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 “tailors” 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

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[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

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[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

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[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.

Although the GHG footprint of pipeline operations is much smaller than the life-cycle footprint of the oil sands crude transmitted through the pipeline, mitigation opportunities exist for reducing GHGs from operations as well. One such opportunity would involve purchase of "green power" – i.e., electricity generated from renewable sources – to provide electricity for operations, potentially eliminating the carbon footprint from electricity. Both EPA (2011) and DOE (2011) provide information on green power products offered by organizations in the United States. These products include green pricing programs (which allow consumers to pay a premium to support utility company investments in renewable energy), retail green power products (i.e., the sale of electricity generated from renewables in competitive markets), and renewable energy certificate (REC) products[21] (also known as green tags or tradable renewable credits) (DOE 2010).[22] In Canada, the Ecologo Program[23] provides third-party certification of renewable electricity products that can be purchased for green power.

Carbon credits and carbon offsets could also be purchased to offset GHG emissions from the Proposed project via GHG reductions made elsewhere. Carbon credits are tradable certificates that allow entities to emit a certain quantity of CO_2 or CO_2-equivalent GHG emissions. Under a cap-and-trade program that establishes a limit on GHG emissions that can be emitted by a group of entities, credits—or excess allowances—are generated by entities that emit below their regulated limit, and can be sold to other regulated and non-regulated entities. In the United States, excess allowances could be purchased from the Regional Greenhouse Gas Initiative (RGGI), and the cap-and-trade system being developed under California's Global Warming Solutions Act (Assembly Bill 32). Carbon offsets, in contrast, are certified reductions in GHG emissions generated from entities not included in cap-and-trade programs. Several organization and entities have developed carbon offset standards and protocols to ensure that offsets are real, measurable, permanent, and in addition to what would have happened without a market for selling offsets.[24] Landfill methane collection and combustion systems, avoiding methane emissions from organic waste, and implementing agricultural and forestry practices to enhance carbon sequestration in soils and forests are examples of projects that can register carbon offsets, provided they meet the requirements of the certifying standard or protocol. Some cap-and-trade programs also allow the use carbon offsets to meet emission limits.

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

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[21] In the context of offsetting GHG emissions, RECs only guarantee that an amount of electricity has been generated from renewable sources; they do not necessarily guarantee that the renewable electricity generated is additional to what would have been generated but for the purchase of a REC.

[22] See EPA's Green Power Partnership (http://www.epa.gov/greenpower/) and DOE's Green Power Network (http://apps3.eere.energy.gov/greenpower/).

[23] The Ecologo is a Type I eco-label (as defined by the International Organization for Standardization (ISO), meaning that it involves third-party certification of environmental performance based on an evaluation of multiple environmental criteria. Ecologo was founded by the Government of Canada in 1988 and is managed by TerraChoice since 1995.

[24] Examples of carbon offset standards and trading entities include: the Clean Development Mechanism (CDM) (http://cdm.unfccc.int/index.html), the Climate Action Reserve (CAR), (http://www.climateactionreserve.org/), the Verified Carbon Standard (http://www.v-c-s.org/), the Gold Standard Registry (http://goldstandard.apx.com/), and the Chicago Climate Exchange (CCX) (https://www.theice.com/ccx.jhtml).

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
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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