtually the same with or without the proposed Project. Even with some differences in the total volume of WCSB crude oil refined in PADD III across the three scenarios presented in Table 3.14.3-4, the average API gravity and the average sulphur content of the crude oil slate would be essentially the same with or without the proposed Project. Additionally, these projections suggest that construction of the proposed Project would not be expected to alter market conditions in PADD III to induce construction of a new refinery, to induce expansion of existing refineries, to induce significant differences in investment levels in refinery down-stream processing units, or to induce significant differences in average crude-slate quality. Therefore there would be little, if any, difference in emissions associated with crude oil refining in PADD III with or without the proposed Project.

These results are consistent with certain known attributes of world crude oil markets:

- Refiners in the United States primarily serve the U.S. market for finished transportation fuel (gasoline, diesel, etc.). Thus, total throughput at U.S. refineries is determined largely by the U.S. demand for transportation fuel derived from crude oil. As discussed in Section 4.1 (No Action Alternative), construction of the proposed Project is unlikely to have any significant impact on demand for transportation fuel.
- Crude oil is a relatively freely exchangeable (fungible) commodity, with low marine-shipping costs, and with prices set within a world market that consumes over 80 million bpd. Therefore shipping 830,000 bpd from a particular source of crude oil to a particular set of refineries would not necessarily have a large impact on the overall crude market or the competitive position of the PADD III refiners relative to that market.
- Refineries are optimized to process a particular crude slate into a particular set of refined products, and it is not easy or economically efficient in the short to medium term for a refinery to make significant changes in its crude slate quality. Thus, refineries (particularly large refineries in the Gulf Coast) typically obtain crude oil from a variety of sources, and blend those crude oils to achieve a consistent crude oil feedstock quality. If a refinery obtains a significant amount of a relatively heavier crude oil compared to what it has been processing, there is significant incentive for that refinery to balance the heavier crude oil with a relatively lighter crude oil to achieve consistent input quality.
- Many of the refineries in PADD III have already made significant capital investments in the downstream processing units necessary to refine a relatively heavier, more sulfurous crude oil blend. As stated previously in Section 1.2.2.3, PADD III has a particularly high heavy crude oil processing capacity in part because Mexico and Venezuela encouraged expansion of the heavy oil refining capacity through joint-venture investments in Gulf Coast refineries to create a more

[1] See the EnSys report in Appendix V for full explanation of individual scenarios assessed.

profitable market for their heavy crude oil resources. Having made those investments, to operate the refineries most efficiently, those refineries have significant incentive to seek out a heavier slate of crude oil, regardless of whether there is increased transport capacity to deliver WCSB oil sands derived crude oils to PADD III. For example, in 2008 and 2009 the fifteen refineries in PADD III that would have direct pipeline access to the proposed Project (which are located in the Houston, Texas; Port Arthur, Texas; and Lake Charles, Louisiana areas) imported 1.25 and 1.07 million bpd respectively of crude oil with a sulfur content higher than 2.5 percent (Table 3.14.3-5). Of those amounts, approximately 600,000 bpd each year was Mexican Maya crude oil, with an API gravity of approximately 22 and sulfur content of approximately 3.4 percent, which is similar to a diluted bitumen product such as Western Canadian Select (although other dilbits also have a slightly higher sulfur content). The EnSys (2010) economic analysis indicates that rather than increasing the total amount of heavy crude oils processed in PADD III, the availability of WCSB crude oils would likely replace heavy crude oils from other sources, particular Mexican Maya, which is projected to decrease dramatically over the next decade.

TABLE 3.14.3-4
Potential PADD III Refinery Operations in 2020 and 2030

	KXL		No KXL		No Exp + P2P3	
Pipeline Construction Scenario	**2020**	**2030**	**2020**	**2030**	**2020**	**2030**
WCSB Oil Sands Crude Oil Refined in PADD III (mbd)	0.59	1.43	0.19	1.39	0.19	1.01
PADD III Total Refinery Throughput (mbd)[a]	8.1	8.5	8.1	8.5	8.1	8.4
WCSB Oil Sands Crude Oil Refined in PADD III (% of total)	7	17	2	16	2	12
PADD III Refinery Investments (cumulative from 2010 in billion $)	25	43	25	43	25	42
PADD III Crude Slate Average API gravity	31.89	30.15	31.98	30.20	31.98	30.36
PADD III Crude Slate Average Sulfur Content (%)	1.47	1.72	1.46	1.72	1.46	1.72

[a] mbd = million barrels per day
Source: EnSys 2010 (see Appendix V).

TABLE 3.14.3-5
2008-2009 Crude Oil Imports with Average Sulfur Content above 2.5%
at PADD III Refineries That Would Have Direct Pipeline Access to Proposed Project

Year	Amount (Million bpd)[a]	Average API	Average Sulfur Content
2008	1.25	23.5	3.13
2009	1.07	21.85	3.16

[a] bpd = barrels per day
Source: EnSys 2010 (see Appendix V).

One important measure of crude quality not included in the EnSys analysis is the total content of the BTEX in the crude oil. These volatile and toxic aromatic components of crude oil are of significant concern when considering the potential health effects from refinery air emissions. In general, lighter crude oils, such as Alaskan North Slope crude oil or Brent Blend, tend to have higher concentrations of these more volatile and toxic aromatic fractions than either the WCSB heavy crude oils or the typical heavy crude oils (e.g., Mexican Maya and Venezuelan Bachaquero) currently refined in PADD III. API gravity and total BTEX content for a variety of crude oils produced in the world are presented in Table

3.14.3-6 with a focus on those currently refined in PADD III. The dilbits that would be delivered by the proposed Project have a slightly higher BTEX content than many other heavy crude oils, but a lower BTEX content than Mexican Maya, a crude oil that has been refined in PADD III in large quantities for many years. Additionally, the BTEX content of the dilbits that would be transported by the proposed Project is much lower than that of many lighter crude oils.

TABLE 3.14.3-6
API Gravity and Total BTEX Content for a Variety of Crude Oils Produced in the World and Currently Refined in PADD III

Crude Name (Origin)	API Gravity	Total BTEX (ppm) [a]
Western Canadian Select (DilSynBit; Canada)	21.3	7700
Cold Lake Blend (DilBit; Canada)	21.6	9800
BCF 24 (Venezuela)	23.4	5210
Alaska North Slope	25 - 30.89	15,430 – 22,624
Hondo (California)	19.6	6830
Sockeye Sour (California)	18.8	6748
Mexican Maya (Mexico)	21.3 – 21.8	5500-9773
SynCrude Synthetic (Canada)	31.7	13,100
CNRL Light Sweet Synthetic (Canada)	35	9500
West Texas Sour	30.2	20,540
West Texas Intermediate	36.4 – 40.8	9640
South Louisiana	32.72	12,210
Empire (Louisiana)	33.8	6110
Arab Light (Saudi Arabia)	31.3	10,950
Brent Blend (UK)	37.8 – 38.3	20,550
Sakhalin (Russia)	32.3	49,212

[a] The publicly available crude assays for many of the imported heavy oils in the Gulf coast (from Kuwait, Saudi Arabia, etc.) do not include information on total BTEX (benzene, toluene, ethylbenzene, xylenes) content; ppm = parts per million.
Source: Environment Canada 2011.

Some commenters expressed concern regarding the potential impacts of the proposed Project relative to refinery emissions in startup, shutdown, and maintenance (SSM) events. During an SSM event, refinery emissions do not count towards emission limits within the facility CAA permit. A review of Texas Council of Environmental Quality data reveals that a substantial percentage of annual refinery sulfur dioxide emissions (up to approximately 50 percent) could be related to SSM events (TCEQ 2009). Since each refinery would likely blend individual feedstock streams to generate an optimized crude oil blend prior to initiating the refining process, emissions associated with SSM events would result from refining the blend, not the individual crude oil components. Since refineries currently optimize the blend prior to refining, future blends would likely be similar to current blends, regardless of the various crude oil sources. For example, blending the WCSB dilbit and SCO crude oils likely to be transported by the proposed Project would create a feed blend for refining that would be similar to West Texas Intermediate crude oil. Therefore, displacement or replacement of crude oils currently refined in PADD III refineries with WCSB crude oils that would be transported by the proposed Project would not likely change the overall load of toxic or noxious refinery emissions during either normal operation or SSM events. There

is no indication that refineries processing Canadian crude oils, including diluted bitumen crudes, have more SSM events.

Some commenters on the draft EIS and supplemental draft EIS requested more site-specific analysis of potential changes in refinery emissions, citing a study (Accufacts 2010) indicating most of the oil sands crude oil from the proposed Project would be delivered to a relatively discrete geographic area in and around Houston and Port Arthur, Texas. For the reasons described above, it is unlikely that the proposed Project would impact refinery emissions examined in those more discrete areas. Additionally, the reason the refineries in that study were identified as candidates to receive heavy crude oil from the proposed Project is that they already have the equipment installed to process such heavy oil -- and are already processing it in significant quantities (see Table 3.14.3-5). There is no indication that the proposed Project would actually induce those refiners to expand or upgrade. The refineries that have made the capital investments necessary to process heavier crude oils (which can total billions of dollars) have a significant financial incentive to obtain these heavy crude oils. In addition to the fact that heavy crude oils typically sell at lower prices than light crudes, these heavy crude refineries cannot process a lighter crude slate as efficiently. As indicated in comments received from IHS CERA (2011), if a refinery configured to process a heavy slate of crude oil were constrained to processing only a light crude oil slate, the volume of gasoline and diesel fuels produced could decrease by 15-20 percent. Not only would the refiner be paying relatively more for that light slate of crude oil, it would be producing less gasoline and diesel from it. This is the primary reason refiners would not typically replace a heavy crude oil slate with 100 percent light crudes. Although the EnSys (2010) report presented results on a PADD-wide basis, the modeling reflects sub-PADD details built into the WORLD model, including different refinery processing capabilities. If there is no projected change in PADD-wide crude slate quality that indicates that there is no change in relative crude slate-quality within more discrete areas within the PADD.

The EnSys (2010) report assessed seven different WCSB crude oil transportation scenarios under both the EIA Annual Energy Outlook 2010 (AEO) for reference global and U.S. petroleum supply and demand projections, and a low demand outlook provided to DOE by EPA (i.e., a total of 14 scenarios were assessed). According to EnSys, all scenarios assessed resulted —… in very similar U.S. refinery investments, expansions, throughputs, and thus total crude import levels, U.S. product import and export levels, U.S. import costs, U.S. and global refinery CO_2 emissions and global life-cycle GHG emissions. Impacts of changing pipeline assumptions on overall U.S. crude slate quality, U.S. Gulf Coast (PADD3) crude slate and refining activity were also limited" (EnSys 2010). One scenario assessed, the No Expansion pipeline scenario (no expansion beyond existing pipeline capacity from WCSB to the U.S. or elsewhere, which limits WCSB crudes export capacity), would result in the lowest volume of WCSB crude oil delivery to PADD III, approximately 100,000 bpd. Without the proposed Project and additional pipelines from PADD II to PADD III, the crude oil demand balancing supply to PADD III would likely be imported from the Middle East and Africa (EnSys 2010).

Under the EnSys (2010) No Expansion Scenario, cumulative refinery investments are similar to the other scenarios in the 2020 timeframe, but approximately 10 percent less than the EnSys (2010) KXL Scenario in 2030. PADD III refinery crude throughputs are slightly lower in the EnSys (2010) No Expansion Scenario (approximately 300,000 bpd less than the EnSys (2010) KXL Scenario), but are offset by corresponding increases in PADD II throughputs, as there is projected expansion there to process the greater supply of —locked-in" WCSB crude in PADD II (approximately 300,000 bpd more than the other scenarios), which would shift any potential, projected refinery expansion in the 20-year time frame from PADD III to PADD II. PADD III crude slate quality was projected to be slightly better in the EnSys (2010) No Expansion Scenario, and was also projected to have up to 5 percent less sulfur than the other scenarios (1.42 percent) and to be up to 4 percent lighter in average API gravity (31.29) than the other scenarios.

As explained further elsewhere, the EnSys (2010) report judged the No Expansion Scenario to be "unlikely" in large part because the WORLD model indicated that if the proposed Project were not constructed, there was projected market demand to support adding broadly similar additional pipeline capacity, including to the PADD III Gulf Coast. This conclusion may be especially true regarding the addition of pipeline capacity between PADD II and PADD III because there are many fewer regulatory hurdles to the construction of such pipelines, and numerous right-of-ways already exist for pipelines that transport crude oil and refined products from PADD III to PADD II, and there is also the possibility of reversing existing lines that currently flow from PADD III to PADD II (EnSys 2011). Also, the EnSys report explicitly excluded examining the possible addition of rail or barge transport capacity. As has been shown by the development of Bakken transportation infrastructure in Montana and North Dakota, significant rail capacity can be added relatively quickly where there is both market demand and constraints on existing pipeline capacity. After reviewing additional information about the potential for expansion of pipeline capacity and alternative modes of transport for crude oil, EnSys revised its previous conclusion that a No Expansion Scenario where no additional crude oil transport capacity is developed over the next 20 years was "unlikely" (EnSys 2010). Based on further analysis, EnSys now considers the No Expansion Scenario "essentially implausible" (EnSys 2011). These observations suggest that the contribution to cumulative air emissions in PADD III resulting from future refinery activities would be independent of the proposed Project (i.e., the total emissions would be similar with or without the proposed Project). The No Expansion Scenario and alternate modes of crude oil transport are discussed in more detail in Section 4.1.2.3.

Whether the No Expansion Scenario is judged to be plausible or implausible, there are additional factors indicating the magnitude of change in crude oil slate quality reflected in the No Expansion Scenario (5 percent change in sulfur quality, 4 percent change in API gravity) would be unlikely to result in significant changes to refinery emissions. The emissions from refineries are dependent not just upon the quality of the crude oil slate input, and the quantity of crude oil processed in a refinery, but also on emissions control technologies employed by the refineries. In PADD III, 91 percent of the refining capacity is subject to consent decrees with the EPA (including all of the refineries in the Gulf Coast area except Lyondell in Houston) that require the addition of better pollution control technologies and emissions monitoring systems.[2] These controls have resulted in significant reductions in emissions, even though there have been fluctuations in the imported crude oil slate quality at those refineries with a magnitude similar to those indicated in the No Expansion Scenario. Additionally, at the national level, total refinery emissions have not appeared to be sensitive to small changes in crude oil slate quality in recent years.[3]

DOS also consulted with the DOE, EIA to obtain data regarding sulfur content of the crude oil slate inputs to Texas and Louisiana refineries and sulfur dioxide emissions from the refineries over several years. These data do not indicate any correlation between the changes to crude oil slate sulfur content (which varied by up to 12 percent) and sulfur dioxide emissions. As shown in Figure 3.14.3-1, while Texas crude oil sulfur content increased from 2002 to 2005 to 2008, and Louisiana crude oil sulfur content decreased over those three years, in both states the sulfur dioxide emissions changes did not correlate with the crude oil slate sulfur content changes.

Additionally, projected differences in the average crude oil slate quality or total refinery inputs in PADD III (EnSys 2010) between the KXL Scenario, the No KXL Scenario and the No Expansion Scenario would not represent an indirect impact of the proposed Project because the differences in the quantity of

[2] http://www.epa.gov/compliance/resources/cases/civil/caa/refineryinitiative-powerpoint021111.pdf
[3] EPA 2-11-2011 presentation, slides 3 and 5.

oil sands crude oil would be two to three times greater than the proposed Project would deliver over that time frame.

It should also be noted that the existing refineries processing heavy crude oil in PADD II and PADD III are designed and permitted to refine heavy crude oil. As a result, the processing of heavy crude oil transported via the proposed Project would occur within existing permit thresholds. Permitting of these facilities is under the authority of EPA as the federal agency that implements and enforces the requirements of the CAA. State agencies with delegated authority to administer air quality programs and with approved SIPs include Texas and Louisiana. The permitting process is designed to avoid significant cumulative impacts to regional air quality associated with air emissions. Potential refinery expansions are in various stages of planning and implementation, and each refinery is unique in regard to the size and type of expansion or upgrade, the type of best available control technology (BACT) that has been or would be implemented, the status of the expansions, the availability of air emissions modeling, and the resulting impact of associated emissions relative to existing conditions.

Federal regulations require that refineries undergoing substantial modification must integrate BACT into their design, operation, and emission offsets. In some cases, expansions in refined oil volume in association with BACT modifications can result in decreases in overall emissions, particularly for older refineries using outdated emission controls.

DOS (2009) provided a review of various refinery expansions and upgrades in PADD II associated with increasing the capacity of heavy crude oil processing. Specifically, DOS quantitatively reported on the change in emissions of criteria pollutants associated with proposed refinery expansions in Illinois, Indiana, and Michigan. Any refinery expansions or upgrades at refineries that could receive crude oil from the proposed Project would likely be required to adhere to similar regulatory standards. As a result of improvements in control technologies and the use of offsets, these refinery upgrades and expansions generally resulted in an overall increase in carbon monoxide, and a decrease in emissions of particulate matter, sulfur dioxide, and nitrogen dioxides. Volatile organic emissions tended to decrease slightly, but not consistently. These results indicate that current BACT requirements for expansion of existing refineries with outdated control technologies could result in an overall reduction in emissions relative to baseline conditions for some criteria pollutants.

Cumulative air emissions in PADD III are likely to change over time as a result of ongoing and planned refinery expansions, whether or not the proposed Project is implemented. The largest permitted refinery expansion for processing heavy crude oil in recent years is for the Motiva refinery in Port Arthur, Texas. This expansion would increase the heavy oil refining capacity of Motiva by 325,000 bpd (from 275,000 to 600,000 bpd) with a projected in-service date of 2012. The Motiva refinery would have direct access to the proposed Project and would have the largest heavy oil refining capacity in PADD III. This expansion would result in increases in most criteria pollutants, although there would be a reduction in VOCs (Table 3.14.3-7). The likely reasons that this expansion would result in net increases in most emissions include the overall size of the expansion and the fact that the existing refinery was already using relatively modern emission controls. Any modification to the existing refining processes would therefore not produce emission reductions in the same proportion as would occur for more outdated refineries. Specific emission estimates are unavailable for other refinery expansions under consideration in PADD III.

TABLE 3.14.3-7 Net Emissions for the Motiva Refinery Expansion[a]									
NO_x (tons)	CO (tons)	VOC (tons)	SO_2 (tons)	PM (tons)	C_6H_6 (tons)	H_2SO_4 (tons)	H_2S (tons)	NH_3 (tons)	Cl_2 (tons)
592.74	1,489.53	-116.73	1679.73	464.37	-0.47	22.24	4.33	125.69	3.77

[a] NOx = Oxides of nitrogen; CO = Carbon monoxide; VOC = Volatile organic compounds; SO_2 = Sulfur dioxide; PM = Particulate matter; C_6H_6 = Benzene; H_2SO_4 = Sulfuric acid; NH_3 = Ammonia; Cl_2 = Chlorine.
Source: TCEQ 2009.

Cumulative air impacts along the proposed Project cumulative impact corridor could change if new refineries are constructed in the future, although EnSys (2010) indicates such potential refinery construction is not sensitive to whether the proposed Project is implemented or not. There are currently no new refineries planned within about 500 miles of any delivery point for the proposed Project, although one new refinery is proposed in the northern portion of PADD II, the Hyperion Energy Center in South Dakota. While no new refinery has been permitted and built in the U.S. in the past 30 years, estimates of emissions used in the permitting process for the proposed Hyperion project can be used to allow quantification of potential emissions from upgraded refineries capable of processing heavy crude oil in PADD III that would use modern technology to process heavy crude oil. In fact, the calculated emissions presented in the permitting process for the proposed Hyperion refinery are generally comparable to those calculated for the ongoing 325,000-bpd Motiva expansion. The calculated emissions resulting from processing up to 400,000 bpd for the proposed Hyperion refinery (SDDNR 2008) are:

- 773 tons of NO_X;
- 1,999 tons of CO;
- 863 tons of SO_2;
- 828 tons of VOCs; and
- 1,046 tons of particulate matter (PM).

It is expected that most of the oil transported by the proposed Project would replace historic crude oil supplies or supplant supplies from less stable or more costly sources for the following reasons:

- The maximum volume of oil that would be transported by the proposed Project (830,000 bpd) represents approximately 7 percent of the overall crude oil refining capacity of PADD II and PADD III (over 12 million bpd);
- The supply of domestic crude oil is substantially diminished and in relative decline (although it increased in 2010 based on increased production from the Bakken shale in North Dakota and Montana, and from offshore extraction);
- The current supply of heavy crude oil delivered to PADD III from current overseas sources is either declining or at risk for political reasons; and
- There is a well developed existing regional infrastructure to facilitate distribution of crude oil transported by the proposed Project among existing PADD II and PADD III refineries.

Although the EnSys (2010) results indicate that the construction of the proposed Project is not likely to impact imported amounts of WCSB crude oil or refinery emissions, the following hypothetical emissions estimate is presented for illustrative purposes. A conservative hypothetical maximum emissions estimate could be developed by assuming that the entire crude oil volume transported by the proposed Project

would be heavy crude oil and that it would be refined at upgraded refineries. Using the emissions estimates discussed above for the Motiva refinery upgrade and the proposed Hyperion refinery project, this hypothetical maximum emissions estimate can be calculated by multiplying the maximum proposed Project throughput (830,000 bpd) by the emission rates per barrel reported for Motiva or Hyperion since these refineries are assumed to be typical for recently upgraded refineries implementing BACT. Hypothetical maximum annual emissions of NO_X would range between about 1,514 and 1,604 tons, CO emissions would range between about 3,804 and 4,148 tons; SO_2 emissions would range between about 1,791 and 4,290 tons, particulate matter emissions would range between 1,186 and 2,170 tons, and VOC emissions would be about 1,718 tons. However, since the crude oil transported by the proposed Project would be replacing or displacing crude oil from other sources, the majority of the emissions generated from refining crude oil transported by the proposed Project would not result in incremental increases to refinery emissions in either PADD II or PADD III. Additionally, it is expected that approximately one-third of the volume transported by the proposed Project would not be heavy crude oil, particularly in light of the proposed Bakken Marketlink and Cushing Marketlink connected actions.

End Use

Some commenters on the draft and supplemental draft EIS expressed concerns relative to indirect contributions to cumulative air quality impacts related to the combustion or other use of petroleum products refined from the crude oil that would be transported to PADDs II and III by the proposed Project. The end use of refined petroleum products could include combustion (e.g., vehicles, power generation, or other industrial facilities) or non-combustion uses (e.g., asphalt, petroleum coke, liquefied refinery gases, and lubricants). The ultimate use of refined product originating from crude oil transported by the proposed Project would not produce different end use emissions. Criteria pollutant emissions from consumer and manufacturing use of refined petroleum products are regulated under permits for some uses (e.g., mass transportation vehicles and petrochemical processing) and not for others (e.g., private vehicles) beyond standard quality rules designed to reduce pollutants (e.g., oxygenated fuels, low-sulfur diesel, CAFÉ standards). For instance, the CAFÉ regulations in the United States, first enacted by Congress in 1975, are federal regulations intended to improve the average fuel economy of cars and light trucks (trucks, vans and sport utility vehicles) sold in the U.S. In 2011, the standard changes to include many larger vehicles.

Greenhouse Gases and Climate Change

Contribution to cumulative impacts from GHG would result directly from construction and operation of the proposed Project. Contribution to cumulative impacts from GHG could also result from activities indirectly related to the proposed Project (e.g., crude oil extraction, refining, and refined product end uses) if those activities were affected by the proposed Project. Many commenters expressed concern on the level of analysis within the draft EIS concerning indirect GHG impacts from production in the WCSB oil sands, from refining the WCSB crude oil that would be transported by the proposed Project, and from end uses of refined products originating from that crude oil. The principal GHG are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), ozone, and water vapor. The reference gas for climate change is CO_2 and, therefore, measures of non-CO_2 GHGs are converted into CO_2-equivalent (CO_2-e) values based on their potential to absorb heat in the atmosphere. The principal GHG of concern related to the proposed Project is CO_2, which enters the atmosphere through the burning of fossil fuels (e.g., oil, natural gas, and coal), solid waste, and trees and wood products, and as a result of other chemical reactions (e.g., manufacture of cement). CO_2 is removed from the atmosphere (or ―sequestered") when it is absorbed by plants as part of the biological carbon cycle or through other natural and anthropogenic methods.

Climate change is defined by the United Nations Framework Convention on Climate Change as ~~"~~a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods" (EPA 2008). Natural processes (e.g., changes in the sun's intensity, slow changes in the Earth's orbit around the sun, animal respiration, and changes in ocean circulation) and human activities (e.g., fossil fuel combustion, deforestation, reforestation, and urbanization) affect emissions of GHG. The accumulation of GHG in the atmosphere affects the Earth's temperature; however, emissions from human activities have caused the concentrations of heat-trapping GHG to increase significantly in the atmosphere. These gases prevent heat from escaping to space, somewhat like the glass panels of a greenhouse. This accumulation has contributed to an increase in the temperature of the Earth's atmosphere and to climate change. If GHG continue to increase, climate models predict that the average temperature at the Earth's surface could increase from 3.2 to 7.2 ºF above 1990 levels by the end of this century (IPCC 2007). Most scientists agree that human activities are changing the composition of the atmosphere, and that increasing the concentration of GHG affects climate change. The rate, intensity, and effects of climate change continue to be assessed. For example, the increased concentration of CO_2 in the atmosphere has increased ocean acidity since pre-industrial times (EPA 2009). The extent of ocean acidification is correlated with atmospheric CO_2 concentration. Ocean acidification affects future climate change by diminishing the ocean's capacity to absorb increasing atmospheric CO_2.

Regulations and Standards Relating to Greenhouse Gases

Federal Programs

On April 2, 2007, in Massachusetts v. EPA, 549 U.S. 497, the Supreme Court found that GHG are air pollutants covered by the CAA. The Court held that the EPA Administrator must determine whether or not emissions of GHG from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In making these decisions, the Administrator is required to follow the language of Section 202(a) of the CAA. The Supreme Court decision resulted from a petition for rulemaking under Section 202(a) filed by more than a dozen environmental, renewable energy, and other organizations. As a result of this decision, on April 24, 2009, the EPA proposed the Endangerment and Cause or Contribute Findings for Greenhouse Gases under the CAA to find that the current and projected concentrations of the mix of six key GHG (CO_2, CH_4, N_2O, HFC, PFC, and SF_6) in the atmosphere threaten the public health and welfare of current and future generations. This is referred to as the endangerment finding. The Administrator is further proposing to find that the combined emissions of CO_2, CH_4, N_2O, and HFC from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of these key GHG and hence to the threat of climate change. This is referred to as the cause or contribute finding. This proposed action, as well as any final action in the future, would not itself impose any requirements on industry or other entities. An endangerment finding under one provision of the CAA would not by itself automatically trigger regulation under the entire Act.

On October 30, 2009, the EPA promulgated the first comprehensive national system for reporting emissions of CO_2 and other GHG produced by major sources in the United States. Through this new reporting, EPA will have comprehensive and accurate data about the production of GHG in order to confront climate change. Approximately 13,000 facilities, accounting for about 85 to 90 percent of industrial GHG emitted in the United States are covered under the rule. The new reporting requirements apply to suppliers of fossil fuel and industrial chemicals, manufacturers of certain motor vehicles and engines (not including light and medium duty on-road vehicles), as well as large direct emitters of GHG with emissions equal to or greater than a threshold of 25,000 metric tpy. This threshold is equivalent to the annual GHG emissions from just over 4,500 passenger vehicles. The direct emission sources covered under the reporting requirement include energy intensive sectors such as cement production, iron and

steel production, electricity generation, and oil refineries, among others. The gases covered by the rule are CO_2, CH_4, N_2O, HFC, PFC, SF_6, and other fluorinated gases, including nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFE). The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

According to the preamble of the rule, the U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations includes storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading operations. EPA does not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions (accounting for much less than 1 percent) and the difficulty in defining a facility. The responsibility for reporting would instead be placed on the processing plants and refineries.

On June 2, 2010, the EPA issued a final rule that establishes an approach to addressing GHG emissions from stationary sources under the CAA permitting programs. These stationary sources would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule sets thresholds for GHG emissions that define when the CAA permits under the NSR/PSD and the Title V Operating Permits programs are required for new or existing industrial facilities. The rule ~~"ta~~ilors" the requirements to limit which facilities will be required to obtain NSR/PSD and Title V permits and cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation's largest emitters (e.g., power plants, refineries, and cement production facilities).

For sources permitted between January 2, 2011 and June 30, 2011, the rule requires GHG permitting for only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHG) and that emit GHG emissions of at least 75,000 tpy. In addition, only sources required to have Title V permits for non-GHG pollutants will be required to address GHG as part of their Title V permitting (note: the 75,000 tpy CO_2-e limit does not apply to Title V). For sources constructed between July 1, 2011 and June 30, 2013, the rule requires PSD permitting for first-time new construction projects that emit GHG emissions of at least 100,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In addition, sources that emit or have the potential to emit at least 100,000 tpy CO_2-e and that undertake a modification that increases net emissions of GHG by at least 75,000 tpy CO_2-e will also be subject to PSD requirements. Under this scenario, operating permit requirements will for the first time apply to sources based on their GHG emissions, even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tpy CO_2-e will be subject to Title V permitting requirements. EPA plans further rulemaking that would possibly reduce the permitting thresholds for new and modified sources making changes after June 30, 2013.

On December 2, 2010, the EPA released its guidance for limiting GHG emissions based on the CAA requirement for new and modified emission sources to employ BACT to limit regulated air pollutants. As a result, the guidance focuses on the process that state agencies will use as they are developing permits for individual sources to determine whether there are technologies available and feasible for controlling GHG emissions from those sources. The guidance is not a formal rulemaking and does not establish regulations, but it provides permitting authorities more detail on EPA expectations for the implementation of its new GHG permitting requirements.

On April 1, 2010, the EPA and USDOT finalized a new joint regulation for GHG emissions and fuel economy for model years 2012 through 2016 light duty vehicles. The EPA regulates GHG emissions from passenger vehicles up to 8,500 pounds gross vehicle weight rating (plus medium-duty SUVs and passenger vans up to 10,000 pounds). The program sets standards for CO_2 emissions on the U.S. federal test procedure. Equivalent Corporate Average Fuel Economy (CAFE) regulations, measured in miles per gallon of fuel consumed, were simultaneously established by the USDOT National Highway Traffic and Safety Administration (NHTSA).

State Programs

Programs for GHG emissions are being adopted by some states along the proposed Project corridor. Montana is a member of the Western Climate Initiative (WCI). The WCI is a collaborative effort of seven U.S. states and four Canadian provinces to identify, evaluate, and implement measures to reduce GHG emissions in participating jurisdictions. The WCI has a regional GHG target of 15 percent below 2005 levels by 2020 to be met through a regional market-based multi-sector mechanism, as well as other policies. The recommended cap-and-trade program has a broad scope that includes six GHG (CO_2, CH_4, N_2O, HFC, PFC, and SF_6) and will cover 90 percent of GHG emissions from the region when fully implemented. The cap-and-trade program will begin January 1, 2012.

The Governor of Nebraska, along with 10 other midwestern Governors and 1 Canadian province Premier, is a member of the Energy Security and Climate Stewardship Platform for the midwest. The Platform lists goals for energy efficiency improvements, low-carbon transportation fuel availability, renewable electricity production, and carbon capture and storage development. In addition to goals related to energy efficiency, renewable energy sources, and biofuel production, the Platform lays out objectives with respect to carbon capture and storage (CCS). Members agreed to have in place a regional regulatory framework for CCS by 2010, and by 2012 to have sited and permitted a multi-jurisdiction CO_2 transport pipeline and have in operation at least one commercial-scale coal-powered integrated gasification combined cycle (IGCC) power plant with CCS, with additional plants to follow in succeeding years. By 2020, all new coal plants in the region will capture and store CO_2 emissions. Numerous policy options are described for states to consider as they work towards these goals. The Platform also lays out 6 cooperative regional agreements. These resolutions establish a Carbon Management Infrastructure Partnership, a Midwestern Biobased Product Procurement System, coordination across the region for biofuels development, and a working group to pursue a collaborative, multi-jurisdictional transmission initiative. States adopting all or part of the Platform include Wisconsin, Minnesota, South Dakota, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nebraska, North Dakota, and Ohio, as well as the Canadian Province of Manitoba.

Kansas, on November 15, 2007, joined 5 other states and one Canadian province to establish the Midwestern Regional Greenhouse Gas Reduction Accord. Under the Accord, members agree to establish regional GHG reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and to develop a multi-sector cap-and-trade system to help meet the targets. Participants also establish a GHG emissions reductions tracking system and implement other policies, such as low-carbon fuel standards, to aid in reducing emissions.

In South Dakota, on February 21, 2008, Governor Mike Rounds signed into law HB 1272, which established a voluntary Renewable Portfolio objective of 10 percent by 2015. Oklahoma and Texas currently do not have state initiatives addressing the reduction in GHG, although Senate Bill 184 required the Texas Commission on Environmental Quality (TCEQ) to develop and present a report to the legislature by December 31, 2010, recommending strategies to reduce the GHG emissions by businesses and consumers of the state.

Low Carbon Fuel Standard

The first low carbon fuel standards (LCFS) were enacted in California in 2007. Since then, other jurisdictions (e.g., British Columbia and the European Union) have enacted similar standards. These standards generally require that overall carbon values life-cycle GHG emissions for transportation fuels decrease by 10 percent over the next decade, although the definition of fuels and the percent reduction over time differ across jurisdictions. More carbon-intensive fuels include those derived from crude oil sources in the WCSB, Venezuela, Nigeria, the Middle East, and California (IHS CERA 2010). The impact of LCFS on U.S. market demand for oil sands crude oil is speculative at this time since few jurisdictions have implemented these standards.

One concern regarding the adoption of LCFS in certain jurisdictions is that GHG-intensive crudes will simply be routed to other markets through "emissions leakage" or "shuffling". Barr (2010) analyzed the potential for the implementation of an LCFS policy to actually result in an increase in GHG emissions (rather than the intended decrease) because of a "shuffling," where the fuels sector would support the most inexpensive avenues to comply with the LCFS, thereby shuffling production and sales that may double GHG emissions resulting from crude oil transport to and from areas affected by the LCFS policy. Barr (2010) suggests that an approved LCFS would result in increased GHG emissions based on a reduction of crude oil imported from Canada and subsequent rerouting of crude imports and exports to account for this displacement. If LCFS were increasingly required in the U.S., this would be expected to discourage overall U.S. imports of oil sands crude from Canada, and in turn would encourage importing of crude oil to the U.S. from areas that produce light sweet crude, likely the Middle East. Canadian crude sources would be diverted to other countries not affected by LCFS, and supplies in the U.S. negatively affected by LCFS requirements would be replaced with supplies from more distant parts of the world. The term "emissions leakage" refers to the phenomenon where consumers and producers can purchase or produce fuels at lowest cost by shifting consumption and production to unregulated markets (Yeh and Sperling 2010). In contrast to the Barr's (2010) finding that emissions leakage through fuel shuffling would result in increased GHG emissions, Yeh and Sperling (2010) note that "studies examining the effectiveness of a regional carbon policy or an LCFS suggest that in the case of extreme leakage, the marginal benefits of a carbon policy can be close to zero", but nonetheless they did not project a net increase in GHG emissions.

The avoidance of emissions leakage through fuel shuffling is a challenge of implementing any climate policy that focuses on the energy sector, including LCFS policies, since transport fuels are internationally traded commodities (Yeh and Sperling 2010). To some extent, leakage could be mitigated if similar standards are adopted throughout the world (Sperling and Yeh 2009). LCFS policies have already been adopted in California, British Columbia, the United Kingdom, and the European Union, and are in development in Oregon and Washington, nine states in the Midwest, and 11 states in the Northeast, according to the Pew Center on Global Climate Change (2011). Adoption of LCFS policies in U.S. and international markets would help mitigate the effect of crude shuffling and emissions leakage.[4] An additional factor that will minimize crude shuffling is the oil refinery sectors' varied processing arrangements designed to process a specific composition of crude oil feedstocks (EPA 1995). The refineries' process optimization for different crude oil feedstocks hinders the ability of fuel refineries to

[4]According to Sperling and Yeh (2009), "a major challenge for the LCFS is avoidance of 'shuffling' or 'leakage.' Companies will seek the easiest way of responding to the new LCFS requirements. That might involve shuffling production and sales in ways that meet the requirements of the LCFS but do not actually result in any net change. For instance, a producer of low-GHG cellulosic biofuels in Iowa could divert its fuel to California markets and send its high carbon corn ethanol elsewhere. The same could happen with gasoline made from tar sands and conventional oil. Environmental regulators will need to account for this shuffling in their rule making. This problem is mitigated and eventually disappears as more states and nations adopt the same regulatory standards and requirements."

switch crude oil feedstocks from light to heavy blends without incurring additional costs for process modifications.

An additional objective of LCFS policies is to stimulate innovation in the transportation and fuels sectors that would minimize fuel shuffling. For example, a study by the University of California indicates that LCFS ―requires innovation in fuel and/or vehicle technologies. Because innovation in the transportation sector is necessary to achieve long-term climate stabilization in any case, the fact that the LCFS will stimulate innovation in the near term is an advantage, not a problem" (Farrell and Sperling 2007). Even in cases where fuel shuffling causes an increase in the GHG emissions resulting from crude oil transport, it is unlikely that overall life-cycle GHG emissions would increase significantly because crude and fuel transportation emissions have a small to moderate effect on well-to-wheel GHG emissions. Jacobs (2009) and NETL (2008) found that crude and fuel transportation emissions make up less than one to four percent of total well-to-wheels (WTW) emissions.

Finally, a goal of LCFS is to promote the development of ultra-low carbon fuels such as advanced biofuels, transportation electricity, biomethane, and hydrogen, and thus to provide an incentive to shift the transportation sector away from fossil fuels. As noted by Sperling and Yeh (2009), as compared to traditional fossil fuels, advanced low- or zero-carbon fuel sources are currently competing on a ―very uneven playing field: the size, organization, and regulation of these industries are radically different." They argue that as LCFS creates a need for the transportation sector to greatly reduce their GHG emissions, these new fuels and vehicles have the opportunity to become more economical and increase their market share.

Cumulative Effects of GHG

Neither the federal government nor states crossed by the proposed Project have established thresholds for determining the significance of GHG emissions. While no final thresholds currently exist, this assessment of the direct and indirect contributions of the proposed Project to global GHG emissions was conducted in accordance with CEQ draft guidance for GHG (CEQ 2010) that established a draft threshold for NEPA purposes of 25,000 metric tpy for CO2-e. There is a general scientific consensus that the cumulative effects of GHG have influenced climate change on a global scale, which is considered a significant cumulative effect.

Construction and Operation Emissions

As discussed in Section 3.12, the GHG emissions during construction of the proposed Project would total approximately 236,978 tpy of CO_2-e over the construction period and direct GHG emissions during proposed Project operation would total approximately 85 tpy of CO2-e. Indirect GHG emissions associated with electrical generation for the proposed Project pump stations are estimated at approximately 2.6 to 4.4 million tons of CO2 per year for a proposed initial capacity of 700,000 bpd and a potential capacity of 830,000 bpd, respectively, as calculated using EPA AP-42 emission factor for large diesel engines and assuming 30 pump stations with 79 to 132 pumps rated at 6,500 hp. This contribution to cumulative GHG impacts from proposed Project construction and operation is very small compared to total GHG emissions for the United States (CO2 equivalents from anthropogenic activities) which totaled 7,054 million tons in 2006, and global CO2 emissions which totaled 28,193 million tons in 2005 (CO2 equivalents from fuel combustion) (EPA 2008). Construction activities associated with the proposed Project for each year represent less than 0.003 percent and 0.0008 percent of the national and global GHG emissions, respectively. While the EPA has released proposed regulations that would require approximately 13,000 facilities nationwide to monitor and report their CO2 and other GHG emissions, the proposed Project would not satisfy the definition of these regulated facilities and there are no federal regulations or guidance to definitively identify the significance of the GHG emissions associated with

operation of the Project. Although the GHG emissions associated with construction of the proposed Project would be greater than the CEQ draft threshold of 25,000 tpy of CO2-e that is suggested as a useful presumptive threshold for disclosure during NEPA review, the overall contribution to cumulative GHG impacts from proposed Project construction and operation would not constitute a substantive contribution to the U.S. or global emissions.

Indirect Cumulative Impacts and Life Cycle Greenhouse Gas Emissions

The following discussion on GHG life cycle emissions associated with oil sands is provided in response to comments on the draft EIS and supplemental draft EIS. DOS is providing this information as a matter of policy, although the proposed Project would not substantively influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the U.S. or refined in the U.S. (EnSys 2010). To assist in addressing concerns relative to GHG, the DOS third party contractor requested that ICF International LLC (ICF) a detailed review of key studies in the existing literature that address life-cycle GHG emissions of petroleum products, including petroleum products derived from Canadian oil sands, and a comparison of life cycle GHG emissions reported in the literature for Canadian oil sands derived crude oil and refined products with those of reference crude oils. A summary of the ICF report is presented in the following sections and the full report is presented in Appendix V.

Introduction

The EnSys (2010) report commissioned by DOE evaluated potential influences of the proposed Project on global, U.S., and regional oil demand; the effect of that demand on continued or expanded development of Western Canadian Sedimentary Basin (WCSB) oil sands crude oil sources; and assessments of global life-cycle GHG impacts under 14 separate crude oil transportation scenarios (Appendix V). As a part of that analysis, EnSys estimates the changes in life-cycle GHG emissions resulting from these scenarios, including a "no expansion" scenario (i.e., a scenario in which no additional pipelines beyond those in operation as of late 2010 are constructed to transport crude oil from WCSB). The GHG emissions estimated for each scenario are related to quantities of specific WCSB oil sands derived crude oils produced and their respective life-cycle GHG intensity. The EnSys (2010) analysis relied on the life-cycle GHG emission factors developed by the DOE National Energy Technology Laboratory (NETL 2008 and NETL 2009).[5] NETL's estimates address a range of the world crude oils consumed in the United States, including the WCSB oil sands crude oils as well as the "average crude" consumed in the United States in 2005.[6] Because the NETL-developed emission factors were selected to be a key input to the EnSys (2010) analysis and to EPA's renewable fuel regulations, they serve as an important reference case for evaluating life-cycle emissions for different crude sources. Thus, while this section provides an assessment of the differences between the life-cycle GHG emissions associated with Canadian oil sands derived crudes that may be refined in the United States versus reference crudes, it also specifically compares results from other literature against the NETL studies' base case. A more detailed description of the ICF review is provided in Appendix V.

Life-Cycle Carbon Overview

Evaluating life-cycle emissions provides a method to assess the relative GHG emissions between various sources of crude oil. The life-cycle assessment (LCA) methodology attempts to identify, quantify and track carbon emissions arising from the development and use of a hydrocarbon resource. It is helpful to

[5] EnSys used factors from the "NETL: Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis – 2005 Baseline Model," which were applied for each scenario within the DOE version of the Energy Technology Perspective (ETP) model.

[6] This 2005 average serves as the baseline in the U.S. Renewable Fuel Standard Program (EPA 2010).

characterize carbon emissions into what can be considered primary and secondary flows. The primary carbon emissions are associated with the various stages in the life cycle from the extraction of the crude from the reservoir to refining to combustion of the refined fuel products (typically referred to as a ―well-to-wheels" analysis). The secondary carbon emissions are associated with activities (e.g., land use impacts) not directly related to conversion of the hydrocarbon resource into useful product fuels.

Most of the GHG emissions from hydrocarbon resource development results from three primary steps in the LCA: production of the crude oil, refining of the crude oil, and combustion of the refined products. Transportation of the crude oil to the refinery and transportation of the products to market also contribute to GHG emissions. The primary objective of refining crude oil is to produce three premium refined products: gasoline, diesel, and kerosene/jet fuel (i.e., gasoline and distillates). These primary GHG emissions associated with fuel production drive the economics and engineering of the oil business. In addition to the primary emissions arising from the production, transportation, refining, and combustion steps of the LCA, there is a range of secondary carbon emissions to be considered. For example, extracting crude can influence secondary GHG emissions, such as changes in biological or soil carbon stocks resulting from land-use change during mining. In addition to premium fuels, typically 5 to 10 percent of the carbon in the petroleum resource ends up in co-products, such as petroleum coke, that are often (but not always) combusted and converted to CO_2. As discussed in greater detail below, these secondary flows are treated differently across the LCA literature and estimates of specific process inputs and emission factors vary according to the underlying methods and data sources used in each LCA.

The GHG emission factors modeled by NETL are based on a well-to-wheels (WTW) LCA. WTW assessments for petroleum-based fuels focus on the GHG emissions associated with extraction of the crude oil from reservoirs, transportation of crude oils to refineries, refining of the crude oil, distribution of refined product (e.g., gasoline, diesel, and jet fuel) to retail markets, and combustion of these fuels in vehicles or planes. For some WCSB oil sands crude oils, the assessment also addresses upgrading of the extracted crude oil (i.e., partial refining of some oil sands crude oils to produce synthetic crude oil). Other analyses (e.g., well-to-tank [WTT] analyses) establish different life-cycle boundaries and evaluate only the emissions associated with the processes prior to combustion of the refined products. Inclusion of the combustion phase allows for a more complete picture of crude oil contribution to GHG emissions because this phase represents between approximately 70 to 80 percent (depending on crude source) of the WTW emissions (CERA 2010). As a result, a WTW analysis reduces the percent differential in total GHG emissions between different crude oil sources. Because a WTT analysis focuses on pre-combustion processes, it highlights the differences in upstream life-cycle GHG emissions associated with the extraction, transportation, and refining of crude oils from different sources, as illustrated in a comparison of Figures 3.14.3-1 and 3.14.3-2.

Scope of Review of Life-cycle Studies

A list of the reports reviewed for this assessment is presented in Table 3.14.3-8. The primary studies and additional supplemental reports for the assessment were selected on the following basis:

- The reports evaluate WCSB oil sands crude oils in comparison to crude oils from other sources;
- The reports focus on GHG impacts throughout the life-cycle of crude oils and their related products;
- The reports were published within the last 10 years, and most were published within the last five years;

- The reports represent the perspectives of various stakeholders, including industry, governmental organizations, and non-governmental organizations; and
- The reports originate from research bodies within the United States, Canada, and international locations.

TABLE 3.14.3-8
Primary and Additional Studies Evaluated[a]

	Type
Primary Studies Analyzed	
NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.	Individual LCA
NETL 2009. An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions.	Individual LCA
IEA. 2010. World Energy Outlook.	Meta-analysis
IHS CERA. 2010. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right.	Meta-analysis
NRDC. 2010. GHG Emission Factors for High Carbon Intensity Crude Oils ver. 2.	Meta-analysis
Energy-Redefined LLC for ICCT. 2010. Carbon Intensity of Crude Oil in Europe Crude.	Individual LCA
AERI/Jacobs Consultancy. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes.	Individual LCA
AERI/TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions.	Individual LCA
Charpentier, et al. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions.	Meta-analysis
Additional Studies/Models Analyzed	
RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.	Individual LCA
Pembina. 2005. Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush.	Partial LCA
Pembina. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil sands issue paper 2.	Partial LCA
McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles.	Individual LCA
Pembina. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis.	White Paper
GHGenius. 2010. GHGenius Model, Version 3.19. Natural Resources Canada.	Model
GREET. 2010. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, Version 1.8d.1. Argonne National Laboratory.	Model

[a] See Appendix V for more information on each study.

For WCSB oil sands crude oils, the assessment focused on those that could be transported through the proposed Project. Based on this criterion, the solid, raw bitumen from oil sands was eliminated except to the extent that it is included within averaged results (e.g., NETL provides a single WCSB oil sands estimate that represents a weighted average of 43 percent crude bitumen from *in situ* production and 57 percent SCO from mining).

This assessment addresses three types of WCSB oil sands crude oils that are extracted either by mining or the *in-situ* thermal processes. Conventional strip-mining methods are used to extract oil sands deposits

that are less than about 75 meters below the surface.[7] To recover deeper deposits of oil sands, *in situ* methods are used. *In situ* recovery methods typically involve injecting steam into an oil sands reservoir to heat – and thus decrease the viscosity of – the bitumen, enabling it to flow out of the reservoir sand matrix to collection wells. Steam is injected using cyclic steam stimulation (CSS), where the same well cycles between periods of steam injection and bitumen production, or by steam-assisted gravity drainage (SAGD), where a pair of horizontal wells is drilled; the top well is used for steam injection, and the bottom well for bitumen production. Due to the high energy demands for steam production, steam injection *in situ* methods are generally more GHG-intensive than mining operations. The WCSB crude oil types assessed in this study are described briefly below:

- Synthetic crude oil (SCO) − SCO is produced from bitumen via a refinery conversion of heavy hydrocarbons to lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude oil without heavy fractions.
- Dilbit (diluted bitumen) − Dilbit is bitumen blended with a diluent, usually a natural gas liquid such as condensate, to create a "lighter" product and to reduce viscosity so the dilbit can be transported via pipeline. Dilbit feedstock processing requires more heavy oil conversion capacity than most crude oils.
- Synthetic bitumen (synbit) – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than SCO or dilbit alone.

The reference crudes evaluated in the literature reflect a range of sources and GHG emissions and include:

- The average U.S. barrel consumed in 2005 (from NETL 2008). This reference was selected because it provides a baseline for fuels produced from the average crude consumed in the United States.
- Venezuela Bachaquero and Mexico Maya, which are representative of heavy crudes currently refined in PADD III refineries. It is assumed that these crude oils would be displaced or replaced by the WCSB oil sands crude oil that would be transported by the proposed Project, although it is likely that they would find markets elsewhere and would still be produced.
- Saudi Light (i.e., Middle East Sour), which was taken to be the balancing grade for world crude oil supplies in the *Keystone XL Assessment* (EnSys 2010). This is the crude that may ultimately be backed out of the world market if additional supply of WCSB oil sands crudes is produced.

Evaluation of Key Factors Influencing the GHG Results

There are many differences in the **study design factors** and **input assumptions** for life-cycle GHG analyses of WCSB oil sands crude oils relative to the four reference crude oils.

Study design factors relate to how the GHG comparison is structured within each study. These factors include the overall purpose and goal of the study, the types of crudes and refined products that are compared to each other, the timeframe over which the results of the study are applicable, the life-cycle boundaries established to make the comparison, the functional units or the basis used for comparing the life-cycle GHGs for crudes or fuels to each other (e.g., expressing GHG emissions per unit of crude, SCO,

[7] Mining accounts for roughly 48 percent of total bitumen capacity in the WCSB oil sands as of mid-2010 (IEA 2010, p. 152).

all refined products, or specific refined products such as gasoline or diesel, in terms of volume, energy, or distance units), and the treatment of co-products other than gasoline, diesel, and jet fuels (e.g., asphalt, petroleum coke, liquefied refinery gases, and lubricants). Some studies allocate a fraction of the GHG emissions from refining to these co-products and exclude these emissions from the life-cycle boundary (i.e., they are not included within the studies' life-cycle results). Other studies include these emissions but assign credits for GHG emissions from other sources that are offset by combustion of the co-products (e.g., electricity exported from a refinery replaces natural gas-fired power generation, and petroleum coke from a refinery replaces coal).

Key design factors across the studies identified through this assessment are summarized in Table 3.14.3-9. In general, the studies reviewed are consistent in their treatment of some factors (e.g., generally excluding emissions associated with land-use changes) but vary in their treatment of other factors (e.g., emissions from petroleum coke and electricity cogeneration). Most studies exclude land-use change and the emissions arising from the construction of capital infrastructure. Importantly, only a few studies modeled the effect that upgrading SCO has on downstream GHG emissions at the refinery. Several (but not all) studies include the following:

- Upstream production of purchased fuels and electricity used to power machinery in the oil fields and at refineries;
- Flaring and venting;
- Fugitive emissions; and
- Methane emissions from oil sands mining and tailings ponds.

Input assumptions impact life-cycle analysis results and assumptions are input at each life-cycle stage. Due to limited data availability and the complexity of and variation in the practices used to extract, process, refine, and transport crude oil, studies often use simplified assumptions to model GHG emissions. For example, for both WCSB oil sands crude oils and reference crude oils, assumptions about how much petroleum coke is produced, stored, and combusted at the upgrader or refinery, and how much is sold to other users, are key drivers of GHG emission estimates. Transportation assumptions have a more limited effect, but vary across the studies. Key input assumptions for WCSB oil sands derived crude oils include:

- Type of extraction process (i.e., mining or *in situ* production);
- Steam-oil ratio assumed for *in situ* operations;
- Efficiency of steam generation, and thus its energy consumption; and
- Upgrading processes modeled for SCO and whether or not estimated refinery GHG emissions account for upgrading.

For the reference crudes, key input assumptions include the oil-water and gas-oil ratios that are used to estimate reinjection and venting or flaring requirements, and whether and what type of artificial lift is considered for extracting crude oil.

Life-cycle GHG emissions for gasoline produced from WCSB oil sands crude oils relative to other reference crude oils consumed in the United States, as reported by NETL (2009) are summarized in Table 3.14.3-10. The results are subject to several input assumptions that influence the results of the analysis. These assumptions and their estimated scale of impact on the WTW results are summarized in the last two columns of Table 3.14.3-10.

TABLE 3.14.3-9
Summary of Key Study Design Features that Influence GHG Results

Estimated Relative WTW Impact:[a]		High					Medium				Low
Source	Data Reference Year(s)	Petroleum coke combustion[b]	Cogeneration credit[c]	Upstream production of fuels incldued[d]	Flaring/ venting GHG emissions included	Capital equipment included[e]	Methane emissions from tailing ponds included	Fugitive leaks included	Local and indirect land use change included	Refinery emissions account for upgrading[f]	Methane emissions from mine face
NETL, 2008	2005	No	NS	Yes	Yes	No	NS	Yes	No	No	NS
NETL, 2009	2005	No	NS	Yes	Yes	No	NS	NS	No	No	NS
IEA, 2010	2005-2009	NS	NS	Yes	NS	NS	Yes	NS	No	NA	NS
IHS CERA, 2010	~2005-2030	V	V	No	NS	NS	V	NS	No	NA	V
NRDC, 2010	2006-2010	NS[g]	NS[g]	P	NS	NS	NS	NS	No	NA	NS
ICCT, 2010	2009	NS	No	P	Yes	No	NS	Yes	No	No	NS
AERI/Jacobs, 2009	2000s	Yes	Yes	Yes	Yes	No	No	No	No	Yes	No
AERI/TIAX, 2009	2007-2009	P	P	Yes	Yes	No	Yes	Yes	No	Yes	Yes
Charpentier, et al., 2009	1999-2008	NS[g]	NS[g]	V	NS	V	NS	NS	No	NA	NS
RAND, 2008	2000s	NS	NS	NS	Yes	No	Yes	Yes	No	No	Yes
Pembina Institute, 2005	2000, 2004	NS	NS	NS	P	No	NS	P	No	No	NS
Pembina Institute, 2006	2002-2005	NS	NS	No	P	No	Yes	Yes	No	No	Yes
McCann, 2001	2007	P	NS	Yes	NS	No	NS	NS	No	NS	NS
GHGenius, 2010	Current	Yes	No	Yes	Yes	No	Yes	Yes	Local	NS	Yes
GREET, 2010	Current	NS	NS	Yes	Yes	No	NS	Yes	No	NS	NS

Notes: Yes = included in life-cycle boundary; No = not included; P = partially included; NS = not stated; NA = not applicable; V = varies by study addressed in meta-study.

[a] High impact = greater than 3% change in WTW emissions. Medium impact = 1 – 3% change in WTW emissions. Low impact = less than 1% change in WTW emissions.

[b] "Yes" indicates that GHG results for products such as gasoline, diesel, and jet fuel do include petroleum coke production and combustion. "No" indicates that GHG emissions from petroleum coke production and combustion were not included in the system boundary for gasoline, diesel, or jet fuel. The effect of including petroleum coke depends on how much is assumed to be stored at oil sands facilities versus sold or combusted, and whether a credit is included for coke that offsets coal combustion.

[c] "Yes" indicates that the study applied a credit for electricity exported from cogeneration facilities at oil sands operations that offsets electricity produced by other power generation facilities. "No" indicates a credit was not applied. Including a credit for oil sands will reduce the GHG emissions from oil sands crudes relative to reference crudes.

[d] Indicates whether studies included GHG emissions from the production of fuels that are purchased and combusted on-site for process heat and electricity (e.g., natural gas).

[e] Indicates whether the study included GHG emissions from the construction and decommissioning of capital equipment such as buildings, equipment, pipelines, rolling stock.

[f] Indicates whether refinery emissions account for the fuel properties of SCO relative to reference crudes. Since SCO is upgraded before refining, it requires less energy and GHG emissions to refine into gasoline, diesel, and jet fuel products.

[g] Not discussed in the meta-study; may vary by individual studies analyzed.

TABLE 3.14.3-10
GHG Emissions for Producing Gasoline from Different Crude Sources from NETL 2009 and Estimates of the Impact of Key Assumptions on the Oil Sands-U.S. Average Differential

	GHG Emissions (g CO2e/MJ LHV gasoline)[a]					Findings on Key Assumptions Influencing Results	
Life-Cycle Stage	**2005 U.S. Average**	**Canadian Oil Sands**	**Venezuela Conventional**	**Mexico**	**Saudi Arabia**	**Description**	**Estimated Ref Crude WTW Impact[b]**
Crude Oil Extraction	6.9	20.4[c]	4.5	7.0	2.5	Oil sands estimate assumes a weighted average of 43% crude bitumen (not accounting for blending with diluent to form dilbit) from CSS *in situ* production and 57% SCO from mining, based on data from 2005 and 2006	NA
Upgrading	NA	IE	NA	NA	NA		
Crude Oil Transport	1.4	0.9	1.2	1.1	2.8	Relative distances vary by study	Low increase or decrease
Refining	9.3	11.5[d]	11.0	12.9	10.4	Did not evaluate impact of upgrading SCO prior to refinery; only affects oil sands crudes	Medium decrease
Finished Fuel Transport	1.0	0.9	0.9	0.9	0.9	Transportation excluded co-product distribution	Low increase
Total WTT	**18.6**	**33.7**	**17.6**	**22.0**	**16.7**		
Fuel Combustion	72.6	72.6	72.6	72.6	72.6	Fuel combustion excluded combustion of petroleum coke and other co-products	Low to high increase[e]
Total WTW	**91.2**	**106.3**	**90.2**	**94.6**	**89.3**		
Difference from 2005 U.S. Average	**0%**	**17%**	**-1%**	**4%**	**-2%**		

Notes: IE = Included Elsewhere; NA = Not Applicable. LHV = Lower Heating Value. WTT = Well-to-Tank; WTW = Well-to-Wheels.

[a] NETL 2009 values converted from $kgCO_2e$/MMBtu using conversion factors of 1,055 MJ/MMBtu and 1000 g/kg.

[b] Estimated impact on the WTW GHG emissions for reference crudes, except where noted (i.e., refining assumption affects oil sands crudes), as result of addressing the key assumptions/ missing emission sources. High = greater than approximated 3% change, Medium = approximated 1 – 3% change, and Low = less than approximated 1% change in WTW emissions.

[c] Included within extraction and processing emissions.

[d] Calculated by subtracting other process numbers from WTT total; report missing this data point.

[e] The effect that including petroleum coke combustion has on WTW results depends upon assumptions about the end-use of petroleum coke and whether it is used to offset coal in electricity generation.

For example, NETL (2009) developed its weighted-average GHG emission estimate for oil sands extraction (including upgrading) from data on mining and CCS in situ operations in 2005 and 2006. The estimate that the NETL study used for mining oil sands was based on a 2005 industry report that estimates higher values than more recent estimates of surface mining GHG emissions (TIAX 2009, Jacobs 2009). The *in situ* GHG estimate is based on a CSS operation which—while CSS operations tend to be more GHG intensive than SAGD processes—is generally in the range of *in situ* estimates in other studies (e.g., TIAX 2009, Jacobs 2009). The NETL study, however, did not account for the fact that natural gas condensate is blended with crude bitumen to form dilbit, which is transported via pipeline to

the United States. Since condensate has a lower GHG intensity than crude bitumen, per-barrel GHG emissions from dilbit are less than per-barrel emissions from crude bitumen.

The NETL study only considered combustion emissions from gasoline, diesel, and kerosene-type jet fuel and allocated the refinery emissions from co-products other than gasoline, diesel, and jet fuel to the co-products themselves. This approach removes the GHG emissions associated with producing and combusting co-products from the study's life-cycle boundary. This approach is consistent with DOE/NETL's objective of estimating the contribution of crude oil sources to the 2005 baseline GHG emissions profile for three transportation fuels (gasoline, diesel, and kerosene-type jet fuel). A portion of the petroleum coke produced from partial refining (upgrading) of WCSB oil sands crudes is stockpiled (sequestered) in Alberta and does not contribute to GHG emissions, whereas virtually all of the petroleum coke produced at U.S. refineries is ultimately combusted. As explained in more detail in the appendix on GHG emissions, if petroleum coke produced from refineries is assumed to offset coal combustion, however, the net emissions from coke combustion will be much smaller (Appendix V). As a result, the effect of including petroleum coke combustion depends upon study assumptions about the end use of petroleum coke at both the refinery and upgrader, and whether petroleum coke use offsets other fuels, such as coal.

Additionally, the NETL study used linear relationships to relate GHG emissions from refining operations to specific crudes based on API gravity and sulfur content. The study notes that these relationships do not account for the fact that bitumen blends (dilbits and synbits) and SCO in particular will produce different fractions of residuum and light ends than "full-range" crudes. Accounting for the variable properties of these crude oil types and resulting refinery GHG emissions would change the differences between WTW GHG emissions for premium fuels refined from WCSB oil sands derived crude oils relative to reference crude oils.

GHG Intensity of WCSB Crudes

The wide variation in design and input assumptions within the various studies leads to a wide divergence in calculated GHG emissions. Based on an extensive review of information provided in the studies reviewed, the WTW and WTT GHG emissions of gasoline produced from WCSB oil sands derived crude oils were compared to similar emission estimates from four reference crude oils (see Figures 3.14.3-1 and 3.14.3-2). Additional information on the data sources and assessment is available in Appendix V.

As shown in Figure 3.14.3-2, the NETL WTW GHG emission estimates from gasoline produced from WCSB oil sands derived crude oils are 17 percent higher than that the GHG emission estimates for gasoline produced from the average mix of crude oils consumed in the United States in 2005, and are approximately 19, 13, and 16 percent higher than GHG emission estimates for Middle East Sour, Mexican Heavy (i.e., Mexican Maya), and Venezuelan[8] crude oils, respectively (NETL 2009).

The WTW emission estimates for gasoline produced from SCO via *in situ* methods of oil sands extraction (i.e., SAGD and CSS) in general are higher than the GHG emission estimates for mining extraction methods (Figure 3.14.3-1). This difference is primarily attributable to the energy requirements of producing steam as part of the *in situ* extraction process.

Gasoline produced from dilbit generally has lower estimated GHG life-cycle emissions than gasoline produced from SCO extracted by mining and *in situ* methods. This is a result of blending raw bitumen with a diluent (e.g., gas condensate) for transport via pipeline. Diluent produces fewer GHG emissions than bitumen, so blending the two together results in lower WTW GHG emissions. This assessment

[8] NETL uses Venezuelan Conventional as a reference crude rather than Venezuelan Bachaquero.

evaluates the refining of both bitumen and diluent at the refinery, since diluent will not be separated from the dilbit blend and recirculated by the proposed Project. WTW GHG emission estimates from gasoline produced from synbit, a blend of SCO and bitumen, are similar to WTW GHG emission estimates for gasoline produced from SCOs produced from bitumen extracted by either mining or *in situ* methods.

Similar trends were evident in the WTT GHG analyses (see Figure 3.14.3-3). The percentage increase in WTT GHG emission estimates for gasoline produced from WCSB oil sands derived crude oils as compared to gasoline produced from reference crudes (Figure 3.14.3-3) is much larger than the percent increases for WTW GHG emission estimates (Figure 3.14.3-2). Most of the gasoline life-cycle WTW GHG emissions occur during the combustion stage irrespective of the feedstock (i.e., reference crude or oil sands). Because WTT GHG emission estimates do not include the combustion phase, the differences in GHG life-cycle emissions associated with crude oil extraction and refining are emphasized; when expressing the comparison in terms of percentage increases, the same incremental differences in the numerator are divided by a smaller denominator.

The GHG emissions associated with different oil sands extraction, processing, and transportation methods vary by roughly 25 percent on a WTW basis. Life-cycle GHG emission estimates for fuels produced from WCSB oil sands crude oils are higher than emission estimates for fuels produced from lighter crude oils, such as Middle East Sour crudes and the 2005 U.S. average mix. Compared to heavier crude oils from Mexico and Venezuela, WTW emission estimates associated with fuels derived from WCSB oil sand-derived crude oils are 37 percent higher than for SAGD SCO (petroleum coke burned at the upgrader) and 2 percent lower for mining-derived SCO (including storing or selling the petroleum coke).

Incremental GHG Emissions from Oil Sands Crudes Potentially Transported by the Proposed Project Compared to Reference Crudes

As noted earlier in this chapter, based on the EnSys (2010) analysis, under most scenarios the proposed Project would not substantially influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the United States or refined in the United States. Thus, from a global perspective, the decision whether or not to build the Project will not affect the extraction and combustion of WCSB oil sands crude on the global market. However, on a life-cycle basis and compared with reference crudes refined in the United States, the reliance on oils sands crudes for transportation fuels would likely result in an increase in incremental GHG emissions.[9] Although a life-cycle analysis is not strictly necessary for purposes of evaluating the potential environmental impacts attributable to the proposed Project under NEPA, it is relevant and informative for policy-makers to consider in a variety of contexts. For illustrative purposes, this section provides information on the incremental life-cycle GHG emissions (in terms of the U.S. carbon footprint) from WCSB oil sands crudes likely to be transported by the proposed Project (or any transboundary pipeline). The incremental emissions are a function of: (i) the throughput of the pipeline, (ii) the mix of oil sands crudes imported, and (iii) the GHG-intensity of the crudes in the pipeline compared to the crudes they displace. Acknowledging the methodological differences in GHG-intensity estimates between the studies, the weighted-average GHG emissions for selected studies were calculated to estimate the incremental GHG emissions from WCSB oil sands relative to displacing an equivalent volume of reference crudes in U.S. refineries.

[9] Note that a substantial share of these emissions would occur outside of the United States. Also note that the U.S. National Inventory Report, like other national inventories, only characterizes emissions within the national border, rather than using a life-cycle approach. If the United States used a life-cycle approach, upstream emissions from other imported crudes would be attributed to the United States.

Jacobs (2009), TIAX (2009), and NETL (2009) formed the sub-set of studies used to develop weighted averages for purposes of the carbon footprint analysis. These studies are independent analyses of WTW GHG emissions from oil sands and reference crudes that utilize consistent functional units for comparison with each other. The other studies included in this assessment either did not look at the full WTW fuel life-cycle, did not evaluate emissions on a consistent functional unit basis for comparison, or are meta-analyses that include the results of the Jacobs and TIAX studies. Despite the underlying differences in study assumptions, the comparisons illustrated below are internally consistent and make comparisons between crudes from the same study.

For illustrative purposes, Figure 3.14.3-4 shows the percent change in weighted-average GHG emissions from the mix of WCSB oil sands crude oil likely to be transported in the proposed Project relative to each of the four reference crudes on a gasoline basis. The change in GHG emissions is calculated for the Jacobs (2009) and TIAX (2009) values by weighting the WTW GHG intensity of oil sands crudes by the composition of crudes that could be transported in the proposed Project. For purposes of this assessment, it is assumed that 50 percent of pipeline throughput would be SCO, and 50 percent would be dilbit. All WCSB dilbit is currently produced using in situ production and 12 percent of SCO is produced via in situ methods (ERCB 2010), yielding a final mix of 50 percent *in situ*-produced dilbit, 44 percent mining-produced SCO, and six percent *in situ*-produced SCO.[10] The results are representative of near term expected WCSB oil sands composition and GHG-intensities.

The Canadian oil sands average from NETL (2009) is also plotted on Figure 3.14.3-4 for comparison with Jacobs (2009) and TIAX (2009), although the NETL result assumes a mix of 43 percent crude bitumen and 57 percent SCO. The results show a 2 to 19 percent increase in WTW GHG emissions from gasoline produced from the weighted-average mix of oil sands crudes potentially transported in the proposed Project relative to the reference crudes in the near term. Heavier crudes generally take more energy to produce and emit more GHGs than lighter crudes, and in particular, the weighted-average WCSB oil sands crude is currently more energy- and carbon-intensive than lighter crudes like Middle Eastern Sour.

For illustrative purposes, Table 3.14.3-11 shows the incremental annual WTW GHG emissions associated with displacement of 100,000 barrels of each reference crude oil per day with WCSB oil sands crude oil using the weighted-average estimate for the mix of WCSB oil sands crudes likely to be transported in the proposed Project. The incremental GHG emissions were calculated by first multiplying the WTW GHG emission intensities per barrel of gasoline and distillates (i.e., gasoline, diesel, and kerosene/jet fuel) for WCSB and reference crudes from each study by the volume of premium fuel products produced by 100,000 barrels of WCSB oil sands crude. WTW GHG emissions from each reference crude were then subtracted from the WTW GHG emissions from the equivalent volume of WCSB oil sands crude to estimate incremental GHG emissions. We converted the 100,000 barrels of crude to an equivalent volume of gasoline and distillate products using yield data provided in each respective study. As previously noted, these incremental GHG estimates provide an example of the potential effect, on a life-cycle basis, resulting from displacement of reference crude oils in PADD III refineries; on a global scale, the decision whether or not to build the Project will not affect the extraction and combustion of WCSB oil sands crude on the global market (EnSys 2010).

[10] Of *in situ* WCSB oil sands production from SAGD and CSS facilities, CSS accounts for 47 percent of production, and SAGD accounts for 53 percent. This ratio was used to calculate an average for *in situ*-produced dilbit for TIAX, which provided separate estimates for CSS and SAGD dilbit. Primary *in situ* production of WCSB bitumen (i.e., using conventional oil production techniques) was not included since estimates were not provided in the studies included in the scope of this assessment. Primary production currently accounts for 32.9 thousand cubic meters per day, or 14 percent of total oil sands production (ERCB 2010).

TABLE 3.14.3-11
Incremental Annual GHG Emissions of Displacing 100,000 Barrels Per Day of Each Reference Crude with WCSB Oil Sands (MMTCO2e) by Study

Reference Crude	Jacobs, 2009	TIAX, 2009[a]	NETL, 2009[a]
Middle Eastern Sour	1.3	2.0	2.5
Mexican Maya	0.5	1.6	1.7
Venezuelan[b]	0.4	0.5	2.4
U.S. Average (2005)	NA	NA	2.3

Note: The incremental annual GHG emissions presented here are calculated using internally consistent comparisons for each reference crude and the weighted average WCSB oil sands crude using information from each respective each study. The incremental annual GHG emissions estimates for displacing the U.S. average (2005) reference crude is only provided for NETL (2009) because only NETL included a U.S. average reference. NA = Not Applicable.

[a] The NETL and TIAX studies allocate a portion of GHG emission to co-products other than gasoline, diesel, and jet fuel products, which are not accounted for in these estimates. As a result, incremental GHG emissions are underestimated for those studies.

[b] Venezuelan conventional crude values for NETL refer to a medium crude, not the heavy crude Venezuelan Bachaquero.

The incremental GHG emissions in Table 3.14.3-7 are compared against four different reference crude oils. To the extent that Middle Eastern Sour is the world balancing crude, as assumed as a model input in EnSys (2010), it may ultimately be the crude that is backed out of the world market by WCSB oil sands crudes. From another perspective, if the proposed Project is built and the PADD III refineries continue using about the same input mix of heavy crudes as they currently use, Venezuelan Bachaquero or Mexican Mayan are likely to be displaced by WCSB oil sand crudes. Finally, NETL (2009) estimated the GHG emissions intensity of the average barrel of crude oil refined in the United States in 2005. The Jacobs and TIAX studies are not compared to this reference crude because they did not include a U.S. average estimate.

The three studies referenced in Table 3.14.3-7 used different methods to allocate GHG emissions between premium fuels (e.g., gasoline, diesel, and jet fuel) and other co-products (e.g., light and heavy ends, petroleum coke, sulfur). Jacobs (2009) attributes all GHG emissions associated with extracting, refining, and distributing other co-products to premium fuels;[11] thus, the incremental GHG emissions shown for Jacobs (2009) in Table 3.14.3-7 take into account the production and use of these co-products.

As noted elsewhere in the EIS, the near-term initial throughput of the proposed Project is projected to be 700,000 barrels of crude per day with a potential capacity of 830,000 barrels per day.[12] Based on the results in the Jacobs study, incremental GHG emissions from the proposed project would be 9 million metric tons of CO_2 equivalent ($MMTCO_2e$) annually at the initial pipeline capacity, and 11 $MMTCO_2e$ annually at the potential capacity, if the oil sands crude oil transported by the proposed Project offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 3.7 to 4.4 $MMTCO_2e$ annually at initial and potential capacities, respectively, if oil sands crude oil offset Mexican Maya crude oil, and 3.1 to 3.7 $MMTCO_2e$ annually if Venezuela Bachaquero crude oil were offset.

Unlike the Jacobs study, the TIAX and NETL studies allocate a portion of GHG emissions to co-products other than gasoline, diesel, and jet fuel products, and these emissions are not included in the studies'

[11] Jacobs (2009) also applies a substitution credit for offsetting other products that are replaced by each of the co-products. For example, the production and use of petroleum coke is assumed to offset GHG emissions from coal-fired electricity production.

[12] It was assumed that the pipeline would be operating 365 days a year at an *initial* capacity of 700 thousand barrels per day and a *potential* capacity of 830 thousand barrels per day.

WTW GHG results. As a result, the incremental GHG emissions estimates for TIAX and NETL in Table 3.14.3-7 may underestimate total incremental GHG emissions.[13]

TIAX (2009, p. 34; Appendix D, p. 42) found that the change in refinery energy use associated with an incremental barrel output of co-products other than gasoline, diesel, and jet fuel contributed to less than one percent of energy use and GHG emissions per barrel of refined product at the refinery, so any error introduced by the underestimate of GHG emissions attributed to co-products is negligible. According to the results of the TIAX study, incremental GHG emissions would be 14 $MMTCO_2e$ at the initial project capacity and 17 $MMTCO_2e$ annually at the proposed project capacity if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil. Incremental emissions would be 11 to 13 $MMTCO_2e$ and 3 to 4 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively, at the initial and potential project capacities.

Based on the results of NETL (2009), incremental emissions would be 18 to 21 $MMTCO_2e$ annually if oil sands crude oil offset an equivalent amount of Middle Eastern Sour crude oil at the initial and potential project capacities. Incremental emissions would be 12 to 14 MMTCO2e and 17 to 20 $MMTCO_2e$ annually if oil sands crudes offset Mexican Maya and Venezuelan Bachaquero crude oil, respectively, at the initial and potential project capacities. Compared to the average barrel of crude refined in the United States in 2005, incremental emissions from oil sands crudes would be 16 to 19 $MMTCO_2e$ annually at initial and potential project capacities. The effect of allocating a portion of the life-cycle GHG emissions of refining crude oils to other, non-premium co-products was larger in the NETL study than in either of the studies by Jacobs (which did not allocate any emissions to other co-products) or TIAX (which allocated less than 1 percent of GHG emissions at the refinery to other co-products). To estimate the magnitude of this effect, the NETL results for WCSB oil sands and the 2005 U.S. average crude oils were adjusted to include other product emissions modeled in NETL's analysis. The lead NETL study author was contacted to vet the approach used to make this adjustment in order to ensure that it was made consistently with the NETL study framework (Personal communication, Timothy Skone, 2011). Adjusting the NETL results to include other product emissions could increase the differential between WCSB oil sands and the 2005 U.S. average crude oils by roughly 30 percent.

The full range of incremental GHG emissions estimated across the reference crudes and sub-set of studies is 3 to 17 $MMTCO_2e$ annually at the near term initial throughput or 4 to 21 $MMTCO_2e$ annually at the potential throughput. This overall range of 3 to 21 $MMTCO_2e$ is equivalent to annual GHG emissions from the combustion of fuels in approximately 588,000 to 4,061,000 passenger vehicles or the CO_2 emissions from combusting fuels used to provide the energy consumed by approximately 255,000 to 1,796,000 homes for one year.[14] The differentials presented here are based on life-cycle emission estimates for current or near-term conditions in the world oil market, as can be seen from the reference years used in each report. Over time, however, the GHG emission estimates for fuels derived from both WCSB oil sands crude oils and the reference crude oils are likely to change.

GHG emissions from the production phase for reference crude oils may become more energy-intensive over time due to the need to extract oil from deeper reservoirs by using more energy-intensive secondary

[13] Adjusting the TIAX and NETL GHG emission estimates to include co-products other than gasoline, diesel, and kerosene/jet fuel would require two pieces of information: (i) the GHG intensity of the other products, for both WCSB crudes and reference crudes, and (ii) the yield of the other products, for both WCSB crudes and reference crudes. TIAX (2009) and NETL (2008) do not provide explicit emissions intensity factors or product yields in a format that enables separate emissions estimates to be developed for these products. These products largely comprise the remaining fractions of the input crude that cannot be converted into premium products.

[14] Equivalencies based on EPA's GHG Equivalency calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html

and tertiary recovery techniques, such as CO_2 flood. Many of the reference crude oil reservoirs are one to two miles (or more) underground or under the ocean floor. In contrast, the WCSB oil sands deposits are much shallower and can be extracted using either surface mining or near-surface *in situ* methods. Exploration efforts for new deep oil reservoirs will continue as known reservoirs continue to deplete.

In contrast, the extent of the WCSB oil sands deposits is well understood and defined. In the future, *in situ* extraction methods are projected to represent a larger share of the overall oil sands production, increasing from about 45 percent of 2009 oil sands production to an estimated 53 percent by 2030 (ERCB 2010). In particular, the share of SAGD *in situ* extraction methods are projected to rise from roughly 15 percent in 2009 to 40 percent of oil sands production in 2030 (CERA 2010).[15] The GHG profile of this more energy-intensive oil sands extraction method may be reduced by new technologies and innovations to reuse steam onsite and/or improve thermal recovery. However, surface mining is projected to remain a dominant extraction method for WCSB crude oils for the next 20 years (CERA 2010). In consideration of these factors, GHG intensity for future reference crude oils may trend upward while the GHG intensity for WCSB oil sands derived crude oils may be relatively constant to slightly upward. If this is the case, the differential in life-cycle GHG emissions for fuels refined from these crude oils may decrease.

Conclusions

The studies show conclusively that combustion (i.e., tank-to-wheels) phase of the fuel life cycle dominates the total GHG life-cycle emissions under all scenarios. Overall, it is clear that comparisons of GHG life-cycle emission estimates for fuels derived from different sources are sensitive to the choice of boundaries, consistent application of boundary conditions within studies, and to key input parameters. In particular, the results depend on assumptions regarding the use of petroleum coke at oil sands facilities, and upon the weighted-average mix of WCSB oil sands crude transported to the United States by the proposed Project or some other transboundary pipeline. SAGD and CSS *in situ* production methods are generally more GHG-intensive than mining, and while SCO requires upgrading prior to pipeline transport, bitumen blends such as dilbit and synbit require additional refining emissions and do not produce an equivalent amount of premium fuel products per barrel input.

Despite the differences in study design and input assumptions, it is clear that WCSB crudes, as would likely be transported through the proposed Project, are on average somewhat more GHG-intensive than the crudes they would displace in the U.S. refineries. Although EnSys (2010) reported that there would be no substantive change in global GHG emissions and, as explained in Section 4.1.2, there would likely be no substantial change in WCSB imports to PADD III with or without the proposed Project in the medium to long term, the life-cycle GHG emissions associated with transportation fuels produced in U.S. refineries would increase if WCSB crude oils replace existing heavy crude oil sources for PADD III.

We also note that the GHG intensity of reference crudes may increase in the future as more of the world crude supply requires extraction by increasingly energy intensive tertiary and enhanced oil recovery techniques[16]. The energy intensity of surface mined Canadian crudes will likely be relatively constant while higher energy intensive in-situ production may increase somewhat; the proportion of in situ extraction is forecast to increase relative to the less energy-intensive surface mining. Although there is

[15] Although the balance of mining and *in situ* extraction will change in the future, there are incentives for producers to keep GHG intensity as low as possible. For example, Alberta's climate policy requires that oil sands producers and other large industrial GHG emitters reduce their emissions intensity by 12 percent from an established baseline.
[16] As with the producers of oil sands, however, in some cases producers of reference crudes are likely to face regulatory pressures or other incentives to lower the GHG intensity of their production process. Such a dynamic could counter the trend towards higher GHG intensities.

some uncertainty in the trends for both reference crude oils and oil sands derived crude oils, on balance it appears that the gap in GHG intensity may decrease over time.

Climate Change

Over the past 30 years, changes in the U.S. climate have included an increase in average temperature, an increase in the proportion of heavy precipitation events, changes in snow cover, and an increase in sea level (CCSP 2008). Climate change can exacerbate stresses on ecosystems through high temperatures, reduced water availability, and altered frequency of extreme precipitation events and severe storms (CCSP 2008). However, climate change can also ameliorate stresses on ecosystems through warmer springs, longer growing seasons and related increased productivity (CCSP 2008).

Anticipated impacts from climate change in North America applicable to the regions crossed by the proposed Project include:

- Stream temperatures are likely to increase and are likely to have effects on aquatic ecosystems and water quality;
- Proliferation of exotic grasses and increased temperatures are likely to cause in increase in fire frequency in arid lands; and
- Decreased streamflow, increased water removal, and competition from non-native species are likely to negatively affect river ecosystems in arid lands (CCSP 2008).

While there are uncertainties in the future of climate change, the response of ecosystems and the effects of management should allow ecosystem adaptations that would reduce anticipated damages or enhance beneficial responses associated with climate variability and change (CCSP 2008). Throughout development of the proposed Project, efforts to reduce overall Project-related impacts have been incorporated into the proposed Project. The proposed CMR Plan (Appendix B) includes construction procedures that would apply directly to the reduction of anticipated climate change-related induced impacts described above, including:

- Restoration of riparian habitats at stream crossings (Sections 3.3 and 3.7);
- Prevention of the spread and establishment of noxious and invasive weeds (Section 3.5);
- Prevention of the spread of aquatic invasive species (Section 3.7); and
- Limiting water withdrawal rates to less than 10 percent (or lower depending on permit requirements) of the base flow and returning water used for hydrostatic testing to the same drainage (Sections 3.3 and 3.7); and
- Avoid, minimize, and mitigate impacts to wetlands, including depressional wetlands (Section 3.4) that may decrease in abundance due to increased evaporation with increased temperature.

A variety of technologies are currently or potentially available in the oil sands sector to mitigate GHG emissions during production. The oil sands industry is exploring technologies that increase energy efficiency and reduce the industry's dependence on fossil fuel resource consumption, which in turn

decrease GHG emissions during production. Notable GHG mitigation technologies or practices currently employed include:[17]

- *In situ* extraction improvements such as improved well configuration and placement, low-pressure SAGD, flue gas reservoir re-pressurization, new artificial lift pumping technologies, use of electric submersible pumps, and overall improvements in energy efficiency which can reduce the steam to oil ratios (SOR) of *in situ* production processes (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011);
- Incorporation of solvents such as ethane, propane, or butane (in addition to heat, in the case of thermal solvent processes) to lower the viscosity of bitumen extracted using vaporized extraction (VAPEX) processes during *in situ* production (Government of Alberta 2011a, RAND 2008, Bergerson & Keith 2010, CAPP 2011);
- Expanded use of cogeneration to produce electricity and steam during the upgrading stages of oil sands production, particularly for *in situ* production (IHS CERA 2010, Bergerson & Keith 2010, CAPP 2011); and
- Use of lower-temperature water to separate bitumen from sand during extraction to reduce the energy required (CAPP 2011).

Emerging technologies that would reduce the use of fossil fuel energy resources (and therefore GHG emissions), but that are not yet widely employed in the oil sands include:

- Steam solvent processes, which use solvents to reduce the steam required for bitumen extraction. Steam solvent processes include solvent-assisted processes (SAP), expanding solvent steam-assisted gravity drainage (ES-SAGD), and liquid addition to steam for enhanced recovery (LASER) (Government of Alberta 2011a, Bergerson & Keith 2010, IEA 2010, CAPP 2011);
- Additional *in situ* bitumen production technologies include *in situ* combustion, where the heavy portion of petroleum is combusted underground (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011), and electrothermal extraction, where electrodes are used to heat the bitumen in the reservoir (Government of Alberta 2011a, Bergerson & Keith 2010, CAPP 2011);[18]
- Use of natural gas or bio-based fuels such as biodiesel or bioethanol in mine and tracking fleets and equipment (Pembina 2006, Bergerson & Keith 2010);
- —Bio-upgrading", a future upgrading technology in development that includes the use of microbes to remove sulfur compounds and impurities (Pembina 2006);
- Use of offgas processing from oil sands facilities through the extraction of natural gas liquids and olefins to provide pipeline-specification natural gas. The net result is fewer overall emissions because the offgas is used as petrochemical feedstock rather than combusted (Government of Alberta 2011a);

[17] The degree to which the GHG emission estimates from LCA studies reviewed in the —Indirect Cumulative Impacts and Life-Cycle Greenhouse Gas Emissions" section incorporated these technologies varies based on the timeframe and facility-level data used to inform the estimates. None of the studies evaluated solvent-based *in situ* extraction methods. Jacobs (2009), TIAX (2009), and IHS CERA (2010) evaluated the effect of cogeneration systems and electricity export on life-cycle GHG emissions.

[18] Keith and Bergerson (2010, p. 6011) note that the GHG emissions from these technologies may depend upon their implementation. For instance, electrothermal *in situ* extraction may reduce GHG emissions if coupled with a source of low-GHG intensity electricity.

- Carbon capture and storage (CCS) technologies to store CO_2 produced from point sources. CCS technologies have existed for years and are currently being employed in the conventional oil and natural gas sectors. The oil sands sector has an opportunity, bolstered by significant Alberta government funding, to employ a variety of CO_2 capture technologies available including pre-combustion, post-combustion, and oxy-fuel systems in order to significantly reduce life-cycle GHG emissions from WSCB oil sands derived crude (Pembina 2006, Bergerson & Keith 2010, RAND 2008, Royal Society of Canada 2010, CAPP 2011);
- Similarly, CO_2 could be sequestered by injecting the gas into oil sands tailings, which has the co-benefit of improving settling rates. A version of this technology is expected to be commercially available in the next three to four years (Royal Society of Canada 2010); and
- Use of Metal Organic Frameworks (MOFs), which could be used to separate CO_2 from low concentration gaseous mixtures like flue gas. MOFs have the potential to absorb CO_2 effectively while requiring less energy to regenerate than other sorbent materials (CAPP 2011).

The Government of Alberta has worked to mitigate the GHG emissions associated with oil sands production through three main policy initiatives. First, the Climate Change and Emissions Management Act, enacted in 2003, establishes mandatory annual GHG intensity reduction targets for large industrial GHG emitters (Government of Alberta 2009a). Those emitters that fall short can either purchase credits from other companies that have reduced their emissions, or pay $15 for every metric ton of CO_2e above their target into a government-run clean energy technology fund (Government of Alberta 2010). Second, the Government of Alberta has dedicated $2 billion to fund four large-scale CCS projects. Of these four projects, two involve oil sands producers. These two projects are together expected to reduce 15.2 million metric tons of CO_2e per year beginning in 2015 (Government of Alberta 2011b). Third, the funds collected as part of the Climate Change and Emissions Management Act are placed in the Climate Change and Emissions Management Fund, which is dedicated to investing in clean energy projects (Government of Alberta 2011c). Several projects selected for funding in 2010 focus on energy efficiency improvements and cleaner energy production at oil sands production facilities (CCEMC 2010a, 2010b).

Other GHG mitigation policy proposals could establish some form of broad fiscal or regulatory national GHG reduction policy that would incentivize or regulate lower GHG emissions from oil sands operations and other sectors of the economy. MK Jaccard and Associates (2009) analyzed the cost and feasibility of meeting a target of a 20 percent reduction from 2006 levels by 2020, and a more aggressive target of a 25 percent reduction from 1990 levels by 2020 though a cap and trade or carbon tax system.[19] For both targets the largest reductions came from petroleum extraction (including, but not limited to the oil sands), accounting for roughly 10 to 20 percent of total reductions of the 20% reduction policy and 25% reduction policy, respectively. Under the 20% reduction policy target, the analysis found that 57 percent of the hydrogen produced for synthetic oil would be made using CCS, while 4 percent of the steam and process heat for oil sands extraction would be made using CCS by 2020. Under the 25% reduction policy target, the shares of each produced using CCS increased to 88 and 50 percent, respectively.[20]

[19] The study examined a policy package that would achieve each target by establishing a CO_2 emissions price and implementing other complementary measures. The 20% reduction policy had a target price that started at $40 per metric ton of CO_2 in 2011, increasing to $100 per metric ton in 2020. The 25% reduction policy had a target price that started at $50 and increased to $200 per metric ton CO_2 in 2020.

[20] The 25% reduction policy required CCS at all new sources of formation CO_2 from natural gas processors, process CO_2 from hydrogen plants, and combustion CO_2 from coal-fired power plants, oil sands facilities, and upgraders starting in 2016.

The potential impacts of climate change would not be expected to affect the proposed Project. An increase in temperatures may increase wildfires in the proposed Project area. Any increased intensity of storm events could result in additional flooding in some areas near the proposed Project within the Gulf Coast Segment and Houston Lateral, particularly if hurricane activity increases as a result of oceanic temperature conditions. The proposed Project would be designed and constructed to be consistent with applicable federal, state, and local standards, and therefore should be resistant to forces associated with reasonably likely climate conditions during the lifetime of the pipeline system. Other effects of climate change, such as air quality degradation, health effects, reduced snow pack, and disruption to agricultural production, would not likely impact the proposed Project.

3.14.4 Extraterritorial Concerns

While the proposed Project analyzed in this EIS begins at the international boundary where the pipeline would exit Saskatchewan, Canada and enter the United States through Montana, the origination point of the pipeline system would be in Alberta, Canada. Neither NEPA nor DOS regulations (22 CFR 161.12) nor Executive Orders 13337 and 12114 (Environmental Effects Abroad of Major Federal Actions) legally require that this EIS include an analysis of the environment or activities outside of the United States. As a matter of policy, and in response to concerns that the proposed Project would contribute to certain continental scale environmental impacts, DOS has included a summary of information regarding environmental analyses and regulations related to the Canadian portion of the proposed Keystone XL Project and WCSB oil sands production. This section addresses (1) the Canadian National Energy Board (NEB) environmental analysis of the Keystone XL Project in Canada, (2) the potential influence of the proposed Project on oil sands development in Canada, (3) a summary of environmental impacts of oil sands development in Alberta, and (4) protections for Canadian and U.S. shared Migratory Bird and Threatened and Endangered Species resources.

3.14.4.1 Canadian National Energy Board Environmental Analysis of the Keystone XL Project

The analysis of the environmental effects of the overall proposed Keystone XL Project has been in progress on both sides of the international border under appropriate regulatory authorities, as discussed in Section 1.4 and Appendix R. In Canada, the Canadian National Energy Board (NEB) conducted that analysis, held public hearings in September 2009, and issued its findings in March 2010.

The NEB identified the nine key issues listed below relative to the proposed Keystone XL Project:

- The need for the proposed facilities;
- The economic feasibility of the proposed facilities;
- The potential commercial impacts of the proposed project;
- The potential environmental and socio-economic effects of the proposed facilities, including those to be considered under the Canadian Environmental Assessment Act (CEA) (presented in Appendix R);
- The appropriateness of the general route of the pipeline;
- The method of toll and tariff regulation;
- The suitability of the design of the proposed facilities;
- The terms and conditions to be included in any approval the NEB may issue; and
- Potential impacts of the project on aboriginal interests.

Relative to impacts to aboriginal or indigenous peoples, the NEB granted intervener status to the following aboriginal groups in Canada:

- Moosomin First Nation;
- Neekaneet First Nation No. 380;
- Red Pheasant Band No. 108; and
- Sweetgrass First Nation.

In the March 2010 finding, the NEB determined that the proposed Keystone XL Project is required in Canada to meet the present and future public convenience and necessity, provided that the NEB terms and conditions presented in the project certificate are met, including all commitments made by Keystone during the hearing process. Pertinent NEB documents are provided in Appendix R.

3.14.4.2 Influence of the Proposed Project on Oil Sands Development in Canada

Based on the findings of EnSys (2010), DOS has concluded that even if the proposed action does not proceed, production from the oil sands in Canada would likely continue at a similar rate. As reported by EnSys (2010):

> "Production levels of oil sands crudes would not be affected by whether or not KXL was built. WCSB production would only be impacted (relative to the CAPP 2010 projection used in the study) if there were no further pipeline expansion out of WCSB and within the USA beyond projects currently under construction. Even then, because of existing available line capacity, oil sands production would not begin to be curtailed until after 2020. Versus the base projections, WCSB production would be curtailed by approximately 0.8 mbd by 2030. Since, to occur, such a scenario would have to entail no expansion of (a) pipelines entirely within Canada that could take WCSB crudes from Alberta to the British Columbia coast, (b) existing cross-border lines from WCSB to the U.S., (c) existing internal domestic U.S. pipelines that could take WCSB crudes to market within the U.S. - and to eastern Canada and (d) alternative proven transport modes, namely rail possibly supported by barge, the scenario is considered unlikely."

In addition to the existing transport capacity into the United States, there would likely be market demand to put in place pipeline capacity into the United States similar to that of the proposed Project, including pipeline capacity to PADD III. Also Canadian producers are actively seeking to develop alternative crude oil markets worldwide, including efforts to develop necessary transportation facilities to allow shipment of WCSB crude oil to British Columbia and onward to Asia, or eastward to Atlantic coast ports for marine shipment will continue. Other countries that would likely represent markets for WCSB crude oil are primarily located in Asia; those nations are experiencing increased demand for crude oil and are currently heavily dependent on OPEC for their supplies. In recent years, Chinese investment in WCSB crude oil production has greatly accelerated. Various pipeline projects have been proposed to transport crude oil from Alberta to the Canadian west coast, although they face significant opposition in the regulatory process (see Section 4.1).

3.14.4.3 Environmental Effects of Oil Sands Development in Alberta

Many commenters on the draft EIS and supplemental draft EIS expressed concerns about impacts in western Canada related to the extraction of crude oil from oil sand deposits in the provinces of Alberta and Saskatchewan, Canada. Additionally, there has been much controversy over environmental impacts to wildlife, boreal forests, threatened and endangered species, and water resources related to oil sands

production. Evaluation of impacts from extraction of crude oil from the oil sands is outside of the scope of analysis legally required under NEPA. Further, it is not expected that the proposed Project would have any impact on the rate of development of extraction in Canada. However, in response to comments and as a policy decision, a summary of general regulatory oversight and environmental impacts in Canada related to oil sands production has been included.

Government regulators of oil sands activities in Canada are working to manage and provide regional standards for air quality, land impact, and water quality and consumption based on a cumulative effects approach. Oil sands environmental regulations are administered by federal and provincial governments including the Ministry of the Environment, the Canadian Environmental Assessment Agency (which administers the Canadian Environmental Assessment Act), the Alberta Department of Environment, and the Alberta Department of Sustainable Resource Development. Oil sands deposits are located primarily in Alberta, but also extend into Saskatchewan. The Canadian Government and the Government of Alberta have a cooperative agreement to minimize regulatory overlap (the Canada-Alberta Agreement for Environmental Assessment Cooperation). Oil Sands development projects undergo an environmental review under Alberta's Environmental Protection and Enhancement Act (EPEA) and the Water Act, as well as the CEA and the Species at Risk Act (SARA). Other federal and provincial agencies may participate in the review as Responsible Authorities or as Federal Authorities with specialist advice.

In early April 2011, the Government of Alberta announced that it had prepared a draft development plan for the Lower Athabascan oil sands region. The plan would require cancellation of about 10 oil sands leases, set aside nearly 20,000 square kilometers (7,700 square miles) for conservation, and set new environmental standards for the region in an effort to protect sensitive habitat, wildlife, and forest land. The draft plan will be reviewed for 60 days and a final draft of legislation is planned to be submitted to the Cabinet in 90 days (The Globe and Mail 2011).

Bitumen, a heavy oil extract, is recovered from oil sands by either *in situ* (in place) recovery or surface mining. Most (80 percent) bitumen is recovered using in situ techniques which use SAGD to pump steam underground through a horizontal well to liquefy the bitumen, which is recovered by an extraction well. *In situ* recovery is less disturbing to the land surface than surface mining and does not require tailings ponds. Oil sands underlie 140,200 km^2 (54,132 mi^2) in three areas of northeast Alberta of which 602 km^2 (232 mi^2) has been disturbed by surface mining activity. Surface mining requires an open pit, similar to many coal, iron ore, copper and diamond mines. Mined oil sands are then transported to a cleaning facility where they are mixed with hot water to separate the oil from the sand. There were 91 active oil sands projects in Alberta as of June 2010, four of which are mining projects (Government of Alberta 2010).

The human footprint within Alberta's boreal forest natural region includes: 12 percent agriculture, 3 percent forestry, 2 percent energy, and 1 percent transportation infrastructure, leaving 82 percent of the region with no human footprint (Alberta Biodiversity Monitoring Institute 2009). The human footprint within the Alberta-Pacific Forest Industries Forest Management Agreement Area (Al-Pac FMA), a 57,331 km^2 area centered on the Athabasca oil sand deposit, includes: 4 percent forestry, 2 percent energy, and 1 percent transportation infrastructure, leaving 93 percent with no footprint (ABMI 2009). Cumulative impacts from oil sands development include GHG emissions and land surface alteration. Land surface alteration includes mine sites, tailings ponds, well sites, industrial roads, pipelines, power lines, seismic cut lines, and facilities. Biodiversity indicators evaluate ecosystem intactness or the proportion of human disturbance by assessing when common species become rare or disappear and when weedy or invasive species become common. Intactness indices for the Al-Pac FMA indicate:

- Intactness for 12 old-forest birds ranged from 96 to 100 percent with 7 of 12 old-forest birds less abundant than expected;
- Intactness for 11 winter-active mammals ranged from 89 to 100 percent with 3 of 11 winter-active mammals less abundant than expected;
- Percent occurrence of 16 non-native weeds ranged from 2 to 28 percent with non-native weeds detected across 39 percent of the Al-Pac FMA;
- For 4 of 17 species at risk that were evaluated, intactness was 97 or 98 percent, and 3 of the 4 species were less abundant than expected (the monitoring system is not designed to evaluate the other 13 species at risk);
- Intactness for four old-forest habitats ranged from 91 to 95 percent and for all old-forest habitats was 92 percent; and
- Intactness for live trees was 97 percent, for snags (standing deadwood) was 95 percent, and for downed deadwood was 98 percent (AMBI 2009).

The following cumulative statistics related to environmental effects from oil sands development in Alberta are derived from the records of the province of Alberta (Government of Alberta 2010):

- Alberta's oil sands account for about 5 percent of Canada's overall GHG emissions and Canada is responsible for about 2 percent of global emissions;
- Oil sands mining projects have reduced GHG emissions intensity by an average of 39 percent between 1990 and 2008 and are working toward further reductions;
- All existing and approved oil sands project may withdraw no more than 3 percent of the average annual flow of the Athabasca River (2008 usage was 0.7 percent of the long-term average annual flow);
- Water use by oil sands mining operations continues to decrease, despite significant increases in production;
- Many *in situ* projects recycle up to 90 percent of the water used in their operations, and use deep-well saline water as an alternative to freshwater wherever possible;
- Long-term air quality monitoring since 1995 shows improved or no change in CO, ozone, fine particulate matter, and SO_2, and an increasing trend in NO_2;
- Air quality in the oil sands region is rated good 95 percent of the time;
- Tailings (water, fine silts, left-over bitumen, salts and soluble organic compounds) ponds are constructed with groundwater seepage-capture facilities, and are closely monitored;
- Tailings settling ponds are designed and located after environmental review and bird deterrents are used to prevent birds from landing on tailings ponds;
- Currently, processing 1 tonne (1.1 tons) of oil sand produces about 94 liters (25 gallons) of tailings;
- About 602 km^2 (232 mi^2) have been disturbed by oil sands mining activity of which 67 km^2 (26 mi^2) has been or is in the process of reclamation (mine operators must provide a reclamation security bond);

- Alberta's boreal forest covers 381,000 km^2 (147,100 mi^2) of which the maximum area available for oil sands mining is 4,800 km^2 (1,854 mi^2) or about 1.25 percent of Alberta's boreal forest area;
- Alberta has committed to a cumulative effects approach that looks at potential impacts of all projects within a region; and
- The Alberta Land Stewardship Act supports the Land-use Framework, which includes province-wide strategies for establishing monitoring systems, promoting efficient use of lands, reducing impact of human activities and including aboriginal people in land-use planning.

3.14.4.4 Protections for Shared Migratory Bird and Threatened and Endangered Species Resources

Oil sands projects and oil transportation pipelines are evaluated and permitted by Canadian federal and provincial Canadian governments. Canada's version of the U.S. Migratory Bird Treaty Act (MBTA) is called the Migratory Bird Convention Act (MBCA). Both the U.S. and Canadian acts are based on the Migratory Birds Convention treaty signed in 1916 by the U.S. and the United Kingdom (on behalf of Canada). The Canadian Wildlife Service handles wildlife matters that are the responsibility of the Canadian federal government. Canadian regulations supporting the MBCA are available at http://laws.justice.gc.ca/en/M-7.01/C.R.C.-c.1036/. In addition Canada's rare and endangered migratory birds are protected under the Species at Risk Act (see http://www.sararegistry.gc.ca/the_act/html). Canadian protections for migratory birds are parallel to U.S. migratory bird protections. Canada also provides for protection of migratory bird habitat within government-recognized sanctuaries. Recent losses of migratory birds at WCSB oil sands tailings ponds have been cited as violations of the MBCA and have been prosecuted by the Canadian government.

Bird resources (waterfowl, waterbirds, shorebirds, landbirds) are shared on a continental scale. The Tri-National North American Bird Conservation Initiative Committee was established to increase cooperation and effectiveness of bird conservation efforts among Canada, the United States, and Mexico. Partnership-based bird conservation initiatives have produced national and international conservation plans for birds that include species status assessments, population goals, habitat conservation threats, issues and objectives, and monitoring needs. Multi-National North American bird conservation plans include the North American Waterfowl Management Plan, North American Landbird Conservation Plan, United States and Canadian Shorebird Conservation Plans, Waterbird Conservation for the Americas, North American Grouse Management Strategy, and Northern Bobwhite Conservation Initiative. At the request of DOS, Keystone provided a synopsis of the TransCanada Corporation's participation in North American migratory bird conservation efforts (see Section 3.14.3.6).

The Partners in Flight conservation assessment concluded that nearly half of native landbirds in Canada, Mexico, and the U.S. depend on habitats in at least two of the countries and more than 200 species (more than 80 percent of all individual landbirds) use habitats in all three countries in at least one season (Berlanga et al. 2010). The landbird assessment identified 148 bird species in need of immediate conservation attention because of highly threatened and declining populations. The most imperiled species include: 44 species with very limited distribution, mostly in Mexico, that are at greatest risk of extinction; 80 tropical residents dependent on deciduous, highland and evergreen forests in Mexico; and 24 species that breed in temperate-zone forests, grasslands, and aridland habitats (Berlanga et al. 2010). Steep declines in 42 common bird species have occurred over the past 40 years with the majority of steeply declining species breeding in the northern United States and southern Canada, and wintering in the southern United States and Mexico (Berlanga et al. 2010). Declining bird populations face a diversity of threats on breeding grounds from land-use policies and practices related to agriculture, livestock grazing, urbanization, energy development, and logging (Berlanga et al. 2010). Migratory species are

threatened on their wintering grounds by loss of grasslands in northern Mexico and tropical forests in southern Mexico (Berlanga et al. 2010).

As discussed in Section 3.14.4.3, oil sands development alters habitats through land surface alteration including: mine sites, tailings ponds, well sites, industrial roads, pipelines, powerlines, seismic cut lines, and facilities. These land alterations reduce the both the amount and the suitability of adjacent habitat available for migratory birds. Project components such as roads and powerlines increase migratory bird collision mortality. Tailings ponds contain residual bitumen and are an exposure risk especially for migratory waterbirds. Alberta's oil sands lease areas cover about 21 percent of the 418,325 mi^2 Boreal Taiga Plains Bird Conservation Region (Government. of Alberta – Energy 2010, U.S. NABCI Committee 2000). One hundred seventy migratory birds (49 waterbirds, 121 landbirds) have been recorded on 19 breeding bird survey routes concentrated within the southern portions of the leased area (Sauer et al. 2011, Government of Alberta – Energy 2010). Population trends for 9 of these 49 waterbirds and 29 of these 121 landbirds experienced significant declines within the Boreal Taiga Plains Region from 1999 to 2009; while nearly 70 percent of these birds showed no significant population trends (Sauer et al. 2010). Waterbirds and landbirds of moderate to high conservation concern present in the oil sands lease area based on the breeding bird survey data are listed in Table 3.14.4-1 (Kushlan et al. 2002, Berlanga et al 2010, Brown et al. 2001, Sauer et al. 2011).

TABLE 3.14.4-1
Waterbirds and Landbirds of Conservation Concern Present in Alberta's Oil Sands Lease Areas

Common Name	Species Name	1999-2009 Trend	Relative Abundance	Average Birds/ Route
Waterbirds				
Eared Grebe	*Podiceps nigricollis*	NS +	4.0	0.93
Western/Clark's Grebe	*Aechmophorus spp.*	NS +	0.2	1.42
American White Pelican	*Pelecanus erythrorhynchos*	NS +	6.4	1.88
Brack-crowned Night-heron	*Nycticorax nycticorax*	UK	UK	0.17
Killdeer	*Charadrius vociferus*	-3.3	5.0	2.95
American Avocet	*Recurvirostra americana*	NS +	0.4	0.44
Greater Yellowlegs	*Tringa melanoleuca*	NS -	0.1	0.45
Lesser Yellowlegs	*Tringa flavipes*	-5.4	1.1	0.84
Solitary Sandpiper	*Tringa solitaria*	NS +	0.1	1.10
Willet	*Catoptrophorus semipalmatu*	NS -	0.2	0.91
Upland Sandpiper	*Bartramia longicauda*	NS +	0.1	0.17
Marbled Godwit	*Limosa fedoa*	NS +	0.5	0.81
Common Snipe	*Gallinago gallinago*	NS +	15.3	4.86
Wilson's Phalarope	*Phalaropus tricolor*	NS -	0.3	0.70
Franklin's Gull	*Larus pipixcan*	-6.0	UK	34.51
California Gull	*Larus californicus*	NS -	11.7	1.77
Forster's Tern	*Sterna forteri*	NS +	0.3	0.25
Black Tern	*Chlidonias niger*	-1.6	11.1	8.16

TABLE 3.14.4-1
Waterbirds and Landbirds of Conservation Concern Present in Alberta's Oil Sands Lease Areas

Common Name	Species Name	1999-2009 Trend	Relative Abundance	Average Birds/ Route
Landbirds				
Olive-sided Flycatcher	*Contopus cooperi*	-2.8	0.9	0.53
Sprague's Pipit	*Anthus spragueii*	NS +	0.9	0.59
Canada Warbler	*Wilsonia canadensis*	NS +	0.5	3.93
Chestnut-collared Longspur	*Calcarius ornatus*	UK	UK	0.07

Source: Government of Alberta 2010, Sauer et al. 2011, Kushlan et al. 2002, Berlanga et al. 2010, Brown et al. 2001

1999 – 2009 Population Trends in the Boreal Taiga Plains Bird Conservation Region: NS + = non-significant positive, NS - = non-significant negative, UK = unknown, numeric values are significant trends.

Numeric scale rating for relative abundance within the Boreal Taiga Plains 0 = least abundant

Average number of birds recorded for the 19 routes within the lease area

Oil sand operations are required to have plans to minimize their effects on wildlife and biodiversity and Alberta's government monitors and verifies that industry adheres to these plans. Alberta's Biodiversity Monitoring Institute collects data and reports on thousands of species, habitats, and human footprint activities for evaluating changes to achieve responsible environmental management in the oil sands area. Techniques used to minimize impacts to migratory birds include: restricting industrial activity during nesting; maintaining the integrity of large river corridors for migration staging; reclaiming land in key habitat areas; deterring birds from industrial areas; reducing industrial footprints and use of low impact technology for seismic exploration; constructing nesting sites to replace lost natural sites (Government of Alberta 2011).

Neither Section 7 of the ESA nor the Section 7 consultation and analysis process under ESA implementing regulations address species outside the borders of the U.S. and nothing in the language of Section 7 indicate that it would apply extraterritorially. Shared species currently covered by both the ESA and the Canadian SARA that could potentially occur within the U.S. and Canadian portions of the proposed Keystone XL Project are listed in Table 3.14.4-2.

Conservation measures developed to reduce impacts to these species for the proposed Project are described in Section 3.8 and the BA, provided in Appendix T. Two U.S. candidate species occurring in Montana and South Dakota are not yet eligible for protection under the ESA but are protected under Canada's SARA (Table 3.14.4-1); and the swift fox is listed as threatened in Canada. Required mitigation, including seasonal restrictions, to minimize impacts of the proposed Keystone XL Project to SARA-protected species is available in Appendix R of the EIS.

TABLE 3.14.4-2
Endangered Species Act (U.S.) and Species at Risk Act (Canada) Species That Occur in Both the U.S. and Canadian Regions of the Proposed Keystone XL Project

Common Name	Scientific Name	Status U.S./Status Canada	Preliminary Findings (U.S.)	Evaluation (Canada)
Mountain Plover	*Charadrius montanus*	Proposed / Endangered	NLAA	NS
Piping Plover	*Charadrius melodus*	Threatened / Endangered	NLAA	NS
Whooping Crane	*Grus americana*	Endangered / Endangered	NLAA	Not Evaluated
Greater Sage Grouse	*Centrocercus urophasianus*	Candidate / Endangered	NA	NS
Sprague's Pipit	*Antus spragueii*	Candidate / Threatened	NA	NS

NLAA = may affect, not likely to adversely affect species
NA = not applicable
NS = effects not significant

3.14.5 Summary of Cumulative Impacts

The proposed Project area includes numerous existing, under construction, and planned linear energy transportation systems, including natural gas pipelines, crude oil pipelines, and electric transmission lines. Additionally, the proposed Project area supports a major water delivery project and a number of energy development projects, including wind power facilities. In some cases, these existing facilities either transect or are located within the proposed Project corridor. Additional oil and natural gas pipelines and electricity transmission lines are proposed or are known to be in the planning or permitting stage and may cross the proposed Project corridor. It is also reasonably foreseeable that additional linear facilities would be considered in the future given the national focus on the reconfiguration of the electrical grid system to access stranded renewable energy resources, particularly with regard to wind power in the central plains region. Construction and operation of the proposed Project would result in additional environmental impacts to those associated with these existing and future projects, although the majority of these would be localized and short-term. Short-term construction impacts could be additive to other proposed construction projects depending on the actual construction timing of individual projects, although at this time, proposed construction schedules would not coincide in the proposed Project corridor. The overall contribution of cumulative impacts associated with existing and future facilities is considered minor. In addition, long-term cumulative economic benefits would be realized in communities that receive tax revenues from the proposed Project and other projects in the area.

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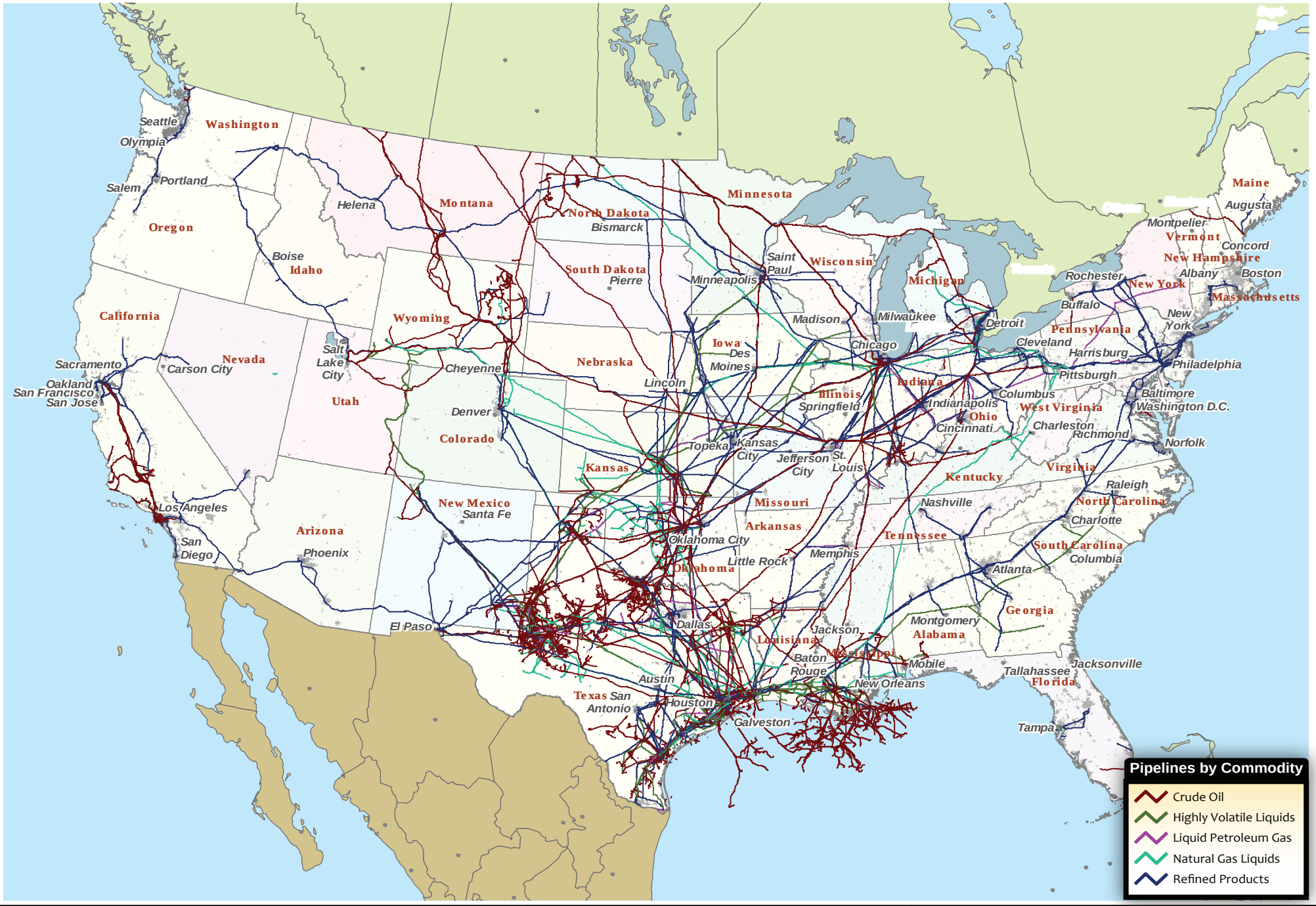
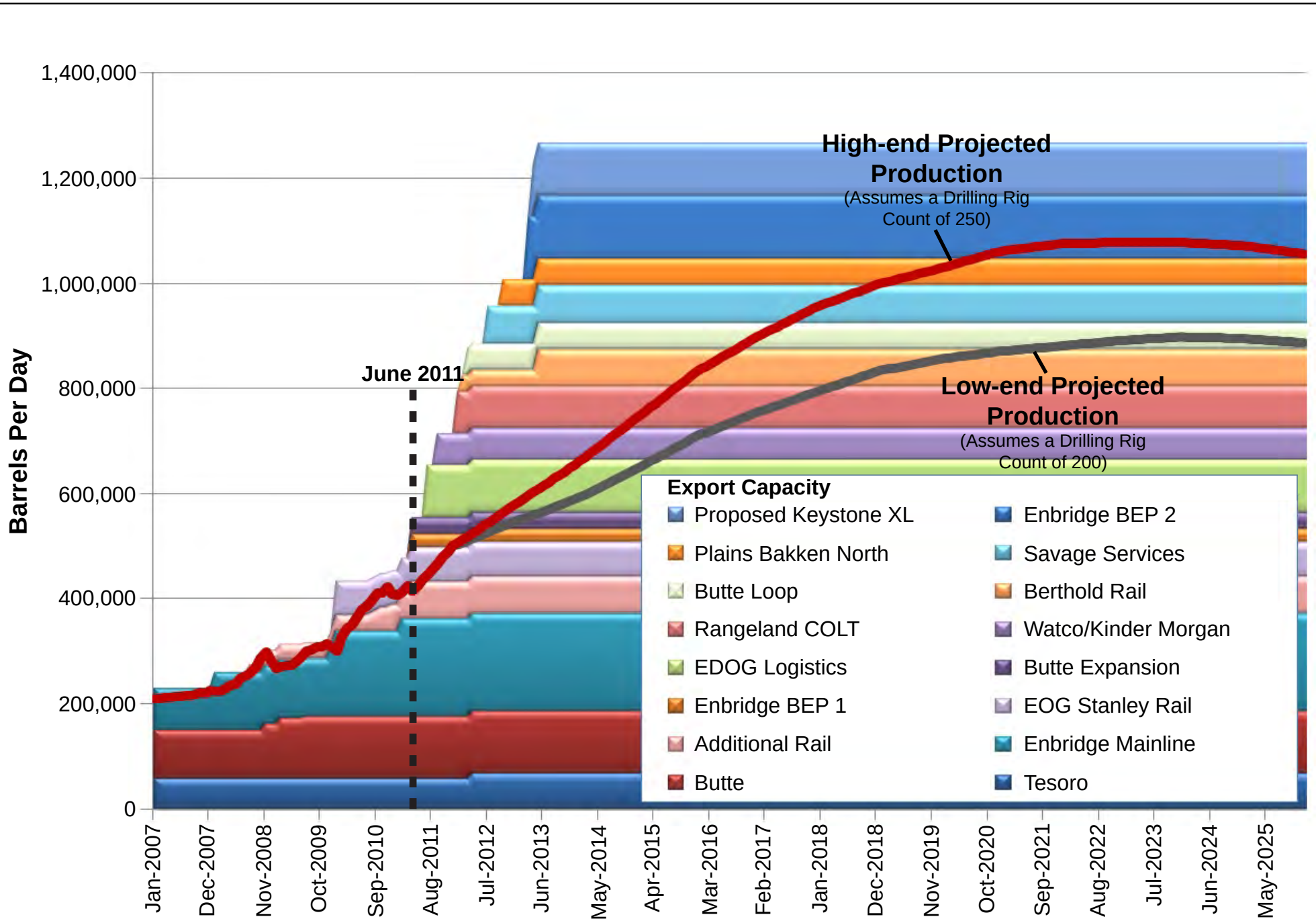


Data Source: Rextag Strategies.

KEYSTONE XL PROJECT

Figure 3.14.2-1

Existing Oil and Gas
Pipeline Systems of the U.S.



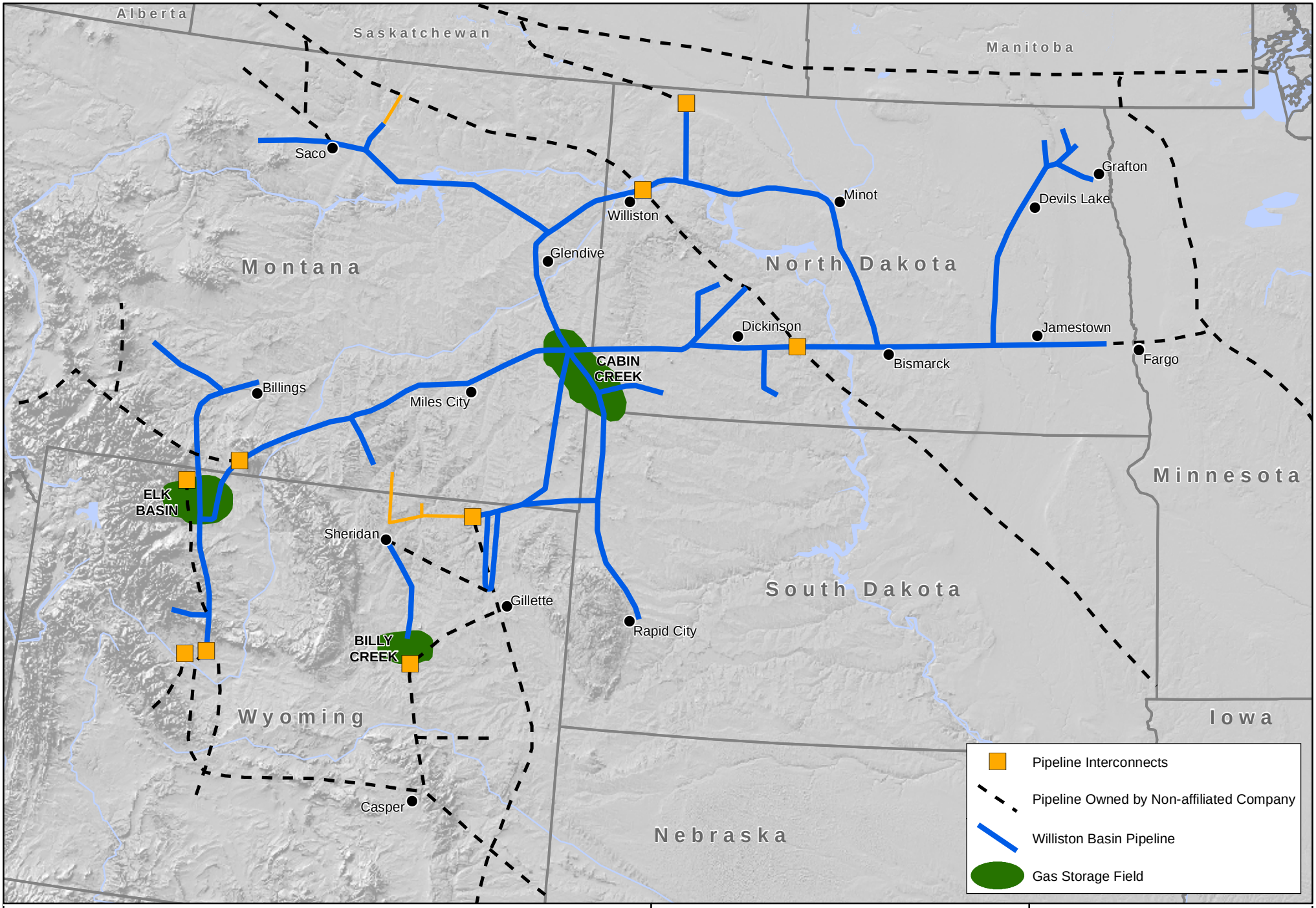
Production forecast is for visual demonstration purposes only and should not be considered accurate for near or long term planning.

Source: https://www.dmr.nd.gov/pipeline/assets/07142011/NDPA%20IOGCC%206-28-2011.pdf

KEYSTONE XL PROJECT

Figure 3.14.2-2

Williston Basin Oil Production and Export Capacity, BOPD

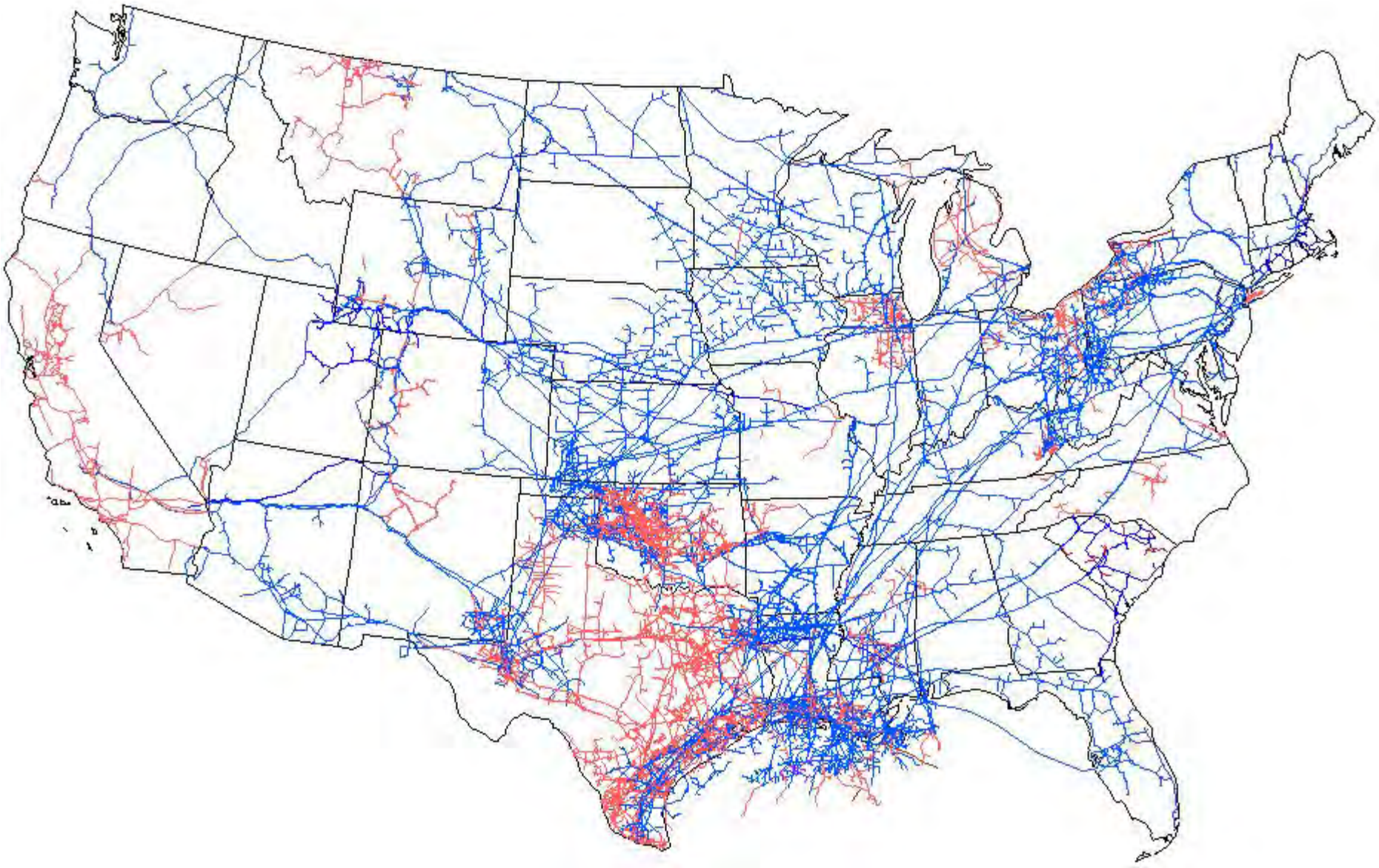


Data Source: http://www.wbip.com/wbip/contributed_images/WBI-Map.gif

KEYSTONE XL PROJECT

Figure 3.14.2-3

Williston Basin Pipeline



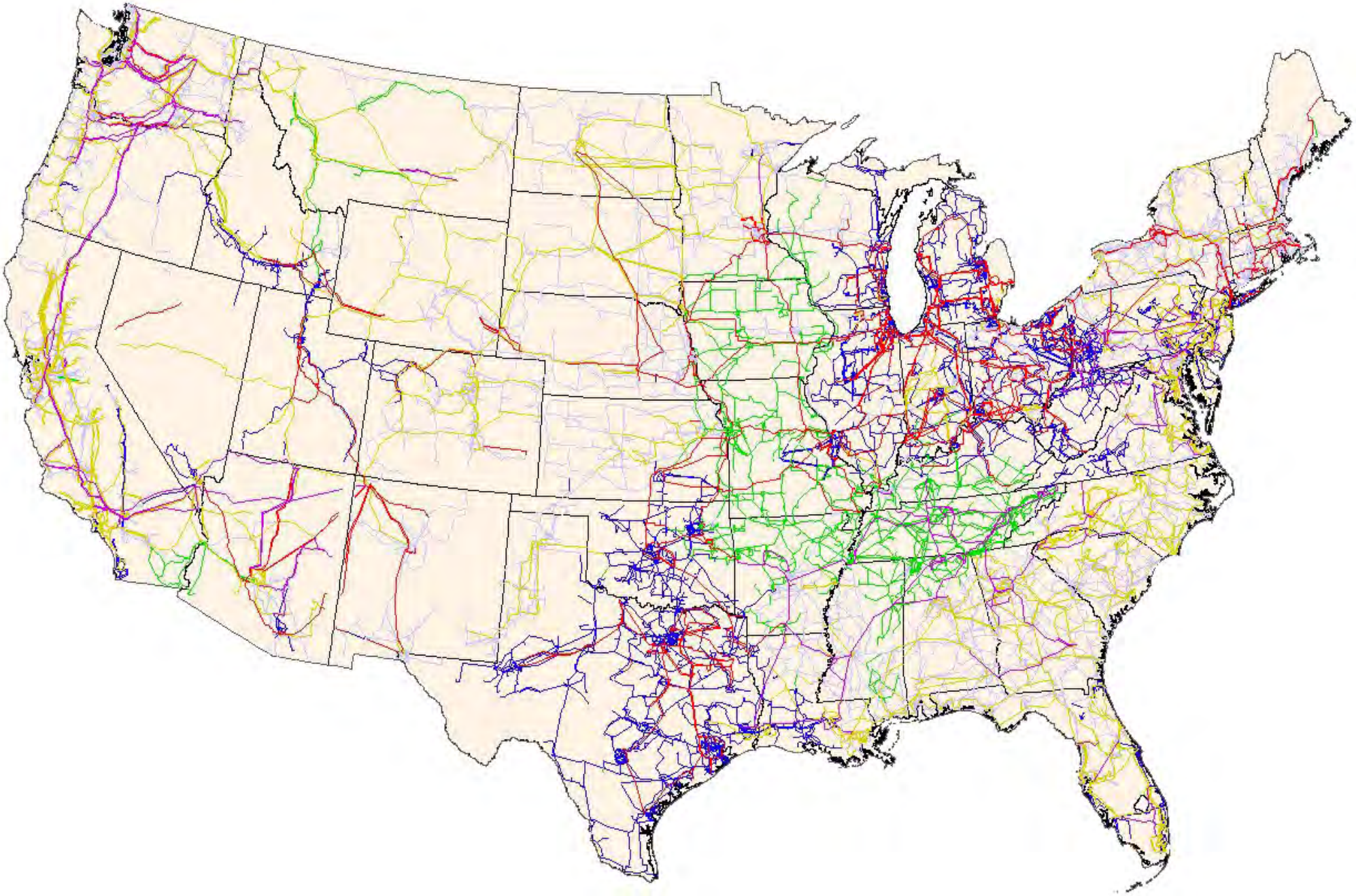
Interstate Pipeline
Intrastate Pipeline

Data Source: EIA, 2009. Obtained at http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html

KEYSTONE XL PROJECT

Figure 3.14.2-4

The U.S. Natural Gas Pipeline Network

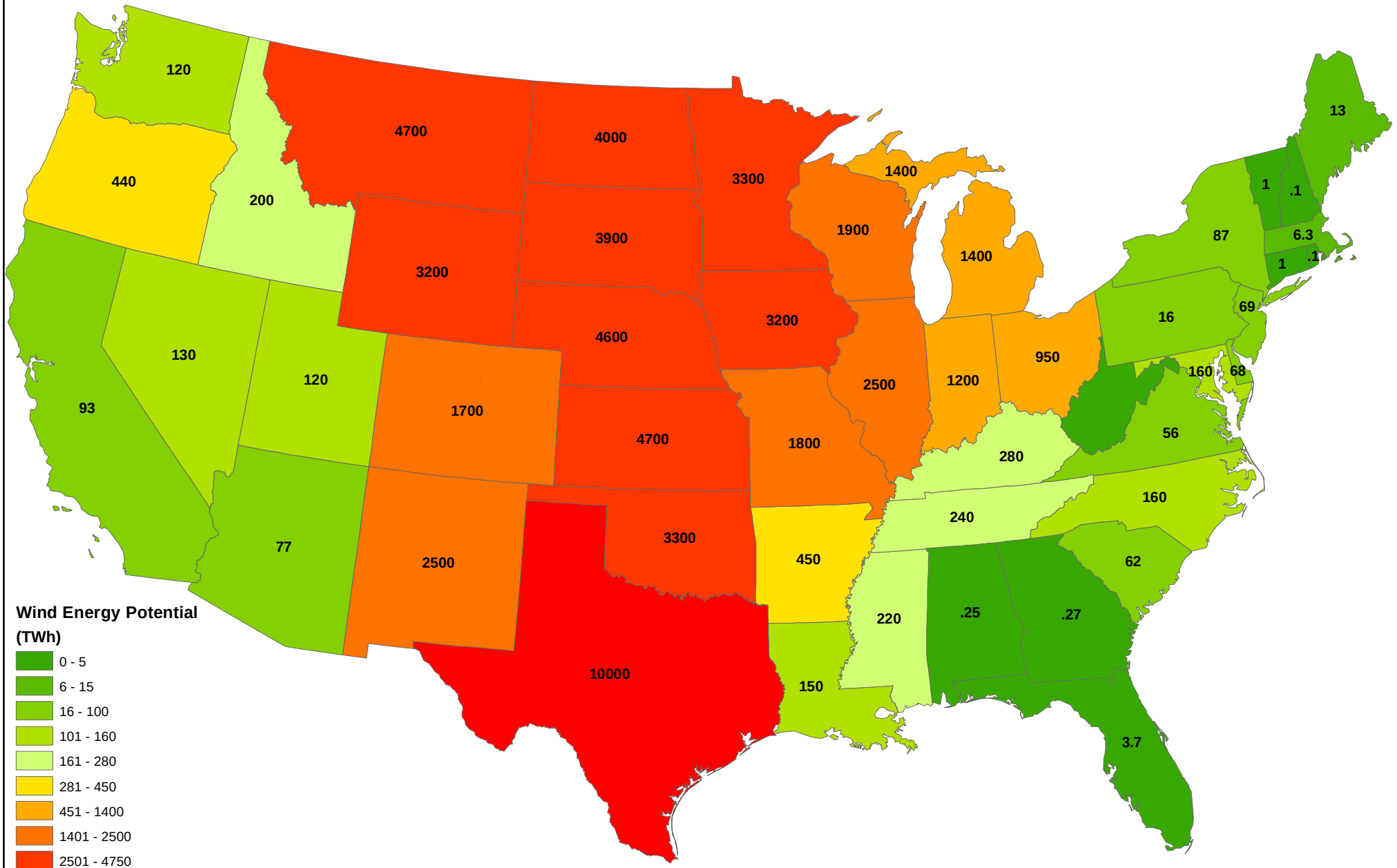


kV
115
138
161
230
345
500

Data Source: FEMA. Obtained at http://upload.wikimedia.org/wikipedia/commons/d/d4/UnitedStatesPowerGrid.jpg

KEYSTONE XL PROJECT

Figure 3.14.2-5
The U.S. Electrical Power Transmission Grid



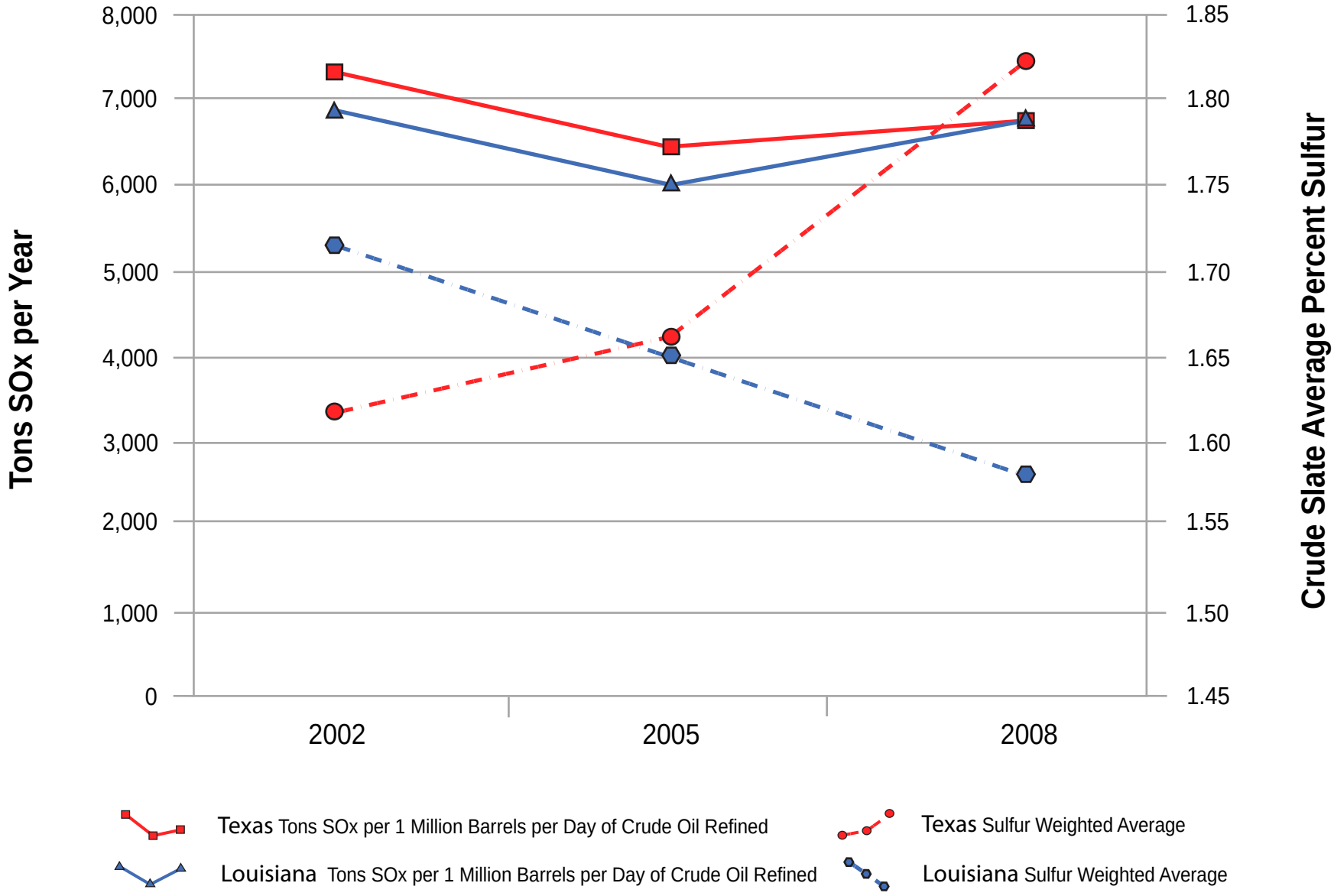
Annual onshore wind energy potential on a state-by-state basis for the contiguous U.S. expressed in TWh and as a ratio with respect to retail sales in the states (2006)

Data Source: Lu, X., McElroy, M. B. and Kiviluoma, J. 2009. Global potential for wind-generated electricity. PNAS July 7, 2009 vol. 106 no. 27 10933-10938.

KEYSTONE XL PROJECT

Figure 3.14.2-6

Annual Onshore Wind Energy Potential

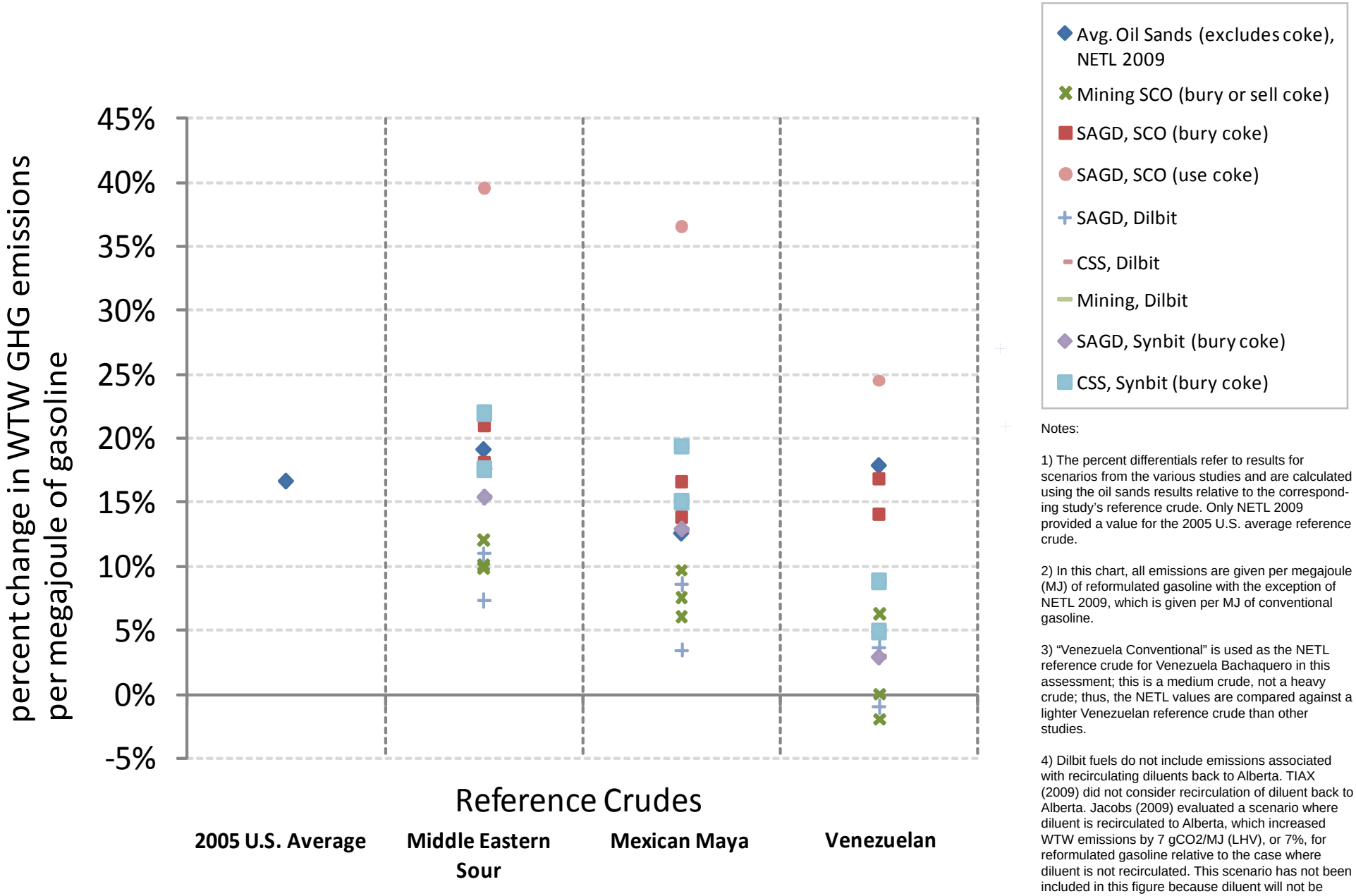


Sources: SOx data from EPA National Emission Inventory Database
http://www.epa.gov/oar/data/neidb.html;
weighted sulfur average data derived from EIA
http://www.eia.gov/dnav/pet/pet_pnp_crq_dcu_nus_m.htm.

KEYSTONE XL PROJECT

Figure 3.14.3-1

Texas and Louisiana Refinery SOx Emissions



Notes:

1) The percent differentials refer to results for scenarios from the various studies and are calculated using the oil sands results relative to the corresponding study's reference crude. Only NETL 2009 provided a value for the 2005 U.S. average reference crude.

2) In this chart, all emissions are given per megajoule (MJ) of reformulated gasoline with the exception of NETL 2009, which is given per MJ of conventional gasoline.

3) "Venezuela Conventional" is used as the NETL reference crude for Venezuela Bachaquero in this assessment; this is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.

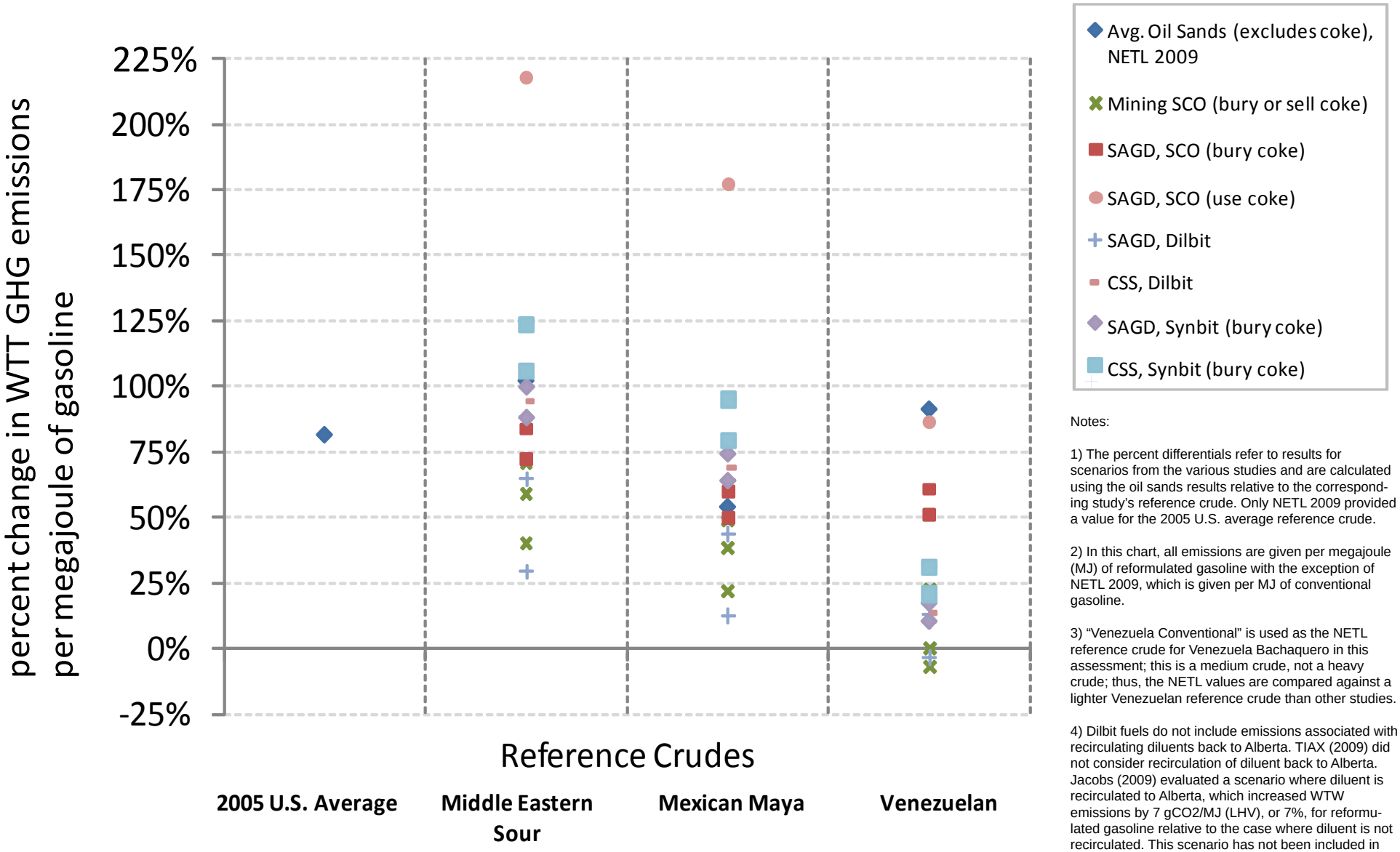
4) Dilbit fuels do not include emissions associated with recirculating diluents back to Alberta. TIAX (2009) did not consider recirculation of diluent back to Alberta. Jacobs (2009) evaluated a scenario where diluent is recirculated to Alberta, which increased WTW emissions by 7 gCO2/MJ (LHV), or 7%, for reformulated gasoline relative to the case where diluent is not recirculated. This scenario has not been included in this figure because diluent will not be recirculated by the proposed Project.

SCO = synthetic crude oil SAGD = steam-assisted

Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

KEYSTONE XL PROJECT

Figure 3.14.3-2
Comparison of the Percent Differential for WTW GHGs from Gasoline Produced from Canadian Oil Sands Relative to Reference Crudes



Notes:

1) The percent differentials refer to results for scenarios from the various studies and are calculated using the oil sands results relative to the corresponding study's reference crude. Only NETL 2009 provided a value for the 2005 U.S. average reference crude.

2) In this chart, all emissions are given per megajoule (MJ) of reformulated gasoline with the exception of NETL 2009, which is given per MJ of conventional gasoline.

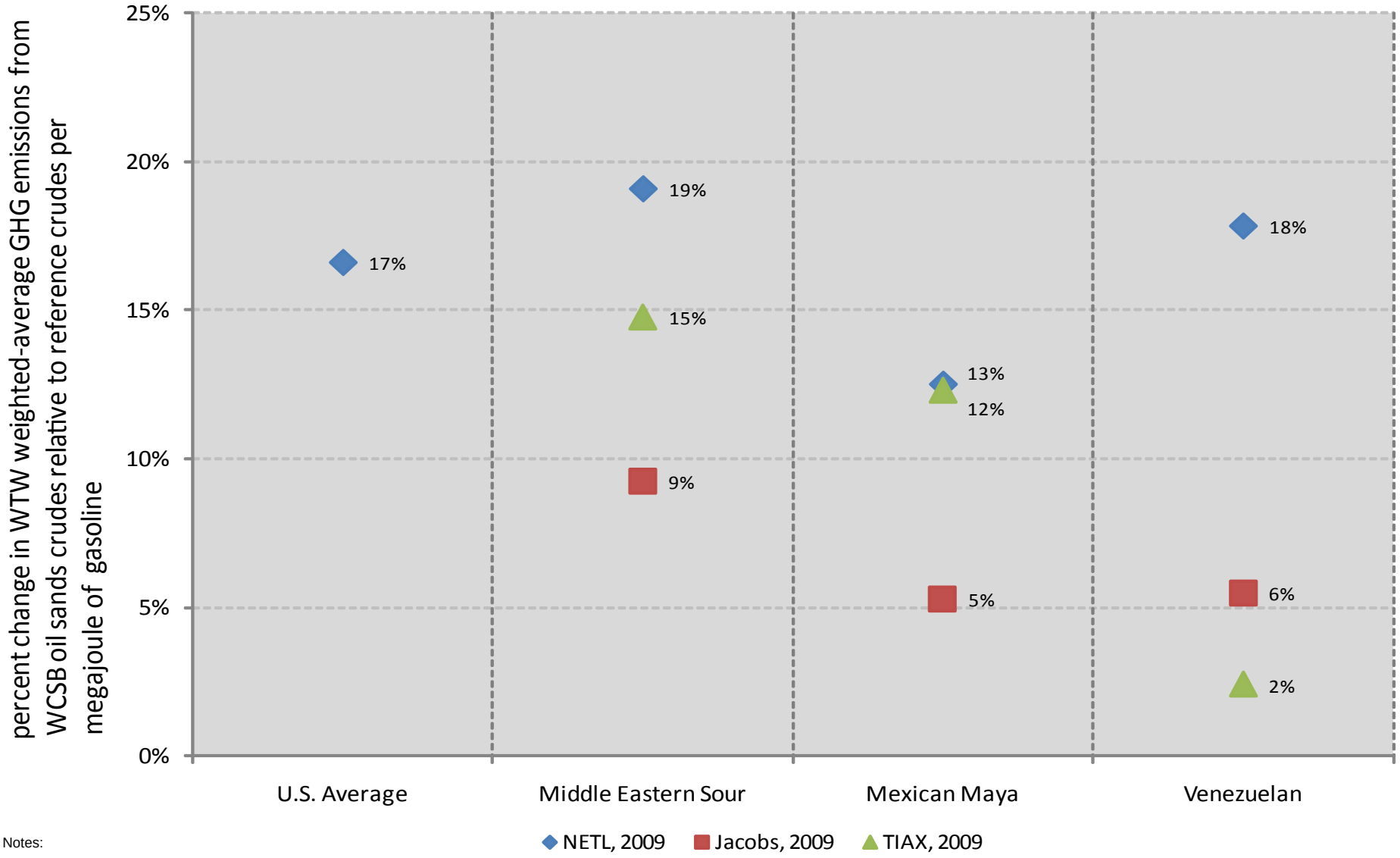
3) "Venezuela Conventional" is used as the NETL reference crude for Venezuela Bachaquero in this assessment; this is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.

4) Dilbit fuels do not include emissions associated with recirculating diluents back to Alberta. TIAX (2009) did not consider recirculation of diluent back to Alberta. Jacobs (2009) evaluated a scenario where diluent is recirculated to Alberta, which increased WTW emissions by 7 gCO2/MJ (LHV), or 7%, for reformulated gasoline relative to the case where diluent is not recirculated. This scenario has not been included in this figure because diluent will not be recirculated by the proposed Project.
SCO = synthetic crude oil SAGD = steam-assisted gravity drainage CSS = cyclic steam stimulation
This scenario has not been included in this figure because diluent will not be recirculated by the

Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

KEYSTONE XL PROJECT

Figure 3.14.3-3
Comparison of the Percent Differential for WTT GHGs from Gasoline Produced from Canadian Oil Sands Relative to Reference Crudes



Notes:

1) In this chart, all emissions are per megajoule (MJ) of reformulated gasoline with the exception of NETL 2009, which is per MJ of conventional gasoline.

2) "Venezuela Conventional" is used as the NETL reference crude for Venezuela Bachaquero in this analysis; this is a medium crude, not a heavy crude; thus, the NETL values are compared against a lighter Venezuelan reference crude than other studies.

3) The percent differentials refer to results for scenarios from the various studies and are calculated using the oil sands results relative to the corresponding study's reference crude.

Sources: Data from NETL 2009, Jacobs 2009, TIAX 2009.

KEYSTONE XL PROJECT

Figure 3.14.3-4
Percent Change in Near-Term WTW Weighted-Average GHG Emissions from WCSB Oil Sands Crudes Relative to Reference Crudes

3.15 SUMMARY OF FINDINGS

The analyses of potential impacts associated with construction and normal operation of the proposed Project suggest that there would be no significant impacts to most resources along the proposed Project corridor assuming the following:

- Keystone would comply with all applicable laws and regulations;
- Keystone would, if the Presidential Permit is granted, incorporate into the proposed Project and into its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402, the set of 57 Project-specific Special Conditions developed by PHMSA;
- Keystone would incorporate the mitigation measures required in permits issued by environmental permitting agencies into the construction, operation and maintenance of the proposed Project;
- Keystone would construct, operate, and maintain the proposed Project as described in this EIS; and
- Keystone would implement the measures designed to avoid or reduce impacts described in its application for a Presidential Permit and supplemental filings with DOS, the Construction, Mitigation, and Reclamation (CMR) Plan presented in Appendix B, and the construction methods described in Appendix H.

PHMSA has the legal authority to inspect and enforce any items contained in a pipeline operator's operations, maintenance, and emergencies manual, and would therefore have the legal authority to inspect and enforce the 57 Project-specific Special Conditions if the proposed Project is approved. DOS, in consultation with PHMSA, has determined that incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450.

Although most resources would not experience significant impacts, there would be significant adverse effects to certain cultural resources along the proposed Project corridor and mitigation measures have been developed under a Programmatic Agreement (PA) consistent with the requirements of Section 106 of the NHPA to address these adverse effects (see Appendix S).

There would also be adverse effects to the American burying beetle from the proposed Project. As a result, formal consultation with USFWS under Section 7 of the ESA was initiated and is ongoing. A Biological Opinion is being developed by USFWS. No critical habitat has been designated for the American burying beetle and therefore none would be affected. Keystone has agreed to provide monetary compensation that would be used for habitat acquisition or other conservation measures as compensatory mitigation for the American burying beetle. Funds would be used to purchase and protect lands which are known to contain sustainable populations of the American burying beetle, providing an ecologically sound option to support conservation efforts of the American burying beetle within its historic range. In addition, general conservation measures have been discussed during consultation among USFWS, DOS, state resource agencies, and Keystone to avoid and minimize potential impacts to the American burying beetle.

Trees and shrubs would not be allowed to regenerate within the maintained right-of-way except within areas with HDD crossings; therefore, removal of forested and scrub-shrub wetland habitats due to pipeline construction would be long term, and the maintained right-of-way would represent a permanent conversion of forested and scrub-shrub wetlands to herbaceous wetlands. The total acreage of affected

forested wetland during construction would be 294 acres, and the total acreage of scrub-shrub wetland affected during construction would be 36 acres. Restoration of some forested and scrub-shrub wetlands may be possible; however, long-term effects would remain. Preliminary mitigation discussions with the USACE districts have identified mitigation options for the proposed Project.

Relative to impacts resulting from crude oil spills from the proposed Project, the impacts to environmental resources would depend primarily on the location and size of the spill. Spills could result from many causes, including corrosion (external or internal), excavation equipment, defects in materials or in construction, over-pressuring the pipeline, and geologic hazards, such as ground movement, washouts, and flooding. Although the leak detection system would be in place, some leaks might not be detected by the system. Impacts from an oil spill would be affected by variables such as the weather, time of year, water level, soil, local wildlife, and human activity. The extent of impact would also depend on the response time and capabilities of the emergency response team. The greatest concern would be a spill in environmentally sensitive areas, such as wetlands, flowing streams and rivers, shallow groundwater areas, areas near water intakes for drinking water or for commercial/industrial uses, and areas with populations of sensitive wildlife or plant species.

4.0 ALTERNATIVES

Consistent with NEPA, DOS and the cooperating agencies conducted an analysis of alternatives to the proposed Project. The alternatives were developed based on the purpose and need for the proposed Project as discussed in Section 1.2. The alternatives analysis relied on information provided to agencies in the presidential permit and MFSA applications (including supplemental submittals), information and suggestions provided during scoping for the EIS and during the public comment period on the draft EIS, and information obtained through research and analyses conducted by DOS and its third-party contractor.

The alternatives analysis included a screening process that first considered a range of categories of potential alternatives. The categories of alternatives considered included:

- No Action Alternative (Section 4.1) − addresses projected beneficial and adverse environmental, social, and economic impacts that would result if the proposed Project were not implemented;
- System Alternatives (Section 4.2) − the use of other pipeline systems or other methods of providing heavy crude oil to the Cushing tank farm (PADD II) and the U.S. Gulf Coast market (PADD III);
- Major Route Alternatives and Route Variations (Section 4.3) − other potential pipeline routes for transporting heavy crude oil from the U.S./Canada border to the Cushing Tank Farm (PADD II) and the U.S. Gulf Coast Market (PADD III), and minor route adjustments along the proposed Project route;
- Alternative Pipeline Designs (Section 4.4) − aboveground installation of the pipeline and alternate pipeline diameters; and
- Alternative Sites for Aboveground Facilities (Section 4.5) − alternative sites for pump stations, MLVs, and the tank farm.

The alternatives analysis presented in the draft EIS was revised based on comments on the draft EIS and updated information or information unavailable at the time the draft EIS was issued. This information includes the recent EnSys Energy and Systems, Inc. report (EnSys 2010) on the need for the proposed Project and the relationship of the proposed Project to production of crude oil from the Canadian oil sands. DOE contracted EnSys to evaluate different WSCB crude oil transportation scenarios through 2030. DOE contracted the study to assist DOS in better understanding the potential impacts of the presence or absence of the proposed Project on U.S. refining and petroleum imports, international markets, and production of crude oil from the WCSB. The EnSys (2010) report is presented as Appendix V of this EIS. The conclusions reached in the revised assessment of alternatives remain the same as those presented in the draft EIS.

4.1 NO ACTION ALTERNATIVE

Under the No Action Alternative, the proposed Project would not be constructed and operated. Therefore, selection of the No Action Alternative would not require the issuance of a Presidential Permit for construction and operation of the proposed Project. Under the No Action Alternative, the environmental effects specific to the proposed Project described in this EIS would not occur. As described below, if the No Action Alternative is implemented it is likely that the other methods of transporting WCSB crude oil to the world marketplace would be implemented. Impact comparison scenarios in the U.S. associated with the No Action Alternative are presented in Table 4.1-1.

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
Geology	• Fossil damage or destruction and unauthorized collection.	No impact to Geology	Less than or equal to	Greater than or equal to	Less than
Soils and Sediments	• Temporary to short-term soil erosion; • Minor loss of topsoil; • Short-term to long-term soil compaction.	No impact to Soils and Sediments	Less than or equal to	Greater than or equal to	Less than
Water Resources	• Temporary to short-term surface water quality degradation and disturbance of areas with high water tables; • Temporary to short-term increase in surface water runoff in the ROW; • Temporary to short-term degradation of aquatic habitat; • Changes in channel morphology and stability; • Temporary to long-term decrease in bank stability; • Temporary reduced flow in streams during hydrostatic testing;	No impact to Water Resources	Less than or equal to	Greater than or equal to	Less than

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
Wetlands	• Loss of wetlands and modification to productivity; • Temporary to permanent change of wetland vegetation community, including forested wetlands • Wetland soil disturbance; • Temporary increase in turbidity and changes in wetland hydrology and water quality; • Permanent alteration in water-holding capacity due to alteration or breaching of water-retaining substrates in the Prairie Pothole and Rainwater Basin regions; • Minor long-term alteration in vegetation productivity and life stage timing due to increased soil temperatures; • Minor and long-term alteration in freeze-thaw timing due to increased water temperatures.	No impact to Wetlands			Less than

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
Vegetation	• Temporary to permanent modification of vegetation community composition and structure, including croplands, grassland/ rangeland, sagebrush, and riparian and upland forests, and CRP and WRP land; • Potential expansion of invasive and noxious weed populations along the pipeline ROW; • Minor short- to long-term soil and sod disturbance potentially altering hydrologic patterns, inhibiting water infiltration and seed germination, or increasing siltation; • Alteration in vegetation productivity and life stage timing due to increased soil temperatures.	No impact to Vegetation	Less than or equal to	Greater than or equal to	Less than
Wildlife	• Short-term disturbance and medium to long-term loss or modification of habitats, including fragmentation, that provide forage, cover, and breeding habitat for wildlife; • Direct mortality during construction and maintenance;	No impact to Wildlife	Less than or equal to	Greater than or equal to	Less than

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
	• Indirect mortality and reduced breeding success due to stress or avoidance of feeding during construction and from noise and human activity during operation; • Reduced survival or reproduction due to decreased abundance of forage species or reduced cover.				
Fisheries Resources	• Habitat loss, alteration, and fragmentation, including habitats for recreationally and commercially important species; • Short- to long-term changes in benthic invertebrate community; • Increased water temperature due to removal of vegetation; • Direct mortality to fishery and aquatic resources during construction; • Gill irritation, avoidance behaviors, and stress due to increase in suspended sediments potentially leading to mortality or reduced productivity;	No impact to Fisheries Resources	Less than or equal to	Greater than or equal to	No impact to Fisheries Resources

Index

A

abandon · 1.9-21, 2.6-64, 2.6-65, 2.6-66, 3.5-34, 3.6-3, 3.6-4, 3.6-8, 3.6-20, 3.7-4, 3.8-21, 3.8-24, 3.8-62, 3.8-63, 3.8-64, 3.8-65, 3.8-66, 3.8-77, 3.8-83, 3.8-99, 3.9-12, 3.9-23, 3.11-14, 3.11-47, 3.11-51, 3.14-1, 3.14-18, 4.2-30
abatement · 1.9-22, 3.12-31, 3.13-74
accident · 1.5-16, 2.2-11, 2.3-23, 2.3-24, 2.4-50, 2.4-52, 2.4-54, 2.4-55, 2.4-56, 3.1-28, 3.8-63, 3.8-78, 3.9-17, 3.10-82, 3.10-83, 3.10-89, 3.11-14, 3.12-12, 3.13-8, 3.13-11, 3.13-15, 3.13-16, 3.13-21, 3.13-24, 3.13-29, 3.13-53, 3.13-72, 3.13-74, 3.13-75, 3.13-76, 3.13-77, 3.13-80, 3.13-100, 3.13-101, 3.14-1, 3.14-16, 3.14-21, 4.2-33, 4.2-35, 4.3-39, 4.3-40, 4.3-41, 4-46, 4-50, 4-63
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TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
	• Minor reduction of population growth through burial of eggs or young fish by sediments; • Temporary blockage or delays to normal fish movements; • Entrainment of eggs, small fish, and drifting macroinvertebrates during withdrawal of hydrostatic test water.				
Threatened and Endangered (T&E) Species	• May affect, but not likely to adversely affect 11 species. American burying beetle potentially adversely affected; • Loss, alteration, and fragmentation of habitat supporting T&E species; • Stress to T&E species, reduced breeding success, and avoidance of feeding due to noise and increased human activity; • Reduced survival or reproduction due to decreased abundance of forage species or reduced cover.	No impact to T&E Species	Unknown	Unknown	Unknown

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	**New Pipeline Between PADDs II and III**	**New Pipeline from Canada/U.S. Border to PADD III**	**Transport by Existing Railroad and Barge Systems[d]**
Land Use, Recreation, and Visual Resources	• Short- to long-term loss of agricultural productivity and crop loss; • Some current land uses would be converted to permanent utility use; • Temporary visual impacts due to construction, and short- to permanent visual impacts from changes in vegetation composition and structure and the presence of aboveground facilities; • Temporary impacts to recreation from increases in noise, dust, and construction activity and traffic.	No impact to Land Use, Recreation, and Visual Resources	Less than or equal to	Greater than or equal to	Less than or equal to
Socioeconomics	• Compensation to property owners for ROW easements; • Economic benefits from the purchase of goods and services during construction and operation; • Positive impact to employment opportunities and income levels; • Positive fiscal impacts associated with property, sales, and other tax revenue;s	No impact to Socioeconomics	Less than or equal to	Equal to	Less than

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	**New Pipeline Between PADDs II and III**	**New Pipeline from Canada/U.S. Border to PADD III**	**Transport by Existing Railroad and Barge Systems[d]**
	• Minor, temporary adverse impacts on services associated with the needs of construction workers; • Minor, temporary impact on transient housing; • Potential changes in property values; • Impact to traffic and transportation; • Impacts to communities.	No impact to Socioeconomics	Less than or equal to	Equal to	Greater than or equal to
Air Quality and Noise	• Emissions from fossil-fuel fired construction equipment and vehicles; • Release of fugitive dust; • Emissions from open burning; • Emission of volatile organic compounds and hazardous air pollutants from temporary fuel transfer systems and storage tanks, surge relief tanks, and crude oil storage tanks; • Minimal fugitive emissions from pipeline connections and pumping equipment at the pump stations; • Minor, short-term, localized, and intermittent impacts from construction noise;	No impact to Air Quality and Noise	Less than or equal to	Equal to	Greater than

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative During Construction and Normal Operation

Resource	Summary of the Key Impacts of Proposed Project[a]	Impact Comparison for Scenarios Associated with the No Action Alternative[b]			
		No New or Expanded Pipelines in Canada or the U.S.[c]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III	Transport by Existing Railroad and Barge Systems[d]
	• Minor noise impacts from operation of the electrically-powered pump stations.				
Direct Greenhouse Gas (GHG) Emissions	• Minor emissions of GHG from construction and operation.	No direct impact to GHG emissions	Less than	Equal to	Greater than
Indirect (Well-to-wheels) GHG Emissions	• No effect on oil sands development or refinery emissions	Equal to	Equal to	Equal to	Equal to

[a] Definitions of duration of impacts:

Temporary impacts generally occur during construction, with resources returning to pre-construction conditions almost immediately afterward.

Short-term impacts last up to approximately 3 years after completion of construction.

Long-term impacts result when resources require more than 3 years to recover.

Permanent impacts occur when resources do not return to preconstruction conditions during the life of the proposed Project (e.g., impacts to vegetation due to construction of aboveground structures).

[b] For most resources, the type, magnitude, and duration of impacts to the resource areas for the scenarios listed would be similar to those of the proposed Project. Therefore, the table indicates the comparison to the suite of impacts listed for the proposed Project for each resource. Greater than, equal to, less than = the impacts of the No Action Alternative for the listed scenario are greater than, equal to, or less than those of the proposed Project.

[c] This alternative assumes that refineries in PADD III would continue to receive crude oil from foreign sources, with the decreasing supply from Mexico and Venezuela to be replaced by crude oil from more distant countries requiring longer shipping routes. EnSys (2010) reported that it is unlikely that there would be no expansion of existing pipelines or installation of new pipelines in both Canada and the U.S. to transport WCSB crude oil from Canada to world markets.

[d] More detailed information on the impacts of rail and barge transport is presented in Section 4.2.3.

4.1.1 PADD III Crude Oil Demand and Supply with the No Action Alternative

EnSys (2010) reported that in 2009, PADD III refineries imported 5.1 million bpd of crude oil, including 2.9 million bpd of heavy crude oil, obtained from more than 40 countries. The top 4 suppliers were Mexico (21 percent), Venezuela (17 percent), Saudi Arabia (12 percent), and Nigeria (11 percent) (EIA 2010b). PADD III refinery runs are projected to grow by over 500,000 bpd by 2020 (Purvin & Gertz 2009); however, Mexico and Nigeria face declining or uncertain production horizons and Venezuelan supplies are subject to both decreasing reserves and political uncertainty. As a result, the PADD III demand for substitute sources of crude oil, particularly the heavy crude oil currently sourced from Mexico and Venezuela, is expected to increase in the future (Sections 1.2 and 1.4) under the EIA (2010) reference case projections, that incorporate reasonably foreseeable energy projects, energy conservation efforts, and renewable energy resource development. Although some analysts project that in the short-term the worldwide crude oil slate could become somewhat lighter due to short-term increases in natural gas liquids and condensate supply, PADD III refiners may find a more competitive world market for heavy crude because there has been a worldwide trend in developing capacity to refine heavier grades of crude, including in countries that produce such heavier grades (e.g., Brazil, Saudi Arabia, Qatar, and Kuwait) (EnSys 2010). As a result, EnSys (2010) stated the following:

> "Taken together, these developments create an outlook where PADD III refiners could have difficulty in the future competing for and obtaining sufficient heavy crudes to fill available heavy crude processing and upgrading capacity, and therefore *a priori* could be expected to have an interest in acquiring heavy WCSB crudes."

Under the No Action Alternative, the PADD III refineries would continue to acquire heavy crude oil primarily from sources other than Canada to fulfill PADD III heavy crude oil demand and/or find alternative methods to deliver WCSB heavy crude oil to PADD III. Under the No Action Alternative, crude oil demand in PADD III would likely be met by one or more of the following options:

- Delivery by marine tankers from countries outside of North America (primarily from the Middle East);
- Delivery from the WCSB through the construction of alternative pipeline systems between the WCSB and PADD III;
- Delivery from the WCSB to PADD III via existing pipeline connections to PADD II and new onward pipeline connections to PADD III;
- Delivery of WCSB crude by other transportation methods (e.g., railroad tank cars, perhaps supported by barge transport); or
- Delivery from the WCSB through the construction of a pipeline to a port in Canada and subsequent shipment of the oil by marine tanker to PADD III.

The No Action Alternative would not provide PADD III with a stable, overland transportation system for access to a secure source of North American crude oil in the near term. As a result, in the near term PADD III would continue to be dependent on less reliable foreign oil supplies that require greater marine shipping distances and, thus, involve longer delays in finding substitute sources to respond to supply disruptions that may occur.

While at least in the short term projections are that world crude oil supplies may become somewhat lighter (EnSys 2010), the longer term trend towards exploitation of heavier crude oil resources and the geographically close supplies of heavy crude from Mexico and Venezuela has led to increased reliance on heavy crude oil at PADD III refineries. PADD III refineries already have substantial capacity at their

existing facilities to allow the refinement of heavy crude oil (Gunaseelan and Buehler 2009, Sword 2008). In addition, major refinery upgrades representing a total of 365,000 bpd of new capacity are planned at Port Arthur, Texas refineries that would have direct pipeline access to oil transported through the proposed Project, and several PADD III refineries without direct pipeline access have either implemented or are planning upgrades to increase heavy oil refining capacity (e.g., Artesia, New Mexico, Garyville, Louisiana, Borger, Texas) (CAPP 2009 2010). Additionally, CAPP 2010 reports that plans for refinery upgrades to handle heavy crude oil have been revived in St. Charles, Louisiana and Tuscaloosa, Alabama.

Under the No Action Alternative, excess pipeline capacity into the northern U.S. from Canada, primarily into PADD II, would likely persist until at least 2020 (EnSys 2010), although the supply of WCSB crude oil to PADD III refineries would be constrained by existing pipeline capacity into PADD III (CAPP 2009, Purvin & Gertz 2009) unless an alternative pipeline from PADD II to PADD III were constructed. PADD III represents the largest refining capacity in the U.S. and therefore would continue to acquire heavy crude oil primarily from sources other than Canada to fulfill demand in the near term. The refineries receive WCSB heavy crude oil from the 96,000-bpd ExxonMobil Pegasus Pipeline, which is the only pipeline that provides PADD III refineries direct access to WCSB crude oil (CAPP 2009). Small volumes of WCSB heavy crude oil currently move to Gulf Coast refineries by barge from PADD II and by marine tanker from the Westridge dock near Vancouver, British Columbia, Canada (EnSys 2010).

If the constraints on delivery of WCSB crude oil into PADD III persisted, there would tend to be upward pressure on the price of heavy crude oil imported into PADD III and on the prices of refined products shipped out of PADD III, although the impact of this upward pressure is projected to be small over the longer term (EnSys 2010). If long-term constraints on delivery of WCSB crude oil to the U.S. Gulf Coast and the Canadian west coast persist, a glut of WCSB crude oil could develop in PADD II potentially leading to downward pressure on the price of crude oil in PADD II sometime after 2020 (EnSys 2010). Currently, the lack of transport capacity out of Cushing has substantially depressed the price of West Texas Intermediate (WTI) crude compared to other world benchmark crudes, such as Brent Blend. It is not yet clear if this is a short-term phenomenon, or whether or how the phenomenon might be reflected in refined fuel prices in the PADD II area.

Under the No Action Alternative, in the immediate future, the gap created by declining supply from traditional heavy crude suppliers, primarily Mexico and Venezuela, would likely be filled by increases in other foreign imports delivered by marine tanker, notably from the Middle East (EnSys 2010). Increased reliance on Middle East supply would lead to increased marine tanker traffic to PADD III and higher priced Middle Eastern medium crudes may not fit the crude slates of upgraded PADD III refineries that are better optimized to process heavy crude oil. In the medium- to long-term, a crude oil pipeline system from Canada to PADD III (other than the proposed Project) could be constructed to provide WCSB crude oil to PADD III refineries, and the EnSys (2010) report results indicate that there is a strong market preference to put in place a broadly similar capacity to that provided by the proposed Project. Alternatively, additional pipeline infrastructure could be constructed to provide greater pipeline capacity between PADD II and PADD III that, in conjunction with existing excess cross border pipeline capacity in PADD II, could meet short term heavy crude oil demand in PADD III (until approximately 2020).

4.1.2 WCSB Crude Oil Production and World Market Access under the No Action Alternative

4.1.2.1 WCSB Crude Oil Production and Existing Export Capacity

Currently, crude oil production from the WCSB totals approximately 2.4 million bpd, with approximately 55 percent coming from the oil sands (CAPP 2010). Forecasts by CAPP project growth in WCSB production to 4.19 million bpd by 2025, with the oil sands comprising 3.5 million bpd. These growth

projections are based upon a survey of projects operating, projects under construction, and projects announced for construction. There are numerous logistical challenges to reaching such production numbers, including limited labor supply and long supply chains to get materials to northern Alberta, but other production outlooks, such as IEO (2010), have similar production amounts from the oil sands for 2025 time period. The other forecasts that include similar numbers for potential oil-sands sands production, show a rough correlation between world crude oil price and oil-sands production – higher world oil prices lead to higher production from the oil sands, lower world oil prices lead to lower production from the oil sands (IEO 2010, IEA 2010).

Currently, there is approximately 3.8 million bpd of existing pipeline capacity to transport crude oil produced in the WCSB into the United States. Comparing the projected production to existing capacity, EnSys (2010) stated that:

> "Under every scenario where pipeline expansion is not restricted, WCSB crude supply is projected to be maintained at the levels projected in 2010 by the Canadian Association of Petroleum Producers . . . [and] . . . current pipeline capacity would be sufficient to deliver projected WCSB production to market at least until 2020 even with no expansion."

Examining the existing cross-border pipeline capacity does not give the entire picture, because, as described in the previous section, there is market demand in PADD III for WCSB crudes, and the existing cross-border pipeline capacity does not deliver to PADD III. That market demand in PADD III is not dependent upon construction of the proposed Project, since market demand would exist to put in place similar capacity to deliver WCSB crudes to PADD III (EnSys 2010).

The United States is currently the only substantial export market for WCSB crudes, as there is limited transport capacity to move the crudes to the world market. However, there is interest on the part of crude oil producers to gain access to other markets.

4.1.2.2 WCSB Crude Oil Potential Access to World Markets

Producers in Canada have stated that if the U.S. market is not available to them, much of the WCSB crude oil would be shipped outside of North America, particularly to Asian markets including Japan, China, South Korea, and India, which are the world's third through sixth largest importers of oil, respectively (CIA 2010).

Under the No Action Alternative, it is likely that there would be an increase in market incentives for WCSB crude oil producers to seek access to Asian markets until sufficient alternative infrastructure becomes available to facilitate access to the U.S. PADD III market. According to EnSys (2010):

> "Over the next twenty years, the principal choice for WCSB exporters is between moving increasing crude oil volumes to the USA or to Asia. Led by China, which has already bought heavily into oil sands production, Asia constitutes the major region for future petroleum product demand and refining capacity growth and offers Canada diversification of markets. In addition, costs for transporting WCSB crudes to major markets in northeast Asia (China, Japan, South Korea, Taiwan) are lower than to transport the same crudes via pipeline to the US Gulf Coast. Projections from this study, which are supported by third party information, indicate that Asian markets are attractive and could absorb at least 1 mbd [million barrels per day] of WCSB crudes, potentially significantly more; this versus the less than 50,000 bpd of WCSB crude that moves to Asia today."

If large quantities of WCSB crude oil were to be shipped to Asia, the oil would likely move by pipeline to

marine ports in Canada and would be transported from there by marine tanker to countries outside of North America. Within Canada, this would require construction of at least one new pipeline from the WCSB production area to a port on the Canadian west coast. It is likely that an existing port would have to be modified or a new port would have to be constructed in order to handle very large volumes of oil exports. Examples of potential world market access pathways based on currently available information are described below.

Northern Gateway Pipeline

In May 2010 Enbridge submitted an application to the NEB seeking approval for construction and operation of the Northern Gateway Pipeline. According to the application, this facility would initially transport up to 525,000 bpd of WCSB crude oil from Edmonton to a port in Kitimat, B.C. The ultimate destination of the crude oil transported by this project would be the Asia-Pacific Rim countries, particularly China and Korea, and to refineries on the U.S. West Coast. The project could be expanded to transport up to 800,000 bpd and would include a diluent pipeline that would transport 193,000 bpd of diluent from a port at Kitimat to the Edmonton area. The proposed route is depicted on Figure 4.1.2-1. The current target for startup is 2016, although the project is encountering strong resistance from First Nations and environmental groups that may delay or postpone the project.

Sinopec Corporation, the second-largest oil producer and largest refiner in China, announced that it is among a group of producers and refiners providing $100 million (Canadian $) to assist in financing the $5.5 billion (Canadian $) Northern Gateway pipeline project (Reuters 2011a). The financing is intended to be used for regulatory and development costs in exchange for guaranteed space on the pipeline and the right to an equity stake.

Kinder Morgan Trans Mountain Pipeline Projects

The existing Kinder Morgan Trans Mountain Pipeline transports WCSB crudes west from Edmonton to the 55,000 bpd Chevron refinery at Burnaby and to a dock at Westridge, both near Vancouver, B.C. The Trans Mountain pipeline also connects to the Puget Sound Pipeline, a spur that extends to four refineries at Ferndale, Anacortes, and Cherry Point in Washington. Crude oil can be shipped via the Westridge or Burnaby docks by barge or tanker to U.S. refineries in Washington, although historically this mode of transport has been primarily to California, the U.S. Gulf Coast, and Asia. Kinder Morgan expanded the Trans Mountain system to a maximum capacity of 300,000 bpd in 2008 via its TMX1 project. However even with that expansion, the system is over subscribed as reported by EnSys (2010):

> "According to a press announcement in late October 2010 [Reuters 2010], the Transmountain pipeline is running at 316,000 bpd, i.e. above nameplate capacity, and is 32% over-subscribed for the month of November as of the time of this report. This tends to reinforce that there is growing demand for the line's capacity."

That situation extended into early 2011, when Kinder Morgan informed shippers that they would only be able to ship approximately 75 percent of the volumes requested (Reuters 2011b).

Kinder Morgan has plans to further expand this pipeline system with its TMX2 looping project that would increase the capacity to 380,000 bpd, and further increase the capacity 700,000 bpd with its TMX3 project. However, as of the time this EIS was prepared, Kinder Morgan had not announced a decision to go forward with either project, and in January 2011, Petroleum News (2011) reported that "Kinder Morgan decided last year to slow plans to further increase Trans Mountain capacity." The routes of the existing Trans Mountain pipelines system and the planned expansions are depicted on Figure 4.1.2-1.

Based on existing information, it is assumed that the expansions would be implemented in the 2015 to 2020 time frame. Kinder Morgan also plans to upgrade the Westridge dock to allow use of larger tankers, although this proposed project faces strong opposition (as does the looping project that would expand capacity of the existing pipeline). In late November 2010, Kinder Morgan applied to the NEB to establish longer term "firm service" contracts for WCSB crude oil shipments across the Westridge Dock (EnSys 2010).

Kinder Morgan has also announced plans for a Northern Leg expansion of the Trans Mountain system. The Northern Leg would extend from Edmonton to near Valemont, B.C., then extend west to Kitimat (see Figure 4.1.2-1). As currently planned, the maximum capacity of the Northern Leg would be 400,000 bpd, and the port at Kitimat can accommodate very large crude carrier class tank ships. The Northern Leg expansion is considered by Kinder Morgan to be a longer-term project. It also faces strong opposition from First Nations and environmental groups. If regulatory approvals were obtained and all of the above expansions are constructed and operated, the Trans Mountain system would have a total capacity of 1.1 million bpd.

Other Potential Projects

There are several other potential projects announced previously that could transport WCSB crude oil that are presently dormant and may be revived in the future. These projects are considered potential System Alternatives and are described in Section 4.2.

4.1.2.3 Likely Future Impacts under the No Action Alternative

Any alternative pipeline system constructed to move WCSB crude oil directly to PADD III refineries would likely have environmental impacts that are similar to those of the proposed Project. Additional pipeline infrastructure constructed to provide greater pipeline capacity between PADD II and PADD III would likely produce environmental impacts similar to those of the Gulf Coast Segment of the proposed Project. Oil shocks (unanticipated supply reductions that result in price spikes) arise through unstable crude oil supplies and would be more likely to occur under the No Action Alternative, as compared to the proposed Project, since crude oil supplies would continue to be sought from unstable foreign sources and transported over longer distances in the near term. Oil shocks reduce the amount of goods and services the U.S. can produce given a fixed amount of other inputs and cause some inputs (e.g., land, labor, and capital) to be under-utilized. In contrast, projects which stabilize crude oil supply through diversification and increased access to politically stable regions, such as the proposed Project, benefit the U.S. economy.

Under the No Action Alternative, in the near term positive socioeconomic impacts associated with construction and operation of the Project would not be realized along the proposed route and elsewhere in the U.S. No annual property tax revenues would be generated, as opposed to an estimated $138.4 million in annual property tax revenues that would be generated by the proposed Project in the region of influence. The generation of local employment as well as substantial expenditures on goods and services would also not occur under the No Action Alternative. However, if an alternative pipeline is constructed at some later date, socioeconomic benefits would be realized as a result of construction and operation of that alternative at that time.

GHG emissions associated with the proposed Project would not occur under the No Action Alternative, but GHG emissions would result from implementation of any alternative transportation network. EnSys (2010) employed both its World Oil Refining Logistics & Demand (WORLD) model and the DOE Energy Technologies Perspective (ETP) model to analyze effects of different transportation scenarios for the delivery of WCSB crude oil to world markets, including a scenario that equates to the No Action Alternative. The EnSys results indicated that with or without the proposed Project, there would be no

substantial change in total U.S. refining activity, total crude and product import volumes and costs, development rate in the oil sands, global refinery CO2 emissions, and total life-cycle GHG emissions. However, the No Action Alternative, combined with a freeze of transport capacity for WCSB crudes at existing levels for 20 years, could lead to a reduction in WCSB oil sands production in the 2025 to 2030 timeframe (EnSys 2010).

Construction of new pipelines, modification of existing ports, and/or the construction of new ports would produce environmental impacts within Canada or in the U.S. that would be similar in nature to those of the proposed Project in terrestrial environments. Port projects would also include construction impacts to marine environments and operational impacts associated with the handling and transport of crude oils in marine environments. In addition, the transport of crude oil by tanker would result in more GHG emissions than would transportation of crude oil by pipeline to the U.S.

Commenters on the supplemental draft EIS suggested that more detailed analysis should be done on potential indirect impacts of the proposed Project associated with upstream (extraction in the oil sands in Canada) and downstream (refining in the Gulf Coast) activities. In the EnSys (2010) analysis that examined the impact of different scenarios of pipeline construction on upstream and downstream activities, there were no differences in the rate of production in Canada in all scenarios where transportation capacity was added in response to projected market demand. Based on the EnSys (2010) modeling results of downstream refining activities, the presence or absence of the proposed Project would not influence the projected market demand for heavy oil-sands crude oils at Gulf Coast refineries. As discussed in Section 3.13.5, the EnSys (2010) report also indicated that overall crude slate quality in PADD III under different transportation scenarios was not particularly sensitive to the varying quantities of WCSB oil sands crude oils delivered to PADD III.

In the supplemental draft EIS, more detailed analysis on the upstream and downstream activities was not undertaken in part because the EnSys report considered the No Expansion Scenario to be unlikely, a judgment the supplemental draft EIS endorsed. In response to the comments received, and to address concerns expressed by EPA regarding the potential connection between the proposed Project and future PADD III refinery emissions, DOS re-examined the assumptions underlying the EnSys analysis in consultation with experts at DOE, including within EIA, and expanded its consideration of the potential for alternate modes of transport from the WCSB to PADD III. DOS and DOE (which had commissioned the original EnSys report) directed EnSys to further examine the No Expansion Scenario, including an assessment of the viability of alternative modes of crude oil transportation, such as rail or barge. As a result, the conclusion that the No Expansion Scenario was unlikely to occur over the 20-year time period examined in the study was confirmed and reinforced. EnSys (2011) states:

> "In summary, we believe a Total No Expansion scenario which freezes at current levels all capacity to transport Western Canadian crudes to market is essentially implausible."

EnSys also updated its earlier analysis of announced and potential pipeline projects and concluded:

> "The update thus reinforces the view expressed in our Keystone XL Assessment report that, while Keystone XL offers a high capacity and "shovel ready" route to move growing WCSB production and also Bakken and Midcontinent crudes to the Gulf Coast, if it were not built (as in our DOE No KXL scenario) then, over time, broadly comparable pipeline capacity would evolve. (The economic / market drivers would be the same.) The result would be broadly similar flows, including to PADD3, subject as before to developments in capacity west to the BC coast."

The EnSys (2011) analysis confirms that if a freeze of pipeline capacity in North America lasting 20 years did occur, the market would likely respond by transporting crude oil by other available, but relatively

more expensive, transport options. This is precisely the response the market has had to the current situations of constrained pipeline capacity out of the Williston Basin in North Dakota and from Cushing, Oklahoma south to PADD III. It should be noted that the No Expansion Scenario is distinct from the No Action Alternative. The No Expansion Scenario includes numerous assumptions in addition to the proposed Project not being constructed, including:

- No addition of pipeline capacity to the Canadian West Coast;
- No addition of new pipeline capacity from Canada into the United States;
- No expansion of pipeline capacity from Canada into the United States;
- No addition or expansion of pipeline capacity within the United States, particularly between PADD II and PADD III; and
- No addition of transportation capacity on other proven modes of bulk-commodity transport such as rail or barge.

The EnSys WORLD model results indicated that if there were not widespread restrictions on crude-oil transport capacity, the market demand would support the expansion of production in the oil sands in line with the projected growth contained in the CAPP (2010) report and delivery to refineries in PADD III in similar amounts whether the proposed Project was constructed or not. Thus, the other assumptions underlying the No Expansion Scenario would be counter to projected market demand.

The EnSys (2010) No Expansion Scenario is not equivalent to the No Action Alternative. It is, however, the only scenario in the EnSys (2010, 2011) reports that showed potential differences in upstream or downstream indirect impacts versus other scenarios assessed in these reports. As crude oil is traded and transported in a relatively unregulated North American (and world) market, it is unlikely that crude oil originating in the oil sands would not be transported in accordance with the projected market demand by some existing or future transportation pathway as is assumed in the No Expansion Scenario. There are numerous potential transportation pathways that could move Canadian crude oil by pipeline to PADD III that are subject to varying levels of regulatory scrutiny.

With respect to the addition of new trans-boundary pipeline capacity, the Canadian NEB and the DOS possess the authority to approve or deny those projects within their jurisdictions. With respect to the potential transportation projects to the Canadian West Coast, there is considerable opposition from groups that could possibly delay or block projects during the Canadian NEB review process (although the different projects would likely face different levels of regulatory approval). Additionally, it is possible that the expansion of existing trans-boundary pipelines could be done without modification of existing permits. Whether that is true for the Presidential Permits issued by DOS would be determined on a case-by-case determination.

With respect to the addition or expansion of crude oil pipeline capacity within the U.S., there is no overall federal permitting authority. The states through which pipelines connecting PADD II to PADD III would most likely pass (Oklahoma, Texas, Missouri, Arkansas, and Illinois) currently do not have regulatory processes that require state approval of pipeline routing and construction. Additionally, there is the possibility of future projects making use of existing pipelines that may be reversed or converted from other uses and/or paralleling existing ROWs (EnSys 2011).

With respect to other modes of bulk-commodity transport such as rail and barge, there is no general regulatory review before increasing crude oil transport, so long as these transportation modes use existing infrastructure (i.e. the existing railroad tracks). The most efficient way of transporting crude by rail is by unit train, a train of cars that stays connected and ships one commodity. The construction of new loading

terminals for unit-trains would likely be subject only to local zoning and building codes. Recent experience in the Williston Basin in North Dakota and Montana and in the Gulf Coast area, indicates that such terminals can be completed in 12 to 18 months (EnSys 2011).

Even in a situation where there was a total freeze in pipeline capacity for 20 years, it appears that there is sufficient capacity on existing rail tracks to accommodate shipping projected WCSB crude oil production through at least 2030, even taking into account CAPP's increased production forecasts in 2011 (EnSys 2011). The rail system in North America is extensive, well-integrated, and transports bulk commodities, (coal in particular) in far greater quantities than would be required to accommodate transporting additional crude oil production in the WCSB over the next several decades. A study conducted on behalf of the Association of American Railroads (Cambridge Systematics 2007) found that, as of 2005, much of the rail capacity in the U.S., including capacity across the border from Canada, was operating well below capacity. Based on that study, EnSys (2011) conservatively estimated that the four major existing cross-border rail lines from Canada to the U.S. could accommodate crude oil train shipments of over 1,000,000 bpd. EnSys (2011) noted that although information was only available about the four major rail crossings of the international border, there were in fact 56 existing rail border crossings with Canada in the geographic area where crude oil train shipments would be most likely.

The rapid development of crude oil transport options in the Williston Basin in North Dakota and Montana provides a case study of how the market could be expected to respond to constraints in pipeline capacity to transport WCSB crude oils. Williston Basin production has increased very rapidly over the past several years and is projected to continue to increase over the next decade. In January 2007 production was approximately 200,000 bpd, in early 2011 it was approximately 400,000 bpd, and by 2021 the North Dakota Pipeline Authority forecasts it could be between approximately 900,000 to 1,100,000 bpd.1 Some private forecasts are projecting that level of production within 5 years.

The existing and projected pipeline capacity to transport crude oil out of the Williston Basin has not kept pace with this current or projected growth. In January 2007 there existed just over 200,000 bpd of pipeline takeaway capacity from the Williston Basin.2 By June 2011, the pipeline capacity had increased to nearly 400,000 bpd, and projected projects (other than the Bakken Marketlink associated with the proposed Project) would increase capacity to approximately 620,000 bpd by the middle of 2013.

Rail capacity has increased rapidly to fill the gap between the increased crude oil production and pipeline transport capacity. The first rail shipments of crude oil out of the Williston Basin occurred in the latter half of 2008. By 2010 there was loading capacity of just over 100,000 bpd. By June 2011 there was nearly 300,000 bpd of rail capacity, and projects announced and under construction will increase that to 450,000 bpd by the end of 2012 (Figure 4.1.2-2). At least one of the rail projects is designed to be expandable to 700,000 bpd of rail capacity that could be available by 2013 if market conditions warranted (EnSys 2011).

Unit-train rail terminals are being built to receive the crude oil in PADD III – including in the Port Arthur and Houston areas (EnSys 2011). These terminals are generally associated with accommodating the shipments from the Williston Basin, but the operators have noted they will be configured to accept heavy WCSB crude oil.

Historically, rail has generally not played a significant role in shipping crude oil in the U.S. or Canada. One of the main reasons for this is that pipelines are less expensive and pipeline capacity has been

[1] NDPA 06-28-2011 Presentation, slide 13.
[2] This capacity, and other pipeline capacity figures, include deliveries to the existing Tesoro refinery in North Dakota.

available. The example of the Williston Basin, however, demonstrates that rail capacity can quickly increase if there are constraints on pipeline capacity. Two of the main reasons are because the rail infrastructure already exists and can generally accommodate additional train shipments and the capital investments in increasing rail capacity are relatively modest in the context of capital investments in the petroleum industry (EnSys 2011). As shippers move to unit trains the economics of rail shipment improves. Industry reports indicate that rail transport costs from the Williston Basin to PADD III are approximately $2 to 3 more expensive per barrel than pipeline transport costs, but that those costs are decreasing as the larger unit-train terminals are being completed. Canadian National rail has asserted that raw bitumen (undiluted) could be transported in heated, insulated tank cars at rates comparable to the rates paid for pipeline transport. The recent EnSys (2011) analysis supports this assertion. Thus, it appears unlikely that the cost of rail transport versus pipeline transport would pose any substantial economic disincentive to continue producing oil sands derived crude oils if there were a long-term freeze in pipeline capacity.

Another factor making the No Expansion Scenario extremely unlikely is the relatively long timeframe examined in the EnSys (2010) report. Based on the economic projections cited above, including CAPP (2011) increased forecasts of WCSB production, existing trans-boundary pipeline capacity could accommodate the projected increases in production (and increases in demand) until sometime shortly before 2020 (EnSys 2011). Thus, if the proposed Project were not constructed, there would be 5 to 8 years for additional transport capacity to become available before any curtailment of production would be experienced. With each incremental amount of capacity that becomes available, the time lag before curtailment of production is pushed back further. EnSys (2011) noted that if there were no additional pipeline capacity, rail transport could accommodate all of the projected increase in WCSB production through 2030, and likely longer, by adding 100,000 bpd of capacity per year beginning in 2016. This rate of rail expansion would be substantially slower than the rate of rail expansion experienced in recent years in the Williston Basin.

The EnSys (2010) report also took a conservative approach to the question of timing of other pipeline projects. In scenarios that did not include the construction of the proposed Project, but allowed for expansion of transport capacity to PADD III in response to projected market demand, the WORLD model did not make that transport capacity available until 2020. There are already multiple proposed projects to increase pipeline transport capacity from PADD II to PADD III. In scenarios that included additional pipeline capacity to the Canadian West Coast, the WORLD model did not add that capacity until 2020 or later (e.g., the TMX expansions was not added until 2020, the Northern Gateway was not added until 2025, and the Northern Leg was not added until 2030). The WORLD model consideration of these projects assumes at least 10 years to achieve needed regulatory approvals for these projects.

In the short term, approval or denial of the proposed Project could have market impacts that affect investment decisions of producers. The Purvin and Gertz (2009) study submitted by Keystone to the Canadian NEB noted that if constructing the proposed Project relieved the transportation bottleneck that was then artificially depressing prices of crude oil in the Midwest, then Canadian producers may obtain a better price of $3 to $4 per barrel for their crude oil. Some analysts have asserted that if the proposed Project raised the price of WCSB crude oil, this would send a clear market signal that would increase upstream production (Pembina 2011). While there is some validity in the points made in these analyses, they examine the proposed Project in isolation, and do not consider how the proposed Project compares to other transportation options (pipelines or otherwise) that would likely have similar impacts on the price of WCSB crude oil. The EnSys (2010) report indicated little difference in the price producers could obtain for their crude oil over the 20 year time frame of the analysis in any of the scenarios that allowed transport capacity for that crude oil to increase in line with projected market demand.

Also, in light of the lead times necessary to begin new WCSB oil sands projects and the long production

lives of those projections, it appears unlikely that short term perturbations in the price of crude oil would substantially change oil sands production. Investments in currently operating oil sands projects are a sunk cost and as long as the operating cost of production and transportation is below the sales price, the oil sands operations would likely continue. Thus, it would likely take an extended period of low oil prices, and/or projections that such an extended period would occur, before a long-term impact on oil sands productions would be likely.

The economic incentive for producers to avoid a long-term No Expansion Scenario would be substantial. As long as sufficient transportation exists, oil sands producers would not set the price of their product but would receive its value in the world market. As has been observed in the past (and as is currently occurring as a result of the Cushing bottleneck), if transportation constraints exist, producers would likely be forced to compete with each other to sell their product in a smaller geographic area and could receive a discounted price relative to the world market. This means that in a long-term No Expansion Scenario, producers would be losing not only potential revenue by not investing in additional production projects, but also revenue on production from investments they had already made. The updated EnSys (2011) report evaluated the potential scope of the economic incentive for oil sands producers to alleviate transportation constraints in a No Expansion Scenario:

> "Under "No Expansion" there would substantial incentives to WCSB producers to relieve logistics constraints. Today's Cushing constraints are creating strains in the market and discounts for WCSB heavy grades versus normal conditions of around $10/bbl. In 2005-2008, when inadequate export capacity was leading to marginal shut-ins, discounts were in the $10 - $20/bbl range. These discounts apply to the total volume of WCSB heavy crudes. Based on our updated assessment, WCSB shut-in volumes under No Expansion could be around 1.4 mbd in 2030 out of around 4 mbd total WCSB supply. Thus, versus an average price of say $100/bbl in normal market conditions, this situation would cost WCSB producers 1.4 million b/d * $100/bbl lost production + 2.6 million b/d * (say) $10/bbl discount on the crudes still being produced, a total of around $166 million per day, $60 billion per year. The cost to relieve those discounts, and avoid the 1.4 mbd of production shut-in, would be the cost of transporting the 1.4 mbd that could not be fed through pipelines. Our estimates are that they could be moved to market at around $10/bbl transport cost. So incurring $14 million per day in incremental transport costs would restore $166 million per day of lost revenues [approximately $5 billion per year]. Even if the alternative transportation costs were appreciably above $10/bbl, (We find it difficult to envisage costs above the $10 to at most $20/bbl range), the incentive to use alternative transportation modes would still far outweigh the costs."

Based on the above considerations, and on the analysis in Section 3.14.3 regarding refinery emissions, it appears highly unlikely that implementation of the proposed Project would have a substantial effect on upstream (extraction of crude oil in the oil sands) or downstream (refinery operations or emissions in the Gulf Coast) activities.

Under the No Action Alternative, the potential adverse and positive impacts associated with the implementation of the proposed Project would not occur. However, impacts associated with the development and/or utilization of alternative transportation pathways from the WCSB oil sands to PADD II and PADD III would likely occur in order to satisfy market demand for heavy crude oil in PADD III. The comparative impacts of new pipelines are presented in Table 4.1-1.

4.1.3 Use of Alternative Energy Sources and Energy Conservation

Many commenters 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 III, is driven primarily by the demand for transportation fuels. Based on EIA (2010a, 2010b) statistics, approximately 78 percent of the refined product produced by PADD III refineries in 2009 was used for transportation fuel. The percentages of total production from PADD III 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 III 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 III refineries, and therefore 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 III to justify selection of the No Action Alternative as the preferred alternative. Although most refined products sold by PADD III 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 (Section 4.1.3.1);
- Use of Alternative Energy Sources in Place of Distillate Fuel Oil for Non-Transportation Uses (Section 4.1.3.2);
- Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses (Section 4.1.3.3); and
- Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products (Section 4.1.3.4).

4.1.3.1 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 will be an increase in consumption of crude oil from unconventional sources, primarily from the Canadian oil sands, over the next several decades. In the United States, the overall demand for crude oil is projected to remain relatively flat over the next 25 years (EIA 2010a).

However, IEA (2010) projected that if policies and legislation were adopted to more aggressively respond to climate change in the United States by promoting fuel efficiency, electrification of motor vehicles, and/or alternative fuels, there could be a substantial reduction in demand for crude oil in the coming decades.

In general, commenters raised two general questions 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 U.S. demand for crude oil eliminate the need for the proposed Project; and
- 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?[3]

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 world-wide consumption), the market demand in PADD III 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 wide-spread adoption of fuel efficient vehicles, or deployment of alternate fuels (including vehicle electrification).

In early 2010, EPA prepared a report examining technically feasible measures that could reduce consumption of crude oil that is refined to produce transportation fuel (EPA 2010). The EPA study looked at two scenarios, which were informally characterized as somewhat aggressive and very aggressive, in attempting to reduce vehicle energy consumption and tailpipe emissions. In that report, EPA stated the following:

> "[The scenarios] do not reflect the entire range of possible outcomes, but rather, a set of outcomes that could occur, based on technical feasibility, if effective policy or market drivers were in place."

Among other factors underlying the somewhat aggressive scenario's assumptions were the following:

- Market penetration of just over 80 percent for hybrid electric, plug-in hybrid electric, and electric vehicles in the new light-duty vehicle sales in 2030;
- 5 percent annual improvement in GHG emission rates in light-duty vehicles through the 2030 time period;
- Current levels of household vehicle utility assumed to be maintained (e.g., range, towing capacity, and interior space);
- 2030 new vehicle fuel economy in light vehicles would be 36 miles per gallon (mpg) for gasoline vehicles, 60 mpg for hybrid electric vehicles, 74 mpg for plug-in hybrid electric vehicles, and a 150-mile range for electric vehicles;
- 12 percent annual reduction from light duty GHG emissions by 2030 from travel efficiency improvements (e.g., speed limit reductions, urban parking restrictions, congestion pricing, and eco-driving);

[3] Commenters also expressed concern about the potential effect that implementation of the proposed Project would have on adoption of policies to reduce crude oil demand. It is too speculative for NEPA purposes to attempt to predict how political factors might result in different policies or legislation being adopted in different scenarios. This section focuses on market demand issues related to more definitive factors such as fuel efficiency and alternate fuels since there several publicly available studies addressing those economic issues.

- For medium- and heavy-duty trucks it includes technology improvements in aerodynamics, tires, powertrain, limited adoption of hybrid into medium-duty applications, weight reduction through improved materials, and travel efficiency scenarios; and
- Similar technology improvements in efficiency, powerplant, aerodynamics, and materials for aviation, rail, and marine sectors.

EPA (2010) reported that implementation of the above measures could result in a reduction in demand for crude oil in the United States of 4 million bpd as compared to the projected demand in the EIA AEO by 2030. The findings of this EPA report were relied upon to construct the low-demand outlook modeled in the EnSys (2010) report. The results of the economic modeling were that the low-demand outlook had little impact on the projected demand for oil sands crudes in the U.S. and little impact on the total production from oil sands throughout the study timeframe. In the AEO demand outlook, total production in the oil sands was projected to be approximately 4.42 million bpd in 2030, and with the low-demand outlook, the production was projected to be approximately 4.23 million bpd in 2030.

IEA (2010) also addressed energy demand and production in three world-wide policy scenarios:

- The Current Policies Scenario, which assumed no change from policies in place in mid-2010;
- 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 a scenario consistent with the goal to limit climate change to 2º C over pre-industrial levels, which equates to stabilizing GHG CO_2-equivalent emissions at 450 ppm.

The impact of the three policy scenarios on world-wide crude oil consumption in 2035 is substantial. Compared to the world-wide total oil production (crude oil, natural gas liquids and unconventional oil) of 83.3 million bpd in 2009, IEA projected the following levels of consumption in 2035:

- Current Policies Scenario – 107.4 million bpd;
- New Policies Scenario – 99 million bpd; and
- 450 Scenario – 81 million bpd.

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

- Current Policies Scenario – 4.6 million bpd;
- New Policies Scenario 4.2 million bpd; and
- 450 Scenario – 3.3 million bpd.

The projected 2035 consumption in each of these scenarios represents a substantial increase from 2009 consumption of approximately 1.3 million bpd oil-sands-derived crude oil. The difference in consumption of the oil-sands-derived crude oil among the different scenarios is largely attributable to the differing world oil price in each scenario (the 450 Scenario's substantially reduced demand for crude oil would result in reduced world oil prices), and the additional expense attributed to the oil sands projects that would be necessary to mitigate their relatively higher greenhouse gas emissions (IEA assumed carbon price of $60 per ton in the New Policies Scenario and $120 per ton in the 450 Scenario). If oil-sands production is reduced to approximately 3.3 million bpd, then existing transboundary pipelines could

accommodate import of that volume of oil-sands-derived crude oil into the U.S. However, that crude oil would not reach the refineries in PADD III.

Based on the outcomes of the EnSys (2010) report and the analyses of policies and market-drivers that would lead to a reduction in the volume of crude oil refined to produce transportation fuel, it appears highly 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. In a recent report examining economic implications of different policies to reduce CO2 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 lead 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 reducing 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 CAFÉ standards. In contrast, the EnSys (2010) analysis stated the following:

> "within each demand outlook, U.S. total [refined] product supply costs are insensitive to pipeline scenario, varying by less than 0.1% in any scenario where normal pipeline expansion is allowed."

The scenarios that included the proposed Project resulted in small reductions in product supply costs in PADD III (less than $0.10 per barrel), that would amount to approximately a ¼-cent impact on the price of a gallon of gasoline. The scenario with the largest variation in refined product supply costs was the No Expansion Scenario, which led to a 0.6 percent reduction in costs of total refined products in 2030 versus the scenario for the proposed Project because of the artificial discount in crude oil prices obtained from the shut-in of WCSB crude oil supply. Finally, the EnSys analysis found that the import to or export from the United States of refined products was not sensitive to the seven pipeline scenarios considered.

It is reasonable to infer based on the EnSys (2010) results, when viewed in combination with the results from the Morrow et al. (2010) study, that 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, alternative transportation fuels (including electrification of the vehicle fleet), or total vehicle miles traveled. The Morrow et al. (2010) report concluded that increases in gasoline prices that would be orders of magnitude greater than likely price impacts of the proposed Project (a $0.42 increase in the cost of a gallon of gasoline in 2030 in the carbon tax scenario) and would only reduce light duty fuel efficiency and light duty total vehicle miles traveled by approximately 1 percent in 2030.

The above factors indicate that even if the United States, or countries around the world, adopt policies that would reduce the consumption of crude oil, there is likely to be a market demand for substantial

increases in the volume in crude oil derived from the oil sands over the next 20 to 25 years. In addition, for all scenarios examined in the EnSys (2010) report, the total throughputs of oil-sands-derived crude oil at PADD III refineries was actually higher in the low-demand outlook than in the AEO outlook. This is because in the low-demand outlook, the reduction in demand for refined transportation fuels in PADD II leads to less oil-sands-derived crude oil being refined there. There would also be a reduction in demand for refined transportation fuels from PADD III refineries, but the volume of oil-sands-derived crude oil that would have been refined in PADD II would be rerouted to PADD III and would displace imports from other countries.

For these reasons, use of alternative energy sources and energy conservation in meeting needs for transportation fuel are not considered an alternative to the proposed Project.

4.1.3.2 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 III refineries in 2009 (EIA 2010a, 2010b). The distillate fuel oil was sold for use in the following categories listed by EIA (2010b):

- "Oil company";
- Industrial use;
- Commercial;
- Electrical power; and
- 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 III 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 III. 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 III 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 III 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 III 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 III refineries.

The use of distillate fuel oil produced by PADD III refineries for the generation of electrical power represents about 0.01 percent of the total output of PADD III refineries. Electrical generation currently fueled by residual fuel from PADD III 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 III 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 III refineries and there would be essentially no effect on the current and future crude oil needs of those refineries.

4.1.3.3 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 III 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 III refineries and the use of alternative fuels and conservation would have a negligible effect on the market demand for crude oil in PADD III.

4.1.3.4 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 II in 2009 was used for transportation purposes. The remaining 22 percent of PADD III 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 and 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 III production. For the most part, these three specialty products (as well the other specialty products produced by PADD III 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 III.

4.1.4 Summary

PADD III refineries currently import approximately 5.1 million bpd of crude oil, including 2.9 million bpd of heavy crude oil (EnSys 2010), the majority of which comes from Mexico, Venezuela, Saudi Arabia, and Nigeria. As reported by EnSys (2010), the demand for crude oil in PADD III is projected to increase and PADD III refinery runs are projected to grow over the next 10 years, even under the low demand outlook. At the same time, three of the four major PADD III crude oil suppliers currently face declining or uncertain production horizons (EnSys 2010). As a result, the market demand in PADD III for heavy crude oil from alternative sources is expected to increase in both the near term and further into

the future. Implementation of the No Action Alternative would not meet this need for heavy crude oil in PADD III, unless a system alternative went forward to connect PADD II to PADD III or to directly transport WCSB crude oil to PADD III. Such alternatives would likely not receive regulatory approval prior to the proposed Project.

If the proposed Project, a similar pipeline system, or another transport mode is not constructed to transport WCSB crude oil to PADD III refineries, those refineries would be forced to rely on oil shipped by barge or tanker from areas outside of North America from regions which are experiencing declining production or are not secure and reliable sources of crude oil. As a result, in the near term, PADD III would continue to be dependent on less reliable and less stable foreign oil supplies from the Middle East, Africa, Mexico, and South America.

EnSys (2010) also projected that there would be no substantial change in total U.S. refining activity, total crude and product import volumes and costs, or global refinery CO2 and total life-cycle GHG emissions whether or not the proposed Project is implemented. Additionally, EnSys (2010) determined that with implementation of the No Action Alternative, the production of crude oil from the Canadian oil sands projects would not be affected and that production would continue at current or higher levels through 2030 unless no other pipeline system or other projects were implemented to transport crude oil from the oil sands projects, an outcome that EnSys considered unlikely.

Under the No Action Alternative, crude oil from the WCSB would not have a ready conduit for export to available refineries and markets in PADD III, and it is therefore likely that alternative transportation systems to move oil to other markets would emerge. Crude oil would be transported by other proposed, planned, or existing pipelines or by alternative transportation methods (such as railroad tank cars, barges, or crude oil tankers) to markets in the global marketplace (these system alternatives are discussed in greater detail in Section 4.2). Several projects have been proposed or are planned to transport WCSB crude oil from the oil sands projects to ports in Canada and in the northwestern and northeastern U.S. Although it is not possible to identify the specific impacts of such projects, it is likely that the impacts of other pipeline projects would be similar in nature to those of the proposed Project. The extent and magnitude of the impacts would likely be different from project to project and would depend on the environmental conditions along the proposed routes. In addition, the transport of crude oil by tanker rather than by pipeline would likely result in greater transportation-related GHG emissions. Under the No Action Alternative, the near-term positive socioeconomic impacts associated with construction and operation of the Project would not be realized along the proposed route and elsewhere in the U.S. No annual property tax revenues would be generated, as opposed to an estimated $138.4 million in annual property tax revenues that would be generated by the proposed Project in the region of influence. The generation of local employment as well as substantial expenditures on goods and services would also not occur under the No Action Alternative. However, if an alternative pipeline is constructed in the future, socioeconomic benefits would be realized as a result of construction and operation of that alternative.

Under the No Action Alternative, improved fuel efficiency and broader adoption of alternative fuels would not likely substantially alter the demand for WCSB heavy crude oil at PADD III refineries for the production of transportation fuels. Other energy sources could potentially replace the energy derived from non-transportation-related uses of PADD III refinery output. However, the non-transportation uses of PADD III refinery output represent a very small percentage of total PADD III refinery output. Therefore, the No Action Alternative would have little effect on overall demand for refinery products that are currently sold by PADD III refineries for non-transportation uses.

As a result of these considerations, DOS does not regard the No Action Alternative to be preferable to the proposed Project.

4.2 SYSTEM ALTERNATIVES

System alternatives to the proposed Project would make use of other existing, modified, proposed or planned pipeline systems, or other transportation systems to meet the purpose of and need for the proposed Project. With implementation of a system alternative to meet the objectives of the Project, the Project would not be constructed and the impacts described in this EIS would not occur. However, as noted below, there would be environmental impacts associated with any system alternative that would meet the purpose and need of the proposed Project. Each system alternative considered was screened for its potential environmental effects versus similar environmental effects for the proposed Project, technical and economic practicability, and the ability to meet the purpose of and need for the proposed Project.

The system alternatives screened include the following:

- Use of Existing or Expanded Pipeline Systems (Section 4.2.1);
- Use of Other Proposed or Planned Pipeline Systems (Section 4.2.2);
- Alternative Modes of Transportation (Section 4.2.3); and
- Intermodal and Combined Transport Systems (Section 4.2.4).

4.2.1 Use of Existing or Expanded Pipeline Systems

Four existing pipeline systems were considered as potential system alternatives. Those systems are described and assessed in the following sections:

- ExxonMobil Pegasus Pipeline (Section 4.2.1.1);
- Express-Platte Pipeline System (Section 4.2.1.2);
- Keystone Oil Pipeline Project (Section 4.2.1.3); and
- Alberta Clipper Pipeline Project (Section 4.2.1.4).

4.2.1.1 ExxonMobil Pegasus Pipeline

There is currently only one pipeline system that extends from the Midwest to the Gulf region: the ExxonMobil Pegasus Pipeline. That system currently transports up to 96,000 bpd of Canadian crude oil from Patoka, Illinois to Nederland, Texas. As described in Section 1.1 the proposed Project would initially transport approximately 535,000 bpd of crude oil to the Cushing tank farm and to delivery points in Texas. Therefore, the Pegasus pipeline would not be capable of delivering the proposed Project's WCSB crude oil volume even if used to full capacity, particularly since most of its capacity is already dedicated to crude oil transport from PADD II to PADD III. Delivering the volumes contracted to the proposed Project would require a substantial expansion of the Pegasus pipeline. Any future expansion of the Pegasus pipeline system would result in impacts along the 835-mile-long route between Patoka and Nederland that would be broadly similar to those of the proposed Project, albeit over a shorter total distance.

In summary, the existing Pegasus pipeline cannot be used to meet the proposed Project's objectives in the near term and there are no announced plans to expand the pipeline. Therefore, the Pegasus Pipeline was not further considered as a system alternative to the proposed Project.

4.2.1.2 Express-Platte Pipeline System

The Express-Platte Pipeline System is a 1,700-mile-long oil transportation network that connects Canadian and U.S. producers to refineries in the Rocky Mountain and Midwest regions of the U.S. The system consists of two crude oil pipelines – the Express Pipeline and the Platte Pipeline. The Express Pipeline transports a variety of light, medium, and heavy crude oil from Hardisty to markets in Montana, Wyoming, Utah, and Colorado, and has a capacity of 280,000 bpd. The Express Pipeline connects to the Platte Pipeline system at Casper, Wyoming. The Platte system transports crude oil from Casper to Wood River, Illinois and has a capacity of 164,000 bpd from Casper to Guernsey, Wyoming. From Guernsey to Wood River, the system has a capacity of 145,000 bpd.

The Express-Platte Pipeline System originates in Hardisty, as would the proposed Project, and passes close to the northern end of the Cushing Extension (near Steele City, Nebraska). However, the Express system has firm commitments for 235,000 bpd that will not expire until 2012 and 2015 and would therefore not have sufficient capacity to meet the market demand to which the proposed Project is responding without a major expansion of the system. In addition, to meet the market demand for heavy crude oil at PADD III refineries and to the Cushing area, use of the Express-Platte Pipeline System as a system alternative would require either (1) a short pipeline to connect to the northern end of the Cushing Extension along with a new pipeline to the Gulf Coast that would likely be similar to the proposed Gulf Coast Segment of the proposed Project, or (2) a new pipeline from the existing Express-Platte pipeline to the Gulf Coast. Either expansion alternative would result in environmental impacts from the northern end of the Cushing Extension to the Gulf Coast delivery points that would be broadly similar to or greater than the Gulf Coast Segment of the proposed Project.

In summary, the existing Express-Platte pipeline cannot be used to meet the proposed Project's objectives in the near term, and expansion of the system to meet the capacity requirements of the proposed Project would not be environmentally preferable to construction and operation of the proposed Project. Therefore, the Express-Platte Pipeline System was not further considered as a system alternative to the proposed Project.

4.2.1.3 Keystone Oil Pipeline Project

The existing Keystone Oil Pipeline Project extends from the U.S. border in North Dakota to Patoka, Illinois; it also includes the Cushing Extension which extends from Steele City, Nebraska to Cushing, Oklahoma. It currently has the capacity to transport 435,000 bpd of WCSB crude from Canada to refineries in PADD II. On December 22, 2010, Argus.com (2010) reported that the existing Keystone Oil Pipeline was transporting approximately 250,000 bpd of crude oil.

Keystone has firm contracts to transport 380,000 bpd on the proposed Project and intends to also transport 155,000 bpd of crude oil on the proposed Project to Cushing, Oklahoma that was originally contracted for transport on the existing Keystone Oil Pipeline for a total initial throughput of 535,000 bpd. For the existing Keystone Oil Pipeline to serve as a system alternative to the proposed Project, it would first need to accommodate its current obligations to ship 155,000 bpd to the existing Cushing terminal and 340,000 bpd to Wood River and Patoka, Illinois, or a total current commitment to ship 495,000 bpd. The excess capacity of the Keystone Oil Pipeline based on these commitments is 96,000 bpd. The Keystone Oil Pipeline does not have the capacity to transport the additional crude oil currently contracted on the proposed Project, and therefore this potential system alternative could not meet the proposed Project objectives without a major expansion in both Canada and the U.S. In addition to the expansion of existing facilities, it would be necessary to construct a pipeline from Cushing to the Gulf Coast area of PADD III that would be essentially the same as the Gulf Coast Segment of the proposed Project. The overall expansion would result in environmental impacts that would be similar to those of the proposed

Project, and would require federal permits in both Canada and the U.S. as well as applicable provincial, state, and local permits.

In summary, the existing Keystone Oil Pipeline cannot be used to meet the proposed Project's objectives in the near term, and due to the overall system expansion required, it would not offer an overall environmental advantage over the proposed Project. Therefore, the existing Keystone Oil Pipeline was not further considered as a system alternative to the proposed Project[4].

4.2.1.4 Alberta Clipper Pipeline Project

Commenters on the draft EIS and supplemental draft EIS have suggested that Enbridge's Alberta Clipper Pipeline Project could be used to transport crude oil from Hardisty to Cushing. The Alberta Clipper Pipeline extends from Hardisty to Superior, Wisconsin and has the current capacity to deliver an average of 450,000 bpd of crude oil from a supply hub near Hardisty to an existing terminal in Superior with a potential maximum capacity of 800,000 bpd assuming additional pumping capacity is added at appropriate locations along the pipeline corridor. During the NEB hearings on the proposed Project, Enbridge made public its position that Keystone could establish a connection to the Alberta Clipper Pipeline near Gretna, Manitoba, construct a pipeline adjacent to the existing Keystone Oil Pipeline to the Cushing Extension, and construct a new pipeline from the southern end of the Cushing Extension to PADD III delivery points. However, during the NEB hearings, Enbridge did not indicate what capacity it would make available to Keystone on its pipeline. To meet flow requirements of the proposed Project, the Alberta Clipper Pipeline would have to be expanded in Canada which would result in additional impacts from the U.S./Canada border to Hardisty. Keystone has stated that the concept introduced by Enbridge at the NEB hearings would require commercial negotiation of acceptable terms and conditions among Keystone, Enbridge and its stakeholders, and shippers on the proposed Project. Keystone and Enbridge discussed the concept further in March 2009 at a meeting arranged by CAPP. Minutes of the meeting were filed as part of the NEB record. As a result of that meeting, Keystone identified business issues of concern and requested a proposal from Enbridge to resolve those issues but did not receive a response. The NEB did not pursue this alternative to the proposed Project beyond limited questioning by the members of the NEB and its staff.

Using the Alberta Clipper Pipeline Project as a potential system alternative would require expansion of existing infrastructure and would produce impacts in Canada and the U.S. similar to those for the Keystone Oil Pipeline system alternative described in Section 4.2.1.3. Additionally, it is not clear that the initial committed flow volumes (535,000 bpd) of the proposed Project could be accommodated by this system alternative due to the contractual issues described above even if the Alberta Clipper system was expanded to its maximum capacity of 800,000 bpd. As a result, the Alberta Clipper Pipeline Project was not considered further as a reasonable system alternative for the proposed Project.

4.2.2 Use of Other Proposed or Planned Pipeline Systems

Other new pipeline system alternatives have been proposed or planned by proponents that if successfully designed, permitted, and constructed could transport crude oil from the oil sands of the WCSB to the PADD III market, either via a direct link from the WCSB to PADD III, or by interconnecting to existing pipeline systems that transport WCSB crude oil into PADD II. For a potential new pipeline system to be considered a viable alternative to the Project, it must meet the purpose of and need for the Project as described in Section 1.2.

[4] An alternative route that would parallel the existing Keystone Oil Pipeline Project in the U.S. is addressed in Section 4.3.3.4.

The proponents of five of the potential system alternatives described below initially announced conceptual plans for the projects and then either abandoned the plans or put them on hold. None of those proponents have established commercial commitments through open seasons and have not submitted permit applications as of this writing. Although at this time the possibility of the future development of those projects is speculative, they are described below and assessed relative to their potential to meet the proposed Project's objectives. The eight potential pipeline system alternatives considered are described in the following sections:

- Altex Pipeline System (Section 4.2.2.1);
- Chinook-Maple Leaf Pipeline System (Section 4.2.2.2);
- Texas Access Pipeline (Section 4.2.2.3);
- Enbridge Trailbreaker Project (Section 4.2.2.4);
- Enbridge-BP Delivery System (Section 4.2.2.5);
- Enbridge Monarch Pipeline (Section 4.2.2.6);
- Seaway Pipeline (Section 4.2.2.7); and
- Double E Pipeline (Section 4.2.2.8).

4.2.2.1 Altex Pipeline System

Plans for the Altex (Alberta-Texas) Pipeline System were initially announced in 2005 by the Calgary-based energy infrastructure-development company, Altex Energy Ltd. The planned Altex Pipeline System included a 2,360-mile-long greenfield pipeline system that would originate north of Fort McMurray, Canada, extend to the Redwater-Fort Saskatchewan area, and from there to Hardisty, Alberta. From Hardisty south it would cross the U.S./Canada border in Montana and extend southeast through Montana, Wyoming, South Dakota, Nebraska, Kansas, Oklahoma, and Texas to the Port Arthur area. As initially planned, service would start no sooner than 2013, with a proposed initial crude oil capacity of 425,000 bpd. In 2008, Altex determined that the project as planned was not economically viable and therefore did not pursue it further. Thus, there has not been an open season, shipper commitments, or an application for a Presidential Permit or other permits in the U.S. and the planned Altex Pipeline System was not considered further as a system alternative to the proposed Project.

After determining that the Altex Pipeline System would not be viable in the near term, Altex concluded that it could develop an interim transportation system that would be financially acceptable during the period that oil sands production increased to the point of making the Altex Pipeline System economically viable. As stated by Altex, the plan would involve transporting bitumen by rail to virtually any market within North America. In 2008, the Canadian National Railway and Altex developed a conceptual plan to accomplish transport of bitumen, not crude oil (termed PipelineOnRailTM**).**

Altex has negotiated long-term rail rates with Canadian National and is offering transportation services in Canada to bitumen producers at rates less than the cost of their pipeline transportation alternatives. To support shippers' needs, Altex stated that it intends to construct terminals near Peace River, Ft. McMurray, and possibly Ft. Saskatchewan, Alberta. The use of rail as an alternate mode of transportation is addressed in Section 4.2.3.2 (Railroad Tank Car Transport).

4.2.2.2 Chinook-Maple Leaf Pipeline System

The Chinook-Maple Leaf Pipeline System was a conceptual project originally considered by Kinder

Morgan and TEPPCO (now merged with Enterprise Products Partners, LP). This 2,050-mile-long pipeline system would originate near Hardisty, Alberta and cross the U.S./Canada border from Alberta into Montana. It would then traverse Montana, Wyoming, Colorado, Kansas, Oklahoma, and Texas to deliver crude oil to the Houston area. The northern portion of the route would be adjacent to the existing Kinder Morgan Express Pipeline.

The Chinook-Maple Leaf Pipeline System was planned to have a capacity of 440,000 bpd between Hardisty and Cushing (Chinook Pipeline), and 550,000 bpd between Cushing and Houston (Maple Leaf Pipeline). If this system were not fully subscribed it could transport a portion of the oil planned for transport in the proposed Project; however, it would not have the capacity to meet the market demand to which the proposed Project is responding (firm contracts to deliver 535,000 bpd across the border, with 155,000 bpd delivered to Cushing and 380,000 bpd delivered to the Gulf Coast).

The proponents initially indicated a planned in-service date of late 2011 or early 2012 (CAPP 2008) for the Chinook-Maple Leaf Pipeline System. However, at the time this EIS was prepared the proponents had not announced an open season or shipper commitments or applied for a Presidential Permit or other permits in the U.S. In addition, neither company lists the Chinook-Maple Leaf Pipeline System as a potential future project. Therefore, the Chinook-Maple Leaf Pipeline System was not considered further as a system alternative to the proposed Project.

4.2.2.3 Texas Access Pipeline

In December 2007, Enbridge and ExxonMobil Pipeline Company announced plans for a new pipeline system that would transport crude oil from Patoka, Illinois to the Texas Gulf Coast. The proponents indicated that the crude oil transported in the Texas Access Pipeline from Patoka would originate in the Canadian oil sands region of Alberta. The conceptual plan included a 738-mile-long, 30-inch-diameter pipeline that would transport the oil from Patoka to refineries in Nederland, Texas, and an 88-mile-long, 24-inch-diameter pipeline that would transport crude oil from Nederland to a delivery point in an area east of Houston. The initial capacity of the Patoka-to-Nederland segment of the pipeline would be 445,000 bpd, and the initial capacity of the Nederland-to-Houston segment would be 169,000 bpd. If this system were not fully subscribed it could transport a portion of the oil planned for transport in the proposed Project. However, it would not have the capacity to meet the market demand to which the proposed Project is responding (firm contracts to deliver 535,000 bpd across the border, with 155,000 bpd delivered to Cushing and 380,000 bpd delivered to the Gulf Coast) without a major expansion.

The proponents did not receive sufficient interest in the project from shippers to justify the construction costs and the Texas Access Pipeline has not progressed. In 2008, Enbridge stated that, based on current market conditions, the project would not go forward and indicated that "it will likely be required as a large-volume solution, probably in the 2014 area." Therefore, the Texas Access Pipeline was not considered further as a system alternative to the proposed Project.

4.2.2.4 Enbridge Trailbreaker Project

In 2008, Enbridge proposed the Trailbreaker Project as an interim option to the Texas Access Pipeline for supplying crude oil to PADDs II and III. As announced, the Trailbreaker Project would involve shipping crude oil by pipeline to the northeastern U.S. and transporting crude oil by tanker from there to PADD III as early as mid 2010. The project would have allowed the transport of WCSB oil production to refineries in Ontario, Quebec, the Canadian Maritime Provinces, and U.S. markets. It would have included an expansion of the existing Enbridge Line 6B from Chicago, Illinois to Sarnia, Ontario, as well as terminal expansions and upgrades, increasing the capacity of existing Enbridge Line 7 between Sarnia and Westover, Ontario, and the reversal of the existing Enbridge Line 9 to flow from Sarnia east to Montreal,

Quebec. Another component of the Enbridge Trailbreaker Project would have been the reversal of the pipeline owned by Portland-Montreal Pipe Line (PMPL), which transports product from Portland, Maine to Montreal. In late 2008, PMPL completed an open season to gauge shipper interest in the proposed reversal; however, they did not receive the level of firm volume commitments required to proceed at that time. In January 2010, Enbridge announced that the Trailbreaker Project was dormant, and the project is no longer included in commercial opportunities in investor presentations. Therefore, the Enbridge Trailbreaker Project was not considered further as a system alternative to the proposed Project.

4.2.2.5 Enbridge-BP Delivery System

In 2008, Enbridge and BP announced that they had entered into an agreement to develop the Enbridge-BP Delivery System to transport WCSB heavy crude oil from Flanagan, Illinois, to Houston and Texas City, Texas, using a combination of existing facilities, new pipeline, and looped pipeline construction where required. As initially announced, the project would traverse parts of Illinois, Missouri, Kansas, Oklahoma, and Texas and would be in service by late 2012 with an initial total system capacity of 250,000 bpd to the Gulf Coast. Enbridge and BP intended to use the BP #1 System and other existing pipelines north of the Cushing crude oil hub with some new pipeline construction south of Cushing to connect to markets in Houston and possibly in Nederland. From Flanagan (where the system would interconnect with the Enbridge Southern Access pipeline) to Cushing the capacity would be approximately 140,000 bpd for further transport to Gulf Coast markets. The remaining 110,000 bpd would originate from interconnecting pipelines at Cushing.

At the NEB hearings for the proposed Project, Enbridge stated that the Enbridge-BP Delivery System is still on the books but is suspended. The project is not listed as a potential opportunity in investor presentations. Therefore, the Enbridge-BP Delivery System was not considered further as a system alternative to the proposed Project.

4.2.2.6 Enbridge Monarch Pipeline

In late 2010, Enbridge announced plans for a 24-inch-diameter pipeline that would extend from its oil terminal in Cushing to the Gulf Coast. The pipeline would have an initial capacity of approximately 150,000 bpd, with the ability to expand to about 350,000 bpd. The objective of the Enbridge Monarch Pipeline is to alleviate a bottleneck for light crude oil at Cushing and provide a transportation route from Cushing to the Gulf Coast refineries in PADD III. No further information was available on the project at the time this EIS was prepared.

Although Enbridge has stated that the Monarch Pipeline would transport some heavy crude oil, it is being designed and proposed to transport lighter crudes to the Gulf Coast. Even without the transport of lighter crudes, its maximum capacity would not be sufficient to satisfy market demand to which the proposed Project is responding (firm contracts to deliver 380,000 bpd to the Gulf Coast). Finally, it would be necessary to construct a pipeline to Cushing to supply the WCSB crude oil. The impacts of construction of that pipeline and construction of the Monarch Pipeline would result in impacts that would be similar in nature and extent to those of the proposed Project along the same approximate distance.

Based on the above considerations, the Enbridge Monarch Pipeline was not further considered as a system alternative to the proposed Project.

4.2.2.7 Seaway Pipeline

ConocoPhillips owns the 530-mile-long Seaway pipeline system (operated by Enterprise Products Partners LP) which transports crude oil from the Houston area to storage facilities at Cushing. The

pipeline has a capacity of approximately 350,000 bpd. The system also supplies crude oil to refineries in the Houston area and has a usable storage capacity of 3.4 million barrels. In 2007, the former operator of the Seaway Pipeline (Teppco Partners, LP) stated it would consider reversing the line to transport crude oil from Cushing to PADD III. However, Bloomberg (2011) stated that ConocoPhillips had decided that it would not reverse the pipeline. As a result, the Seaway pipeline was not further considered as a system alternative to the proposed Project.

4.2.2.8 Double E Pipeline

Enterprise Products Partners L.P. and Energy Transfer Partners, L.P. have formed a joint venture to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. The Double E Pipeline would provide up to 450,000 barrels per day of takeaway capacity for crude oil currently stranded at the Cushing storage hub due to a lack of southbound pipeline infrastructure. The pipeline would offer greater access to Gulf Coast refineries, while providing refiners with a reliable, domestic source of crude oil as an alternative to higher priced imported crude oil that currently represents their largest source of supply. The Double E Pipeline would utilize existing pipelines and construct 354 miles of new pipeline, to create a 584-mile long pipeline which would originate at crude oil storage facility owned by Enterprise in Cushing, Oklahoma and terminate at the ECHO crude oil storage and terminal facility owned by Enterprise in southeast Harris County, Texas. The ECHO crude oil terminal would offer access to major Texas Gulf Coast refining centers in Texas City, Pasadena/Deer Park, Baytown and on the Houston Ship Channel. The open season for the Double E Pipeline ended on August 12, 2011. Subject to shipper commitments during the open season and the required regulatory approvals, the proponents expect the new pipeline to begin service in the fourth quarter of 2012.

4.2.3 Alternative Modes of Transportation

Three modes of surface transportation of crude oil from the U.S./Canada border near Morgan to Cushing, Nederland, and Moore Junction were considered as alternatives to the proposed Project as described in the following sections:

- Truck Transport (Section 4.2.3.1);
- Railroad Tank Car Transport (Section 4.2.3.2); and
- Barge and Marine Tanker Transport (Section 4.2.3.3).

4.2.3.1 Truck Transport

The transport of crude oil by truck is occasionally done to serve as an interim transportation solution for smaller volumes of crude oil or petroleum product. For example, due to pipeline limitations in the Bakken oil field in Montana and North Dakota, a portion of the crude oil produced in that area is currently transported by tank truck. However, transport by truck is not a reasonable alternative to transport the volume of oil that would be shipped by the proposed Project. Large tank trucks have a maximum volume of about 9,000 gallons (about 214 barrels). It would therefore require about 2,500 trucks per day to transport the 535,000 bpd that the Project would initially transport. To sustain a delivery rate of 535,000 bpd, as many as twice that number of trucks would likely have to be devoted exclusively to traveling to and from the border and the delivery points.

Table 4.2.3-1 summarizes accident statistics by method of transport compiled by Association of Oil Pipe Lines (AOPL). As indicated in the table, transport of oil by pipeline is substantially safer than transport by trucking. AOPL reported that trucking is 87 times more likely than pipeline transport to result in a human fatality. In similar findings, fire and/or explosions are 35 times more likely when transporting

crude oil via truck. Vehicle accidents and accidental releases are also concerns with surface transportation crude oil delivery. The Bureau of Transportation Statistics (2009) reported that the transport of hazardous liquids (including crude oil) on highways resulted in five times as many fatalities as transportation of hazardous liquids by pipeline between 1975 and 2007.

TABLE 4.2.3-1
Reported Incident Rates for Alternative Methods of Liquids Transport

Method of Transport [a]	Death	Fire/Explosion	Injury
Truck	87	35	2
Rail	3	9	0.1
Barge	0.2	4	4
Tank Ship	4	1	3
Pipeline	1	1	1

[a] Relative rates were calculated based on incidents per ton-mile for each transportation mode (AOPL 2004).

The trucking alternative would add substantial congestion to highways in all states along the route selected, particularly at and near the border crossing and in the vicinity of the delivery points. At those locations it is likely that there would be significant impacts to the existing transportation systems. The trucks would consume millions of gallons of fuel per year, with subsequent exhaust emissions (including GHG) and other negative environmental effects. Trucking would likely be subject to interruptions due to unfavorable weather and road conditions, especially in Montana and other northern states. At the Gulf Coast delivery points, surface transportation would necessitate substantial new transfer facilities and personnel.

As a result of these considerations, truck transportation was not considered a reasonable alternative to meeting the Project objectives and was not further evaluated.

4.2.3.2 Railroad Tank Car Transport

As noted in Section 4.2.2.1, Altex and the Canadian National Railway have developed a transportation strategy termed PipelineOnRailTM to move oil sands production to markets in North America or Asia. At the end of 2010, the system was shipping approximately 10,000 bpd within Canada from producers whose reserves are stranded without pipeline access. The system reportedly could have the capacity to ship up to 4 million bpd throughout North America (Financial Post 2009). Canadian National stated that it can ship crude oil directly into the U.S. or to the Canadian west coast for shipment to Asia. The system would use insulated and heated double-hulled tank cars to ship bitumen or would ship bitumen diluted with condensates or other diluents (CN 2010). Canadian National also stated that the rail system to the west coast of Canada is already in place and it could ship 2.6 million bpd to the west coast of Canada if 20,000 tank cars were added to its fleet. It further stated that the increase in the number of rail tank cars in use would not clog its system in Canada (Financial Post 2010). As noted in The Globe and Mail (2011), Canadian National is currently transporting crude oil from the Bakken area of southern Saskatchewan to the U.S. Gulf Coast. The current and projected takeaway capacity from the Williston Basin to PADD II and PADD III is discussed Section 3.14.2.1. As noted in that section, EnSys (2011) reported that the rail-loading capacity for Williston Basin crude oil could be as high as 750,000 bpd by 2013.

The maximum size tank car allowed by regulations in 49 CFR 179.13 is 34,500 gallons (about 820 barrels). Use of these cars to ship 535,000 bpd would require approximately 650 rail tank cars per day at

the delivery sites and returning to Canada. At maximum capacity, approximately 1,010 rail tank cars would be required to unload at the delivery points each day. It is likely that unit trains would be created and devoted exclusively to the Project, with each train consisting of from 60 to 100 tank cars. Transporting the maximum throughput of 830,000 bpd would require from about 10 to 17 unit trains delivering oil to the receipt points each day, as well as at least the same number of trains making the return trip. It is possible that for continuous operation, the transporters may need to have additional trains in transit along the route or routes selected.

The number of train trips required would likely affect traffic on the existing rail system in the vicinity of the route used from the Canadian border to the Gulf Coast. For example, this volume of rail traffic may result in periodic or long-term rerouting of some existing train traffic in the regions of the route selected by Canadian National. This alternative would also directly affect communities that have rail lines that would be used for this transport or by creating delays on the rail lines due to the substantial increase in rail traffic across railroad crossings of roads. There could be indirect impacts to some communities due to the redirection of some existing rail traffic to other rail lines and due to increased traffic on those lines. This alternative would also substantially increase noise along the route selected and in communities indirectly affected due to increases in redirected train traffic. In addition, there would be an increase in the emission of combustion products due to the use of diesel engines which could have an adverse impact on air quality along the route selected. As compared to the proposed Project, this alternative would have substantially greater GHG emissions during operation due to the combustion of diesel fuel.

Interruptions in the delivery of crude oil would be more likely than with the proposed Project due to conditions such as weather and congestion of the rail lines. To meet the market demand that the proposed Project would meet, rail systems development would likely include new infrastructure such as spur lines, train storage yards at the delivery points, and additional oil storage facilities. Development of these facilities would likely produce localized impacts, but these impacts would not occur along the same distance as those of the proposed Project since many existing rail lines would be available for use. As noted above, during normal operations the impacts on communities in the vicinity of utilized rail lines and in communities affected by redirected rail traffic would likely be greater than those of the proposed Project during normal operations.

As noted in Table 4.2.3-1, rail transport of liquids is not as safe a mode of transportation as pipelines. With the number of trains and tank cars required to transport volumes of crude oil similar to those of the proposed Project, the safety of communities along the route could be an issue of concern. The maximum release of oil from a train accident would likely be less than the maximum possible release from the proposed Project.

The use of rail tank cars for delivery of WCSB crude oil may not be as cost-effective as transport by pipeline and may result in higher transportation costs. Although the Canadian National website has suggested that transport prices on rail are at least competitive with pipeline tariffs, the EnSys (2010) report states the following regarding PipelineOnRailTM:

> "This study did not allow for the expansion of the Pipeline*OnRail*™ capacity in any scenario because tariffs for rail are generally not considered attractive relative to pipelines. However, during a period of constrained pipeline capacity, the Pipeline*OnRail*™ could compete as an alternative."

In summary, the use of existing or enhanced rail systems to transport the volume of crude oil that would be transported by the proposed Project would likely produce less impact from construction than would the proposed Project. However, there would likely be greater safety concerns and greater impacts during operation, including higher energy use and GHG emissions, greater noise impacts, and greater direct and

indirect effects on many more communities than the proposed Project. Rail transportation would also be subject to more frequent delivery interruptions than the proposed Project. As a result, transportation of the volume of crude oil that would be transported by the proposed Project entirely by rail tank car would not offer an overall environmental or safety advantage over the proposed Project.

4.2.3.3 Barge and Marine Tanker Transport

As stated in EnSys (2011), a wide range of viable opportunities exists for moving potentially substantial volumes of WCSB crude oils to multiple markets using barges or tankers either in conjunction with or independent of existing pipelines. Options include:

- Moving both domestic and WCSB crude oils from PADD II to PADD III refineries along river systems;
- Intermodal transport of WCSB crude oils across the Great Lakes if pipelines running within Canada were extended to the Great Lakes or rail movements were employed. Destinations could include PADD II and PADD III refineries if barge transportation is included and to refineries in eastern Canada via the St. Lawrence Seaway; and
- Potential expansion of transport via tanker from British Columbia ports to PADD III refineries.

Inland transport of crude oil by barge to PADD III from the U.S./Canada border would require an inland waterway capable of supporting barge traffic to Cushing and to PADD III. However, there is no inland waterway that could accommodate that traffic and therefore barge transport of crude oil to the delivery points at Cushing and in Texas was not considered a reasonable alternative. Barge transport could serve as an element of intermodal transport of crude oil to PADD III in conjunction with railroad tank cars, trucks, or pipelines. Currently, trucks are transporting 5,000 bpd of crude oil from Cushing, Oklahoma in PADD II to the port of Catoosa in Tulsa, Oklahoma for barge shipment along the Arkansas and Mississippi Rivers to refineries in the Saint James, Louisiana area in PADD III.

Marine transport by either barge or marine tanker would require that crude oil be transported from the WCSB producers to ports on either the east or west coasts of Canada or the U.S. The Enbridge Trailbreaker, discussed in Section 4.2.2 as a system alternative, was a previously proposed transportation plan that would have transported crude oil to a northeast U.S. port and shipped it by marine tanker to PADD III. However, that project is not being actively pursued by Enbridge and was not further considered as a system alternative to the proposed Project. In addition, although marine transport by either barge or tanker to PADD III would be possible, it would require other forms of transport as well to reach Cushing, and therefore would not meet all proposed Project objectives without additional infrastructure.

As noted in Section 4.1, there are several proposed projects that would transport WCSB crude oil to the Canadian west coast for transport from existing, modified, or new marine terminals. Although those projects could be considered potential system alternatives, implementation of the projects would not be possible in the time frame necessary to meet the proposed Project objectives. Construction of those projects would have impacts that would be similar in nature, extent, and magnitude as those of the proposed Project, although the impacts would likely occur only in Canada.

Transport of crude oil by marine tanker or barge would result in substantially more energy consumption than transport by the proposed Project and would result in substantially more GHG emissions than during operation of the proposed Project. As noted in Table 4.2.3-1, both marine tanker and barge transport of hazardous liquids have greater safety concerns than transport by pipeline. Additionally, this method of transport to the Gulf Coast would be more costly than transport by pipeline.

In summary, marine transport of WCSB crude oil would not meet the proposed Project objectives, would result in greater energy consumption and GHG emissions, would increase the cost of delivered crude oil to the Gulf Coast refineries, and would have greater safety concerns than the proposed Project. Therefore, marine transport of WCSB crude oil was not further considered as a system alternative to the proposed Project.

4.2.4 Intermodal and Combined Transport Systems

None of the individual pipeline system alternatives considered in Sections 4.2.1 and 4.2.2 would supply a sufficient volume of crude oil to satisfy the near-term market demand of Gulf Coast refineries and therefore would not meet the purpose of the proposed Project. DOS then considered various combinations of those pipeline systems and determined that no combination of existing and proposed pipeline systems would deliver a similar volume of crude oil to PADD III without constructing more than one of the proposed pipelines from PADD II to PADD III. More than one new pipeline would be required based on the volumes that are planned for the pipelines as described in Section 4.2.2. A combination of the pipeline systems considered could, over time, deliver volumes of Canadian oil sands crude oil in volumes similar to the volumes that would be transported by the proposed Project. However, that would not meet the near-term need for heavy crude oil at the Gulf Coast refineries and the required construction of these new pipelines would likely produce, in combination, greater impacts than the proposed Project Gulf Coast Segment.

An intermodal crude oil transportation system that comprised some combination of new or expanded pipelines, railroad tank cars, trucks, and barges could potentially deliver a volume of WCSB crude oil and other crude oils to PADD III similar to or greater than the volume that would be transported by the proposed Project (EnSys 2011). However, in combination, the construction of additional pipeline capacity and additional railroad, barge and truck loading and unloading facilities would likely result in impacts similar to or greater than those of the proposed Project Gulf Coast Segment. Additionally, during operations, rail, barge and truck transport of substantial quantities of crude oil would not offer a similar level of safety as that of the proposed Project, and these combined transport modes would not offer an environmental advantage over the proposed Project, as described in Section 4.2.3.

4.3 MAJOR ROUTE ALTERNATIVES AND ROUTE VARIATIONS

4.3.1 Introduction

DOS considered potential alternative routes to determine whether or not there are route alternatives that would avoid or reduce impacts to environmentally sensitive resources as compared to the impacts of the proposed Project while meeting the objectives of the proposed Project. In identifying route alternatives, consideration was given to suggestions received from tribes, agencies, and the public during the scoping period and in comments on the draft EIS. In addition, variations to the proposed route were also considered. Variations are relatively short deviations from a proposed route that are developed to resolve or reduce construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, residences, and terrain conditions.

This section addresses major route alternatives by segment and route variations in the following subsections:

- Approach (Section 4.3.2);
- Alternative Routes for the Steele City Segment (Section 4.3.3);

- Alternative Route for both the Steele City Segment and Cushing Extension (Western Alternative; Section 4.3.4);
- Alternative Routes for the Gulf Coast Segment (Section 4.3.5);
- Alternative Routes for the Houston Lateral (Section 4.3.6); and
- Route Variations (Section 4.3.7).

The agency preferred route is presented in Section 4.3.8.

4.3.2 Approach

The alternatives analysis was conducted as a screening process that involved the following steps:

- Establish criteria for screening alternatives;
- Identify potential alternatives that meet the criteria;
- Determine whether the potential alternatives could meet the purpose and need of the proposed Project and whether or not they would be technically and economically practicable; and
- For those alternatives that could meet the purpose and need of the proposed Project and appear to be technically and economically practicable, determine whether or not an alternative offers an overall environmental advantage over the proposed route. If it was determined that the potential alternative would not offer an overall environmental advantage, it was eliminated from further consideration.

4.3.2.1 Screening Criteria

Control Points Criterion

The control points are locations where alternatives would have to begin and end to meet the Project objectives. These fixed control points, which placed geographic constraints on potential alternatives, consisted of the following:

- The U.S./Canada border crossing between Saskatchewan and Montana near the town of Morgan, Montana where the pipeline of the Canadian portion of the proposed pipeline terminates (the Canadian portion of the pipeline has already been permitted) – that control point is the northern end of the Steele City Segment;
- The northern end of the existing Cushing Extension of the Keystone Oil Pipeline near Steele City, Nebraska – that control point is the southern end of the Steele City Segment;
- The southern end of the Cushing Extension in Cushing, Oklahoma – that control point is the northern end of the Gulf Coast Segment;
- The crude oil delivery point in PADD III at Nederland, Texas – that control point is the southern end of the Gulf Coast Segment; and
- The crude oil delivery point near Moore Junction, Texas – that control point is the southwestern end of the Houston Lateral.

These control points provide the basic framework for identifying alternative routes. However, as described in Section 4.3.3.1, in response to an agency scoping comment and comments on the draft EIS and supplemental draft EIS regarding alternatives, we also considered alternatives that originated at

Hardisty, Canada and extended into the U.S. at a point other than near Morgan.

The control points at the northern and southern ends of the Cushing Extension were established to take advantage of the nearly 300 miles of 36-inch-diameter pipe that is currently in place and available for use by modifying the operation of the existing Keystone Oil Pipeline. Use of the Cushing Extension would avoid the impacts associated with construction of a pipeline of similar length. However, as described in Section 4.3.4, an alternative to using the Cushing Extension was also identified and evaluated.

Avoidance Criterion

The second criterion established was to avoid or minimize effects to or crossing of the following areas to the extent practicable:

- Public lands (except in Montana, where there is a state regulatory preference for the use of public lands; this issue is addressed in Appendix I and in Section 4.3.7);
- Large waterbodies and water control structures;
- Rugged terrain that could impact constructability;
- Large wetland complexes;
- Highly developed urban areas and urban infrastructure;
- Properties listed on the NRHP;
- Wildlife refuges and management areas;
- Key waterfowl use or nesting areas;
- Irrigated croplands;
- Forested areas, including commercial forest lands; and
- Residences and outbuildings.

Although the alternatives identified avoided or minimized crossings of these areas to the extent possible, the extent, shape, and prevalence of many resources (e.g., rivers, historical trails, wetlands, and farmlands) preclude completely avoiding impacts to them on any selected route, particularly for a route that would extend from the U.S./Canada border to the Gulf Coast.

Many commenters on the draft EIS and supplemental draft EIS requested that DOS consider avoidance of or minimization of pipeline length in the Sand Hills topographic region of Nebraska as well as areas in Nebraska underlain by the NHPAQ system. These commenters considered that the potential for accidental oil releases associated with the proposed Project operations would lead to unacceptable risk to the NHPAQ system and that the potential for erosion in the Sand Hills topographic region associated with the proposed Project construction would lead to unacceptable environmental degradation. The NHPAQ system extends across approximately 64,400 square miles of Nebraska, essentially underlying all but the eastern-most portion of the state. Almost all reasonable potential routes through Nebraska from the control point at Morgan, Montana to the control point at the northern end of the existing Cushing Extension would cross the NHPAQ system, including the existing Keystone Oil Pipeline corridor. DOS has addressed these concerns in Sections 3.2, 3.3, and 3.13. Key findings of the analyses in these sections include:

- As discussed in Section 3.13, experience from previous oil pipeline releases in shallow groundwater areas with conditions similar, although not identical to those within the NHPAQ

system indicates that the impacts from even very large spills would likely be limited to localized groundwater contamination that would not threaten the regional viability of the aquifer system.

- The proposed Project would be constructed and operated using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of 57 even more stringent Project-specific Special Conditions developed in consultation with PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the Project-specific Special Conditions that are also provided in Appendix U. In aggregate, these procedures would substantially reduce the potential risk of an accidental oil release from the pipeline anywhere along the proposed Project corridor. As discussed in Section 3.13.4, DOS analyzed databases of historical spills on existing pipeline systems to establish annual spill frequencies per mile of existing pipeline in the U.S. and then applied that frequency to the length of the proposed Project. The DOS estimates of spill frequency based on the PHMSA database for significant spills range from 1.18 incidents per year for hazardous liquid spills to 1.83 incidents per year for crude oil spills greater than 50 bbl (see Table 3.13.4-1). Using the NRC database, DOS estimates of hazardous liquid spill frequencies range from 1.16 incidents per year for spills of any size to 0.6 incidents per year for spills up to 50 bbl. In addition, for crude oil spills, the NRC database estimates range from 1.38 incidents per year to 0.68 incidents per year for spills up to 50 bbl (see Table 3.13.4-2). The estimate of incident frequencies for hazardous liquid and crude oil spills of any size using both the PHMSA significant spill database for spills greater than 50 bbl and the NRC database for spills up to 50 bbl ranged from 1.78 hazardous liquid spills per year to 2.51 crude oil spills of any size per year.
- To assess a spill frequency for the proposed Project specific to the likelihood of a breach of the pipeline itself that would take into account specific design elements, materials strength, anti-corrosion measures, proposed construction and inspection procedures, and applicable regulatory requirements, Keystone performed a two step spill frequency assessment. Keystone initially calculated a baseline spill frequency using the PHMSA (2008) database of 1.38 spills per year. In addition, Keystone then adjusted that spill frequency based on the impact of these proposed Project-specific measures on the key threats to pipeline integrity as described in Section 3.13.4 of the EIS. The adjusted Project-specific spill frequency determined by Keystone for the entire pipeline is 0.22 spills per year (see Table 3.13.4-4).
- During the proposed Project design effort, local Natural Resources Conservation Service (NRCS) offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan and would be incorporated into the implementation of any alternative route across the Sand Hills (see Section 3.2.2.1, Appendix B, and Appendix H for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or any other alternative selected. With proper measures, risks of wind erosion during the time period when vegetation is being reestablished can be largely eliminated.
- The installation and operation of crude oil pipeline systems is a compatible land use in Nebraska under existing federal and state land use policies and regulations. Major pipelines currently overlie the NHPAQ system in Nebraska, including crude oil pipelines (e.g., Kinder Morgan's Express Platte Pipeline and TransCanada's Keystone Oil Pipeline Project) and oil products and ammonia pipelines (e.g., NuStar's pipeline and Magellan Pipeline Company's ammonia and petroleum pipelines (see Figure 4.3.2-1). These crude oil and petroleum products pipelines comprise approximately 1,160 miles of pipelines crossing the NHPAQ system in Nebraska.

As a result of these findings, avoidance of the Sand Hills topographic region and NHPAQ system are not considered appropriate screening criteria for the identification of alternative routes. Also, Keystone has committed to provide replacement water if an accidental release from the proposed Project that is attributable to Keystone's actions contaminates groundwater used for drinking water or irrigation. Nonetheless, DOS considered one potential alternative (Western Alternative) that would avoid the Sand Hills topographic region and NHPAQ system entirely and six potential alternatives (Alternative SCS-A, Alternative SCS-A1A, Keystone Corridor Alternatives 1 and 2, I-90 Corridor Alternatives A and B) that would reduce pipeline mileage crossing either the Sand Hills topographic region or the NHPAQ system. Four of the examined alternatives, the Keystone Corridor Alternatives 1 and 2 and the I-90 Corridor Alternatives A and B, were developed specifically in response to comments received on the draft EIS and supplemental draft EIS and the extensive public debate that has continued since that time. DOS has also considered concerns related to the Sand Hills topographic region and the NHPAQ system in its assessment of alternative routes that meet the four screening criteria for alternative routes.

Length of Alternative Routes Criterion

Within the constraints of the control point criteria, development of alternative routes considered minimizing the length of pipeline that would be required to reach the control points. As a general rule, construction of each mile of pipeline would impact approximately 13.3 acres, not including extra workspaces, access roads, construction yards, pipe yards, and rail yards. Operation of each mile of pipeline would affect approximately 6.0 acres. As a result, there usually are environmental advantages to keeping the length of pipe required to reach the control points as short as possible while considering all other issues of concern.

Distance Parallel to Existing Linear ROW Criterion

In determining potential route alternatives, the fourth criterion was to establish routes that would have all or part of their length parallel to existing linear facility ROWs. Routes were considered parallel to existing ROWs if they were overlapping, directly adjacent to, or within 150 feet of an existing ROW. The industry standard for new pipeline centerline separation from existing pipelines is 25 feet, a distance sufficient to provide room for maintenance and construction restrictions.

The rationale for siting a new pipeline parallel to an existing ROW is that concentrating linear facilities in or near existing linear corridors may reduce the impacts to resources that have not previously been disturbed by major linear project construction. Installation of a new pipeline along existing, cleared ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if the new pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that is not parallel to an existing ROW. In addition, in some cases it may be advantageous to select a new pathway, depending on the number of miles of new construction that may be required to capitalize on existing development corridors and the specific effects of corridor expansion in areas with important human development, cultural resources, or environmental resources. For example, while a new corridor may contribute to habitat fragmentation in areas with currently uninterrupted species use areas, the lateral expansion of an existing corridor with a new ROW may exacerbate the problem along that linear corridor. This criterion addresses the concern of many commenters that DOS should consider an alternative route paralleling the existing Keystone Oil Pipeline along all or part of its route.

4.3.2.2 Identification of Route Alternatives

The four criteria listed in Section 4.3.2.1 were used in the screening process to identify potential

alternative routes to the proposed Project route within each segment. As described in Section 4.3.2, the routes were evaluated based on technical and economic practicability, and whether the or not the route alternative would meet the purpose of and need for the proposed Project. Alternatives that met those criteria were then evaluated to determine whether or not they offered an overall environmental advantage over the proposed route, particularly with regard to the avoidance criterion. Consistent with 40 CFR 1502.14, the reasons for eliminating alternative routes from further detailed study are provided for each potential alternative in the comparison of potential alternatives to the proposed route presented below. Additional information on the proposed Project route is presented in Sections 2.0 and 3.0.

4.3.3 Alternative Routes for the Steele City Segment

The Steele City Segment extends from the U.S./Canada border near Morgan, Montana to the northern end of the Cushing Extension near Steele City, Nebraska. For the Steele City Segment, the following potential route alternatives were considered:

- Express-Platte Alternative Routes (Section 4.3.3.1);
- Steele City Segment (SCS) Alternative A (Section 4.3.3.2);
- Alternative SCS-A1A (Section 4.3.3.3);
- Keystone Corridor Alternatives 1 and 2 (Section 4.3.3.4);
- I-90 Corridor Alternatives A and B (Section 4.3.3.5); and
- Baker Alternative (Section 4.3.3.6).

These alternative routes are depicted in Figures 4.3.3-1, 4.3.3-2, and 4.3.3-3. All alternatives would require inclusion of a new pipeline from the southern end of the Cushing Extension to delivery points in PADD III. In this analysis, it has been assumed that the route of the Gulf Coast Segment and the Houston Lateral of the proposed Project would be included in the Steele City Segment alternatives and that the impacts of construction, operation, and maintenance of those portions of these alternatives would result in impacts that would be identical to those identified in Section 3.

To comply with the requirements of Montana's MFSA, MDEQ considered two other route alternatives in Montana as well as many minor route variations in Montana. The development and analysis of the MFSA-related alternatives and variations in Montana are described in Appendix I to the EIS and summarized in Section 4.3.7.

4.3.3.1 Express-Platte Alternatives

The Express-Platte Pipeline System is a 1,700-mile-long oil transportation network that connects Canadian and U.S. producers to refineries in the Rocky Mountain and Midwest regions of the U.S. The system consists of two crude oil pipelines – the Express Pipeline and the Platte Pipeline. The Express Pipeline extends from Hardisty, Alberta Canada to markets in Montana, Wyoming, Utah, and Colorado. It crosses the U.S./Canada border near the Port of Wild Horse, Montana and connects to the Platte Pipeline system at Casper, Wyoming. The Platte system extends from Casper to Wood River, Illinois.

At the request of MDEQ, Express-Platte Alternative 1 was developed to parallel the Express-Platte System from Hardisty to a point near the northern end of the Cushing Extension where it would require a short new pipeline to connect with the Cushing Extension. Although this alternative would not meet the control point criterion of starting near Morgan, where the Canadian portion of the route ends, the alternative was compared to the proposed route at the request of MDEQ. In addition, Express-Platte

Alternative 2 was developed to meet the control-point criterion; i.e., it would begin at the control point at Morgan. Both of these alternative routes would require construction of a new pipeline to connect the southern end of the Cushing Extension to the delivery points in Texas (Gulf Coast Segment). In the assessment of the two Express-Platte alternatives, it was assumed that the route of the Gulf Coast Segment would be the same as for the proposed Project.

The Express-Platte alternative routes are addressed below. The existing Express-Platte System and the two Express-Platte alternatives are depicted on Figure 4.3.3-1.

Express-Platte Alternative 1

The U.S. portion of Express-Platte Alternative 1 (i.e., the Steele City Segment of the alternative) would be approximately 1,049 miles long. The proposed Project route in this area (Alternative SCS-B) would be approximately 851 miles long. Express-Platte Alternative 1 would parallel the existing Express-Platte corridor through Montana, Wyoming, Nebraska, and Kansas before diverting to connect with the Cushing Extension at Steele City. In comparison, the proposed Project route would be parallel to about 30 miles of existing ROWs along its 851.6-mile length. Although Express-Platte Alternative 1 would parallel an existing pipeline corridor, the existing easements along that corridor are in the control of a different company and it may not be possible to construct the alternative pipeline within the existing ROW.

Comparisons of the impacts of Express-Platte Alternative 1 on key environmental resources with those of the proposed Project route are presented in Table 4.3.3-1. The alternative is about 234 miles longer than the proposed Project route and would affect about 3,200 more acres than the proposed Project route when considering the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance. Express-Platte Alternative 1 would also affect more wetlands, developed land, forested lands, rangeland and grassland, agricultural land, and federal lands as compared to the proposed route. It would also cross more streams and rivers and would extend across approximately 439 miles of the NHPAQ system as opposed to the 247 miles of the proposed route that would extend over the aquifer (see Figure 4.3.3-2). The alternative would cross approximately 31.9 miles of the Sand Hills topographic region as compared to 68.1 miles for the proposed Project.

In comparison to the proposed route, Express-Platte Alternative 1 would cross fewer miles of the Sand Hills topographic region. However, it would be substantially longer, have a greater area of impact, affect more areas of key resources, and would extend over more land underlain by the NHPAQ system. Therefore, the Express-Platte Alternative 1 would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

Additionally, Keystone has obtained the necessary permits to construct the proposed Project in Canada which terminates north of the U.S./Canada border near Morgan. Implementation of Express-Platte Alternative 1 would require submitting a new permit application to NEB for a revised route in Canada, and the approval process would not be completed in a time frame that would meet the proposed Project objectives. For the above reasons Express-Platte Alternative 1 was eliminated from further consideration.

Express-Platte Alternative 2

Express-Platte Alternative 2 was developed to provide an alternative route that would start at the control point near Morgan while still paralleling the existing pipeline system over much of its length. This alternative, which is depicted on Figure 4.3.3-1 and included in the impact comparisons in Table 4.3.3-1, would be approximately 1,085.5 miles long. It would not require a new route in Canada.

TABLE 4.3.3-1
Impact Comparisons for the Steele City Segment Alternatives

Characteristic	SCS-B (Proposed Route)	SCS-A	SCS-A1A	Express-Platte 1	Express-Platte 2	Keystone Corridor 1	Keystone Corridor 2
Total Length (Miles)	851.6	923.2	954.6	1,049.2	1,085.5	1,102.2	639.6
Land Use (Acres)[a]							
Agricultural Land	2,974.6	7,264.5	7,617.6	5,240.6	4,434.2	10,360.5	5,554.3
Barren Land	6.3	8.6	10.5	66.1	81.7	1.5	1.5
Developed Land	174.2	363.8	363.2	432.6	400.7	521.6	323.1
Forested	33.0	89.6	89.9	93.1	140.5	171.1	106.1
Rangeland/Grassland	8,002.7	4,369.0	4,431.7	7,843.3	9,165.2	3,041.3	2,260.6
Wetlands	148.1	150.2	147.9	290.3	229.2	486.7	246.9
Open Water	15.8	63.6	67.2	23.3	21.8	113.3	36.0
Total	11,354.7	12,309.3	12,728.0	13,989.3	14,473.3	14,696.0	8,525.5
Federal Land Ownership (Acres)[b]							
Bureau Land Management	595.2	271.9	283.4	1,380.7	1,957.3	331.7	0.0
Bureau of Reclamation	0.0	0.0	0.0	286.8	286.8	0.0	0.0
Department of Defense	0.0	16.2	16.2	0.0	0.0	0.0	0.0
Fish and Wildlife Service	0.0	0.0	2.9	0.0	0.0	0.0	0.0
Forest Service	0.0	97.5	97.5	0.0	0.0	0.0	0.0
National Park Service	0.0	18.9	18.9	0.0	0.0	18.9	18.9
Total	595.2	404.5	418.9	1,667.5	2,244.1	350.6	18.9
Fort Peck Indian Reservation (Acres)[c]	0.0	1,200.0	0.0	0.0	0.0	0.0	0.0
Number of Streams and Rivers crossed[d]	454	544	538	695	693	540	395

[a] Land use from U.S. Geological Survey (USGS) 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Fort Peck Indian Reservation from ESRI 2004a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[d] Streams and rivers from ESRI 2004b.

Comparisons of the impacts on key environmental resources of Express-Platte Alternative 2 with those of the proposed Project route are presented in Table 4.3.3-1. This alternative would be about 198 miles longer than the proposed route and would affect about 2,700 more acres when considering the construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance. In addition, it would cross the Antelope Creek Wilderness Study Area from MP 112.7 to MP 114.9. BLM manages wilderness study areas under the National Landscape Conservation System to protect their value as wilderness until Congress decides whether or not to designate them as wilderness. On the north side of the Missouri River, 9,600 acres of this 12,350-acre wilderness study area were recommended for full wilderness designation. The area has many opportunities for solitude and recreation such as hiking, hunting, rock climbing, and photography.

Although in comparison to the proposed route, Express-Platte Alternative 2 would cross fewer miles of the Sand Hills topographic region, it would be substantially longer, have a greater area of impact, affect more areas of key resources, and would extend over more of the NHPAQ system. It would also cross a National Wilderness Study Area that has been recommended for full wilderness status. As a result, Express-Platte Alternative 2 would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.2 Steele City Segment Alternative A (SCS-A)

Alternative SCS-A would parallel the existing Northern Border Pipeline ROW in its northernmost section for approximately 555 miles. It would then intersect and parallel the ROW of the existing Keystone Oil Pipeline for approximately 368 miles until reaching the control point at the northern end of the Cushing Extension. In comparison, the proposed Project route would parallel about 30 miles of existing ROWs along its 851.6-mile length. Alternative SCS-A would cross parts of Montana, North Dakota, South Dakota, and Nebraska. It would also cross 90 miles of the Fort Peck Indian Reservation in Montana, affecting approximately 1,200 acres of the reservation when considering the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance.

In Montana, Alternative SCS-A would cross the BLM-managed Bitter Creek Wilderness Study Area, an area designated under the Federal Land Policy and Management Act as having wilderness characteristics consistent with the provisions of the Wilderness Act of 1964. In North Dakota, Alternative SCS-A would cross the Little Missouri National Grassland managed by the USFS. It would also cross the Missouri River along the South Dakota-Nebraska border and the Missouri River National Recreational Area administered by the NPS. However, it would avoid a crossing of the Yellowstone River.

Comparisons of the potential impacts on key environmental resources of Alternative SCS-A to those of the proposed route are presented in Table 4.3.3-1. SCS-A would cross substantially more agricultural and developed land, more wetlands, more forested land, and approximately 110 more streams and rivers than the proposed Project route. It would cross substantially less rangeland and grass land than the proposed route.

Alternative SCS-A would cross approximately 2.4 miles of the Sand Hills topographic region, whereas the proposed route would cross approximately 68.1 miles of the Sand Hills topographic region. However, the proposed Project route in the Sand Hills topographic region was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see CMR plan, Appendix B). During the proposed Project design effort, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and

restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2.2.1, CMR plan in Appendix B, Pipeline Construction in Sand Hills Native Rangelands in Appendix H for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or Alternative SCS-A.

Alternative SCS-A would extend across approximately 145 miles of the NHPAQ system in comparison to the 247 miles of the proposed Project route that would extend over the aquifer (see Figure 4.3.3-2). The proposed Project route would be constructed and operated across the aquifer using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of even more stringent Project-specific Special Conditions developed by PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the 57 Project-specific Special Conditions developed by PHMSA that are also provided in Appendix U. In aggregate, these procedures would substantially reduce the potential risk of an accidental oil release from the pipeline anywhere along the proposed Project corridor. Based on the most recent PHMSA data for incidents associated with hazardous liquid pipelines (see Section 3.13.3.2), there is a statistical probability of 0.0007 incidents per mile of pipeline per year. These incident statistics include all releases from pipelines of all ages and are therefore conservative when compared to the potential risks from new pipelines designed consistent with current regulations, industry standards, and with the 57 Project-specific Special Conditions developed by PHMSA that would apply to the proposed Project. The majority of pipeline releases are small as further discussed in Section 3.13.

In summary, although the proposed Project route would cross more of the Sand Hills topographic region and overlie more of the NHPAQ system than would Alternative SCS-A, Alternative SCS-A would be approximately 72 miles longer than the proposed route and would affect at least 1,000 more acres than the proposed route when including the 110-foot-ROW, extra work space areas along the ROW, additional pipe and construction yards, and additional access roads. It would also impact more than twice as many acres of agricultural land, developed land, and forested land. Alternative SCS-A would cross more open water, substantially more streams and rivers, and slightly more wetlands than the proposed route. It would also cross tribal lands, wilderness areas managed by BLM, grasslands managed by USFS, and a major recreational area under the jurisdiction of NPS. Therefore, route Alternative SCS-A would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.3 Steele City Segment Alternative A1A

Except for a short distance along the northern portion of Alternative SCS-A1A, this route is the same as that of Alternative SCS-A (see Figure 4.3.3-1). Alternative SCS-A1A deviates from Alternative SCS-A to avoid affecting lands within the Fort Peck Indian Reservation in Montana. The deviation would begin in central Valley County, Montana and extend to the east along a path that would be north of the reservation. It would then turn south to pass to the east of the reservation in Sheridan County until crossing into Roosevelt County, Montana where it would extend to the southeast and cross into Williams County, North Dakota. From there, Alternative SCS-A1A would follow the same route as Alternative SCS-A to reach the control point at the northern end of the Cushing Extension.

Alternative SCS-A1A would cross Diversion Ditch No. 1 in the Medicine Lake National Wildlife Refuge (NWR), a canal that connects the refuge to Big Muddy Creek in Sheridan County and prairie potholes east of the Fort Peck Indian Reservation. Medicine Lake NWR is a 31,660-acre refuge established to provide breeding habitat for migratory birds and other wildlife. Prairie potholes are present in northeastern Montana and North Dakota. These are depressional wetlands (primarily freshwater marshes)

that are either permanent or temporary potholes that provide breeding areas and habitat for migratory birds and help prevent downstream flooding. These sensitive habitats are more prominent in the eastern portion of Alternative SCS-A1A than other Steele City Segment alternatives.

Comparisons of the potential impacts on key environmental resources of Alternative SCS-A1A to those of the proposed Project route are presented in Table 4.3.3-1. Alternative SCS-A1A would cross substantially more agricultural and developed land, more forested land, and 84 more streams and rivers than the proposed route. However, the alternative would cross substantially less rangeland and grass land than the proposed route. Alternative SCS-A1A would be approximately 103 miles longer than the proposed Project route and would affect at least 1,400 more acres when including the 110-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads. Alternative SCS-A1A would have the same route as Alternative SCS-A across the Sand Hills topographic region and the NHPAQ system.

In summary, the impacts to key environmental resources associated with Alternative SCS-A1A, including impacts to BLM-managed Bitter Creek Wilderness Study Area, the Little Missouri National Grassland managed by the USFS, and the Missouri River National Recreational Area administered by the NPS are similar to those of Alternative SCS-A. However, Alternative SCS-A1A would also cross the Medicine Lake NWR and would affect the environmentally sensitive prairie pothole areas. Therefore, as with Alternative SCS-A, Alternative SCS-A1A would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.4 Keystone Corridor Alternatives

Although Alternatives SCS-A and SCS-A1A would parallel the existing Keystone Oil Pipeline ROW for about 368 miles, several commenters on the draft EIS and supplemental draft EIS requested that the proposed Project follow a route that would parallel the entire existing Keystone Oil Pipeline in the United States. Many commenters on the draft EIS and supplemental draft EIS expressed particular concerns about the risks to groundwater resources and recommended that the existing Keystone route be used to reduce the distance of pipeline that would overlay the Sand Hills topographic region of Nebraska and the NHPAQ system, which includes the Ogallala aquifer. As a result of these comments, a Keystone Corridor Alternative (now identified as Keystone Corridor Alternative 1) was examined in the supplemental draft EIS (see Figure 4.3.3-1).

Commenters on the supplemental draft EIS suggested that the border crossing at Morgan, Montana be replaced with a border crossing at Pembina, North Dakota, the border crossing location for the existing Keystone Oil Pipeline. In response to these comments, DOS examined Keystone Corridor Alternative 2 (see Figure 4.3.3-1) with a border crossing at Pembina, even though such an alternative would not meet the control point criterion (see Section 4.3.2.1) of starting near Morgan, Montana, where the Canadian portion of the proposed Project route would end.

Keystone Corridor Alternative 1 is approximately 251 miles longer in the United States than the proposed Project. Keystone Corridor Alternative 2 is approximately 212 miles shorter than the proposed Project route in the United States, but would increase the route of the proposed pipeline in Canada by approximately 250 miles. The proposed Project route and Keystone Corridor Alternative 1 would start near Hardisty, Alberta and would follow a relatively direct route that includes approximately 329 miles of new pipeline in Canada to the international border crossing near Monchy, Saskatchewan and Morgan, Montana. Keystone Corridor Alternative 2 would parallel the approximately 769-mile Canadian portion of the existing Keystone Oil Pipeline Project from Hardisty, Alberta to the international border crossing near Haskett, Manitoba and Pembina, North Dakota. Keystone Corridor Alternative 2 would therefore require an additional 440 miles of new pipeline in Canada.

Keystone Corridor Alternative 1 extends eastward approximately 463 miles from Morgan, Montana to Pembina, North Dakota but diverts southeastward and then northwestward along the route to avoid major national wildlife refuges and several smaller refuges as well as the Turtle Mountain Indian Reservation that are present near the northern border of North Dakota. From Pembina, North Dakota, both Keystone Corridor Alternatives 1 and 2 extend southward paralleling the existing Keystone Oil Pipeline route for about 640 miles to the control point at the northern end of the Cushing Extension. In comparison, the proposed Project route would parallel about 30 miles of ROWs of the existing Northern Border Pipeline and the existing Keystone Oil Pipeline along the proposed Steele City Segment.

Consistent with NEPA regulations, DOS requested that Keystone provide an assessment of the relative costs of Keystone Corridor Alternatives in comparison to the proposed Project, to consider the economic feasibility of those alternatives. The original Keystone Oil Pipeline crossed the border near Pembina, North Dakota because an existing 30 inch natural gas pipeline in Canada was converted for use as part of the original Keystone Oil Pipeline, thus reducing the need for new pipeline in Canada by the length of that converted pipeline segment. As explained above, following either of the Keystone Corridor Alternatives would require approximately 250 miles of additional new pipeline construction either in the United States or Canada compared to the proposed Project route. That additional mileage of new construction, as well as other modifications that would need to be made to the proposed Project, would produce additional costs of approximately $1.6 billion, approximately a 25 percent increase in the total cost of the proposed Project.

In comments on the supplemental draft EIS, Keystone stated that the added costs of the Keystone Corridor Alternatives would make those routes economically infeasible. In a subsequent email submitted to DOS, Keystone provided the following clarification:

> "The Keystone XL project that the shippers supported was the project as presented in the Presidential Permit application. A material departure from this proposal and the associated higher cost would have made the project commercially infeasible. . . . Contract shippers on Keystone XL pay a fixed and a variable toll to transport crude oil to market while spot shippers pay a toll higher than the combined contract toll. Both the fixed and spot tolls would have increased by approximately 25% from adoption of the Keystone Corridor Alternative at the initial routing stage as a result of the increase in capital costs. Transportation rates at this level would not have been acceptable and commercial support for the project would not have been received."

There are a number of factors that must be evaluated when considering the economic feasibility of a privately funded project. In the case of a pipeline system, as indicated in Keystone's comment, increased capital costs are passed along to shippers in the form of higher tariffs. Thus, the economics of a particular pipeline project involve both capital financing and the ability and/or willingness of shippers to pay higher tariffs resulting from increased capital costs of pipeline construction. The higher tariffs could impact the decisions of the shippers who signed binding contracts to ship crude oil on the proposed Project as well as future shippers who may purchase transport capacity on the pipeline on the spot market.

In the 2008 Keystone XL Project Open Season, the shippers who signed contractual commitments with Keystone to transport 380,000 bpd selected the proposed Project over several other planned or potential projects. Potential projects available to shippers at that time included, as explained in Section 4.2.2, the Chinook-Maple Leaf Pipeline System, the Texas Access Pipeline, the Enbridge Trailbreaker Project, the Enbridge-BP Delivery System, and the Canadian National and Altex PipelineOnRail concept. The shippers who selected the proposed Project over those planned or potential projects did so based on a range of potential tariff charges. A 25 percent increase in capital costs and a resultant similar increase in tariffs for the proposed Project would have substantially changed the economic choice for shippers.

The proposed Project would hold approximately 28 percent of its ultimate operating capacity (830,000 barrels per day) available for shippers to purchase on the spot market.5 Although many of the competing pipeline projects from 2008 are not currently active proposals, there are still many proposed pipeline options to transport WCSB crude oil, and those potential options have increased in the past 8 months (EnSys 2011). Further, the rapid development of crude oil rail transport capacity in the Williston Basin in North Dakota and Montana and the barge transport between PADD II and PADD III discussed in Section 4.2.3.3 demonstrate that alternate modes of transport can be a competitive option to pipeline transport in some circumstances. It is reasonable to infer that a 25 percent increase in tariffs for the proposed Project would have influenced shippers to select other pipeline projects, other modes of transport (particularly rail), or intermodal transport options.

This is consistent with the findings of EnSys (2011). The EnSys (2011) results suggest that a 25 percent pipeline tariff increase to approximately $8.75 per barrel would place pipeline transport tariffs only slightly below the range of railroad tank car transport costs for dilbits (estimated to be $9 to $12 per barrel). Additionally, EnSys (2011) estimated the cost of shipping raw bitumen to PADD III by rail to range from $6 to $10 per barrel, depending upon whether the train cars returned to the WCSB empty, or backhauled diluent. Further, EnSys (2011) notes that this is competitive with the net cost of diluting bitumen and transporting it by pipeline when accounting for the shipping cost of the diluent mixed with the bitumen. Given that these cost comparisons were based on tariff estimates for the proposed Project without an additional 25 percent tariff increase, it is reasonable to infer that the selection of either Keystone Alternative 1 or 2 would produce a tariff that would be much less competitive than rail transport.

In light of the above considerations, DOS determined that the Keystone Corridor Alternatives could have been eliminated without further evaluation as unreasonable route alternatives because they are not economically practical or feasible. In light of the intense public interest in those potential alternatives, and in response to comments received on the draft EIS and supplemental draft EIS on the topic, DOS further evaluated those alternative routes with a focus on a comparison of potential impacts to groundwater resources.

As noted in the discussion of the criterion regarding use of existing ROWs in Section 4.3.2.1, installation of a new pipeline along existing, previously cleared and maintained ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if a pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that is not parallel to an existing ROW. It is possible that the route of the Keystone Corridor Alternatives could be included within part of the existing Keystone Oil Pipeline permanent ROW along some of the route since Keystone would be the owner of both pipelines. However, it is also likely that a 25-foot separation between pipelines would be required for safety. This would result in the alternative pipeline being installed no closer than at about the edge of the existing 50-foot-wide permanent ROW (25 feet on each side of the existing pipeline) except in areas where there are constraints outside of and adjacent to the existing ROW. In those areas the route would have to be aligned to be as close to the existing ROW as possible but would not be adjacent to it. In addition, to avoid damage to the existing pipeline, construction equipment and most construction activities would be limited to one side of that pipeline. Therefore, construction of either of the Keystone Corridor Alternatives would require an area outside of the permanent ROW of the existing Keystone Oil Pipeline to accommodate the construction equipment and activities. This area would also extend beyond the previously disturbed construction

[5] If increased tariffs made it economically infeasible for Keystone to transfer the 150,000 bpd it has contracted to deliver to Cushing, Oklahoma on the existing Keystone Oil Pipeline to the proposed Project, the planned available capacity for spot shipments could increase to approximately 46 percent.

ROW of the existing Keystone Oil Pipeline since the edge of that construction ROW was typically about 55 feet from the center of the pipeline. In addition, the portion of the construction ROW of the existing pipeline that is outside of the permanent ROW (i.e., the area typically 30 feet from the edge of the permanent ROW) has been reclaimed and would be cleared and disturbed again if either of the Keystone Corridor Alternatives were constructed, thus negatively affecting ROW restoration already implemented or ongoing along these corridors.

It is likely that construction of the Keystone Corridor Alternatives would require a construction ROW that is approximately the same width as the construction ROW of the proposed Project. Therefore, for comparison purposes, it was assumed that the Keystone Corridor Alternatives would have a construction ROW that would extend 110 feet from the existing pipeline and that there would be only minor disturbances to the existing permanent ROW between the edge of that ROW and the existing pipeline. The portion of the route between Morgan, Montana and the existing pipeline for Keystone Corridor Alternative 1 would also require a 110-foot-wide construction ROW. In addition, construction of the alternatives would require land for pipe rail yards, pipe storage yards, construction yards, temporary access roads, and in the portion of Keystone Corridor Alternative 1 between Morgan and the existing pipeline, construction camps would likely be required to house the workforce since that area is remote and there is little transient housing available.

As a result, construction of Keystone Corridor Alternative 1 between Morgan and the existing Keystone ROW and along the area adjacent to the existing 640-mile-long ROW would affect an area that would be approximately 3,400 acres larger in the United States than the area affected by construction of the proposed Project. Construction of Keystone Corridor Alternative 2 areas affected adjacent to the existing Keystone Oil Pipeline ROW would be approximately 2,822 acres smaller in the United States than the area affected by construction of the proposed Project, but would increase the acreage in Canada by an amount similar to the increased acreage of the Keystone Corridor Alternative 1.

Potential Risks to Groundwater Resources Associated with Proposed Project Corridor and Keystone Corridor Alternatives 1 and 2

As the Keystone Corridor Alternatives were developed primarily in response to comments expressing concern about the risk to groundwater resources, particularly the NHPAQ system, a comparison of potential risk to groundwater resources based on aquifer characteristics and existing groundwater use (as determined by number of wells and well density) was performed. Potential environmental consequences in the event of an accidental spill from the proposed Project are discussed in Section 3.13.6.3.

Both Keystone Corridor Alternatives would reduce mileage over the NHPAQ system from approximately 247 miles along the proposed Project route, to approximately 145 miles. Limiting mileage over the NHPAQ system, however, does not necessarily limit cumulative risk to groundwater resources. Although the NHPAQ does not extend under eastern North Dakota and South Dakota (see Figure 4.3.3-2), there are significant numbers of shallow and very shallow wells along the Keystone Corridor Alternatives in those states (see Figure 4.3.3-3). These shallow wells are completed in aquifers that are known to be important groundwater resources. The USGS Groundwater Atlas of the United States notes: "Unconsolidated deposits are widespread throughout [Montana, North Dakota, South Dakota, and Wyoming] and compose important aquifers either at the land surface or buried beneath low-permeability material. The aquifers are particularly widespread . . . in the subsurface in buried glacial valleys in eastern North Dakota and South Dakota." (USGS 2009). In addition, the Keystone Corridor Alternatives would cross from South Dakota into Nebraska in Cedar County, Nebraska where heavily used shallow groundwater resources with high hydraulic conductivity are present and are not part of the NHPAQ system, including highly utilized alluvial aquifers in the Missouri River Valley (Olsson Associates 2010). These findings suggest that reduced mileage over the NHPAQ system does not necessarily equate to a reduction in risk to

groundwater resources.

Groundwater resources at various depths are utilized in all states through which the proposed Project route and the Keystone Corridor Alternatives would pass. Well depth categories for groundwater wells within one mile of the centerline of the proposed Project route and the Keystone Corridor Alternatives are presented in Table 4.3.3-2 and in Figure 4.3.3-3. Within the U.S., Keystone Corridor Alternative 2 has the fewest wells within 1 mile on either side of the centerline. This is consistent with the fact that in the U.S. Keystone Corridor Alternative 2 is approximately 212 miles shorter than the proposed Project route and approximately 463 miles shorter than Keystone Corridor Alternative 1. As noted above, Keystone Corridor Alternative 2 minimizes total mileage in the U.S. by substantially increasing the mileage of new pipeline construction that would be required in Canada. Keystone Corridor Alternative 1 is the longest of the three alternatives in the U.S. (approximately 251 miles longer than the proposed Project) and also has the highest number of wells within 1 mile of either side of its centerline.

In Nebraska, the proposed Project route would be approximately 255 miles in length compared to approximately 204 miles (approximately 25 percent more mileage) for the Keystone Corridor Alternatives. This longer distance is reflected in 19 percent more nearby wells occurring along the proposed Project route than near the Keystone Corridor Alternatives.

Close examination of Figure 4.3.3-3 in light of the locations and number of wells provided above, provides insight relative to groundwater usage along the 2 mile wide corridors surrounding each centerline. For instance, while the number of shallow wells shown in Table 4.3.3-2 along the proposed Project is higher than the number of shallow wells along the Keystone Corridor Alternatives, these shallow wells are primarily concentrated in the Platte River Unit of the NHPAQ system, not within the Sand Hills Unit.

TABLE 4.3.3-2
Well Locations within 1 Mile of the Centerline for the Proposed Route and the Keystone Corridor Alternatives by Depth Category

Likely Depth to Groundwater Category[a]	SCS-B (Proposed Route)	Keystone Corridor 1	Keystone Corridor 2
Montana			
A	51	10	-
B	22	5	-
C	46	11	-
D	38	12	-
E	59	14	-
Total	216	52	-
North Dakota			
A	-	28	5
B	-	43	22
C	-	29	2
D	-	145	30
E	-	61	17
Total	-	306	76
South Dakota			
A	11	2	2
B	13	9	9
C	5	8	8
D	40	82	82
E	58	278	278
Total	127	379	379

TABLE 4.3.3-2
Well Locations within 1 Mile of the Centerline for the Proposed Route and the Keystone Corridor Alternatives by Depth Category

Likely Depth to Groundwater Category[a]	SCS-B (Proposed Route)	Keystone Corridor 1	Keystone Corridor 2
Nebraska			
A	183	70	70
B	62	25	25
C	115	75	75
D	205	218	218
E	629	583	583
Total	1,194	971	971
Totals			
A	245	110	77
B	97	82	56
C	166	123	85
D	283	457	330
E	746	936	878
Total	1,537	1,708	1,426

[a] Categories are as follows:

Category A: very shallow water depth likely with reported water level less than or equal to 10 feet bgs and total well depth less than or equal to 50 feet bgs;

Category B: shallow water depth likely with reported water level between 10 and 50 feet bgs and total well depth less than or equal to 50 feet bgs;

Category C: water depth unclear but potentially very shallow since reported water level is less than or equal to 10 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate very shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions);

Category D: water depth unclear but potentially shallow since reported water level is between 10 and 50 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions); and

Category E: deep water depth likely with reported water level greater than 50 feet bgs and total well depth greater than 50 feet bgs.

Likely depth to groundwater categories are described in more detail in Section 3.3.1.1.

In general, since well locations are not evenly distributed either along the overall proposed Project pipeline route or along the Keystone Corridor Alternatives, it is useful to compare the number of miles in particular categories of well density to determine which route would traverse areas of relatively heavier use. A comparison of the mileage along the proposed Project route and the Keystone Corridor Alternatives by well density category is shown in Table 4.3.3-3. Most of the distance for all three routes occurs in areas where the well density is 2 wells or less per square mile. The proposed Project route and Keystone Corridor Alternative 1 traverse approximately 107 miles with a well density of 2 or more per square mile and Keystone Corridor Alternative 2 traverses approximately 90 miles within the same well density category. Additionally, the proposed Project route traverses approximately 61 miles within the 0 to 1 well density category overlying the Sand Hills Unit of the NHPAQ system. Overall, the proposed Project route traverses the fewest miles with a well density of 4 or more wells per square mile (62 miles), compared to the Keystone Corridor Alternative 1 (83 miles) and Keystone Corridor Alternative 2 (69 miles).

TABLE 4.3.3-3
Miles Crossed per Well Density Category[a] for the Proposed Route and the Keystone Corridor Alternatives

Well Density	SCS-B (Proposed Route)	Keystone Corridor 1	Keystone Corridor 2
Montana			
0-1	253.5	153.9	-
1-2	13.9	0.3	-
2-4	11.5	1.2	-
4-8	1.2	2.2	-
8-16	1.4	0.9	-
> 16	0.0	0.3	-
Total	281.5	158.8	-
North Dakota			
0-1	-	494.8	199.9
1-2	-	2.9	1.5
2-4	-	3.7	1.9
4-8	-	9.6	2.2
8-16	-	6.1	2.6
> 16	-	0.1	0.0
Total	-	517.2	208.1
South Dakota			
0-1	309.1	195.1	195.1
1-2	5.2	5.0	5.0
2-4	0.0	6.3	6.3
4-8	0.0	9.5	9.5
8-16	0.0	3.4	3.4
> 16	0.0	1.0	1.0
Total	314.3	220.3	220.3
Nebraska			
0-1	136.1	129.7	129.7
1-2	26.7	9.9	9.9
2-4	33.3	13.4	13.4
4-8	45.1	27.8	27.8
8-16	11.2	20.1	20.1
> 16	2.8	2.1	2.1
Total	255.2	203.0	203.0
Totals[b]			
0-1	698.7	973.5	524.7
1-2	45.8	18.1	16.4
2-4	44.8	24.6	21.6
4-8	46.3	49.1	39.5
8-16	12.6	30.5	26.1
> 16	2.8	3.5	3.1
Total	851.0	1,099.3	631.4

[a] Well density is defined as the number of wells per square mile within a 2 mile corridor surrounding proposed route or alternative centerline. Sources for water wells by state are depicted in Figures 3.3.1-1 through 3.3.1-5. Wells per square mile were determined by using the ArcGIS Kernal Density tool. Well density categories were derived from those used for University of Nebraska-Lincoln study available at http://snr.unl.edu/data/download/water/GWMapArchives/2010GWMaps/Density.pdf.

[b] The ArcGIS Kernal Density tool estimated mileage for each route will not exactly match total mileage depicted in Table 4.3.3-1 due to missing density values.

In Nebraska, the NHPAQ system is extensively studied and has very complete publicly available information about hydraulic conductivity throughout the system (see Figure 4.3.3-4). Hydraulic conductivity is a mathematical expression of the ease with which water can move through the aquifer. There are areas along the Keystone Corridor Alternatives where the hydraulic conductivity of aquifers within the NHPAQ system is substantially higher than in the Sand Hills topographic region or along any other segment of the proposed Project route in Nebraska overlying the NHPAQ system (Figure 4.3.3-4). These areas tend to coincide with areas of shallow groundwater, as shown in Figure 4.3.3-5.

There are three segments of the proposed Project route in Nebraska where there is a relatively high well-density that coincides with very shallow groundwater (10 feet or less below the ground surface) (see Figure 4.3.3-5). Each of these segments is approximately 20 miles in length. They occur in Northwest Holt County within the Sand Hills topographic region, in Merrick County north of the Platte River crossing, and in York County. A close examination of Figures 4.3.3-4 and 4.3.3-5 indicates that the densest concentration of the very shallow wells along the proposed Project route does not occur within the Sand Hills topographic region, but rather where the proposed Project route crosses the Platte River Unit of the NHPAQ system in Merrick County. On the proposed Project route, other areas with relatively shallow groundwater occur within Northeast Garfield county and Saline County.

Along the Keystone Corridor Alternatives in Nebraska there are also three segments where relatively higher well densities coincide with very shallow groundwater. Two of these segments are associated with the alluvium of either the Platte or the Loup and Elkhorn River Valleys and exhibit higher hydraulic conductivities than the Sand Hills topographic region (see Figure 4.3.3-4). These segments comprise approximately 10 miles in central Stanton County along the Elkhorn and Loup Rivers, and approximately 20 miles across the border of Colfax and Butler counties within the Platte River valley. The third segment comprises approximately 20 miles within Seward and Saline counties. A study conducted as part of the Eastern Nebraska Water Resources Assessment (University of Nebraska-Lincoln 2010) reported that many areas that would underlie the Keystone Corridor Alternatives consist of unconsolidated sediments of ancient valleys (paleovalleys) which have high porosity and permeability. Other areas with relatively shallow groundwater also occur along these alternatives including segments along the Missouri River through most of Cedar County, and within Seward and Saline counties.

As stated above, many of the areas of very shallow groundwater and relatively high groundwater use along the Keystone Corridor Alternatives also coincide with areas within the NHPAQ that exhibit much higher rates of hydraulic conductivity (see Figure 4.3.3-4) than similar areas along the proposed Project route. In particular, the Keystone Corridor Alternatives pass through approximately 20 miles in Stanton, Colfax, and Butler counties where the hydraulic conductivities range from 100 to 300 feet per day. In contrast, the proposed Project route would traverse less than 3 miles of areas within the NHPAQ with shallow groundwater, relatively high well density, and hydraulic conductivities between 100 and 200 feet per day. Additionally, the proposed Project route would not cross any areas of the NHPAQ in Nebraska with hydraulic conductivities above 200 feet per day. Most areas with very shallow groundwater and high well density within the NHPAQ along the proposed Project route occur in areas where the hydraulic conductivity ranges between 25 and 50 feet per day.

At the suggestion of EPA, areas of potential groundwater recharge within Nebraska along the proposed Project route and the Keystone Corridor Alternatives were also assessed. The Sand Hills topographic region has very high recharge potential, including where the proposed Project route would traverse Holt County, Garfield County, and Wheeler County (Szilagyi et al. 2005). Other areas of high recharge potential along the proposed Project route include areas within the Niobrara River valley, and the Platte River valley in Merrick County. The Keystone Corridor Alternatives traverse areas of high recharge potential in the Missouri River valley in Northern Cedar County, in Central Stanton County in the area of the Loup and Elkhorn River valleys, in Southern Colfax and Northern Butler counties in the Platte River

valley, and in Southern Seward County and the southern half of Saline County (Szilagyi et al. 2005). While the total mileage through areas of high recharge potential along the proposed Project route is higher, most of that mileage occurs in areas of the Sand Hills topographic region with very low well density (from 0-1 wells per square mile).

To summarize, the Keystone Corridor Alternatives would transfer groundwater risks to a route through North Dakota and South Dakota with increased mileage overlying shallow groundwater aquifers compared to the proposed Project route through Montana and South Dakota, and while the Keystone Corridor Alternatives would reduce the total mileage overlying shallow groundwater in Nebraska largely by avoiding the Sand Hills topographic region, they do not significantly reduce the total mileage across areas with shallow groundwater in Nebraska, and increase the mileage across areas with higher groundwater usage. Further, they would increase the mileage across areas of the NHPAQ system in Nebraska with substantially higher hydraulic conductivities than those in the Sand Hills topographic region. The Keystone Corridor Alternatives therefore would not eliminate the risk to groundwater resources. Rather, they would transfer that risk to other groundwater areas and other groundwater users, both within the NHPAQ system and elsewhere.

Comparative Assessment of Potential Impacts to Other Key Environmental Resources Associated with Proposed Project Corridor and Keystone Corridor Alternatives 1 and 2

A comparison of potential impacts to key environmental resources of the Keystone Corridor Alternatives to those of the proposed Project route is presented in Table 4.3.3-1.

The proposed Project route would affect about 2.6 times more rangeland and grassland than Keystone Corridor Alternative 1 (4,961 more acres) and about 3.5 times more than Keystone Corridor Alternative 2 (7,907 more acres). This would represent an increase in the potential for impacts to rangeland and grassland soils, lost grazing areas and grazing time, and other short- to long-term impacts to those areas as compared to the alternatives. However, Keystone Corridor Alternative 1 would affect about 3.5 times more agricultural land than the proposed Project route, or about 7,386 more acres. Similarly, Keystone Corridor Alternative 2 would affect about 1.8 times more agricultural land than the proposed Project route, or about 5,354 more acres. This would result in increasing the potential for short- to long-term impacts to soil, crop production, and other damages to agricultural land as compared to the impacts of the proposed Project.

The Keystone Corridor Alternative 1 would affect almost 3 times more acres of developed land than the proposed Project route, or about 523 more acres. Similarly, Keystone Corridor Alternative 2 would affect about 1.8 times more developed land than the proposed Project route, or about 149 more acres. Impacts in developed land would be associated primarily with construction, although it is possible that pump stations and MLVs could be in the vicinity of the developed areas and would affect visual quality and create noise impacts during operation. However, there has not been a hydraulic design of the Keystone Corridor Alternatives and it is not possible to identify the locations of pump stations or MLVs along the alternative routes.

The Keystone Corridor Alternative 1 would affect about 3.3 times more wetland area than the proposed Project route, or about 339 more acres. Similarly, The Keystone Corridor Alternative 2 would affect about 1.7 times more wetland area than the proposed Project route, or about 99 more acres. This is a substantially greater area of wetland, although mitigation measures would be implemented to avoid or minimize the impacts to wetlands and compensatory mitigation would likely be required as part of the USACE Section 404 permitting process.

The Keystone Corridor Alternative 1 would affect approximately 5 times more forested area, or about 138

more acres. Similarly, The Keystone Corridor Alternative 2 would affect approximately 3 times more forested area, or about 73 more acres. That is a substantially greater area of forest impact than that of the proposed Project and could affect visual resources, wildlife habitat, and habitat fragmentation.

Both Keystone Corridor Alternatives would apparently involve more acreage of open water crossings than the proposed route. However, while Keystone Corridor Alternative 1 would have approximately 86 more stream crossings than the proposed route, Keystone Corridor Alternative 2 would have approximately 59 fewer stream crossings than the proposed route.

Comments received in 2007 on the draft EIS for the Keystone Oil Pipeline Project are informative relative to the likelihood of public acceptance of a second pipeline paralleling that project. Specific concerns were expressed at that time from residents of North Dakota, South Dakota, and Nebraska relative to the possibility of future pipelines following the existing Keystone Oil Pipeline route. Commenters from North Dakota expressed concern about the project's effect on water supplies, including the water supplies for Fargo, North Dakota and the potential for contamination of the Sheyenne River drainage. Contamination of that drainage could lead to transboundary impacts to Lake Winnipeg and the Hudson Bay drainage in Canada, as well as potential contamination of shallow aquifers. Commenters from South Dakota were concerned about impacts of the Keystone Oil Pipeline Project crossing of the Missouri River, especially through a National Wild and Scenic River reach. The Keystone Corridor Alternatives would cross the Missouri River in the same reach.

Additional concerns were related to rural water supply impacts, including the WEB, Clark, Hanson, Turner McCook, Lewis and Clark, and B-Y water systems. Concerns raised in 2007 by commenters from Nebraska included the project route through Seward, Nebraska and potential impacts to the Seward water system. In all three states, the presence of shallow groundwater aquifers beneath the Keystone route was a concern, including concerns about potential impacts to the NHPAQ system, which includes the Ogallala Unit of the aquifer.

While the Keystone Corridor Alternatives would eliminate most disturbance of the Sand Hills topographic region, the proposed Project route was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see the CMR plan in Appendix B). During the proposed Project design effort, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2 and Appendices B and H for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or the Keystone Corridor Alternatives.

Summary

Groundwater information reflected by well depth data, well density data, and hydraulic conductivity data (where available) suggest that there is no overall environmental advantage to either Keystone Corridor Alternative 1 or Keystone Corridor Alternative 2 in terms of cumulative risk to groundwater resources overall or in Nebraska specifically.

Comparison of potential impacts to other key environmental resources, as well as public concerns relative to the existing Keystone Oil Pipeline Project as expressed in comments during that project's

environmental review, also suggest that there is no overall environmental advantage to either Keystone Corridor Alternative 1 or Keystone Corridor Alternative 2 (see Table 4.3.3-1), although in general, shorter routes tend to produce fewer environmental effects, thus suggesting that in the U.S. Keystone Corridor Alternative 2 may provide an environmental advantage due to its shorter length. However, any environmental benefit from reduced mileage in the U.S. would be more than offset by increased mileage in Canada. Implementation of Keystone Corridor Alternative 2 would result in approximately 200-300 additional miles of pipeline from Hardisty, Alberta to Steele City, Nebraska.

As stated previously, DOS determined that the Keystone Corridor Alternatives are not reasonable route alternatives because they are not economically practical or feasible. In addition, after further evaluation of all screening level environmental impact comparisons, DOS determined that there would not be an overall environmental advantage to either Keystone Corridor Alternative 1 or Keystone Corridor Alternative 2 as compared to the proposed Project. For the above reasons, these alternatives were eliminated from further consideration.

4.3.3.5 I-90 Corridor Alternatives A and B

The I-90 Corridor Alternatives A and B were also developed as alternatives that would reduce the length of pipeline over the Sand Hills topographic region and the NHPAQ aquifer system, which includes the Ogallala formation. While these alternatives are not consistent with the screening criterion of avoiding major water bodies, they were developed largely in response to comments received on the draft and supplemental draft EIS expressing concerns regarding the risk of spills to the NHPAQ system.

The alternatives were developed to parallel I-90 or other existing ROWs to the extent possible to minimize new corridor development while avoiding to the extent practicable crossings of either the Sand Hills topographic region or the NHPAQ system. The I-90 Corridor Alternatives divert from the proposed Project route after crossing under I-90 in Nebraska and extend roughly eastward along the south side of I-90 to a point approximately 2 miles west of Alexandria, South Dakota. At that location, the Burlington Northern and Santa Fe (BNSF) railroad line diverts from the I-90 corridor and extends to the southeast parallel to State Highway 262 for approximately 16 miles. The I-90 Corridor Alternatives parallel the railroad/262 corridor to a point east of Emery, South Dakota where they intersect the existing Keystone Oil Pipeline Project ROW. From there, the alternative routes parallel the existing Keystone Oil Pipeline Project ROW to the control point at Steele City, Nebraska (see Figure 4.3.3-1 and Figure 4.3.3-6).

The pipeline for the I-90 Corridor Alternatives would not be installed within the existing highway ROW since the South Dakota Department of Transportation does not allow pipelines to be installed laterally within the I-90 ROW, although it does allow pipelines to cross the I-90 ROW. These alternatives would therefore require the development of new ROW in undisturbed land to the south of the existing highway ROW. The pipeline would not be installed within the BNSF railroad ROW but would be parallel to the ROW and would require the development of new ROW in undisturbed land near the existing railroad ROW.

The I-90 Corridor Alternatives would require two more crossings of the Missouri River than the proposed Project route, and these crossings would be within environmentally sensitive areas. One of these crossings would be at Lake Francis Case, a reservoir along the Missouri River formed by Fort Randall Dam. This dam is approximately 90 miles downstream of the potential crossing sites. Given the sensitivity of the crossing area, two variations of the I-90 Corridor Alternatives (A and B) were considered. I-90 Corridor Alternative A is parallel to I-90 through the Oacoma area and crosses Lake Francis Case adjacent to I-90. I-90 Corridor Alternative B parallels the South Dakota Highway 16/South Dakota Highway 50 alignment through the Oacoma area and across Lake Francis Case (see Figure 4.3.3-7). I-90 Corridor Alternative A avoids the downtown area of Chamberlain but requires crossing a steep

bluff on the east side of the lake. I-90 Corridor Alternative B extends through the downtown area of Chamberlain but avoids the steeper portions of the bluff.

The two crossing sites are approximately 5,200 and 5,800 feet long and would likely involve the use of the HDD method if geotechnical considerations are appropriate. However, for large-diameter pipelines, the HDD method is limited to a distance of approximately 6,000 feet. When considering the onshore distance from the drill site to the exit hole, the height of the bluff, and the depth of the hole that would be bored, the aggregate distance could be too great for the HDD method. More detailed engineering studies would be required to determine whether or not the HDD method would be feasible for this crossing, assuming that geotechnical conditions were suitable for HDD. If the HDD method is not suitable, a wet-cut crossing method using barges and bottom dredging would likely be required. Such a wet-cut method would increase the construction impacts of constructing the pipeline in Lake Francis Case, and would not place the pipeline as far below the bottom of the lake as an HDD crossing.

Also, the steep bluff on the west bank of Lake Francis Case raises additional technical difficulties regarding the design of the pipeline to avoid slack line conditions (see Section 3.13.5.1). More detailed engineering studies would be required to determine whether a crossing of Lake Francis Case at the proposed locations is feasible, regardless of the method used for crossing the lake.

Keystone identified several additional technical difficulties for the two proposed crossings of Lake Francis Case. For the I-90 Corridor Alternative A crossing Keystone noted:

- Adequate workspace to facilitate an HDD pullback is not available based on the proposed crossing location, which poses a major safety risk to construction personnel and the drill installation;
- An HDD at this location would pose a risk of damage to existing road infrastructure such as piles and man-made road supporting berms with the pilot drill;
- The pullback drill string would block the highway; and
- A frac-out could cause unforeseen consequences to the man-made berm supporting the highway, the bridge supports, or to the towns in close proximity to the drill.

For the I-90 Corridor Alternative B crossing Keystone noted:

- The necessary pipeline inflection point cannot occur in the river;
- The drill would enter/exit in the town of Chamberlain which is not practicable; and
- Adequate workspace to facilitate an HDD pullback is not available based on the proposed crossing location which poses a major safety risk to construction personnel.

Keystone also noted that HDD crossings exceeding 4,000 feet, such as the two proposed crossings, tend to create additional installation stresses, which would be exacerbated by the significant elevation differentials on either side of the crossings. In light of those considerations, the likelihood of exceeding allowable limits for the loads and stresses on the pipe during installation is high. Further, paralleling an interstate highway makes it more likely that the pipeline ROW would encounter more developed lands and denser population centers. As a result, the I-90 Corridor Alternatives would cross within 1 mile of 5 more villages, 5 more towns, and 9 more cities than the proposed Project route.

Although other shorter potential routes through undeveloped land south of I-90 could be considered, they would likely have to cross either an extension of the NHPAQ system before meeting the existing

Keystone Oil Pipeline ROW or cross the Niobrara River, Niobrara State Park, and/or the Santee Sioux Indian Reservation. A route in that general area would also be in the watershed of and parallel to a portion of the Missouri River that is designated as the Missouri National Recreational River and is included in the National Wild and Scenic Rivers System. The Missouri National Recreational River was established by Congress to protect the natural, cultural, and recreational resources of two remaining free-flowing segments of the Missouri River in as natural a state as possible and to keep them available for the public. The goal is to preserve, protect, interpret, restore, and enhance the natural and cultural resources of those segments of the river for the enjoyment of present and future generations.

Consistent with NEPA regulations, DOS requested that Keystone provide an assessment of the relative costs of the I-90 Corridor Alternatives in comparison to the proposed Project. That assessment suggests that implementation of either I-90 Corridor Alternative would produce additional costs of approximately $473 million.

In light of the above considerations, DOS determined that the I-90 Corridor Alternatives could have been eliminated without further evaluation as unreasonable route alternatives they are not technically practical or feasible – particularly due to the inconsistency with the route screening criterion of avoiding major water bodies, the additional technical challenges associated with crossing Lake Francis Case, and the practical concerns associated with siting the pipeline ROW nearer denser population areas. In light of the intense public interest in those potential alternatives, and in response to comments received on the draft EIS and supplemental draft EIS on the topic, DOS further evaluated those alternative routes with a focus on a comparison of potential impacts to groundwater resources.

Potential Risks to Groundwater Resources Associated with Proposed Project Corridor and I-90 Corridor Alternatives A and B

A comparison between the number of wells by depth category for each I-90 Corridor Alternative and the proposed Project is shown in Table 4.3.3-4 and in Figure 4.3.3-8. Each I-90 Corridor Alternative has 67 (approximately 5 percent) more wells within 1 mile on either side of their centerlines than does the proposed route. This is not surprising since they are approximately 70 to 72 miles (approximately 22 percent) longer than the proposed Project route.

TABLE 4.3.3-4
Well Locations within 1 Mile of the Centerline for the Proposed Route and the I-90 Corridor Alternatives by Depth Category

Likely Depth to Groundwater Category[a]	SCS-B (Proposed Route)	I-90 Corridor Alternatives
South Dakota		
A	7	0
B	3	6
C	3	3
D	16	60
E	14	264
Total	43	333
Nebraska		
A	183	70
B	62	25
C	115	75
D	205	218
E	629	583

TABLE 4.3.3-4
Well Locations within 1 Mile of the Centerline for the Proposed Route and the I-90 Corridor Alternatives by Depth Category

Likely Depth to Groundwater Category[a]	SCS-B (Proposed Route)	I-90 Corridor Alternatives
Total	1,194	971
Totals		
A	190	70
B	65	31
C	118	78
D	221	278
E	643	847
Total	1,237	1,304

[a] Categories are as follows:

Category A: very shallow water depth likely with reported water level less than or equal to 10 feet bgs and total well depth less than or equal to 50 feet bgs;

Category B: shallow water depth likely with reported water level between 10 and 50 feet bgs and total well depth less than or equal to 50 feet bgs;

Category C: water depth unclear but potentially very shallow since reported water level is less than or equal to 10 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate very shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions);

Category D: water depth unclear but potentially shallow since reported water level is between 10 and 50 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions); and

Category E: deep water depth likely with reported water level greater than 50 feet bgs and total well depth greater than 50 feet bgs.

Likely depth to groundwater categories are described in more detail in Section 3.3.1.1.\

A comparison of the mileage within the proposed Project route and the I-90 Corridor Alternatives by well density category is shown in Table 4.3.3-5. These comparisons provide insight relative to the importance of groundwater resources along each centerline. For instance, while the wells in South Dakota are mostly deep along the proposed route and the I-90 Corridor Alternatives, the well densities are higher along the I-90 Corridor Alternatives.

TABLE 4.3.3-5
Miles Crossed per Well Density Category for the Proposed Route and the I-90 Corridor Alternatives

Well Density[a]	SCS-B (Proposed Route)	I-90 Corridor Alternatives
South Dakota		
0-1	82.1	150.7
1-2	2.8	30.8
2-4	0.0	16.5
4-8	0.0	2.9
8-16	0.0	0.0
> 16	0.0	0.0
Total	84.9	200.9
Nebraska		
0-1	130.5	68.0
1-2	24.2	38.5
2-4	37.4	55.5
4-8	43.3	35.4

TABLE 4.3.3-5 Miles Crossed per Well Density Category for the Proposed Route and the I-90 Corridor Alternatives		
Well Density[a]	SCS-B (Proposed Route)	I-90 Corridor Alternatives
8-16	9.9	4.8
> 16	3.0	0.0
Total	248.3	202.1
Totals[b]		
0-1	212.6	218.7
1-2	27.0	69.3
2-4	37.4	72.0
4-8	43.3	38.3
8-16	9.9	4.8
> 16	3.0	0.0
Total	333.2	403.0

[a] Well density is defined as the number of wells per square mile within a 2 mile corridor surrounding proposed route or alternative centerline. Sources for water wells by state are depicted in Figures 3.3.1-1 through 3.3.1-5. Wells per square mile were determined by using the ArcGIS Kernal Density tool. Well density categories were derived from those used for University of Nebraska-Lincoln study available at http://snr.unl.edu/data/download/water/GWMapArchives/2010GWMaps/Density.pdf.

[b] The ArcGIS Kernal Density tool estimated mileage for each route will not exactly match total mileage depicted in Table 4.3.3-6 due to missing density values.

The I-90 Corridor Alternatives would follow the same route through Nebraska as the Keystone Corridor Alternatives. A comparison of the risks to groundwater resources in Nebraska was discussed extensively previously in the Keystone Corridor Alternatives comparison.

In summary, groundwater well and well density data indicate that there is no overall environmental advantage to either I-90 Corridor Alternative in terms of risk to groundwater resources overall or in Nebraska, other than the reduced mileage of both alternatives in Nebraska. The proposed route and the I-90 Corridor Alternatives cross the highly utilized Platte River Unit of the NHPAQ system. The I-90 Corridor Alternatives cross aquifers within the NHPAQ system with the highest hydraulic conductivities and the highest well densities and also cross an area of higher well concentration in South Dakota.

Comparative Assessment of Potential Impacts to Other Key Environmental Resources Associated with Proposed Project Corridor and I-90 Corridor Alternatives A and B

A comparison of the impacts on key environmental resources of the I-90 Corridor Alternatives to those of the proposed Project route is provided in Table 4.3.3-6. The I-90 Corridor Alternatives would be approximately 70 miles longer than the proposed Project route and would affect at least 1,000 more acres during construction than the proposed Project route, including the 110-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads.

The I-90 Corridor Alternatives would parallel approximately 144.5 miles of I-90 or I-90 and state highways 16 and 50, about 12.1 miles of state highway 262 and the BNSF ROW, and about 246.4 miles of the existing Keystone ROW. In comparison, the proposed Project route would parallel about 30 miles of existing ROWs. As noted in the discussion of the criterion regarding use of existing ROWs in Section 4.3.2.1, installation of a new pipeline along existing, cleared ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if the new pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that

is not parallel to an existing ROW. In this case, the I-90 Corridor Alternatives would be installed outside of the existing ROW. As with the Keystone Corridor Alternatives, a portion of the I-90 Corridor Alternatives parallels the newly constructed Keystone Oil Pipeline Project. In this area, construction of either I-90 Corridor Alternative would likely impact previously implemented or ongoing restoration activities along that corridor.

The proposed Project route would affect almost 5 times more rangeland and grassland than the I-90 Corridor Alternatives, or about 1,956 more acres. This would represent an increase in the potential for impacts to rangeland and grassland soils, lost grazing areas and grazing time, and other short- to long-term impacts to those areas as compared to the alternatives. It would also increase the amount of compensation that Keystone would be required to provide for lost grazing opportunities and other damages. The alternative route would affect about 1.5 times more agricultural land than the proposed Project route, or about 835 more acres. This would result in increasing the potential for short- to long-term impacts to soil, crop production, and other damages to agricultural land as compared to the impacts of the proposed Project.

TABLE 4.3.3-6
Impact Comparisons of the I-90 Corridor Alternatives and the Associated Segment of the Proposed Project Route

Characteristic	Proposed Route	I-90 Corridor Alternatives
Total Length (Miles)	333.0	403.1 / 404.5[e]
Northern High Plains Aquifer System Crossed (Miles)[a]	247.2	144.9
Land Cover (Acres)[b]		
Agricultural Land	1,698.3	2,533.7
Developed Land	96.6	2,202.1
Forested	21.5	38.4
Rangeland/Grassland	2,521.3	564.7
Wetlands	92.0	21.9
Open Water	10.3	13.9
Total	4,440.0	5,374.7
Federal Land Ownership (Acres)[c]		
National Park Service (Missouri National Recreation Area)	0.0	26.4
U.S. Army Corps of Engineers (Lake Francis Case)	0.0	13.0 / 15.0e
Number of Stream Crossings[d]		
Perennial	22	25
Intermittent	157	200
Total	179	225

[a] Northern High Plains Aquifer from U.S. Geological Survey Water Resources Program.

[b] Land Cover from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.

[c] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.

[d] Streams and rivers from ESRI 2004b.

[e] I-90 Corridor Alternative B.

The I-90 Corridor Alternatives would cross 46 more streams and rivers than the proposed Project. Although HDD would be used to cross the major streams, about 43 of the additional crossings would be constructed using one of the wet open cut methods described in Section 2.3. As compared to the proposed Project route, this increase in the number of stream crossings represents a substantial increase in the potential for impacts to water quality, fisheries resources and the habitats that support the fisheries.

As mentioned previously, two of the river crossings added are at environmentally sensitive locations of the Missouri River. The first would be at Lake Francis Case, which extends about 107 miles from the Fort Randall Dam to the Big Bend Dam. The crossing would be approximately 20 river miles south of Big Bend Dam. Around 1 million people use the 19 recreation areas along the lake each year (USACE 2010). Recreational opportunities include boating, fishing, swimming, hunting (outside of recreational areas), geocaching, camping, and picnicking. Construction of the alternative route through this area on both sides of the reservoir would disrupt recreational traffic and recreational activities for the duration of the construction period in that area. Clearing the ROW would result in changes to the composition and structure of vegetation, including forested areas. This would result in changes to the visual character and may be considered adverse impacts to those using the area for recreation. It would also alter the habitats supporting species that are hunted. In addition, both crossing variations and the ROW of the alternatives are in the vicinity of historic American Island and other areas associated with the Lewis and Clark expedition. If the HDD installation method is used, the pipeline would be installed substantially below the bottom of the reservoir to minimize the potential for outside forces (e.g., anchor drag) that could cause an accidental release of crude oil from the portion of the pipeline under the lake during operation. However, the potential for such releases from the onshore portions of the pipeline adjacent to the crossing would be the same as for those within other terrestrial areas where the pipeline is buried.

The second crossing of the Missouri River would be near Yankton, South Dakota most likely adjacent to the existing Keystone ROW crossing. The crossing area is within the Missouri National Recreational River, a 98-mile-long portion of the river administered by the National Park Service that extends from Ponca, South Dakota on the southeast end to the Fort Randall Dam on the northwest end. As noted above, the Missouri National Recreational River was established by Congress to protect the natural, cultural, and recreational resources of two remaining free-flowing segments of the Missouri River in as natural a state as possible and to keep them available for the public. The second Missouri River crossing would likely be accomplished using the HDD method, the same installation method used for the existing Keystone Oil Pipeline Project, to minimize construction impacts.

The proposed Project would affect approximately 70 acres more wetlands than the I-90 Corridor Alternatives (92 acres and 21.9 acres respectively) based on data in the National Land Cover Dataset (USGS 2001). However, reviews of recent aerial photographs along the I-90 Corridor Alternatives suggest that there would be substantially more than 21.9 acres of wetlands affected by implementation of the alternatives, and USGS appears to have categorized some of the wetland areas as “developed land” that is adjacent to the I-90 corridor. In addition, I-90 Corridor Alternatives mileage of wetlands crossed in South Dakota was approximately 2.9 miles by the National Wetlands Inventory in South Dakota versus 0.9 mile for NLCD. Although it is likely that the proposed Project would affect more wetland area than the alternatives, the difference is likely less than 70 acres. Minor route adjustments and other mitigation measures would be implemented to avoid or minimize the impacts to wetlands, and compensatory mitigation would likely be required as part of the USACE Section 404 permitting process.

The alternative routes would also affect almost 20 times more acres of developed land (approximately 2,201 acres versus 92 acres), including land within or near several communities along the routes. These include Oacoma, Mitchell, Alexandra, and Emery, South Dakota. Impacts in those areas would be related primarily to construction, although it is possible that both pump stations and MLVs could be in the vicinity of the developed areas and would affect visual quality and create noise impacts during operation.

However, there has not been a hydraulic design of the I-90 Corridor Alternatives and it is not possible to identify the locations of pump stations or MLVs at this time.

Comments received in 2007 on the draft EIS for the Keystone Oil Pipeline Project are informative relative to the likelihood of public acceptance of a second pipeline paralleling that project. Specific concerns were expressed at that time from residents of South Dakota and Nebraska relative to the possibility of future pipelines following the existing Keystone Oil Pipeline route. Commenters from South Dakota were concerned about impacts of the Keystone Oil Pipeline Project crossing of the Missouri River, especially through a National Wild and Scenic River reach. The I-90 Corridor Alternatives would cross the Missouri River in the same reach, and as discussed earlier would also involve a second Missouri River Crossing to the north through Lake Francis Case (see Figure 4.3.3-7).

Additional concerns were related to rural water supply impacts, including the WEB, Clark, Hanson, Turner McCook, Lewis and Clark, and B-Y water systems. Concerns raised in 2007 by commenters from Nebraska included the project route through Seward, Nebraska and potential impacts to the Seward water system. In all three states, the presence of shallow groundwater aquifers beneath the Keystone route was a concern, including concerns about potential impacts to the NHPAQ system, which includes the Ogallala Unit of the aquifer. In essence, the I-90 Corridor Alternatives, while reducing the distance over the shallow groundwater of the Sand Hills Unit of the NHPAQ system and other portions of the NHPAQ system, do not eliminate the risk to areas of shallow groundwater; rather they would transfer any spill risks to aquifers in other regions, including other shallow aquifers within Nebraska.

While the I-90 Corridor Alternatives would eliminate most disturbance of the Sand Hills topographic region, the proposed Project route was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see the CMR plan in Appendix B). During the proposed Project design effort, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2 and Appendices B and H for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or the I-90 Corridor Alternatives.

Summary

Groundwater, well and well density data, and hydraulic conductivity data indicate that there is no overall environmental advantage to either I-90 Corridor Alternative in terms of risk to groundwater resources overall or in Nebraska. While the I-90 Corridor Alternatives would reduce the total mileage where the pipeline route would overlay shallow groundwater in Nebraska, largely by avoiding the Sand Hills topographic region, they do not significantly reduce the total mileage across areas with shallow groundwater in Nebraska where there is higher groundwater usage. Further, they would increase the mileage through areas of the NHPAQ system in Nebraska with substantially higher hydraulic conductivities than those in the Sand Hills topographic region. The Keystone Corridor Alternatives therefore would not eliminate the risk to groundwater resources. Rather, they would transfer that risk to other groundwater areas, including other areas of the NHPAQ system, and to other groundwater users in South Dakota and Nebraska.

The comparisons of other key environmental issues and the greater area of impact of the I-90 Corridor

Alternatives, as well as public concerns relative to the existing Keystone Oil Pipeline Project as expressed in comments during that project's environmental review, suggest that the alternatives would not offer an overall environmental advantage over the proposed Project route. Additionally, crossing Lake Francis Case using the HDD method may not be technically feasible due to the length of the crossing, the height of the bluff on the eastern shore of the lake, and the depth of required boring. Detailed engineering studies would be required to determine whether or not the HDD crossing is technically feasible, including geotechnical studies to determine whether or not the soil conditions in the bluff and under the river would be receptive to using HDD. If HDD is not suitable, a wet-cut crossing using barges and bottom dredging would likely be required. With this method there would be substantial construction impacts to water quality, fisheries habitats, benthic communities, and recreational uses as compared to the impacts of the proposed Project. Also, detailed engineering studies would be required to determine if the crossing could be made at those locations without creating a sudden elevation change in the pipeline that could increase the possibility of slack line conditions.

As stated previously, DOS determined that the I-90 Corridor Alternatives are not reasonable route alternatives because they are not technically practical or feasible. In addition, after further evaluation of all screening level environmental impact comparisons, DOS determined that there would not be an overall environmental advantage to either I-90 Corridor Alternative A or I-90 Corridor Alternative B as compared to the proposed Project. For the above reasons, these alternatives were eliminated from further consideration.

4.3.3.6 Baker Alternative

The Baker Alternative was developed in response to an agency request made during the scoping period. The alternative deviates from the proposed route in the vicinity of Baker, Montana and extends through an area that had previously been disturbed by ongoing construction and operation of oil production and delivery systems (see Figure 4.3.3-1 and Figure 4.3.3-9). The Baker Alternative would deviate from the proposed Project route in Fallon County, Montana and would extend for approximately 62.1 miles parallel to an existing pipeline ROW into Bowman County in southwest North Dakota. The alternative would return to the ROW of the proposed Project in Harding County, South Dakota. The Baker Alternative would be approximately 2.4 miles shorter than the segment of the proposed Project route it would replace. It would also cross an existing oil and gas field southeast of Baker. Within the existing oil and gas field, construction of the alternative would require special pipe crossing techniques. Construction could result in interruptions to crude oil production gathering systems and an increase in the potential for environmental impacts resulting from damage to gathering system pipelines. There would also be a human health and safety concern, including potential injury to pipeline construction workers and the public, due to the proximity of the Baker Alternative to existing oil wells with the potential to release hydrogen sulfide. A comparison of the impacts on key environmental resources of the Baker Alternative to those of the proposed route is provided in Table 4.3.3-7. This alternative would extend through the Baker Lake watershed and would cross substantially less agricultural land and less forested land and wetlands than the comparable segment of the proposed route. However, it would also cross more developed areas, rangeland and grassland, and streams and rivers than the proposed route and would affect a substantially larger area of BLM land.

TABLE 4.3.3-7 Impact Comparisons for the Baker Alternative and the Associated Segment of the Proposed Route		
Characteristic	**Proposed Route**	**Baker Alternative**
Total Length of Alternative (Miles)	851.6	849.1
Length of Segment of Proposed Route and Baker Alternative (Miles)	64.5	62.1
Land Use (Acres)[a]		
Agricultural Land	102.0	34.7
Barren Land	0.0	1.2
Developed Land	1.8	7.8
Forested	3.0	0.9
Rangeland/Grassland	747.9	781.2
Wetlands	5.3	2.2
Open Water	0.0	0.0
Total	860.0	828.0
Federal Land Ownership (Acres)[b]		
Bureau of Land Management	2.7	163.8
Number of Streams and /Rivers Crossed[c]	37	47

[a] Data in remainder of table are for the segment of the proposed route that would be replaced and for the Baker Alternative. Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.

[b] Federal lands from ESRI 2004a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.

[c] Streams and rivers from ESRI 2004b.

Implementation of the Baker Alternative would create additional unique environmental risks and safety concerns by crossing an existing oil and gas field and the alternative would not offer an overall environmental advantage over the segment of the proposed route it would replace. Therefore the Baker Alternative was eliminated from further consideration.

4.3.4 Western Alternative (Alternative to Both Steele City Segment and the Cushing Extension)

The Western Alternative would substitute for both the Steele City Segment and the Cushing Extension. This approximately 1,277-mile-long alternative would enter the U.S. at Morgan and extend through Montana, Wyoming, Colorado, Kansas, and Oklahoma to the control point at the southern end of the Cushing Extension as depicted on Figure 4.3.3-1.

Although the Western Alternative would parallel the existing Express-Platte System corridor for approximately 350 miles, the existing easements along that corridor are in the control of a different company and it may not be possible to construct the alternative pipeline within the existing ROW. Therefore, construction of the alternative may result in the same impacts as construction of a pipeline of similar length that is not parallel and adjacent to an existing ROW.

A comparison of the impacts on key environmental resources of the Western Alternative to those of the proposed route is provided in Table 4.3.4-1. The Western Alternative would be approximately 426 miles longer than the proposed route and would affect about 6,000 more acres than the proposed route,

including the 100-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads. The Western Alternative would affect substantially more agricultural land, developed land, forested land, rangeland and grassland, and wetlands than the proposed route. It would also cross substantially more streams, rivers, and federal land than the proposed route. The Western Alternative would avoid crossing the NHPAQ system and the Sand Hills topographic region of Nebraska. The route would also avoid crossing the Charles M. Russell National Wildlife Refuge, the Medicine Bow National Forest, and the Pawnee National Grassland.

The Western Alternative is not considered a reasonable alternative to the proposed Project due to the financial impracticability of constructing a pipeline that would be substantially longer than the proposed route. In addition, the Western Alternative would not offer an overall environmental advantage over the proposed route. Therefore, this alternative was eliminated from further consideration.

TABLE 4.3.4-1
Impact Comparisons for the Proposed Route and the Western Alternative

Characteristic	Proposed Route	Western Alternative
Total Length (Miles)	851.6	1,277.4
Land Use (Acres)[a]		
Agricultural Land	2,978.6	4,672.2
Barren Land	6.3	55.3
Developed Land	174.2	505.0
Forested	33.0	327.8
Rangeland/Grassland	8,006.7	11,136.4
Wetlands	148.1	247.5
Open Water	15.8	87.8
Total	11,362.7	17,032.0
Federal Land Ownership (Acres)[b]		
Bureau of Land Management	595.2	2,250.8
Bureau of Reclamation	0.0	277.4
National Park Service	0.0	0.0
Total	595.2	2,528.2
Number of Streams and Rivers Crossed[c]	454	821

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Streams and rivers from ESRI 2004b.

4.3.5 Gulf Coast Segment Alternative Routes

The Gulf Coast Segment extends from the southern end of the Cushing Extension to the proposed Project's delivery point at Nederland, Texas. Two route alternatives for the Gulf Coast Segment were identified: the proposed route (Alternative GCS-A) and Alternative GCS-B. These alternatives are depicted on Figure 4.3.5-1 and compared below.

The proposed route would be approximately 480 miles long and would parallel an existing natural gas pipeline corridor (Texoma Pipeline) from Cushing to Nederland (portions of the Texoma line have been sold and are operated by other companies, but the corridor is still intact). The proposed Project route would avoid the Angelina National Forest in Angelina, Nacogdoches, San Augustine, and Jasper counties in east Texas along the shores of the Sam Rayburn Reservoir. Alternative GCS-B would be west of the proposed route and closer to the Dallas-Ft. Worth metropolitan area than the proposed route and would extend east of Durant, Oklahoma.

Both routes would extend through active and inactive oil and gas fields south of Cushing. Approximately 82 percent of the proposed route would parallel the existing ROWs of other linear facilities. Approximately 98 percent of Alternative GCS-B would parallel existing ROWs, including 190 miles of the Seaway Pipeline ROW south of Cushing before diverting to a path that would pass east of Lake Texoma. It is not known whether Alternative SCS-B would be constructed within existing ROWs and therefore it is not clear that it would offer an environmental advantage over the proposed route due to the use of more existing ROWs.

Both alternative routes would avoid the Big Thicket Natural Preserve in Liberty County, Texas by routing the pipeline along the Texas highway. The Big Thicket Natural Preserve is a combination of pine and cypress forest, hardwood forest, meadow, and blackwater swamp, and in 2001 the American Bird Conservancy designated the Big Thicket National Preserve as a Globally Important Bird Area (National Park Service 2010b). The predominant ownership along the proposed route is private land, with less than 1 percent of the ROW corridor owned by either the State of Oklahoma or Texas.

A comparison of the impacts on key environmental resources of the two Gulf Coast Segment alternatives is provided in Table 4.3.5-1. The proposed route would cross more wetlands and forested land than Alternative GCS-B. However, Alternative GCS-B would cross more agricultural land, rangeland and grassland, developed land, more open water and rivers and streams than the proposed route. In addition, Alternative GCS-B would be in close proximity to more developed areas along its route than the proposed route. Alternative GCS-B would be 6 miles longer than the proposed route and would affect about 90 more acres during construction, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads.

As a result, Alternate GCS-B would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

TABLE 4.3.5-1 Impact Comparisons for the Gulf Coast Segment Alternatives		
Characteristic	**Proposed Route (Alternative GCS-A)**	**Alternative GCS-B**
Length (Miles)	480	486
Land Use (Acres)[a]		
Agricultural Land	1,646.4	1,974.8
Barren Land	3.7	4.2
Developed Land	346.1	381.8
Forested	1,930.5	1,185.7
Rangeland/Grassland	1,767.8	2,378.8
Wetlands	747.6	552.8
Open Water	8.5	20.6
Total	6,450.6	6,498.7
Number of Streams and Rivers crossed[b]	246	255

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Streams and rivers from ESRI 2004b.

4.3.6 Houston Lateral Alternative Routes

The Houston Lateral would extend from the Gulf Coast Segment to a point in the Moore Junction area east of Houston. Moore Junction is a large area that extends to the north and south of the Houston Ship Channel and includes a large number of oil industry facilities. Two route alternatives for the Houston Lateral were identified: the proposed Project route (Alternative HL-A) and Alternative HL-B. These alternatives are depicted on Figure 4.3.6-1 and compared below. As indicated on Figure 4.3.6-1, the alternatives have different starting and ending points.

The proposed route would be 48.6 miles long and would initiate at a point on the Gulf Coast Segment in central-east Liberty County. From there it would extend south and west through Chambers County to Harris County, ending near Moore Junction, north of the Houston Ship Channel. Approximately 40 percent of the proposed route would parallel other utility corridors.

Alternative HL-B would start at Nederland (Jefferson County) and extend in a west-southwest direction to a point north of the main body of Galveston Bay, then extend to the southwest and would terminate near Moore Junction, south of the ship channel. The route would be approximately 77.4 miles long with 97 percent of the route paralleling other utility corridors. It would extend through Jefferson, Liberty, Chambers, and Harris counties. Although Alternative HL-B would be parallel to substantially more existing ROWs, it is not known whether it would be constructed within existing ROWs and therefore it is not clear that it would offer an environmental advantage over the proposed route due to the use of more existing ROWs.

Alternative HL-B would be about 30 miles longer than the proposed route and would affect about 400 more acres during construction, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads.

The southwestern end of the proposed route would extend through heavily developed urban areas in the east Houston area. Both the beginning and ending portions of Alternative HL-B would also extend through heavily developed urban areas.

The proposed route would extend through approximately 4 miles of land within the Texas Coastal Zone Boundary (TCZB) along the Gulf Coast and would be subject to regulation under the federally approved Texas Coastal Management Program. Any project that may affect land or water in the Texas coastal zone and that requires a federal license or permit must be reviewed for consistency with the Texas Coastal Management Program. Assuming a 110-foot-wide construction ROW, there would be approximately 60 acres affected within the TCZB in Harris County, including extra work spaces and additional access roads. It is not likely that contractor and pipe yards would be required within that distance.

Alternative HL-B would cross approximately 31 miles of land within the TCZB in Harris and Chambers counties, and construction would disturb about 450 acres, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads. As a result, Alternative HL-B would affect about 390 more acres in the TCZB than the proposed route. Alternative HL-B would likely encounter greater regulatory barriers than the proposed route due to its proximity to the Gulf Coast and due to the area of the coastal zone that would be affected.

Alternative HL-B would require a marine crossing of an arm of Galveston Bay in the vicinity of the Houston Ship Channel. The crossing distance would be approximately 1.8 miles, and would produce impacts to benthic communities and nearshore environment along the proposed route. In comparison, the proposed Project route would not cross any portion of Galveston Bay.

A comparison of the impacts on key environmental resources of the two Houston Lateral alternatives is provided in Table 4.3.6-1. The proposed Project route would cross less agricultural land, less developed land, less rangeland and grassland, and fewer streams, rivers, and other open water than Alternative HL-B. However, it would also cross through more wetlands and federal lands than Alternative HL-B.

As compared to proposed route, Alternative HL-B would be longer and would have a larger area of impact due to construction, would have substantial coastal zone concerns, would cross more developed land in urban areas, and more rivers, streams, rangeland and grassland, and agricultural land. Most importantly, it would involve a marine crossing of an arm of Galveston Bay. As a result, Alternative HL-B would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

TABLE 4.3.6-1
Impact Comparisons for the Houston Lateral Alternatives

Characteristic	Proposed Route (Alternative HL-A)	Alternative HL-B
Total Length (Miles)	48.6	77.4
Land Use (Acres)[a]		
Agricultural Land	286.5	438.7
Barren Land	0.0	0.3
Developed Land	27.4	208.5
Forested	27.1	11.7
Rangeland/Grassland	66.6	182.4
Wetlands	236.5	165.5
Open Water	3.9	24.9
Total	648.0	1,032.0

TABLE 4.3.6-1 Impact Comparisons for the Houston Lateral Alternatives		
Characteristic	**Proposed Route (Alternative HL-A)**	**Alternative HL-B**
Federal Land Ownership (Acres)[b]		
U.S. Fish and Wildlife Service	46.7	18.7
Number of Streams and Rivers crossed[c]	12	28

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Streams and rivers from ESRI 2004b.

4.3.7 Route Variations

A variation is a relatively short deviation from a proposed route that is developed to address state agency concerns and requirements or resolve or reduce construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, residences, and terrain conditions. Variations are different from major route alternatives in that alternatives are typically substantial distances from proposed pipeline routes, are generally much longer than variations, and are developed to reduce overall environmental impacts, reduce or eliminate engineering and constructability concerns, and avoid or minimize conflicts with existing or proposed residential and agricultural land uses while meeting the goals of a project. Although route variations also may be many miles in length, they are typically shorter and nearer to a proposed route than a major route alternative. Many requests for variations were submitted by concerned landowners during the review period for the draft EIS as well as in direct negotiations with Keystone as design of the proposed route progressed.

Because most route variations were identified to avoid or minimize specific environmental impacts and land use conflicts, in response to landowner comments, and to increase the use of public land in Montana consistent with the requirements of MFSA, they may not in all cases display a substantial environmental advantage over the segments of the proposed Project route that they would replace. Since the variations are generally close to the route segments they would replace and for the most part extend across similar terrain, the construction methods would be essentially the same and the visual character of the variations would be essentially the same as that of the proposed Project after reclamation is complete. In most cases, the impacts associated with implementation of the variations would be essentially the same as the impacts that would result from construction and operation of the route segments that the variations would replace.

Route variations assessed in this analysis include:

- Variations in Montana (Section 4.3.7.1);
- Niemi Variation in South Dakota (Section 4.3.7.2); and
- Minor Realignments Negotiated with Landowners (Section 4.3.7.3).

4.3.7.1 Montana

In Montana, MFSA and MEPA require that MDEQ implement a specific process to identify landowner concerns, preferential use of public lands, and other considerations to develop alternatives to proposed routes. A detailed discussion of the requirements of MFSA and MEPA is included in Section 1.0 of Appendix I to the EIS. As noted in that section, MDEQ must identify the route that minimizes adverse environmental impacts and uses public land (which may include federal land) whenever the use of public lands is as economically practicable as the use of private land before it can approve the proposed Project or any alternative to the proposed Project.

In addition to the alternatives described in Sections 4.1, 4.2, and 4.3.1 through 4.3.6, MDEQ required that Keystone identify and assess two additional alternative routes in Montana that would increase the use of public lands in comparison to the proposed route. These alternative routes were developed using a GIS database model (i.e., ground surveys were not conducted) that incorporated a set of weighted environmental factors agreed to by MDEQ. Using that approach, the Canada to North Dakota (CND) and Canada to South Dakota (CSD) alternatives were developed and compared at a screening level to the proposed route relative to environmental impacts and the use of public lands. As described in detail in Section I-2.0 of Appendix I, both routes were eliminated from further consideration as a result of this screening analysis. However, MDEQ identified portions of the CSD Alternative that would cross more public land than the segments of proposed Project route they would replace and considered them as potential route variations. MDEQ also identified additional route variations that would avoid or minimize impacts to specific resources, minimize conflicts with existing or proposed residential and agricultural land uses, and that responded to requests submitted by concerned landowners during both the scoping period and the draft EIS comment response period.

In total, MDEQ identified 19 potential route variations in Montana and prior to the draft EIS, preliminarily selected 9 of these variations as preferable to the segments of the proposed route that they would replace. As a result of continuing review and analysis, MDEQ has revised its selection of potential route variations and will develop a preferred route that includes portions of the proposed Project route and selected route variations out of a total suite of nearly 100 potential route variations assessed. MDEQ mailed a certified letter to each of the landowners affected by these potential variations and requested comments. In addition, where requested, MDEQ staff met affected landowners in the field to further describe the routing variations and listen to landowner concerns and suggestions for further adjustments. These variations will be addressed in the final EIS. Beginning in mid to late April, these suggested routing variations in Montana can be viewed at MDEQ's web site: http://svc.mt.gov/deq/wmaKeystoneXL/. MDEQ will continue to consider these and other route variations prior to completing the MFSA review process and issuing a Certificate of Compliance. The variations that MDEQ may ultimately select are relatively close to the proposed Project route segments they would replace. Both DOS and MDEQ have conducted environmental reviews of the proposed Project route in Montana as reported in this EIS. MDEQ maintains information related to the proposed Project on its website located at: http://deq.mt.gov/MFS/KeystoneXL/KeystoneXLIndex.mcpx. Along with information related to Keystone's application and the EIS review and comment process, the website also provides an interactive map detailing available updates to the proposed Project variations in Montana and the MDEQ suggested variations. Though the website is intended to provide the most up-to-date data when available, information not provided on the site will be included in the final EIS.

4.3.7.2 South Dakota

As a result of negotiations with two landowners in the vicinity of Buffalo, South Dakota, Keystone surveyed the landowners' properties and developed a route variation that would avoid areas that were being developed for commercial excavations of paleontological resources. The variation, termed the

Niemi Route Variation, diverts from the proposed route just north of MP 309 on the Steele City Segment, and returns to the proposed route just north of MP 315. The segment of the proposed route that would be replaced is about 6.56 miles long, and the variation is about 7.02 miles long, or about 0.46 miles longer than the proposed route. The routes of the variation and the segment of the proposed route it would replace are depicted on Figure 4.3.7-1 and the impacts of the two routes on key environmental resources are compared in Table 4.3.7-1.

The variation is slightly longer than the proposed route, but would cross less state land than the segment of the proposed route it would replace. Both the variation and the segment of the route it would replace have one isolated cultural resources find, and neither is eligible for nomination to the NRHP. The Keystone survey identified a rock cairn along the route of the variation. The site is potentially eligible for the NHRP, but impacts would be mitigated through construction avoidance methods including necking and fencing.

As noted in Table 4.3.7-1, the variation would cross 4 more intermittent streams and 3 more wetlands than the proposed route. Impacts to these resources would be avoided or minimized by incorporating the permitting requirements of the USACE Nationwide Permit and the procedures described in Keystone's CMR plan (Appendix B).

During 2009 field surveys, sage grouse leks were not identified near either the proposed Project route or the Niemi Route Variation. However, data from the South Dakota Game, Fish and Parks Department indicates that there are two historic (inactive) leks about 0.2 mile southwest of the Niemi Route Variation. Raptors, raptor nests, or bald eagle winter roost sites were not identified during aerial raptor surveys conducted in February and April 2009 along either the proposed route or the Niemi Route Variation.

Field surveys conducted in November 2010 determined that (1) the proposed route would cross multiple locations of known paleontological resources as well as an ongoing commercial paleontological excavation, and (2) the variation would cross three "significant" (as defined by BLM) paleontological areas, all of which are on private land. Prior to construction surface collections of paleontological resources along the variation would occur and during construction the ROW would be monitored by a qualified paleontological expert.

The Niemi Route Variation would replace a short segment of the overall proposed Project, is relatively close to the proposed route; addresses a specific issue relevant to landowners; would be implemented in accordance with applicable regulatory requirements of federal, state, or local permitting agencies; and would have environmental impacts similar to those of the segment of the proposed route it would replace. As a result, incorporation of the Niemi Route Variation into the proposed Project, with implementation of the procedures described above, is acceptable to DOS.

TABLE 4.3.7-1
Comparison of Niemi Route Variation with the Segment of the Route it Would Replace

Item	Miles of Land Crossed (except where noted)		Difference
	Proposed Route Segment	Niemi Route Variation	
Length	6.56	7.02	-0.46
Land Cover[a]			
Agriculture	0.45	0.37	+0.08
Developed	0.13	0.08	+0.05
Rangeland	5.98	6.57	-0.59
Total	6.56	7.02	-0.46
Land Ownership[b]			
State of South Dakota	0.51	0.48	+0.03
Private Land	6.05	6.54	-0.49
U.S. Bureau of Land Management	0.00	0.00	0.00
Total	6.56	7.02	-0.46
Number of Private Properties	2	2	0
Number of Road Crossings[c]			
Major Roads	1	1	0
Minor Roads	1	0	+1
Total	1	0	+1
Number of Stream Crossings[d]			
Perennial Streams	0	0	0
Intermittent Streams	5	1	+4
Total	5	1	+4

Item	Miles of Land Crossed (except where noted)		Difference
	Proposed Route Segment	Niemi Route Variation	
Slope[e]			
< 5%	6.44	6.93	-0.49
≥ 5% and ≤ 15%	0.12	0.09	+0.03
> 15% and ≤ 30%	0.00	0.00	0.00
> 30%	0.00	0.00	0.00
Number of Water Wells within 100 ft[f]	0	0	0
Number of Residences			
Residences within 25 ft	0	0	0
Residences within 500 ft	0	0	0
Number of Structures			
Structures within 25 ft	0	0	0
Structures within 500 ft	0	0	0
Cultural Resource Findings			
Cultural Findings	1 Not Eligible	1 Not Eligible, 1 Potentially Eligible	-1 Potentially Eligible
Paleontological Findings	1 Significant, 2 Non-Significant	3 Significant	-2 Significant, +2 Non-Significant
Number of Grouse Leks[g]			
Sage-Grouse within 4 miles	0	0	0
Wetlands[g]	2 (PEM)	5 (PEM)	-3 (PEM)
Areas with Noxious Weeds[g]	1	0	+1
Number of Waterbodies[g]	5 ephemeral	1 stream, 1 ephemeral	-1 stream, +4 ephemeral

[a] Land use from USGS 2001.
[b] Federal lands from ESRI 2004a. State land from South Dakota GIS, 2010.
[c] Roads from ESRI 2003.
[d] Streams and rivers from ESRI 2004b.
[e] Slope from USGS 2002.
[f] Well Locations from South Dakota Department of Environment and Natural Resources 2010.
[g] Data from Trow Engineering Consultants 2010; Note: the variation was surveyed, the proposed route segment survey was incomplete.

4.3.7.3 Minor Realignments Negotiated with Landowners

During detailed design of the proposed route and the associated continuing field surveys, areas along the proposed route were identified that would require minor deviations to avoid small but sensitive resources, that would require difficult construction procedures, or that were concerns to landowners due to potential conflicts with existing land uses. As a result, many route variations were identified that would replace segments of the proposed Project route. These variations would replace short segments of the proposed Project, are relatively close to the proposed route and would be implemented in accordance with applicable regulatory requirements of federal, state, or local permitting agencies (see Appendix W). As a result, incorporation of these variations into the proposed Project in place of the segments they would replace is acceptable to DOS.

4.3.8 Agency-Preferred Route

Alternatives were developed and assessed based on information provided in the Presidential Permit application and supplemental submittals related to the application, information provided by the cooperating agencies, public comments received in the scoping process and on the draft EIS, and information obtained from research of relevant available information conducted by DOS and its third-party contractor.

Based on the assessment of alternatives described above, the DOS-preferred route consists of the following alternatives by segment:

- Steele City Segment: Alternative SCS-B (including route variations in Montana selected by MDEQ, the Niemi Route Variation, and minor route realignments listed in Appendix W);
- Existing Cushing Extension (including two new pump stations);
- Gulf Coast Segment: Alternative GCS-A; and
- Houston Lateral: Alternative HL-A.

4.4 ALTERNATIVE PIPELINE DESIGN

DOS received comments on the draft EIS requesting consideration of the alternative of constructing the pipeline above ground and comments requesting that we consider the alternative of using smaller diameter pipe for the Project. Those two alternatives are addressed in the following sections:

- Aboveground Pipeline (Section 4.4.1); and
- Smaller Diameter Pipe (Section 4.4.2).

4.4.1 Aboveground Pipeline

Although it is technically feasible to construct the proposed Project pipeline aboveground in most areas along the proposed route, there are many disadvantages to an aboveground pipeline. In comparison to an aboveground pipeline, burying a pipeline reduces the potential for pipeline damage due to vandalism, sabotage, and the effects of other outside forces, such as vehicle collisions. Further, there has been increased concern about homeland security since the September 11, 2001 attacks, and burying the pipeline provides a higher level of security.

In addition, 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 more accessible to those intent on damaging the pipeline.

Nearly all petroleum transmission pipelines in the U.S. are buried. As stated in Section 2.3, the proposed Project would be constructed, operated, maintained, inspected, and monitored consistent with the PHMSA requirements presented in 49 CFR 195, relevant industry standards, applicable state standards, and a set of Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project design, operations, maintenance and monitoring commitments. Construction, operation, inspection, and maintenance of the Project in this manner would result in a pipeline system with a higher degree of safety than any other domestic oil pipeline system and with a higher degree of safety along the entire length of the pipeline system than is required in HCAs as defined in 49 CFR 195.450.

As a result, an aboveground pipeline is not a reasonable alternative for the proposed Project and was not further considered.

4.4.2 Smaller Diameter Pipe

As noted in Section 1.1, the proposed Project would transport a maximum capacity of 830,000 bpd of crude oil to meet current and future market demand for heavy crude oil in PADDs II and III. A pipeline system with a pipe diameter that is less than the proposed Project's 36-inch-diameter pipeline would have lower throughput capacities and would not be capable of providing this volume of crude.

Even if a smaller diameter pipe were commercially viable, construction of smaller lines would have essentially the same impacts as those of the proposed 36-inch-diameter pipe since the construction right-of-way width would be approximately the same for all but the smallest diameter pipe. 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, not the diameter of the pipe itself. For all pipelines over 30 inches in diameter, the working ROW dimensions would be essentially the same.

The proposed pipeline is sized to efficiently deliver the volume of crude oil proposed to be transported by the proposed Project (i.e., an initial capacity of 700,000 bpd and an ultimate maximum capacity of 830,000 bpd with increase pumping capacity). While there are limitations to the ultimate capacity of throughput based on pipeline diameter, the operational throughput is a 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 it is not likely that those pressures and velocities would be in consistent with PHMSA regulations. Further, even with high 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. In addition, as of February 2011, Keystone had firm contract commitments to transport 600,000 bpd of crude oil to Cushing (155,000 bpd of WCSB crude oil for delivery to Cushing that is currently contracted for shipment on the Mainline of the existing Keystone Oil Pipeline Project, 380,000 bpd of WCSB crude oil for delivery to the Gulf Coast, and 65,000 bpd of Bakken crude oil). 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, use of a smaller diameter pipe for the proposed Project was not considered 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 potential alternative was eliminated from further consideration.

4.5 ALTERNATIVE SITES FOR ABOVEGROUND FACILITIES

The major aboveground facilities of the proposed Project consist of pump stations, MLVs, and the Cushing Tank Farm. Alternative sites for those facilities are addressed in the following sections:

- Alternative Pump Station Sites (Section 4.5.1);
- Alternative MLV Sites (Section 4.5.2); and
- Alternative Tank Farm Sites (Section 4.5.3).

Pig launching and receiving facilities would be located within pump stations, and therefore alternate sites for those facilities are not addressed separately.

4.5.1 Alternative Pump Station Sites

All pump stations for the proposed Project would be sited within the permanent ROW. As a result, alternate locations for pump stations were included in general in the assessment of alternate pipeline routes discussed in Section 4.3. The specific sites selected for pump stations were based on system hydraulics, and there would be a minimal distance along the pipeline corridor for alternate pump station sites due to the pumping requirements of each portion of the system. Minor modifications in pump station footprint location may occur as a result of input from appropriate regulatory authorities.

4.5.2 Alternative MLV Sites

All MLVs for the proposed Project would be sited within the permanent ROW. As a result, alternate locations for MLVs were included in general in the assessment of alternate pipeline routes discussed in Section 4.3. In addition, the locations of MLVs must be consistent with 49 CFR 195.260 and the specific conditions related to MLVs included in the Project-specific Special Conditions developed by PHMSA that Keystone has agreed to incorporate into the Project (see Appendix U). As a result, there is little option to install MLVs at alternative sites. However, MLV locations have been selected to avoid sensitive environmental resources to the extent practicable while complying with the PHMSA regulatory requirements and will be modified to comply with the relevant Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project specifications.

4.5.3 Alternative Tank Farm Sites

Initially, the proposed Project included a tank farm at Steele City, Nebraska. That location would have provided opportunities for batch shipment on either the proposed Project or the existing Keystone Oil Pipeline Project. It was later determined that installing the tank farm at Cushing would be preferable from an operational perspective and would provide better options for delivery systems interconnection and tankage installation for the Bakken Marketlink and the Cushing Marketlink projects if either or both of those projects are implemented (see Sections 2.5.3 and 2.5.4 for information on the potential Bakken Marketlink and Cushing Marketlink projects).

The proposed Cushing tank farm site was selected to be adjacent to the proposed site of pump station 32. It is also less than 0.5 mile from the existing Cushing Oil Terminal, which is the largest oil terminal in the U.S. Siting near the pump station and the existing terminal would avoid disturbance to areas farther from the facility and would eliminate the need for a connecting pipeline extending beyond the proposed ROW. As described in Section 3, construction and operation of the Cushing tank farm would not result in substantial impacts. As a result, there do not appear to be any alternative tank farm sites that would offer an overall environmental advantage to the proposed site.

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