ENBRIDGE™

Enbridge Energy, Limited Partnership

Before the North Dakota Public Service Commission
Case No. PU-07-108

Application for a Corridor Certificate and Route Permit for a Crude Oil Pipeline

EXHIBIT
2

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Consolidated Application for Corridor Certificate and Route Permit

Enbridge Energy, Limited Partnership

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF ENBRIDGE ENERGY, LIMITED PARTNERSHIP FOR THE CONSTRUCTION OF APPROXIMATE 28 MILES OF 36-INCH PIPELINE AND ASSOCIATED FACILITIES IN PEMBINA COUNTY, NORTH DAKOTA.	CASE NO. PU-07-108

Consolidated Application of Enbridge Energy, Limited Partnership for Waiver or Reduction of Procedures and Time Schedules for a Corridor Certificate and Route Permit

Enbridge Energy, Limited Partnership ("Applicant") whose address for purposes of this application is 1100 Louisiana, Suite 3300, Houston, Texas 77002, pursuant to the Energy Conversion and Transmission Facility Siting Act codified at North Dakota Century Code Chapter 49-22 ("Act"), hereby submits this Consolidated Application for Waiver or Reduction of Procedures and Time Schedules for a Corridor Certificate and Route Permit ("Application").

Applicant requests that the North Dakota Public Service Commission ("Commission") waive and/or reduce the procedures and time schedules required by the Act or in the Commission's regulations set forth in Title 69-06 of the North Dakota Administration Code, to accomplish the purposes as requested herein. These include, but are not limited to: (1) waive, pursuant to North Dakota Century Code §§ 49-22-07.2, 49-22-13(2), and North Dakota Administrative Code § 69-06-01-02(3) and Chapter 69-06-06, provisions of North Dakota Century Code §§ 49-22-08(5), 49-22-08.1(5), 49-22-13 and North Dakota Administrative Code § 69-06-01-02 which requires separate filings of such applications, separate notices of such applications, separate hearings on such applications and certain time schedules as set forth in said statutes and rules; (2) approve a one-mile wide corridor rather than a 2.8 mile wide corridor pursuant to North Dakota Administrative Code § 69-06-04-02(1)(b); (3) hold one expedited and consolidated public hearing on this Application in conjunction with the hearing in Case No. PU-07-75 being Enbridge Pipelines (Southern Lights) LLC application for its LSr Project; (4) find that the proposed facilities are of such design, location and purpose that they will produce minimal adverse effects; and (5) designate and approve the requested facilities as identified in this Application, and issue the appropriate corridor certificate and route permit.

The Commission's Application Guidelines for Waiver of Procedures and Time Schedules requires a description of the facility, the need for the facility, the cost of the facility and separate justification for each provision of the Act for which the Applicant is requesting a waiver, together with evidence that the project will produce minimal adverse effects or that a demonstrable emergency exists. As demonstrated in this Application, and summarized below, Applicant's requests for waivers or reduction of procedures and time schedules and the issuance of a corridor certificate and route permit are justified as the proposed facilities are of such design, location and purpose that they will produce minimal adverse effects, and that the urgent demand for additional pipeline capacity to deliver petroleum to markets in the United States and Canada requires construction at an early date.

DESCRIPTION

The proposed project (the "Alberta Clipper Project") consists of approximately 990 miles of new 36-inch liquid petroleum pipeline extending from Hardisty, Alberta, Canada to Superior, Wisconsin. Approximately 28 miles of this pipeline will be located in Pembina County, North

Dakota. The Alberta Clipper Project will be located adjacent to Enbridge Energy, Limited Partnership's multiple line rights easements, and parallel to its pipeline systems, some of which have been previously sited by the Commission. Enbridge Energy, Limited Partnership further anticipates that additional permanent right-of-way will be needed for the Alberta Clipper Project in addition to the right-of-way requirements for the 20-inch liquid petroleum pipeline, referred to as the "LSr Project," the subject of Docket No. PU07-75. Such additional right-of-way is needed to accommodate the new pipelines and provide sufficient space for a buffer zone, as Enbridge Energy, Limited Partnership intends to maintain a 25-foot offset between the existing and new pipelines and the edge of the right-of-way. Applicant proposes to use pumping units at existing station sites. Thus, no new surface facilities will be constructed within the State of North Dakota other than pipeline markers, rectifiers, and block valves which may include small fenced-in enclosures to house associated power and control systems to allow some valves to be operated remotely

NEED

The purpose of the Alberta Clipper Project is to transport crude oil and other liquid hydrocarbons from western Canada to serve the increasing demand for crude oil in Midwestern markets and beyond. Moreover, the Alberta Clipper Project will be operationally integrated with and form part of the Enbridge Mainline System and be used to transport crude petroleum to the Superior, Wisconsin tankage facilities. From the Superior terminal, the crude oil will be further transported into Midwestern markets via the Lakehead System, which is currently being expanded to increase capacity between Superior, Wisconsin and the Chicago area through the completion of the Southern Access Project, as more fully described in this Application,.

Addtionally, the Alberta Clipper Project will provide incremental capacity into the Enbridge Clearbrook tank farm and terminal facility for subsequent delivery to Minnesota Pipe Line, which is owned by others and delivers to the Minneapolis-St. Paul area.

Due to the fact that the Alberta Clipper Project will cross the international border between the United States and Canada, Applicant must obtain a Presidential Permit from the United States Department of State. Significant lead times are anticipated in securing such a Presidential Permit. In order that the Alberta Clipper Project be constructed and placed in service in a timely manner, Applicant is at this time seeking necessary approvals and permits from the Commission and from the appropriate regulatory agencies in the states of Minnesota and Wisconsin. In order that the Alberta Clipper Project be constructed in a timely manner, it is imperative for Applicant to obtain the appropriate state permits as soon as possible so that construction can commence when the Presidential Permit is issued.

COST

The estimated cost of constructing the Alberta Clipper Project in the State of North Dakota is $90,700,000.00.

JUSTIFICATION

In previous cases before this Commission for what is known as the Lakehead System, comprehensive environmental analyses, including cultural resources surveys, were completed. Applicant has updated said environmental analyses and cultural resource surveys for the Alberta Clipper Project. These studies demonstrate that there will be minimal adverse effects by construction.

For the foregoing reasons, Applicant hereby submits there is substantial justification for the requested waivers and/or reduction of time schedules and procedures, as the Alberta Clipper Project will produce minimal adverse effects.

Applicant respectfully requests the Commission to grant the requested waivers and/or reductions of procedures and time schedules; and to render an expeditious decision approving the requested corridor certificate and route permit.

Dated this 16th day of July, 2007.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
FLECK, MATHER & STRUTZ, Ltd.
P.O. Box 2798
Bismarck, ND 58502

By ______________________
BRIAN R. BJELLA

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

Brian R. Bjella, being first duly sworn on oath, deposes and says that he is the attorney for the applicant herein named, that he has read the above and foregoing application, knows the contents thereof, and that the same is true to the best of this affiant's knowledge, information, and belief.

____
BRIAN R. BJELLA

Subscribed and sworn to before me this 16th day of July, 2007.

____
Michelle Wenger, Notary Public
Burleigh County, North Dakota
My Commission Expires:

(S E A L)

MICHELLE WENGER
Notary Public
State of North Dakota
My Commission Expires Oct. 30, 2009

B

APPLICATION FOR CORRIDOR CERTIFICATE

SECTION A

DESCRIPTION OF PROPOSED FACILITY

A.1. Describe the type of transmission facility addressed in this application. The description shall include the purpose of the facility and the technology to be employed:

In this application, Enbridge Energy, Limited Partnership ("EELP") proposes to construct, own and operate a 36-inch outer-diameter liquid petroleum pipeline referred to hereinafter as the "Alberta Clipper Project." The Alberta Clipper Project will be integrated as part of the Enbridge Mainline System[1] and will transport crude oil and other liquid hydrocarbons from Hardisty, Alberta to Superior, Wisconsin.

As proposed, the Alberta Clipper Project consists of approximately 990 miles of 36-inch diameter crude oil pipeline, including all associated valves and appurtenances. This new pipeline will originate at Canadian affiliate Enbridge Pipelnes Inc.'s Enbridge's facilities near Hardisty, Alberta, Canada and extend southeasterly to end at EELP's terminal and tank farm facility in Superior, Wisconsin. Approximately 326 miles will be located in the United States, with 28 miles located in North Dakota, beginning at the U.S.-Canada border near Neche, North Dakota and extending southeast leaving North Dakota at the Minnesota border approximately 2 miles northeast of Bowesmont, North Dakota. The remaining 298 miles will be located in Minnesota and Wisconsin, which will terminate at the Enbridge's tank farm and terminal facility near Superior, Wisconsin.

EELP plans to install the Alberta Clipper Project generally adjacent to its existing Lakehead System multiple pipeline right-of-way. EELP further anticipates that additional permanent right-of-way will be needed for the Alberta Clipper Project in addition to the right-of-way requirements for the 20-inch liquid petroleum pipeline, referred to as the "LSr Project," the subject of

[1] Enbridge Inc.'s subsidiary, Enbridge Pipelines Inc., owns and operates the Canadian pipeline system that interconnects with and delivers into Enbridge Energy, Limited Partnership's "Lakehead System" at the International Border near Neche, North Dakota. These operationally integrated pipeline systems together form the longest liquid petroleum pipeline in the world. Together, these two systems are referred to as the "Enbridge Mainline System." Collectively these affiliated entities are referred to as "Enbridge."

Docket No. PU07-75. Such additional right-of-way is needed to accommodate the new pipelines and provide sufficient space for a buffer zone, as EELP intends to maintain a 25-foot offset between the existing and new pipelines and the edge of the right-of-way. Enclosed herewith as Exhibit H is a more detailed description of the right-of-way requirements for the Alberta Clipper and LSr Projects within the state of North Dakota. Both projects will be located parallel to the existing Lakehead System right-of-way and installed within the same construction footprint with an approximate six-month difference in construction timeframe between the installations. As described in Exhibit H, a final determination of the Alberta Clipper Project's right-of-way requirements will be made following completion of field surveys and preliminary engineering design activities.

The Alberta Clipper Project will have an annual capacity of 450,000 barrels per day ("bpd"). No new pumping stations or surface facilities will be installed in the State of North Dakota, other than pipeline markers, rectifiers, and block valves which may include small fenced-in enclosures to house associated power and control systems to allow some valves to be operated remotely.

Enbridge Pipelines Inc. has filed regulatory applications in Canada to construct the Canadian segment of Alberta Clipper Project. The Canadian portion of the Alberta Clipper Project consists of approximately 664 miles of 36-inch outer-diameter pipeline, beginning at the Hardisty, Alberta tank farm and terminal facility and extending to the southeast to end at the U.S.-Canadian boundary in the Province of Manitoba, which is north of Neche, North Dakota.

As stated above, the Alberta Clipper Project will be operationally integrated with and form part of the Enbridge Mainline System and will be used to transport crude petroleum to the Superior, Wisconsin tankage facilities.[2] From the Superior terminal, the crude oil will be further transported into Midwestern markets via the Lakehead System, which is currently being expanded to increase capacity between Superior, Wisconsin and the Chicago area through completion of the Southern Access Project. Additionally, the Alberta Clipper Project will provide incremental capacity into the Enbridge Clearbrook tank farm and terminal facility for subsequent delivery to non-affiliated Minnesota Pipe Line which then transports crude oil to refiners in the Minneapolis/St. Paul area.

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[2] See Exhibit I for a schematic drawing of the North Dakota portion of the Alberta Clipper Project as it relates to the Enbridge Mainline System.

The estimated cost of the North Dakota portion of the Alberta Clipper Project is approximately $90.7 million. Enbridge plans to commence construction during December, 2008 and complete construction by late December, 2009. Table 1 - Corridor Certificate shows the annual capacities of the Enbridge pipelines before and after the Alberta Clipper Project. *See, infra,* p. 5.

As an interstate common carrier of crude petroleum and natural gas liquids the Lakehead System's rates, tariffs, and accounting practices are subject to the regulatory authority of the U.S. Federal Energy Regulatory Commission (FERC). The tariff rates for the Alberta Clipper Project will be filed in accordance with applicable FERC rules and regulations, and approved by FERC prior to placing the facilities in-service.

Based on the current throughput forecasts, the economic life of the Alberta Clipper Project is estimated to be no less than 25 years.

A.2. Describe the type, source, and final destination of the product to be transmitted by the proposed facility:

As defined in its FERC Tariff on Rules and Regulations for the Lakehead System, Enbridge currently transports the following commodities on the Lakehead System within the United States:

Condensate (CND)
Light Crude Petroleum (LGT)
Medium Crude Petroleum (MED)
Heavy Crude Petroleum (HVY)
Natural Gas Liquids (NGL)

The Alberta Clipper Project is expected to transport light crude petroleum and heavy crude petroleum.

Enclosed herewith as Exhibit A are three maps showing the Enbridge Mainline System in the following pictorial overviews: Map A-1 provides a view of the Enbridge Mainline System within the international liquid transportation grid in Canada and the various Petroleum Administration for Defense Districts ("PADD") of the United States (a geographic grouping of regions as designated by the U.S. Departments of Energy and Defense). This map, along with a more specific map of PADD II enclosed herewith as Map A-2, shows the

Lakehead System, proposed expansion projects within this region, and all interconnecting pipelines and refineries within this region. Also enclosed is Map A-3, a map showing existing delivery points to numerous refineries along the Enbridge Mainline System in Canada and United States.

As shown on these maps, the Lakehead System also receives crude petroleum from Montana and North Dakota producing fields through the affiliated Enbridge Pipeline (North Dakota) L.L.C. pipeline system (formerly the Portal Pipe Line), which delivers these volumes of crude oil to the Enbridge Clearbrook terminal facility in Clearwater County, Minnesota. Although the Alberta Clipper Project has no direct receipt or delivery points within the State of North Dakota, it does provide two substantial benefits to North Dakota. First, the Alberta Clipper Project increases the capacity east of Clearbrook so that all shippers, including those shipping North Dakota production, have greater access to refineries in the Great Lakes area and other regions of the United States.[3] Second, by increasing capacity from western Canada to the Great Lakes area, the Alberta Clipper Project reduces the volumes from Canada that might otherwise compete with crude oil produced in the Williston Basin in the Rocky Mountains market area.

The Alberta Clipper Project will provide incremental capacity needed to transport the increasing supplies of crude oil produced from western Canada (and, as noted above, to a lesser extent, Montana and North Dakota production) to refineries in PADD II, PADD III and potentially eastern U.S. refinery markets through direct or indirect connections. Other delivery locations include refineries and connected carriers in Minnesota, Wisconsin, Michigan, New York, Ohio and Ontario, and through connections in Illinois, to refineries in the U.S. Gulf Coast or to the Cushing, Oklahoma terminal hub.

As shown in Table 1 - Corridor Certificate, the Alberta Clipper Project creates incremental capacity on the Enbridge Mainline System, allowing additional volumes of crude oil to move from Hardisty, Alberta to Clearbrook, Minnesota and to Superior, Wisconsin. At Clearbrook, EELP will have the ability to deliver volumes of crude oil to the non-affiliated Minnesota Pipe Line for ultimate redelivery to refineries in the Minneapolis/St. Paul area, and the ability to continue the crude oil movement further east on the Lakehead System to

[3] Enbridge is currently expanding its North Dakota System by adding approximately 30,000 bpd of capacity by late 2007 (Docket Nos. PU06-330 and PU06-349) and has proposed a further "Phase 6" expansion to its North Dakota System that would, if shipper support is secured and FERC approval received, expand the system to approximately 155,000 bpd by 2009, with all increased capacity delivered to the interconnect to the Enbridge Mainline System at Clearbrook, Minnesota.

Superior, Wisconsin. From the Superior terminal, the crude oil will be further transported into Midwestern markets via the Lakehead System, which is currently being expanded to increase capacity between Superior, Wisconsin and the Chicago area through completion of the Southern Access Project.

Table 1 – Corridor Certificate
Alberta Clipper Project and Other Mainline Upgrades
U.S. Border to Superior, Wisconsin
Annual Capacity (bpd)

Line No.	Pre-Alberta Clipper Project (Dec. 31, 2008)	Capacity Additions	Post-Alberta Clipper Project (Dec. 31, 2009)
1	237,000	0	237,000
2	442,000	0	442,000
3	503,000	0	503,000
4[1/]	793,000	88,000	881,000
13	172,000	0	172,000
LSr Project[2/]	186,000	0	186,000
Subtotal	2,333,000	88,000	2,421,000
Alberta Clipper Project		450,000	450,000
Total Mainline Capacity	**2,333,000** [3/]	**538,000**	**2,871,000**

1/ Includes minor upgrades.
2/ The LSr Project was filed by Enbridge on April 20, 2007, and is currently under review by the ND-PSC in PU-07-075.
3/ This assumes that the LSr Project is operational and in-service on Dec. 31, 2008 as scheduled.

Generally, liquids pipelines are designed at a specified capacity for a known liquid. Most liquids pipelines transport a variety of liquids. The change in fluid characteristics (density, viscosity, etc.) of the transported liquids will affect the capacity of the pipeline. Liquids are also batched in a pipeline in a repeatable sequence. Both the fluid characteristics and batch sequence will affect the capacity of the pipeline.

Two definitions are used to describe pipeline capacity: "Design Capacity" and "Annual Capacity".

Design Capacity is the theoretical capacity of the pipeline for given types of liquids and their batch sequence. Design Capacity is calculated assuming

Table 2 – Corridor Certificate Capacity Definitions		
		Alberta Clipper Project Capacities (bpd)
Ultimate Annual Capacity	**Maximum economic expansion capacity of individual pipeline that is sustainable average daily rate per day over a year.**	**800,000**
Ultimate Design Capacity	**Maximum economic expansion capacity of individual pipeline. Requires additional pumping horsepower over current design to meet this capacity**	**880,000**
Design Capacity	**Theoretical capacity**	**500,000**
Annual Capacity	**Average sustainable rate average barrels per day over a year**	**450,000**

theoretically ideal operating conditions. With respect to the Alberta Clipper Project, the Design Capacity is 500,000 bpd.

Annual Capacity is the average sustainable throughput over a year. Annual Capacity is calculated assuming historic average annual and operating conditions. These operating conditions include scheduled and unscheduled maintenance, normal operating problems and crude supply availability. Annual Capacity of a pipeline is typically 90% of Design Capacity. Table 2 – Corridor Certificate, Capacity Definitions provides design data pertinent to the new 36-inch diameter pipeline.

EELP has and will continue to provide information on the Alberta Clipper Project to landowners and several county and state officials and to persons who request the information.

A.3. Size and Design:

a. **provide a description of the size and design of the ELECTRICAL facility including, but not limited to, the following:**

1. **Width of right-of-way;**
2. **Estimated span lengths;**
3. **Anticipated type of structure;**
4. **Approximate length of facility;**
5. **Voltage; and**
6. **The requirement for and general location of any new associated facilities.**

b. **provide a description of the size and design of the PIPELINE facility including, but not limited to, the following:**

1. **Width of right-of-way;**
2. **Estimated distance between surface structures such as manholes or block valves;**
3. **Pipe size;**
4. **Approximate length of facility;**
5. **Maximum design operating pressure and temperature;**
6. **Maximum design flow rate; and**
7. **The number and general location of compressor or pumping stations**

A.3.a. Not applicable (Electrical Facility).

A.3.b. Description of size and design of pipeline facility.

A.3.b.(1) <u>Width of the Right of Way</u>

The majority of the easements for the Lakehead System in Pembina County, North Dakota were acquired in 1950 for the installation of an 18-inch pipeline. The easements were predominantly blanket easements and stated no specific right-of-way width. Since the initial 18-inch pipeline was constructed, 20-inch, 26-inch, 34-inch and 36/48-inch liquid petroleum pipelines have also been installed within the right-of-way corridor. In 1997, a 12-mile section of 34-inch replacement pipe was installed in

Pembina County, North Dakota. To assure the safety of the public and allow adequate space for maintenance of the lines, the right-of-way is typically kept clear for approximately a 125-foot width. See Exhibit H for more specific details relative to right-of-way requirements.

A.3.b.(2) Estimated Distances Between Surface Structures

Within North Dakota, two (2) mainline remotely operated valves will be installed: one valve will be located at Mile Post 792.0 (Joliette Station) and the other valve will be located upstream (western side) of the Red River of the North at Mile Post 801.1. Other surface structures will be limited to pipeline markers and rectifier sites, which are part of the pipeline system's cathodic protection system.

A.3.b.(3) Pipe Size

The pipe size will be 36-inch outside diameter, 0.469-inch wall thickness, API 5L Grade X70, double submerged are (DSAW) steel pipe. The maximum allowable operating pressure will be 1,050 to 1,313 psig. Enclosed herewith as Exhibit K is the Enbridge Pipe Specification EES-103.

The valves to be installed will be 36-inch ANSI 600, weld end by weld end, full port, rising stem gate valves. These valves will be manufactured in accordance with API Standard 6D "API Specification for Steel, Gate, Plug, Ball and Check Valves for Pipeline Service." The maximum allowable operating pressure of the valve will be 1480 psig. Enclosed herewith as Exhibit K is the Enbridge Valve Specification EES-105.

A.3.b.(4) Approximate Length of Facility

Of the total 990 miles of pipe, approximately 326 miles will be located in the United States and 664 miles will be located in Canada. In the United States, approximately 28 miles will be located in North Dakota, beginning at the international boundary near Neche, North Dakota and extending southeast, leaving North Dakota at the Minnesota border approximately 2 miles northeast of Bowesmont, North Dakota. Enbridge encloses herewith as Exhibit B an overview map showing the location of the Alberta

Clipper Project route through Pembina County, North Dakota. The remaining 298 miles will be located in Minnesota and Wisconsin, terminating at Enbridge's tank farm and terminal facility near Superior, Wisconsin.

A.3.b.(5) Maximum Design Operating Pressure and Temperature

The Annual Capacity of the Alberta Clipper Project will be 450,000 bpd. The maximum allowable operating pressure of this pipe will be 1050 to 1313 psig. The maximum temperature of the petroleum will be 104°F.

A.3.b.(6) Maximum Design Flow Rate

The maximum design flow rate of the Alberta Clipper Project is 500,000 bpd.

A.3.b.(7) The Number and General Location of Pumping Stations

No new pumping stations or units will be required within the State of North Dakota at this time.

A.4. Time Schedule

A.4.a. Certificate of Corridor Compatibility

Expected on or before December 31, 2008.

A.4.b. Route Application

Route application submitted in July 2007 as part of this consolidated Certificate of Corridor Compatibility and Route Application.

A.4.c. Route Permit

Expected before December 31, 2008.

A.4.d. Construction Start Date

Proposed commencement date for construction is October 2008.

A.4.e. Construction Complete

Estimated construction completion date is on or before December 31, 2009.

A.4.f. In Service Date

Estimated in-service date is December 2009. EELP expects to have completed its line-fill and be fully operational by mid-2010.

APPLICATION FOR CORRIDOR CERTIFICATE

SECTION B - STUDIES

Enbridge's 1994 Capacity Expansion pipeline project (reference Case No. PU-179-93-767) was located along the same route as the Alberta Clipper Project. In planning the 1994 project, Enbridge completed the following evaluative studies or assessments of the environmental impacts of the proposed facility:

- An extensive cultural resources review was conducted for the Capacity Expansion area in coordination with the State Historical Society of North Dakota (SHSND). This work included a files search and literature review of the Capacity Expansion area, development of an archaeological sensitivity model, performance of Phase I archaeological investigations of selected areas within the corridor, and performance of Phase II evaluations of four potentially significant sites identified in the Phase I investigation. One site, a historic ox-cart trail (the "Angle Road"), was determined to be eligible for listing on the National Register of Historic Places. During the 1994 construction, Enbridge elected to bore under Angle Road to avoid any disturbance.

- A field wetland delineation was conducted to identify jurisdictional wetlands crossed by the route. The presence and demarcated boundaries of wetlands were determined using hydrophytic vegetation, hydric soils, and hydrologic criteria. Each delineated wetland was classified according to the Classification of Wetlands and Deepwater Habitats of the United States (Cowardin system).

- Appropriate federal and state agencies were consulted to identify known occurrences of protected species or sensitive areas in the Capacity Expansion area.

Much of the information obtained during through the 1994 activities listed above is relevant to the Alberta Clipper Project. As it did in 1994, Enbridge plans to bore under the Angle Road to avoid impacting that site. To update cultural resource information, Enbridge has met with the SHSND and has conducted a current files search and literature review. The results of this work will be provided to the SHSND, and Enbridge will continue to work with the SHSND to identify additional cultural review work, if any, necessary for the Alberta Clipper Project.

Enbridge has consulted with the North Dakota Game and Fish Department and the U.S. Fish and Wildlife Service. Based on these consultations, no state-listed or federally listed species are known to frequent the Alberta Clipper Project area. Enbridge has contacted (or will contact) other appropriate regulatory agencies (*e.g.*, the U.S. Army Corps of Engineers, North Dakota State Water Commission, North Dakota Department of Health Water Quality Division) and will continue to work with these agencies to address potential environmental impacts and obtain applicable permits.

APPLICATION FOR CORRIDOR CERTIFICATE

SECTION C

NEED FOR FACILITY

C.1. an analysis of the need for the proposed facility based on present and projected demand for the product transmitted by the facility, including the most recent system studies supporting the analysis of the need.

a. Planned Use and Purpose

The Alberta Clipper Project has been developed following careful evaluation of short- and long-term supply and demand patterns for crude oil in North America and in consultation with industry members. Industry consultations include western Canadian producers and the downstream refineries that refine the crude oil produced in Alberta's oil sands. Based on this analysis and in consultation with shippers on the Enbridge Mainline System that seek increased pipeline capacity out of the Western Canadian Sedimentary Basin ("WCSB"), Enbridge concluded that, starting in 2010, there will be a shortfall of pipeline capacity from western Canada to U.S. refinery markets. Even after taking into account other current or planned expansions of the Enbridge Mainline System and other non-Enbridge pipeline capacity and new systems, Enbridge concluded there will be more crude oil from the WCSB than there is available pipeline capacity between Alberta and Superior, Wisconsin beginning in 2010.

Enbridge delivers crude oil to refineries either through direct connections to refineries or through indirect connections via pipelines owned by others. See Map A-3 (Exhibit A) showing the current configuration of the Enbridge Mainline System, interconnecting carriers and refinery markets served.

Enbridge investigated a number of alternatives before determining that the Alberta Clipper Project provided the most economical, integrated transportation solution available to the industry as discussed in more detail in Section C.2. The Alberta Clipper Project also provides flexible and scaleable incremental capacity to connect refineries to growing production from the WCSB.

As demonstrated over the last few years, the demand for crude oil transportation on the Lakehead System has increased, rising from 1.34 million bpd in 2005 to 1.63 million bpd during the fourth quarter 2006. In direct response to this demand for increased capacity out of the WCSB, Enbridge has undertaken a number of expansions and extensions to both the Canadian and U.S. portions of the Enbridge Mainline System. (See discussion on "Other Expansions on the Enbridge Mainline System" in Section C.1.f below.)

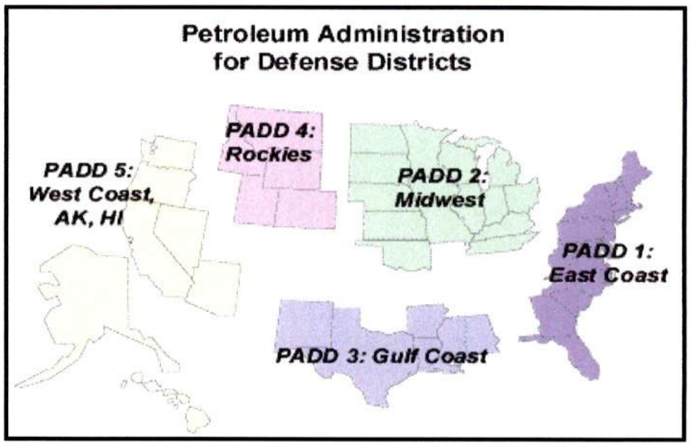
As stated above, the Alberta Clipper Project will transport crude oil from Hardisty, Alberta and deliver such supplies into the tank farm and terminal facilities at Superior, Wisconsin. From the Superior terminal, the crude oil will be further transported into Midwestern and other United States refinery markets via the Lakehead System, which is currently being expanded to increase capacity between Superior, Wisconsin and the Chicago area through completion of the Southern Access Project.

Once commissioned, and in conjunction with other expansions which Enbridge has underway, the Alberta Clipper Project will provide the additional capacity between Alberta and Superior, Wisconsin needed to satisfy its shippers' requirements, while also providing increased future flexibility to meet supply forecasts and accommodate changing crude oil slates over time. Increased flexibility can be very important to accommodate unscheduled crude supply outages, such as in 2005 when hurricanes severely curtailed the oil industry's ability to deliver crude to the Midwest from the Gulf Coast. The Alberta Clipper Project will have an initial capacity to deliver 450,000 bpd of crude oil. The design of the Alberta Clipper Project allows for future expandability up to an Ultimate Annual Capacity of 800,000 bpd through the addition of new and modification of existing Enbridge pumping stations should future growth of WCSB crude production and demand by refineries in the United States and eastern Canada require capacity expansions. No plans for such an expansion are under active consideration or have been approved, although Enbridge and its customers are continuously assessing demand and supply patterns and various other pipeline infrastructure development projects to determine if and when future expansions or changes are needed in the Enbridge Mainline System to meet market needs.

b. Petroleum Supply and Demand in Midwest

According to the most recent statistics available from the U.S. Energy Information Administration ("EIA"),[4] the petroleum-using public in the U.S. Midwest consumes over 5.2 million bpd of refined petroleum products, which includes gasoline, diesel, jet fuel, asphalt, heating fuel and petrochemical products. To meet this demand, refineries in PADD II (as defined by the EIA and shown in Figure C.1.b) processed 3.3 million bpd of crude oil in 2005.

Figure C.1.b.1



There is significant interdependence between PADD regions, with both crude oil and refined products transported between PADDs. In 2005, the latest year for which data are available, approximately 1 million bpd of refined petroleum product was transported <u>from</u> PADD III <u>to</u> PADD II to assist in meeting the Midwest's refined product demand.[5] The assessment of this supply-demand forecast prompted Enbridge to commission Muse, Stancil & Co. to undertake a market assessment and benefit study for the Alberta Clipper Project 2010 – 2020, which is appended hereto as Exhibit J.

Enbridge anticipates that demand from refineries based in PADD III and PADD I for crude oil produced in the WCSB will also grow as these refineries face waning domestic onshore production in PADD III and look to supplies from Canada as economical and secure alternatives to oil production countries outside North America.

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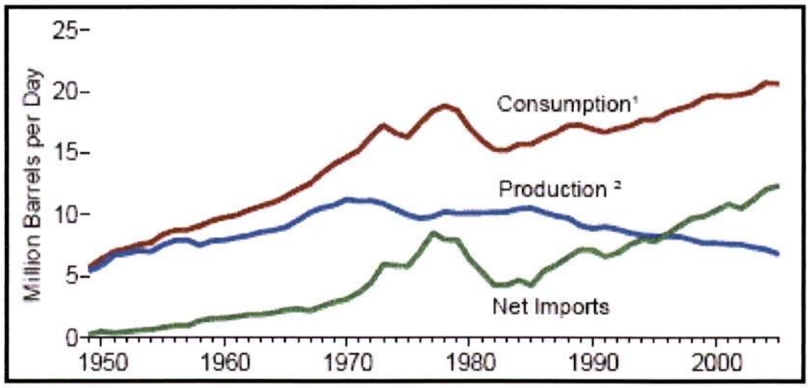
[4] The statistical arm of the Department of Energy
[5] Refer to EIA energy data at: http://www.eia.doe.gov/

Demand for petroleum products as an energy source and for other purposes is growing, and will continue to escalate throughout the Midwest area as population increases and economic activity expands, despite energy conservation, use of alternative energy and efficiency measures. Anticipating future petroleum demand is influenced by a number of factors and various experts have a variety of forecast future scenarios. One such forecast, completed by the EIA in its Annual Energy Outlook, shows that oil consumption in the United States will increase by one-third to approximately 27.6 million bpd by 2030.[6] Satisfying this demand will include the importation of crude oil into PADD II, as production in PADD II has fallen to approximately 0.44 million bpd, compared to a high of over 1 million bpd in the mid-1980's.[7]

In addition to the possibility of increased energy conservation and alternative energy sources, the solution to meeting the public's demand for petroleum products could include more imports of refined petroleum into the United States. However, a significant part of the petroleum energy supply solution is for existing refineries to maintain, and in some cases increase, their output and continue to access reliable supplies of crude oil feedstock. This is driving demand for increased supplies of crude oil sourced from western Canada and the necessary pipeline infrastructure to meet that demand. As shown in Figure C.1.b.2, EIA has tracked petroleum demand and supply for many years and, as widely reported, consumption has increased; however, U.S. domestic production of crude oil has steadily fallen since the 1970s, requiring an increase in imported crude oil. Specifically, there has been a continual decline from production sources in Texas (decline of 3% per year) and nearby states (0.6% per year) that deliver crude oil to Upper Midwest refineries.

[6] U.S. Department of Energy, EIA "Annual Energy Outlook 2007 with Projections to 2030", Report #:DOE/EIA-0383(2007)
[7] *Ibid.*

Figure C.1.b.2 United States Petroleum Overview
Energy Information Administration



Historically, a significant portion of the crude petroleum required to satisfy the public demand for refined products has been sourced from crude oil production areas in various western Canadian provinces and has been transported to the U.S. Midwest through common carrier pipelines such as the Enbridge Mainline System.

Refineries served directly or indirectly by the Enbridge Mainline System are shown on Table C.1.b.3:

Table C.1.b.3
Refineries Served Directly or Indirectly by Enbridge Systems

Refinery	Location	Capacity (cubic meters/day)	Capacity[1] (barrels/day)	Connected Directly from Enbridge	Connected Indirectly
Minnesota and Wisconsin					
Marathon Petroleum Co.	St. Paul Park, Minnesota	11,129	70,000		Yes - Minnesota Pipeline
Flint Hills Resources	Rosemount, Minnesota	44,516	280,000		Yes - Minnesota Pipeline
Murphy Oil USA Inc.	Superior, Wisconsin	5,286	33,250	Yes	
Total		**60,932**	**383,250**		

Refinery	Location	Capacity (cubic meters/day)	Capacity[1] (barrels/day)	Connected Directly from Enbridge	Connected Indirectly
Illinois and Indiana					
ExxonMobil Refining & Supply Co.	Joliet, Illinois	37,839	238,000	Yes	
Citgo Petroleum Corp.	Lemont, Illinois	25,223	158,650	Yes	
BP PLC	Whiting, Indiana	63,436	399,000	Yes	
Total		**126,498**	**795,650**		
Kentucky and Southern Illinois and Indiana					
Marathon Petroleum Co.	Robinson, Illinois	30,526	192,000		Yes - Mustang/ Marathon
ConocoPhillips	Wood River, Illinois	48,650	306,000		Yes - Mustang/ Capwood
Countrymark Cooperative	Mt. Vernon, Indiana	3,736	23,500		Yes - Mustang/ Marathon
Marathon Petroleum Co.	Catlettsburg, Kentucky	35,295	222,000		Yes - Mustang/Marathon
Total		**118,207**	**743,500**		
Michigan and Ohio					
BP PLC	Toledo, Ohio	23,411	147,250	Yes	Yes - Sun Pipeline
Sunoco Inc.	Toledo, Ohio	22,258	140,000		Yes - Sun Pipeline
Marathon Petroleum Co.	Detroit, Michigan	15,899	100,000	Yes	Yes - Sun Pipeline
Marathon Petroleum Co.	Canton, Ohio	11,606	73,000		Yes - Mustang/ Marathon
Valero Energy Corp.	Lima, Ohio	25,676	161,500		Yes – Mustang/ Marathon
Total		**98,850**	**621,750**		
Pennsylvania					
United Refining	Warren, Pennsylvania	10,604	66,700	Yes	

Ontario					
Refinery	**Location**	**Capacity (cubic meters/day)**	**Capacity[1] (barrels/day)**	**Connected Directly from Enbridge**	**Connected Indirectly**
Imperial Oil	Nanticoke, Ontario	17,807	112,000	Yes	
Imperial Oil	Sarnia, Ontario	19,206	120,800	Yes	
Shell Canada	Corunna, Ontario	11,352	71,400	Yes	
Suncor Energy Products	Sarnia, Ontario	11	70	Yes	
Nova Chemicals (Canada)	Corunna, Ontario	12,719	80,000	Yes	
Total		**61,094**	**384,270**	**Yes**	
Cushing					
Coffeyville Resources	Coffeyville, Kansas	15,899	100,000	Yes-Spearhead	
ConocoPhillips	Borger, Texas	23,212	146,000	Yes-Spearhead	
ConocoPhillips	Ponca City, Oklahoma	29,731	187,000	Yes-Spearhead	
Frontier Oil Corp.	El Dorado, Kansas	17,489	110,000	Yes-Spearhead	
NCRA	McPherson, Kansas	12,910	81,200	Yes-Spearhead	
Sinclair Oil Corp.	Tulsa, Oklahoma	7,949	50,000	Yes-Spearhead	
Sunoco Inc.	Tulsa, Oklahoma	13,514	85,000	Yes-Spearhead	
Valero Energy Corp.	Ardmore, Oklahoma	14,547	91,500	Yes-Spearhead	
Valero Energy Corp.	Sunray, Texas	26,497	166,660	Yes-Spearhead	
Wynnewood Refining Co.	Wynnewood	8,347	52,500	Yes-Spearhead	
Total		**170,094**	**1,069,860**		
U.S. Gulf Coast*					
Total		**10,493**	**66,000**		Yes - Mustang/ Pegasus

1. United States refinery capacities as published in the Oil & Gas Journal December 18, 2006.
2. Canadian refinery capacities as published in Oil & Gas Journal December 18, 2006.
3. U.S. Gulf Coast refining capacity is limited to the capacity of the Pegasus Pipeline from Patoka, IL to Beaumont, TX

*(Note the capacity noted is limited to the capacity of the Pegasus Pipeline. The U.S. Gulf refinery capacity is significantly larger.)

Refineries in PADD II and PADD III and potentially PADD I are increasing demand for crude oil from the WCSB. Specifically, BP announced its intention to significantly expand its heavy crude oil processing capability and expand its refined products output by up to 15 percent at its Whiting, Indiana refinery.[8] BP also stated in testimony before the Illinois Commerce Commission during proceedings related to another Enbridge expansion project that BP's expansion is contingent on increased pipeline capacity from western Canadian supply sources being available. As well, the Marathon refinery in Detroit is planning to add 65,000 bpd of heavy crude capacity to increase its production of transportation fuels and the Sunoco refinery in Toledo is increasing its capacity by approximately one-third to increase its utilization of Canadian crude. Coffeyville Resources has stated its support for Enbridge expansions in Wisconsin and Illinois (which will transport volumes of crude oil delivered to Superior, Wisconsin by the Alberta Clipper Project). It intends to increase its demand of crude oil transported from western Canada.

Demand for transportation of crude oil south of the Chicago area into Oklahoma and the U.S. Gulf Coast is evidenced by the demand for capacity on Enbridge's Spearhead Pipeline, reversed in March 2006 to move crude oil from the Chicago area to Cushing, Oklahoma, and on the ExxonMobil Pegasus Pipeline, also reversed in early 2006 to transport western Canadian crude oil from the Patoka, Illinois hub south to the U.S. Gulf Coast. Both systems have been faced with monthly nominations that often exceed available capacity. Thus, on March 2, 2007, Enbridge Inc. announced an Open Season on Spearhead seeking commitments to an expansion program on its Spearhead Pipeline that could increase capacity by 65,000 bpd.[9] Further, on June 5, 2007 ExxonMobil Pipeline and Enbridge Inc. jointly announced their discussions with shippers to determine interest in expanding capacity south of Patoka, Illinois to move significant volumes of crude oil to one or more refinery hubs along the U.S. Gulf Coast that, combined, process more than 6.5 million bpd, or about 40 percent of crude oil in the United States. [10]

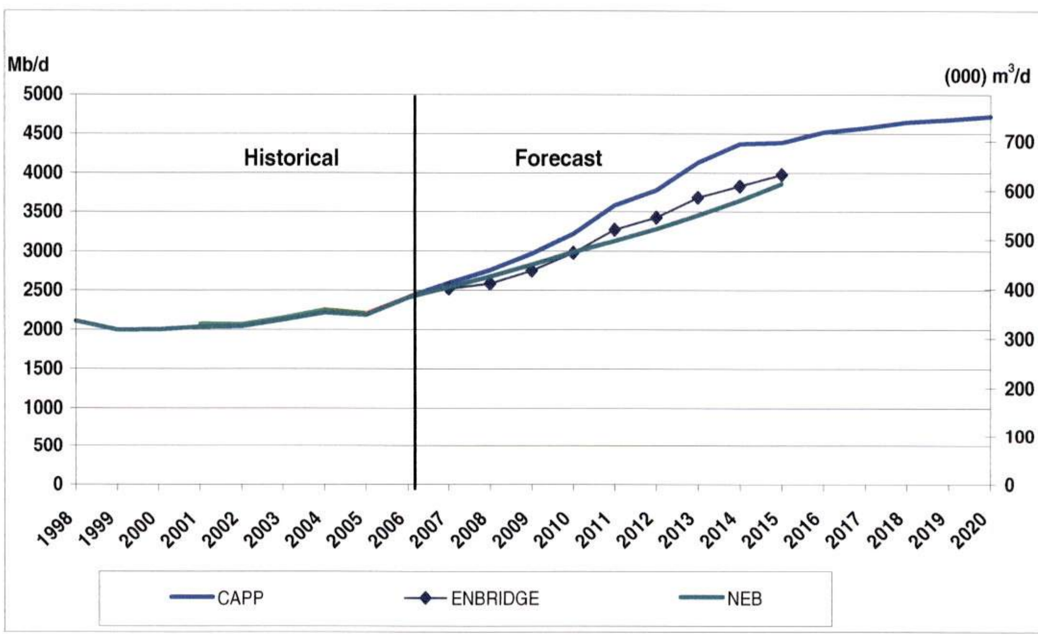
[8] BP News Release September 26, 2006.
[9] Enbridge Inc. News Release March 2, 2006 see www.enbridge.com
[10] Enbridge Inc. and ExxonMobil Pipeline joint news release dated June 5, 2007 see www.enbridge.com

c. Need for the Alberta Clipper Project is amply demonstrated by industry forecasts.

Production and supply forecasts for the WCSB consistently show strong growth for the foreseeable future. Supply forecasts from the National Energy Board ("NEB"),[11] the Canadian Association of Petroleum Producers ("CAPP"),[12] and Enbridge Pipelines Inc.[13] all predict significant growth in the WCSB production over the next 15 years. By 2010, the forecasts show that there could be between 600,000 to 880,000 bpd of incremental crude oil production (see Figure C.1.c.1 below). Existing long-haul pipeline capacity will not be sufficient to accommodate this growth.

Figure C.1.c.1

Comparisons of WCSB Production Forecasts (2006)



[11] See Exhibit G
[12] See Exhibit E
[13] See Exhibit F

This expected supply increase from Canada comes at a time of growing demand from the Midwest region. In 2006 Enbridge exported seventy percent (70%) of the crude oil and natural gas liquids produced in western Canada. Enbridge transports crude oil from the WCSB, as well as production from North Dakota and the Williston Basin, to regional refineries to meet approximately seventy-one percent (71%) of the refinery demand in Minnesota, one hundred percent (100%) in Wisconsin and sixty-two percent (62%) in the greater Chicago area.[14]
The 2006 CAPP forecast report for Canadian crude production covering the period 2006 – 2020 (see Table 5 in Exhibit E) show that absent pipeline expansions, there will be a deficit in pipeline capacity of 1.65 million bpd in 2015 and 2.0 million bpd in 2020. The Alberta Clipper Project is needed and in the public interest as it will provide the timely addition of incremental capacity necessary to connect the increasing oil sands production to refining centers in the Midwest.

d. Alberta Clipper Project Increases Pipeline Capacity into the Midwest

The Alberta Clipper Project will deliver volumes into the Enbridge terminal facilities at Superior, Wisconsin and for subsequent reentry into the Lakehead System for delivery into refinery markets in the Midwest, eastern Canada, eastern United States and, through interconnecting carriers, as far south as the U.S. Gulf Coast. Also, the Alberta Clipper Project provides feedstock to two Minnesota refineries (Flint Hills and Marathon) through the interconnection with Minnesota Pipeline at Clearbrook.

The construction of the Alberta Clipper Project, along with the other Enbridge Mainline System expansions planned or underway, will efficiently configure the Enbridge Mainline System to the supply patterns of the crude oil producing community, and maximize capacity for transportation to refinery centers. A number of alternatives to the Alberta Clipper Project were considered, as discussed in Section C.2; however, a new pipeline was the most effective and efficient solution for providing the most economical, integrated transportation solutions available to the industry while ensuring flexible and scaleable incremental capacity out of the WCSB.

[14] See Enbridge Energy Partners 10K at: http://www.enbridgeus.com/Reports/

e. Advantages to U.S Refinery Sector and U.S. Public

Increased western Canadian crude oil supply is critical to realizing the significant economic and strategic benefits that will accrue to growing U.S. refinery demand and ultimately to the residential and industrial refined products' consumer. Domestic U.S. onshore production of crude oil, particularly in the onshore U.S. Gulf states, has been declining and will continue to decline, as is evident from the annual crude oil production forecasts distributed by the Energy Information Administration.[15]

Canadian-produced crude affords Midwest refiners and consumers a supply source that is reliable, ample, secure, and economical. For such reasons, demand by Midwest refiners for Canadian crude has been increasing. Access to Canadian crude is now, and can be in the future, a secure means of satisfying public need and demand for petroleum products.

Interstate and international transmission pipelines, such as those operated by Enbridge, are the only practical and secure means of meeting the Midwest's need for petroleum. No combination of railroad tank cars and/or tanker trucks could effectively and economically move the huge quantities of crude oil needed to keep the Midwest refineries functioning.

Refineries that can obtain and process economical Canadian crude oil may enjoy lower supply costs as well as more dependable sourcing and expeditious delivery than otherwise available. Ultimately consumers benefit as enhanced low cost, crude supplies help restrain product prices, secure product availability, maintain the Midwest refining industry and its economic contributions to the area, and may act to cushion the Midwest market against supply disruptions caused by natural phenomena and world oil shocks and consequences thereof.

f. Other Expansions on the Enbridge System

Since constructing the first pipeline from Alberta to Superior, Wisconsin in 1949 and beginning operations in 1950, Enbridge has expanded the Enbridge Mainline System a number of times to increase transport capability from western Canada and North Dakota to U.S. Midwest and eastern Canadian markets. Currently, Enbridge has several expansion projects in various stages of development along the Enbridge Mainline System as discussed below.

[15] U.S. Department of Energy, Energy Information Administration's "Annual Energy Outlook," http://www.eia.doe.gov/oiaf/aeo/

Also, enclosed as Exhibit C is a pictorial overview map of these expansion projects.

North Dakota Expansion: The Enbridge Pipelines (North Dakota) L.L.C. System ("Enbridge North Dakota System") is undertaking an expansion (ND PSC Docket Nos. PU06-330 and PU06-349) to increase its annual capacity into the Enbridge Clearbrook terminal from 80,000 bpd to 110,000 bpd. Further , on June 15, 2007, Enbridge announced an Open Season for Phase 6 of an expansion program that would expand capacity to 155,000 bpd subject to shipper commitments, regulatory and FERC approvals. The Alberta Clipper Project will also help meet North Dakota producers' increasing demand for additional capacity east of Clearbrook to Midwest markets and beyond as the supply forecast from the Williston Basin increases.

Southern Access Project : In addition to the Alberta Clipper Project detailed in this application, Enbridge is currently expanding and extending its Lakehead System via a project consisting of three-stages referred to as the "Southern Access Project." The first stage of the Southern Access Project is a new 42-inch diameter pipeline, adding 146,000 bpd of capacity from Superior, Wisconsin to the Chicago area and is currently under construction for start-up in early 2008. The second stage of the Southern Access Project continues the construction of the new 42-inch diameter pipeline to Flanagan, Illinois (just southwest of Chicago) for completion in early 2009. When complete, these two stages together will add 400,000 bpd of capacity to the Lakehead System. In a third stage of the Southern Access Project referred to as the Southern Access Extension Project, Enbridge will extend its pipeline system by constructing a 36-inch diameter pipeline from Flanagan, Illinois to reach the Patoka, Illinois hub, subject to regulatory approvals currently in progress.

Southern Lights Project: The Southern Lights Project is a new 20-inch diameter pipeline from Chicago to Clearbrook, Minnesota. At Clearbrook, this new 20-inch diameter pipeline will connect to Enbridge's Line 13, which will be reversed. The Southern Lights Project will carry light hydrocarbons known as "diluents" to Edmonton for use in diluting the heavy crudes produced in Alberta's oil sands and facilitating their transportation by pipeline. Enbridge has already started construction of portions of the Southern Lights Project from Chicago to Superior, Wisconsin as the Southern Lights Project was concurrently permitted to be built in parallel phases and immediately adjacent to the Southern Access Project for the majority of the route. No construction will be required in North Dakota to reverse the flow of Line 13; thus, no ND-PSC authority is being sought herein.

LSr Project: Enbridge filed with the North Dakota Public Service Commission ("Commission") in Docket No. PU07-75, a request for permission and approval to construct, own and operate a new 20-inch diameter crude oil pipeline referred to as the "LSr Project." The LSr Project will add critical incremental transportation capacity in an early timeframe (2008) to the Enbridge Mainline System from Cromer, Manitoba to Clearbrook, Minnesota in order to transport the light and medium crude oil volumes that are received into the Enbridge Mainline System at Cromer, Manitoba. The transportation of these volumes on the LSr Project will free up long-haul capacity on the Enbridge Mainline System west of Cromer, thereby partially relieving the forecast capacity constraint for all grades of crude oil moved on the Enbridge Mainline System.

Enbridge/ExxonMobil Proposed New Pipeline from Patoka, Illinois to U.S. Gulf: On June 5, 2007, Enbridge and ExxonMobil announced that they were in discussions with shippers to solidify initial interest expressed in adding pipeline capacity from southern Illinois to one or more refinery hubs along the U.S. Gulf Coast.

g. Summary

As supported above, the Alberta Clipper Project provides a competitive and timely alternative to address the critical need for increased transportation capacity out of the WCSB, as a result of increased oil production over the next fifteen years. The planned December 2009 construction completion for the Alberta Clipper Project meets industry's needs and avoids potential capacity apportionment that effectively removes otherwise available supplies from the market. Also, the Alberta Clipper Project provides expanded system flexibility which can be implemented in stages, meeting future shipper demands for additional pipeline capacity.

Moreover, the Alberta Clipper Project affords shippers access to the widest variety of refinery hubs of any other major crude oil pipeline system in North America, providing options to access various refinery markets to allow shippers to adapt to market conditions. As a direct result, shippers have the added flexibility to immediately respond to market conditions, such as oversupply in one area caused by a refinery outage or supply restraints in another area due to infrastructure damage such as that caused by the 2005 hurricane season in the Gulf Coast region.

Therefore, the construction and operation of the Alberta Clipper Project is in the public interest. The Alberta Clipper Project provides a reliable, efficient and cost effective alternative for delivering the large volumes needed by the U.S. Midwestern refiners in the timely manner required.

C.2 Alternatives to the Proposed Facility

As stated above, the Alberta Clipper Project is a new 990-mile, 36-inch diameter oil pipeline extending from Hardisty, Alberta to Superior, Wisconsin. The Alberta Clipper Project will provide capacity in a timely manner, as required by the market to meet the take-away capacity requirements of upstream producers and the refined product needs of the publics served by the refineries that are supplied either directly or indirectly by the Alberta Clipper Project. To review reasonable alternatives to building the Alberta Clipper project, it is important to recap the scope of the Alberta Clipper Project against which each alternative needs to be compared.

- 326 miles of pipeline located generally along an existing pipeline route and pre-disturbed right-of-way.
- Three pump stations, booster pumps, and manifold connections at existing, predisturbed, station and terminal sites.
- Integration with the Enbridge Mainline System to optimize the use of tankage at Clearbrook, Minnesota and Superior, Wisconsin, operating and maintenance personnel and equipment, co-inspections and optimization of pipeline usage between adjacent pipelines during outages of one or more of the parallel pipelines.
- A delivery connection at Clearbrook to facilitate deliveries to Minnesota refineries.
- Interconnection with four liquid petroleum pipelines east and south of Superior to maximize potential markets served and flexibility for shippers.

Enbridge investigated a number of alternatives before determining that the Alberta Clipper Project was the most economic and feasible expansion available to industry to provide flexible and scaleable incremental capacity out of the WCSB and into the U.S. Midwest markets. In the past, Enbridge expansions have been significantly less substantial capacity increases, and traditional pipeline alternatives such as pipeline looping and the addition of horsepower at existing and new intermediate stations were studied in great detail and implemented to the extent feasible. The only alternative available to accommodate the very significant supply growth from western Canada is a new pipeline. Therefore, Enbridge extensively considered alternatives of varying line dimensions (diameter), other projects under development and alternate transportation modes:

C.2.a <u>Alberta Clipper 42-inch Option</u>

- **a discussion of the design and the geographical area affected:** Enbridge investigated building a new 42-inch pipeline from Hardisty to Superior in lieu of the 36-inch pipeline.
- **an estimate of the in-service date:** The projected in-service date for the 42-inch alternative is estimated to be three months later than the Alberta Clipper Project due to availability of pipe and materials.
- **a discussion of the method of operation:** The method of operation would be similar; however, it is likely that the minimum flow rate to achieve turbulent flow would not be achieved for a number of years following a 2010 start-up. In an effort to mitigate the potential significant loss of value caused by the commingling of batches, Enbridge would likely add facilities to allow the insertion of batch separation devices (referred to as batch pigs) into the pipeline.
- **its costs:** This option would require an incremental capital investment approximately 15% higher than the Alberta Clipper Project.
- **its economic life:** This alternative has a similar 25 year economic life as the Alberta Clipper Project.

- **its reliability:** As discussed above, the reliability of the 42-inch segment is hampered by the inability to move enough volumes to keep the pipeline in turbulent flow. Turbulent flow for the 42-inch option is a minimum flow rate of 525,000 bpd as compared to 450,000 bpd for the 36-inch option. Therefore, the 42-inch option would require batch pigs or co-mingling of crude types which does not meet shipper needs.
  Consequently, this option was rejected as an alternative.

C.2.b <u>TransCanada's Keystone Pipeline</u>

- **a discussion of the design and the geographical area affected;** Keystone Pipeline is a pipeline project with an initial capacity of 435,000 bpd. Keystone is owned by TransCanada and is currently pursuing regulatory approvals, including with the North Dakota Public Service Commission, at the federal, provincial and state levels in order to proceed to construction in Canada and the United States. Keystone is supported by confidential contracts and, as such, commercial details are not publicly available. Public information about Keystone can be found on its website at www.transcanada.com/keystone. The website also provides links to news releases and regulatory proceedings.
  Industry forecasts for supply growth from western Canada consistently show supply growth in excess of 1.5 million barrels per day by 2015. With this very significant supply growth, the Alberta Clipper and Keystone Projects are not competing for the same production nor are they delivering to the same markets in the United States. Without the Alberta Clipper Project, 1 million barrels per day of pipeline capacity will still be required over the capacity expected in late 2009, even if current expansions in the industry, such as Keystone, are completed.
  It should be noted that the Alberta Clipper Project and the Keystone Project serve different markets. Keystone does not provide needed pipeline capacity to refineries in Minnesota, Wisconsin, the greater Chicago area and other Midwest refineries. Significant refinery expansions have been announced in Minneapolis and Chicago and potential expansions have been announced in Ohio. Enbridge and Keystone will compete in the Wood River and Patoka markets once placed in service. Western Canadian producers are supporting both the Keystone and the Alberta Clipper Projects.
- **an estimate of the in-service date:** According to recent regulatory filings, Keystone states an in-service date of November 2009.
- **a discussion of the method of operation:** As an interstate and international liquid petroleum pipeline, Keystone will be operated and maintained in accordance with Canadian and U.S. pipeline safety

standards. The Keystone Project has an interconnect with the Wood River Refinery in southern Illinois, and laterals proposed to connect to the Patoka hub in southern Illinois and the Cushing hub in Oklahoma where volumes will be delivered into other markets connected to these two hubs.

- **its costs:** Current cost information is not available to Enbridge. As noted in mid-2006 regulatory filings, Keystone estimates capital costs at US$2.6 billion. Enbridge understands that a re-estimate of the project costs are included in the confidential Transportation Services Agreement negotiated with the committed shippers.
- **its economic life:** Current information is not available to Enbridge. Keystone has represented at regulatory proceedings in Canada that the average contract term is 18 years with the longest being 20 years.
- **its reliability:** Assumed to be consistent with industry standards for pipelines in the United States.

C.2.c <u>Trucking Alternative</u>

- **a discussion of the design and the geographical area affected**: In order to transport 450,000 bpd of heavy crude oil proposed by the Alberta Clipper Project, a fleet of thousands of tractors and trailers would be required as detailed below:

  <u>Computation of Trucking Requirements</u>
  Crude oil volumes = 450,000 bpd
  Per Truck capacity = 150 barrels per truck
  Number of trucks required = 450,000 / 150 = 3,000 trucks per day
  Assume each truck requires loading, in-transit full (3 days), in-transit empty (3 days) and unloading time
  Therefore 3,000 x 3 trucks are required in-transit, 3,000 x 3 trucks in-transit for return trip (empty) and 20% of the in-transit fleet loading and unloading = 9,000 +9,000+3600 = 21,600 trucks (ignoring scheduled/unscheduled down time and time to cross customs at international border crossing).
  Number of drivers required = 21,600 x 2 drivers/truck = 43,200

  In order to facilitate this operation, significant truck loading and offloading terminal facilities would have to be constructed at Hardisty and Superior. In addition, it is likely that substantial upgrades and ongoing maintenance would be required (at public expense) to the connecting roadways along the entire route.
- **an estimate of the in-service date:** While it is possible that the terminal facilities could be constructed on the same timeline as the Alberta Clipper Project, Enbridge does not have an estimate of the time that would be

required to acquire the trucking fleet described above, how long it would take to attract and train the associated drivers, nor how extensive the roadway upgrade program would be.

- **a discussion of the method of operation:** This operation would be highly labor intensive, with a significant workforce required at both terminal locations to allow for the constant loading and offloading requirements. This option would require a significant driver pool to maintain the constant movement of the entire truck fleet.
- **its costs:** EELP is not aware of any trucking operation on the 450,000 bpd scale required that could provide cost comparisons. However, Enbridge has estimated the trucking costs for this alternative could be anticipated to be well over a billion dollars per year range (ignoring the costs of new vehicles and infrastructure facilities necessary).
- **its economic life:** With mileage that the trucks would incur in steady service, EELP estimates that the economic life of a truck would not exceed 3 to 4 years. The truck loading and unloading terminals would have an estimated economic life of 25 years. Enbridge does not have an assessment of the impact that this amount of incremental truck traffic would have on the various roadways.
- **its reliability:** This operation would be inherently much less reliable than the Alberta Clipper Project as truck traffic is affected by weather conditions, mechanical failure, manpower (driver shortages), road maintenance or closures, and border crossing delays. Trucks have a significantly higher rate of accidents affecting driver and public safety than compared to pipelines, according to the National Transportation Safety Board.
  Trucking cannot compete with pipelines for volumes over large volumes over long distances given physical limitations on truck and unloading facilities that are required to sustain operations of this nature. Therefore this alternative was not further considered.

C.2.d <u>Rail Alternative</u>

- **a discussion of the design and the geographical area affected:** in order to transport 450,000 bpd of heavy oil, a fleet of rail cars would be required as detailed below:

  <u>Computation of Railcar Requirements</u>
  Crude oil volumes = 450,000 bpd
  Rail car capacity = 600 barrels per rail car
  Tank cars required = 450,000/600 = 750 rail cars per day

Estimated time to move each rail car from Hardisty to Superior (various carriers and through various rail assembly yards) = 10-15 days

Number of cars in transit = 750 X 10 days = 7,500

Number of cars returning empty = 750 x 10 = 7,500

Assuming each car takes 1 hour to fill and one hour to empty, number of Cars loading/unloading = 120

Total tank car requirements = 7500+7500+120=15,120

Approximately 15,000 rail cars would have to be in route each day, making the roundtrip between those two locations in approximately 20-30 days. In order to facilitate this operation, significant spur lines, rail sidings, and terminal facilities would have to be constructed at Hardisty and Superior. In addition, substantial upgrades and ongoing maintenance would be required to the connecting railways.

- **an estimate of the in-service date:** While it is possible that the terminal facilities could be constructed on the same timeline as the Alberta Clipper Project, Enbridge does not have an estimate of the number of rail cars that would be required are available, nor do we have an estimate of the time that would be required to manufacture them. Enbridge does not have an estimate of the time required to construct the required upgrades the associated railway infrastructure.
- **a discussion of the method of operation:** This operation would be highly labor intensive, with a significant workforce required at both terminal locations to allow for the constant loading and offloading requirements and railcar operation.
- **its costs:** EELP is not aware of any rail operation on the 450,000 bpd scale required that could provide capital cost estimation guidance. EELP also is unsure if rail carriers have or would provide a joint rail tariff(s) for the service contemplated. However, Enbridge has estimated the rail costs for this alternative could be anticipated to be well over a billion dollars per year (without considering the costs of new rolling stock and infrastructure facilities necessary).
- **its economic life:** With mileage that the cars would incur in steady service, the applicant estimates that the economic life of a rail car would not exceed 10 to 15 years. The rail loading and unloading terminals would have an estimated economic life of 25 years.
- **its reliability:** This operation would be inherently much less reliable than the Alberta Clipper Project. The entire operation would be subject to weather related delays, delays caused by scheduling conflicting rail traffic, and a significant mechanical/maintenance requirement exposure based on the number of rail cars involved in this operation.

C.2.e Summary of the conclusions reached with respect to the alternative and the reason for its rejection.

Based on the forecast of demand and supply for crude oil discussed at length in Section C.1 (Needs Summary), Enbridge determined and shippers have supported the need to expand the Enbridge Mainline System by an initial 450,000 bpd with the ability to add future economical expansions through the addition of pump stations in future years if and when further capacity is needed. The alternatives examined with respect to optimizing the existing system, looping, alternative modes of transportation, alternative pipe size or alternative pipeline systems do not economically meet the demand for 450,000 bpd of capacity. In many cases, the alternatives are cost-prohibitive or impose higher public and environmental costs, such as the trucking or rail alternatives discussion.
The Alberta Clipper Project's 36-inch design provided the most efficient and cost effective combination of capital cost and pumping horsepower requirements for the capacity required at this time and allows for future expandability of the Enbridge Mainline System without the foreseeable need for additional pipelines or looping in this geographic area.

Enbridge next evaluated route alternatives, a discussion of which is included in the route permit and environmental supplement report, which is submitted as a consolidated application with the corridor certificate to the ND-PSC.

Based on this assessment, Enbridge constrained the examination of routing alternatives for the Alberta Clipper Project to maximizing the use of existing pipeline and infrastructure and to a route generally within or adjacent to Enbridge's right-of-way for new pipeline construction. This approach also allowed EELP the benefit of utilizing existing pumping station and breakout tank sites and infrastructure at Enbridge fee-owned pump station and terminal sites where fee-owned property has previously been disturbed.

C.3. Statement Concerning Deviations from Most Recent 10-Year Plan

Enbridge's currently filed 10-year plan with the ND-PSC did not anticipate the need to install an additional pipeline along the Lakehead System. Enbridge does not own any of the crude petroleum or natural gas liquids transported in its pipeline and Enbridge does not determine markets or destinations for petroleum commodities. Enbridge's business activity is to provide a cost effective transportation service which is available to anyone tendering commodities for transportation pursuant to tariffs published and on file with the FERC and in accordance with said rules and regulations as well as the Interstate Commerce Act. Enbridge diligently works to anticipate the need for additional pipeline capacity by relying upon forecasts for throughput generated by shippers on the system but also on shippers' service requests, recognizing that they are generally aware of market dynamics consequent dispositions of petroleum and petroleum-based commodities.

Within the last few months, new forecasts have prompted shippers on the Enbridge Mainline System to request additional capacity that requires Enbridge to expand its existing system. Thus Enbridge is responding to such shippers' request by constructing the Alberta Clipper Project as well as other capacity initiatives.

APPLICATION FOR CORRIDOR CERTIFICATE

SECTION D

LOCATION

D.1. Study Area:

The study area and corridor selected comprise the existing right-of-way in which the Lakehead System is located. As stated above, this right-of-way consists predominantly of blanket easements. Enbridge has historically maintained the existing easements in North Dakota by clearing brush and trees for approximately a 125-foot width. Since the pipeline is proposed to be installed immediately adjacent to the existing right-of-way as described in more detail in Exhibit H, Enbridge hereby requests the Commission to waive the requirement contained in N.D.A.C. 69-06-04-02(1)(b) that the width of the corridor be at least ten percent of its length and not less than one mile. As the pipeline will be constructed adjacent to existing pipelines in an area previously studied and approved by the ND-PSC; EELP requests the ND-PSC establish a one-mile wide corridor for this new pipeline.

D.2. Map of Proposed Corridor:

Since this application is a consolidated application for a corridor certificate and a route permit, maps showing the location of exclusion and avoidance areas in area of the corridor are attached as Appendix D of the route permit portion of the application. The original corridor and route of the Lakehead System were selected prior to the adoption of the North Dakota Siting Act but are wholly compatible with the criteria established in the Act.

D.3. Relative Value of Each of the Criteria

Since this application is a consolidated application for a corridor certificate and a route permit, these matters are discussed in Sections B.4, B.5 and B.6 of the route permit portion of the application.

D.4. Criteria to be Evaluated

Since this application is a consolidated application for a corridor certificate and a route permit, these matters are discussed in Sections B.4, B.5 and B.6 of the route permit portion of the application.

D.5. General Mitigative Measures to be Taken

Since this application is a consolidated application for a corridor certificate and a route permit, these matters are discussed in Sections B.4, B.5 and B.6 of the route permit portion of the application.

D.6. Qualifications of Persons Contributing to the Study

The qualifications of the personnel who contributed to the corridor location study are as follows:

(1) James Crawford, Director, Engineering
Degree: Bachelor of Science, University of Wisconsin
Experience: 21 years experience in pipeline engineering and operations
Other Training: Engineering Professional Development, Engineering Mechanics, University of Wisconsin

(2) Jerrid Anderson, Supervising Project Manager Engineer
Degree: Bachelor of Mechanical Engineering, University of Minnesota
MBA, University of St. Thomas
Experience: 16 years experience in pipeline engineering field
Professional License, Registered Professional Engineer, Minnesota (P.E.)

(3) Shaun Kavajecz, Supervisor, Environmental Business Development
Degree: B.S. Accounting
Experience: 22 years experience with 19 years directly related to pipeline safety, compliance and environmental management.

(4) Paul Meneghini, Senior Environmental Analyst
Degree: BS Civil Engineering, MBA in Environmental Management

Experience: 4 years experience in pipeline environmental regulatory compliance, and thirteen years total in general environmental compliance.

Other: Professional Engineer (Minnesota)

(5) Joe Reinemann

President, Natural Resource Group, Inc.

Degree: BA, Geography, University of Wisconsin – Madison 1988

Other Training: Alaska Native Cultural Awareness Workshop

FERC Interstate Natural Gas Facility Planning

FERC Natural Gas Pipeline Environmental Compliance

FERC Environmental Report Preparation

FERC Industry Outreach Training – Cultural Resources

Environmental Training Inst. National Environmental Policy Act Compliance

Minnesota Pollution Control Agency Erosion and Sediment Control Plan Design Certification

Member, National Association of Environmental Professionals

Experience: 18 years experience in energy-related regulatory compliance, including 18 years of pipeline-related environmental assessment and permitting

(6) Michael Harris, Sr. Lands and Right-of-Way Specialist

Degree: A.A.S., Supervisory Management

Experience: 18 years experience in Right-of-Way, land acquisitions and damage settlements.

Other Training and Licenses: International Right of Way Association designation of Sr. Right-of-Way Agent, with IRWA certifications in Environment and Negotiations

D.7. Maps

a. Map of Criteria Within Study Area

A copy of the Pembina County map including U.S.G.S. Quad and Aerial Maps of the Alberta Clipper Project are enclosed herewith as Exhibit D. Additionally, since this application is a consolidated application for a corridor certificate and a route permit, maps of the ND PSC Exclusion and Avoidance Areas with the route of the Alberta Clipper Project are attached hereto as Appendix D of the route permit portion of the application.

b. Mylar maps of study area.

As this process for producing construction maps and drawings is no longer in use, Mylar maps have not been included as part of this application.

C

Enbridge Energy, Limited Partnership
ND-PSC Application July 2007
Case No PU07-108

ENBRIDGE™

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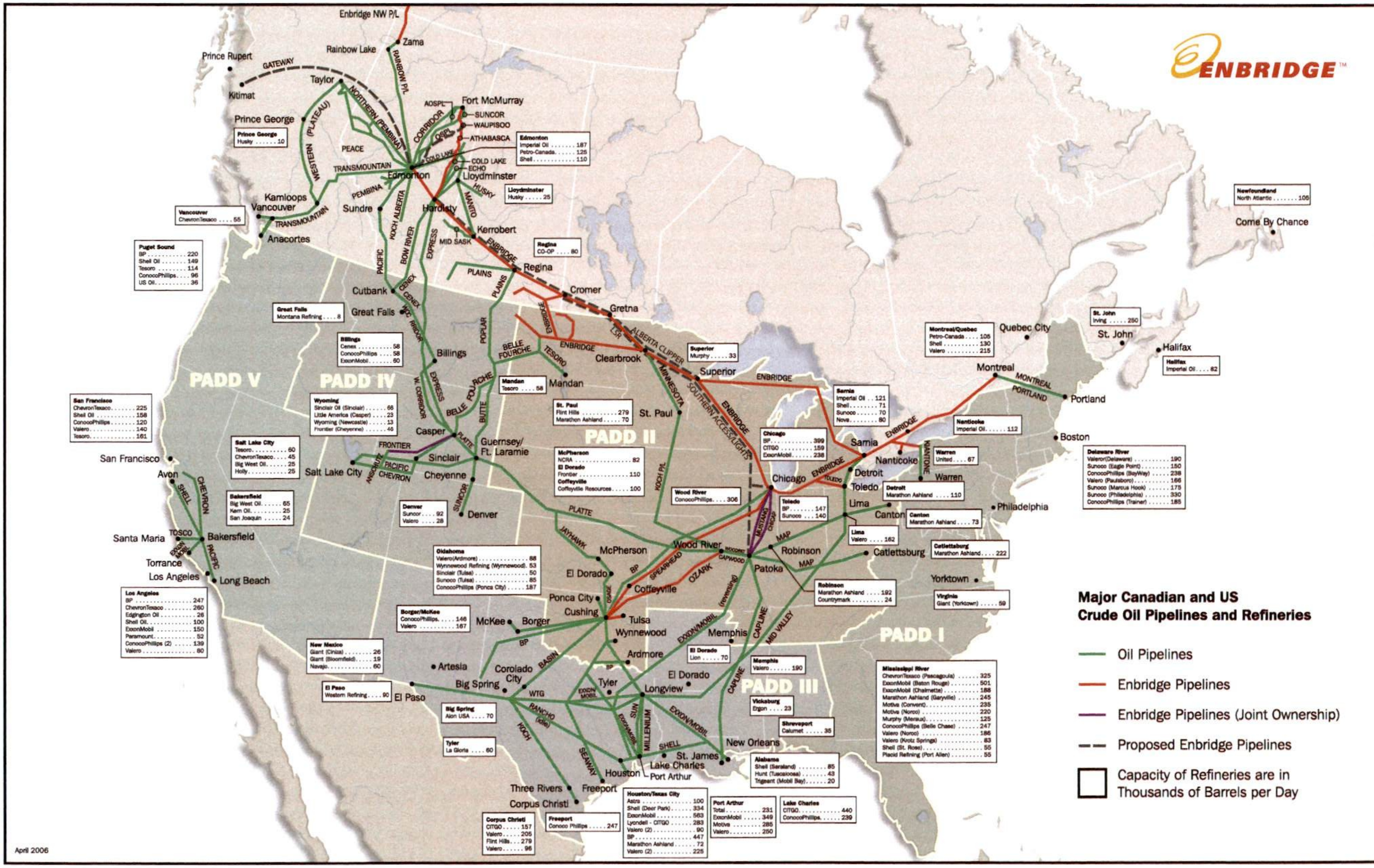
ENBRIDGE™
Major Canadian and US Crude Oil Pipelines and Refineries
Oil Pipelines
Enbridge Pipelines
Enbridge Pipelines (Joint Ownership)
Proposed Enbridge Pipelines
Capacity of Refineries are in Thousands of Barrels per Day
PADD V
PADD IV
PADD II
PADD III
PADD I
Enbridge NW P/L
Zama
Rainbow Lake
RAINBOW P/L
Prince Rupert
Kitimat
GATEWAY
Taylor
NORTHERN (PEMBINA)
WESTERN (PLATEAU)
Prince George
Prince George Husky 10
PEACE
TRANSMOUNTAIN
Edmonton
Fort McMurray
AOSPL
CORRIDOR
SUNCOR
WAUPISOO
ATHABASCA
COLD LAKE
ECHO
Lloydminster
Edmonton Imperial Oil ...... 187 Petro-Canada ...... 125 Shell 110
Lloydminster Husky 25
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Vancouver ChevronTexaco 55
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HUSKY
MANITO
Kerrobert
MID SASK
EXPRESS
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CAPWOOD
Patoka
Robinson
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Corolado City
BASIN
Big Spring
El Paso
El Paso Western Refining 90
WTG
Big Spring Alon USA 70
RANCHO
KOCH
Tyler
Tyler La Gloria 60
Longview
El Dorado
SUN
MILLENNIUM
SEAWAY
SHELL
EXXON/MOBIL
St. James
New Orleans
Lake Charles
Port Arthur
Houston
Freeport
Three Rivers
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Shreveport Calumet 35
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Freeport Conoco Phillips 247
Houston/Texas City Astra ...... 100 Shell (Deer Park) ...... 334 ExxonMobil ...... 563 Lyondell - CITGO ...... 283 Valero (2) ...... 90 BP ...... 447 Marathon Ashland ...... 72 Valero (2) 225
Port Arthur Total ...... 231 ExxonMobil ...... 349 Motiva ...... 285 Valero 250
Lake Charles CITGO ...... 440 ConocoPhillips 239
Mississippi River ChevronTexaco (Pascagoula) ...... 325 ExxonMobil (Baton Rouge) ...... 501 ExxonMobil (Chalmette) ...... 188 Marathon Ashland (Garyville) ...... 245 Motiva (Convent) ...... 235 Motiva (Norco) ...... 220 Murphy (Meraux) ...... 125 ConocoPhillips (Belle Chase) ...... 247 Valero (Norco) ...... 186 Valero (Krotz Springs) ...... 83 Shell (St. Rose) ...... 55 Placid Refining (Port Allen) 55
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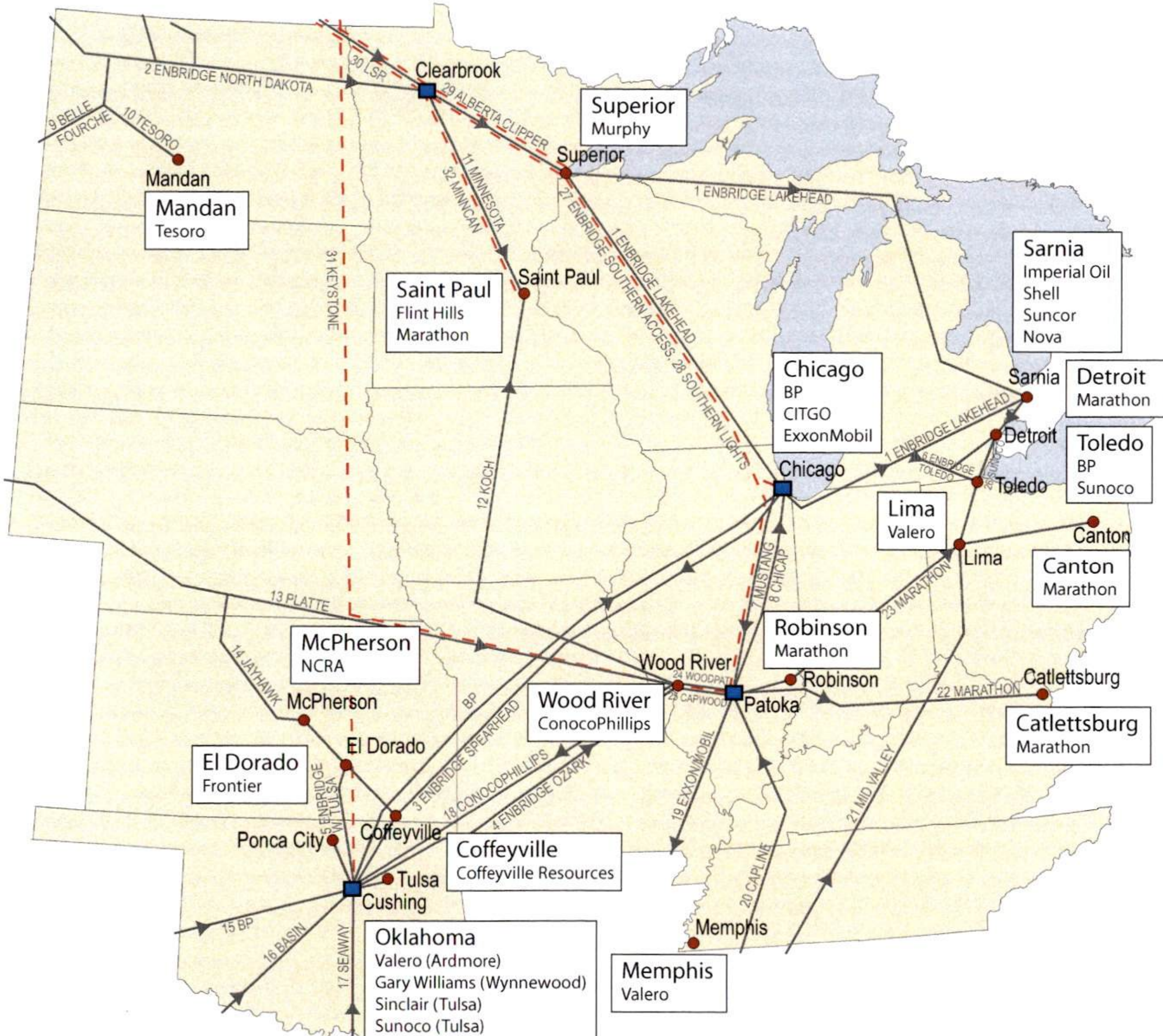
St. John
St. John Irving 250
Halifax
Halifax Imperial Oil 82
Newfoundland North Atlantic 105
Come By Chance
April 2006

MAP A-2
Major Crude Petroleum Pipelines and Refineries in PADD II



PIPELINES

NAME	CAPACITY (bbls/d)	OWNER/OPERATOR*
1 Lakehead	1,430,000	Enbridge
2 North Dakota	75,000	Enbridge
3 Spearhead	125,000	Enbridge
4 Ozark	230,000	Enbridge
5 West Tulsa	68,500	Enbridge
6 Toledo	100,000	Enbridge
7 Mustang	100,000	ExxonMobil*, Enbridge
8 Chicap	360,000	BP*, Chevron, Enbridge
9 Belle Fourche	50,000	True Companies
10 Tesoro	58,000	Tesoro
11 Minnesota	290,000	Koch*, Marathon, Trof Inc.
12 Koch	N/A	Koch
13 Platte	150,000	Kinder Morgan
14 Jayhawk	37,000	Nat'l. CRA
15 BP	177,000	BP
16 Basin	400,000	Plains*, TEPPCO
17 Seaway	350,000	TEPPCO*, ConocoPhillips
18 ConocoPhillips	20,000	ConocoPhillips
19 ExxonMobil	65,000	ExxonMobil
20 Capline	1,140,000	Shell*, Marathon, Plains, BP, Chevron
21 Mid Valley	238,000	Sunoco*, BP
22 Marathon	210,000	Marathon
23 Marathon	300,000	Marathon
24 Woodpat	310,000	Marathon
25 Capwood	277,000	Plains*, Valero
26 Sunoco	190,000†	Sunoco
PROPOSED PIPELINES		
27 Southern Access	400,000	Enbridge
28 Southern Lights (diluent)	180,000	Enbridge
29 Alberta Clipper	450,000	Enbridge
30 LSR	186,000	Enbridge
31 Keystone	435,000	TransCanada
32 MinnCan	165,000	Koch*, Marathon, Trof

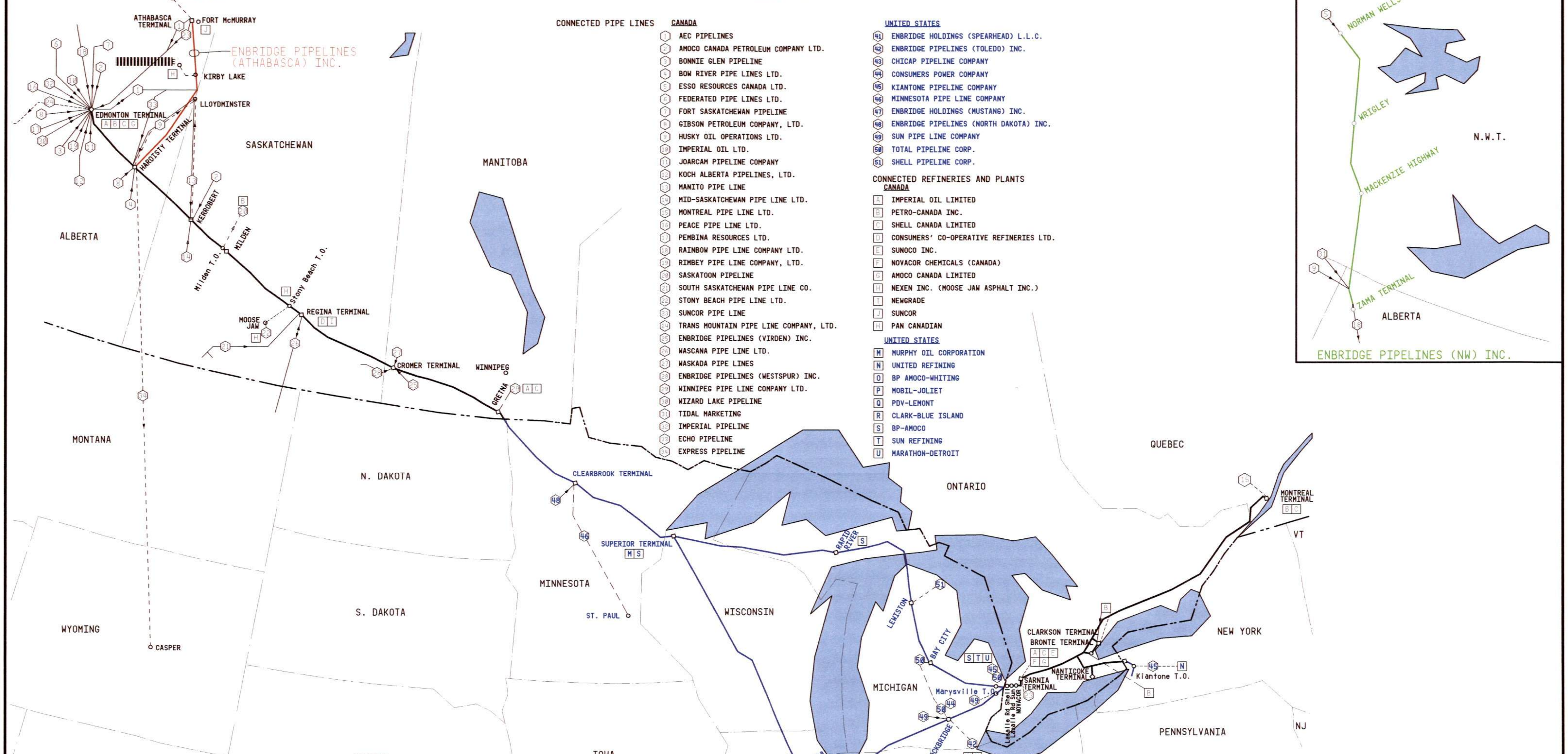
*Indicates operator for joint venture pipelines
†After expansion completion in 2007

LEGEND

- Major crude oil pipelines
- Proposed crude oil/diluent pipelines
- Local refineries
- Pipeline hubs

Based on publicly available mapping information.
Not to scale. June 2006.

MAP A-3



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11	REVISED AS PER UPDATE	01/15/2001 AMJ	KB
10	REFORMATTED BORDER	05/11/2000 AJ	EGH

ENBRIDGE

Enbridge Pipelines Inc.
10201 Jasper Avenue
Edmonton Alberta Canada

SYSTEM MAP
CONNECTING SYSTEMS

DRAWN	AJ	CHECK	EGH	APPR	
DATE	05/11/2000	SCALE	2:00	APPR	EGH

D-0.0-1681-12-0

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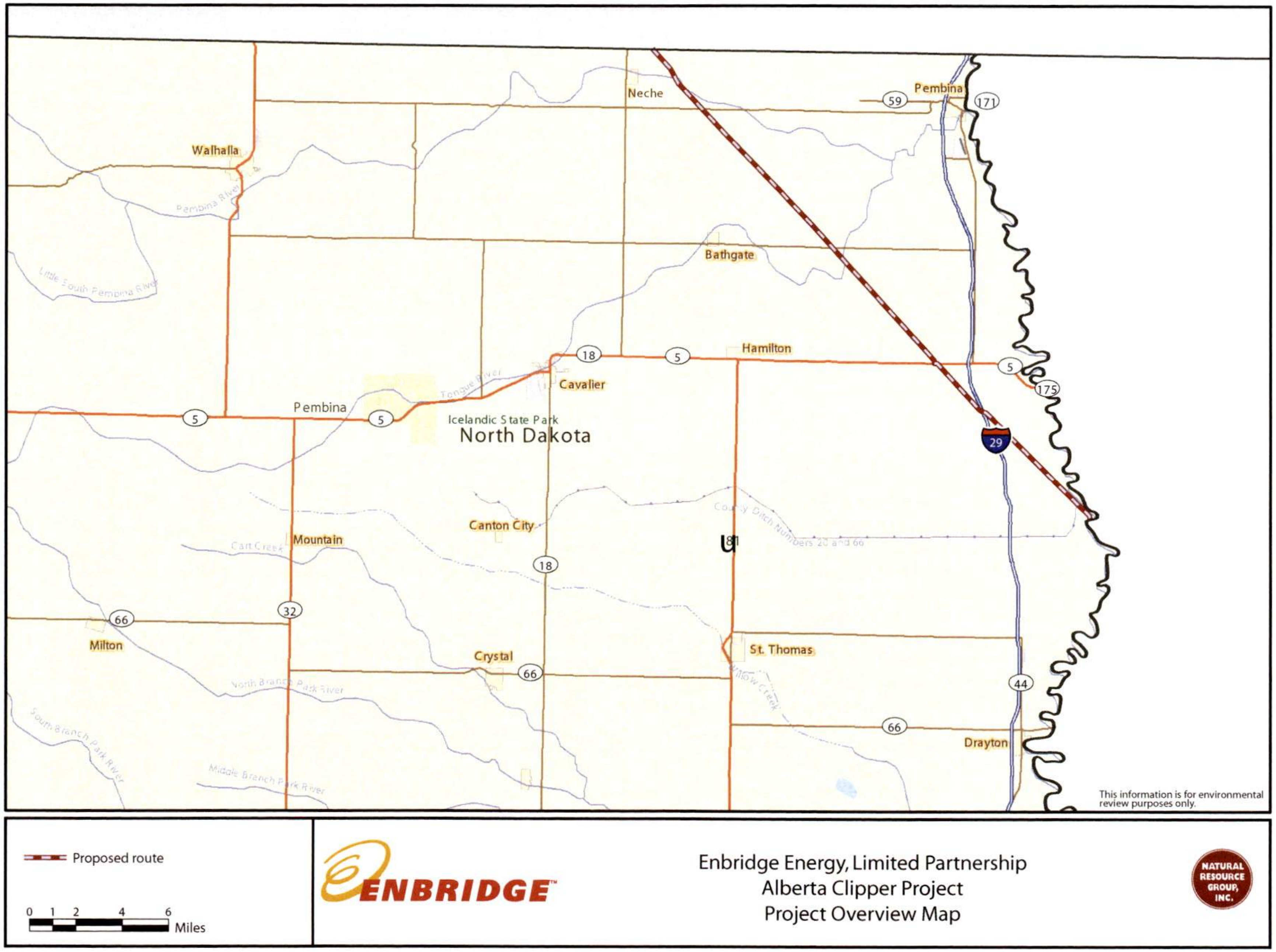
X:\Cood Users\CosterDS\CAL_WORK\D-0.0-1681-0.DWG, 8/18/2006 10:14

EXHIBIT B



ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Project Overview Map

NATURAL RESOURCE GROUP, INC.

MAP C

Enbridge Expansion Projects
Existing Enbridge pipelines
Existing Enbridge pipeline reversed to transport diluent
Southern Access Stage 1 Expansion
Southern Access Stage 2 Expansion
Southern Access Extension
Southern Lights North (of Superior, Wis.)
Southern Lights South (of Superior, Wis.)
Alberta Clipper
New 20-inch Crude Oil Line
North Dakota System pump station expansion
Fort McMurray
Edmonton
Hardisty
Kerrobert
Regina
Cromer
Gretna
Clearbrook
Superior
Delavan
Detroit
Flanagan
Chicago
Patoka
Wood River
Cushing

USGS Quad and Aerial Maps
of

Proposed Route

(See 11" x 17" Map Book attached hereto separately as Exhibit D)

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Canadian Crude Oil Production
and Supply Forecast
2006 - 2020

May 2006

1.0 Introduction

The Canadian Association of Petroleum Producers (CAPP) 2006-2020 forecast has been developed to provide industry with a long-range outlook for Canadian crude oil production. The primary use of this forecast is to enable members to plan for pipeline capacity requirements for transporting Canadian crude oil to markets. This forecast includes a production outlook for both western and eastern Canada, however the analysis focuses on western Canadian production and supply because offshore eastern oil production does not rely on pipeline access to reach markets.

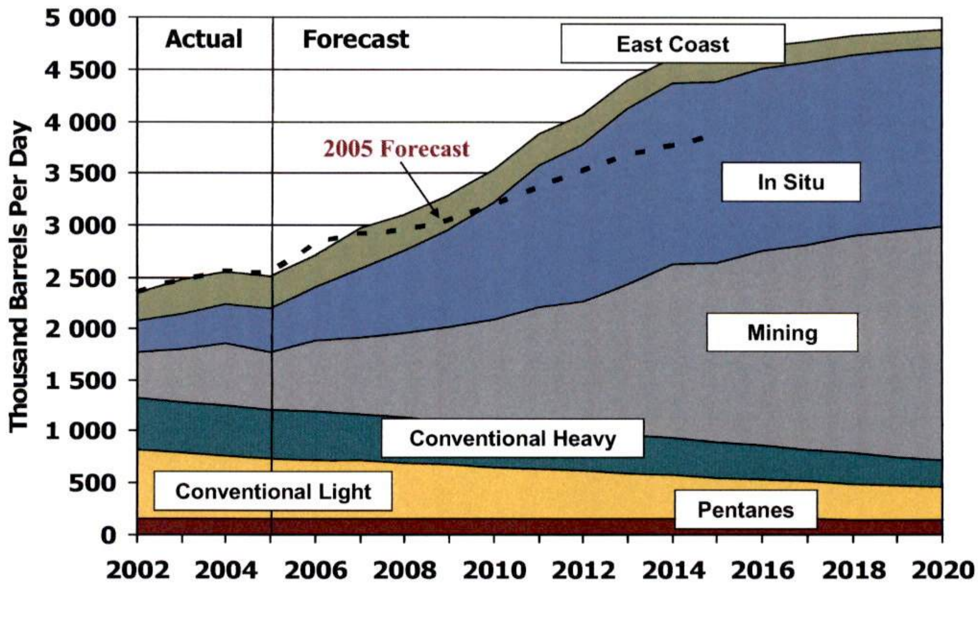
The main source of growth in the western Canadian production forecast, over the next fifteen years, comes for Alberta's oil sands. The outlook for oil sands production included in this forecast is based on a survey of CAPP members; more information on the methodology used to develop this forecast is provided in the methodology section presented at the end of this document.

2.0 Canadian Crude Oil Production

Canadian crude oil production is forecast to grow from 2.5 million barrels per day (b/d) in 2005 to 4.6 million b/d by 2015, with further potential growth to 4.9 million b/d by 2020. Chart 1 presents the forecast by types of Canadian crude oil production. Atlantic Canada's East Coast conventional light production comes from offshore projects while western Canadian production comes from both conventional sources and oil sands. Bitumen production from the oil sands can be extracted using one of two recovery processes, in-situ for areas deeper than about 80 meters and with mining operations where deposits are closer to the surface.

The 2006 forecast represents an increase compared to last year's forecast by about 750,000 b/d in 2015. The increase reflects more aggressive scheduling for some projects and new investments in the oil sands.

Chart 1: Canadian Crude Oil Production Forecast



The forecast for the East Coast reflects a reduction due to the removal of the Hebron project, which was previously included in the projection developed in 2005.

Table 1: Canadian Crude Oil Production

Thousand Barrels Per Day

	1990	1995	2000	2005	2010	2015	2020
Western Canada							
Conventional Light	940	936	734	577	495	400	309
Conventional Heavy	263	415	510	476	413	340	263
Pentanes	116	161	194	160	156	152	149
Oil Sands Mining	209	279	321	552	1 019	1 750	2 273
Oil Sands In-Situ	135	149	289	438	1 132	1 745	1 724
Total	**1 663**	**1 940**	**2 048**	**2 204**	**3 215**	**4 387**	**4 718**
Offshore East Coast	**0**	**21**	**145**	**305**	**320**	**230**	**160**
Canada	**1 663**	**1 961**	**2 193**	**2 509**	**3 535**	**4 617**	**4 878**

3.0 Western Canadian Crude Oil Production

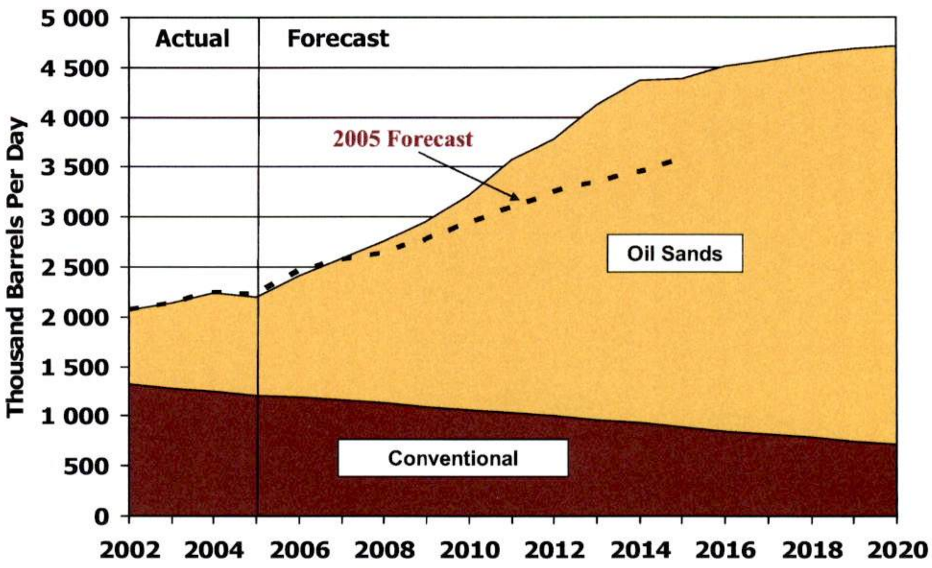
Western Canadian crude oil production is projected to grow from 2.2 million b/d in 2005 to 4.7 million b/d, by 2020.

Some of the highlights are:

- Conventional production in western Canada has been declining slowly since the late 1990s. By 2020, conventional oil production is reduced to about 550,000 b/d, about one-half of its current level.
- Recent trends indicate that the year-over-year decline rate for conventional production has slowed somewhat due to high oil prices but the overall trend is continued declines.
- Both in-situ and mining projects contribute to the growth in oil sands production, with a four-fold increase in production for each category.
- Western Canadian crude production growth, which more than doubles over the next 15 years will require construction of new pipelines to ensure new oil supplies can be transported to markets in Canada, the U.S. and potentially offshore.
- The share of western oil production generated by oil sands grows from 45 percent in 2005 to about 80 percent, by 2020.
- Compared to CAPP's 2005 forecast, the outlook for oil production from western Canada has increased by about 800,000 b/d in 2015.

Chart 2 depicts the split between oil sands and conventional production and also shows the increase in western Canadian production over last year's projection. The significant growth in oil sands production means four in five barrels produced is sourced from the oil sands by 2020.

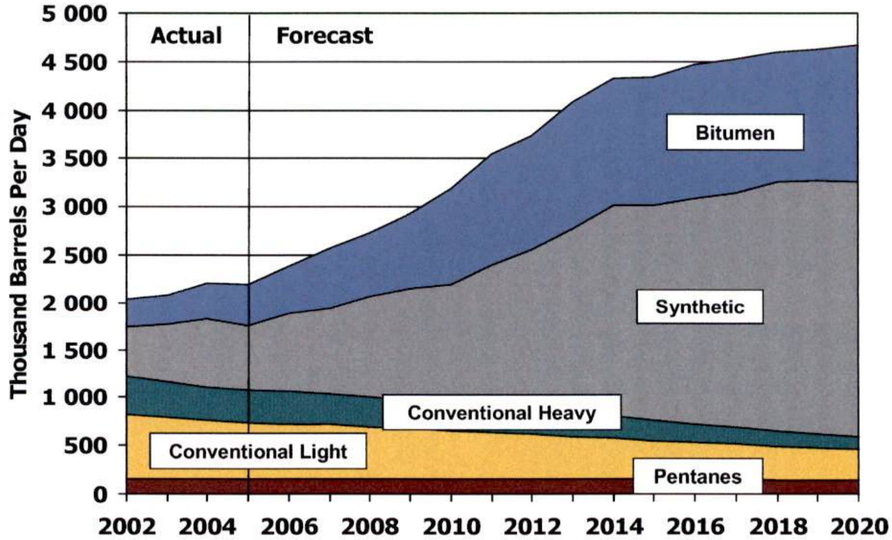
Chart 2: Comparison of Oil Sands versus Conventional Oil Production



Oil sands bitumen production can be marketed as a heavy crude blend or it can be further upgraded and marketed as synthetic oil. Chart 3 shows the split between bitumen and synthetic production for the oil sands along with the conventional light and heavy production forecast.

A number of projects such as Suncor and Syncrude have upgrading as part of an integrated operation. In addition to the integrated oil sands projects a number of stand-alone or merchant upgrader projects have been announced and planned and are included in the forecast. The potential supplies from these projects have been included in the synthetic shown in Chart 3.

Chart 3: Western Canadian Crude Oil Supply Forecast



4.0 Western Canadian Crude Oil Supply to Market

To enable conventional heavy oil and bitumen oil to be transported using pipelines, it must be diluted with a lighter commodity such as condensate/pentanes or synthetic crude. This blending process lowers the viscosity and density of the crude allowing for efficient transportation through pipelines.

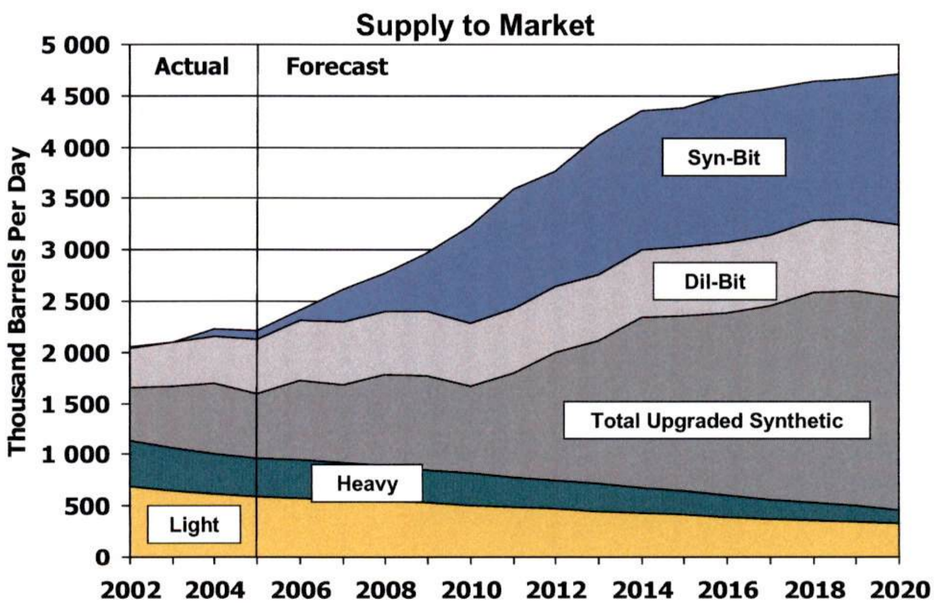
The main source of diluent has been condensates/pentanes produced in western Canada. These products are slowly declining and will not provide sufficient supplies of diluent to match forecast growth of bitumen. Producers have been evaluating options to import condensate using either existing infrastructure such as railroads or through a condensate import pipeline. As an alternative, producers are also considering using synthetic for blending.

When bitumen is blended with traditional condensate/pentanes the blended crude is typically referred to as a dil-bit blend. Bitumen blended using synthetic crude has been referred to as syn-bit.

4.1 Supply Scenario with Synthetic Crude Used as Diluent

Chart 4 shows the amount of syn-bit developed as a result of the limited supply of condensate. The forecast shows the volume of dil-bit as generally constant. Over the forecast period, the development of a syn-bit blend uses substantial volumes of synthetic for blending purposes.

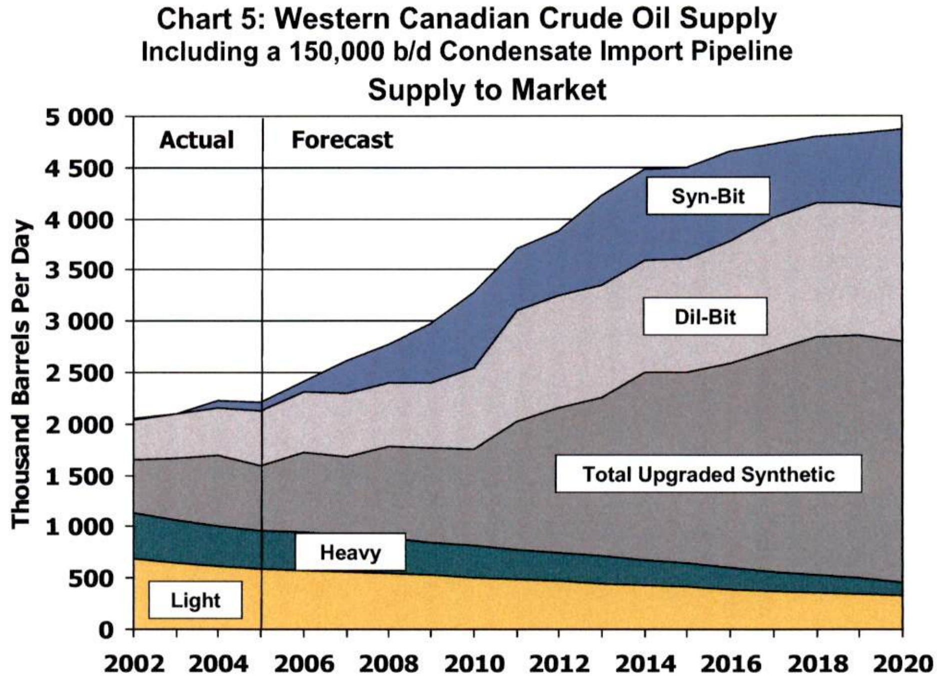
Chart 4: Western Canadian Crude Oil Supply
With Synthetic Crude used for Blending



4.2 Supply Scenario with Imported Condensate Used as Diluent

Currently, western Canadian producers have limited capability to import large volumes of condensate from other areas due to a lack of pipeline access. This scenario assumes producers support the development of a pipeline to import condensate. The forecast assumes initial imports of 150,000 b/d growing to 200,000 b/d by 2020.

The access to condensate has a significant impact on the crude mix produced. Chart 5 shows the growth in dil-bit and the offsetting reduction in syn-bit and growth in synthetic crude.



5.0 Forecast Potential and Risks

As noted, the primary purpose for the forecast is to ensure producers have information to plan for increases in pipeline capacity to market their growing supplies of crude oil. As such, the forecast is prepared to not be too conservative because the cost of a small amount of surplus pipeline capacity is preferable to the lost revenue from shut-in production due to insufficient pipeline capacity.

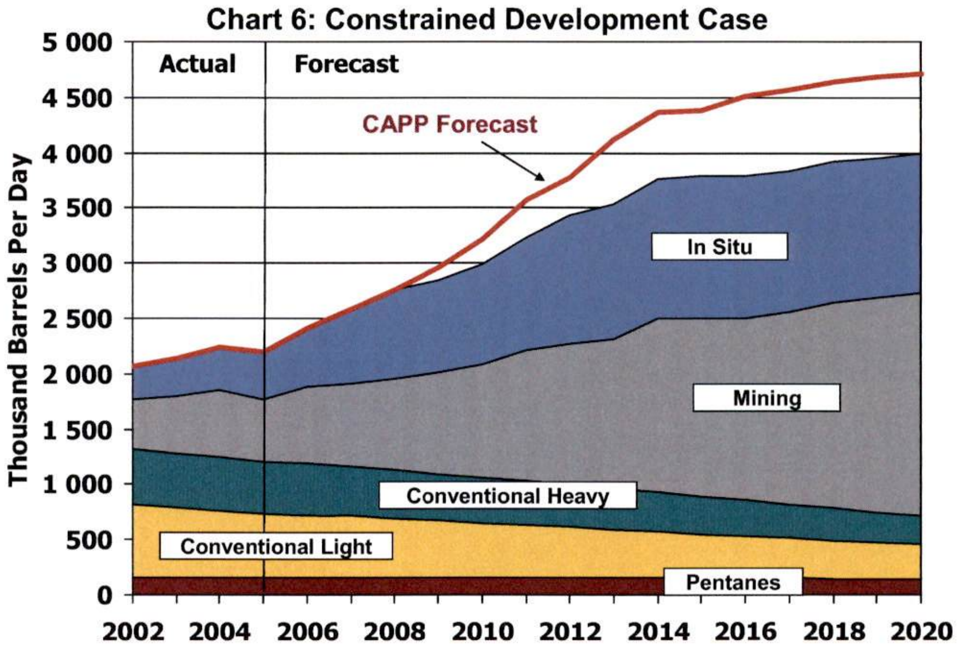
Due to competing strong economic growth in many sectors, the potential oil sands development underpinning the forecast may be subject to a number of delays and risk factors that could slow the pace of development and the corresponding increase in production being forecast in the "base" case. The development capacity to convert the plans for new oil sands projects into construction and facilities may be constrained by a limited supply of manpower, infrastructure and other resources. The following points illustrate areas that may slow the pace of oil sands development.

- Unemployment levels in Canada and Alberta are near record low levels. The demand for manpower exceeds the available supply of skilled workers in many sectors of the economy, including oil sands. Although solutions such as training and immigration are planned, it takes time to gear up government processes and support systems that deal with increasing the supply of qualified manpower. This may pose a challenge not only for oil sands development but also the key support sectors, such as education, housing and infrastructure that are integral to achieving the forecast pace of development;

- Refiner's abilities to run and process oil sands crudes are currently at full capacity in the market areas served by Canadian producers. Refineries will need to undertake plant conversions and expansions to utilize and absorb the growth in crude supplies from the oil sands and producers will need to extend beyond their traditional market areas. Producers will be reluctant to grow supplies without markets to absorb the crude. As such, the ability to grow production may be constrained if the pace of refinery development or market expansion does not keep pace with potential oil sands development.

- Strong economic growth and activity levels in Alberta, other regions in North America and global markets means competing demands for key resources essential to oil sands development, such as steel and fabricating facilities. Finite capacity to produce and manufacture key input materials and equipment could possibly result in a degree of queuing for essential components, which could translate into delays for some projects.
- A number of the in-situ recovery processes, such as steam assisted gravity drainage (SAGD) recovery techniques, are still at an early stage. As many projects transition from pilot to commercial level projects, there is a risk that start-up delays and/or unanticipated technical challenges may slow the pace of production in the early years of the forecast.

The following chart reflects the potential impact associated with development being constrained or delayed. By 2020 the forecast is reduced by about 800,000 b/d of production.



6.0 Methodology

CAPP annually prepares a crude oil production and supply forecast. The oil sands components are developed from a survey of CAPP members which encompasses all projects. CAPP received a 100 percent response to the survey, as members have a vested interest to help ensure the production forecast accurately portrays expected production.

Survey responses reflect both planned and envisioned projects because it covers a fifteen year period. CAPP has risk adjusted some of the envisioned projects by adjusting the potential completion schedules for projects which are deemed more uncertain. As such, the CAPP forecast is reduced compared with the ultimate potential reflected in the survey raw survey data.

For conventional crude oil production, CAPP extrapolates production based on historical trends adjusted to reflect recent events and developments in the industry. Both the conventional and oil sands production are benchmarked based on the most recent actual production data published by government agencies.

This forecast reflects a relatively optimistic outlook for western Canadian crude oil production and assumes that the development of markets and pipeline infrastructure will coincide to support the forecast growth in western Canadian production. A key use of the forecast is to allow members to plan for needed pipeline capacity increases.

The survey results do not prescribe any forecasts of future oil prices and rely on individual companies incorporating their own internal price expectations to develop their production forecasts.

7.0 Production and Supply Tables

The following tables provide the detailed forecast data from which the charts were created. Three sets of tables are included to show production, two supply scenarios and a high level assessment of the need for incremental pipeline capacity.

Table 1

CAPP CANADIAN CRUDE OIL PRODUCTION FORECAST 2006 - 2020

	Thousand barrels per day			Actuals		Forecast														
CONVENTIONAL	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Light & Medium																				
Alberta	481	438	414	389	374	366	359	348	334	321	308	296	284	273	259	246	234	222	211	200
B.C.	43	42	37	35	30	30	29	28	27	26	25	24	23	22	21	20	19	18	17	16
Saskatchewan	143	139	138	137	141	138	135	131	126	121	116	111	107	102	97	92	88	83	79	75
Manitoba	11	11	11	11	14	13	13	13	12	12	11	11	10	10	10	9	9	8	8	7
N.W.T.	25	24	22	21	19	18	18	18	17	16	15	15	14	14	13	12	12	11	11	10
Total Conv. Light and Medium	**704**	**653**	**622**	**593**	**577**	**566**	**554**	**538**	**516**	**495**	**476**	**457**	**438**	**421**	**400**	**380**	**361**	**343**	**326**	**309**
Heavy																				
Alberta Conv. Heavy	240	222	216	211	197	194	188	182	177	171	166	161	155	149	141	134	127	121	115	109
Saskatchewan Conv. Heavy*	283	282	282	286	278	273	265	257	249	241	234	227	218	209	199	189	180	171	162	154
Total Conventional Heavy	523	504	498	497	476	466	452	439	426	413	400	388	373	358	340	323	307	292	277	263
TOTAL CONVENTIONAL	**1 226**	**1 157**	**1 120**	**1 089**	**1 053**	**1 032**	**1 007**	**976**	**942**	**908**	**876**	**845**	**811**	**779**	**740**	**703**	**668**	**634**	**603**	**572**
PENTANES/CONDENSATE	186	163	164	162	160	159	159	158	157	156	155	155	154	153	152	152	151	150	149	149
OIL SANDS																				
Oil Sands Mining	349	441	514	608	552	696	751	826	908	1 019	1 182	1 264	1 481	1 701	1 750	1 909	1 996	2 121	2 195	2 273
Oil Sands In-Situ	310	303	349	386	438	520	676	794	957	1 132	1 370	1 513	1 683	1 736	1 745	1 753	1 752	1 740	1 730	1 724
TOTAL OIL SANDS	**659**	**744**	**863**	**994**	**991**	**1 216**	**1 427**	**1 620**	**1 865**	**2 151**	**2 552**	**2 777**	**3 164**	**3 437**	**3 495**	**3 661**	**3 748**	**3 861**	**3 925**	**3 997**
WESTERN CANADA OIL PRODUCTION	**2 071**	**2 065**	**2 147**	**2 245**	**2 204**	**2 407**	**2 592**	**2 754**	**2 964**	**3 215**	**3 583**	**3 777**	**4 129**	**4 369**	**4 387**	**4 516**	**4 567**	**4 645**	**4 677**	**4 718**
TOTAL CANADIAN OIL PRODUCTION	**2 220**	**2 350**	**2 484**	**2 560**	**2 509**	**2 722**	**2 967**	**3 109**	**3 294**	**3 535**	**3 883**	**4 062**	**4 394**	**4 614**	**4 617**	**4 731**	**4 767**	**4 830**	**4 852**	**4 878**

Notes:

* Re-allocates Saskatchewan Area III "Medium" into medium and heavy. Reserves data shows about 17% of Area III is > 900 kg/m3

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 2

BLENDED SUPPLY to Trunk Pipelines and Markets

Supply Scenario with Synthetic Crude Used as Diluent

Thousand barrels per day					Actual	Forecast														
CONVENTIONAL	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Light and Medium	704	653	622	593	567	555	544	528	507	487	467	448	430	413	393	373	354	337	320	304
Net Conventional Heavy to Market	463	443	418	395	379	368	353	337	323	308	294	280	263	246	226	207	189	172	155	140
TOTAL CONVENTIONAL	**1 166**	**1 097**	**1 041**	**988**	**946**	**924**	**897**	**865**	**829**	**795**	**761**	**729**	**694**	**659**	**619**	**580**	**543**	**508**	**475**	**443**
NGL Mix	37	37	30	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
OIL SANDS																				
Upgraded Light (Synthetic)	377	465	492	560	495	615	605	705	737	664	814	1 012	1 171	1 305	1 398	1 469	1 545	1 675	1 704	1 694
Heavy Equivelant																				
Dil Bit Blend and Synthetic Heavy	435	446	531	587	669	753	769	805	805	807	837	884	872	1 021	998	999	1 030	1 080	1 100	1 093
Syn-Bit	6	5	7	69	87	104	316	371	581	949	1 155	1 117	1 352	1 351	1 341	1 447	1 426	1 352	1 372	1 463
Total Heavy Equivelant	441	451	538	656	756	857	1 085	1 176	1 387	1 756	1 992	2 001	2 224	2 372	2 338	2 446	2 456	2 432	2 472	2 556
Synthetic Used as Diluent			*3*	*31*	*39*	*47*	*142*	*167*	*262*	*427*	*520*	*503*	*609*	*608*	*603*	*651*	*642*	*609*	*617*	*658*
TOTAL OIL SANDS AND UPGRADERS	**818**	**917**	**1 030**	**1 216**	**1 251**	**1 472**	**1 690**	**1 882**	**2 123**	**2 420**	**2 806**	**3 013**	**3 395**	**3 678**	**3 736**	**3 915**	**4 001**	**4 107**	**4 176**	**4 250**
Total Light Supply	1 118	1 156	1 144	1 175	1 084	1 192	1 171	1 255	1 266	1 172	1 303	1 482	1 623	1 741	1 812	1 864	1 921	2 033	2 046	2 020
Total Heavy Supply	904	895	956	1 051	1 135	1 225	1 438	1 514	1 709	2 064	2 286	2 282	2 487	2 619	2 565	2 653	2 645	2 604	2 627	2 696
WESTERN CANADA OIL SUPPLY	**2 021**	**2 051**	**2 100**	**2 226**	**2 219**	**2 418**	**2 609**	**2 769**	**2 975**	**3 236**	**3 589**	**3 764**	**4 111**	**4 359**	**4 377**	**4 517**	**4 566**	**4 637**	**4 673**	**4 715**

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 3

BLENDED SUPPLY to Trunk Pipelines and Markets

Supply Scenario with Condensate Used as Diluent

Thousand barrels per day					Actual	Forecast														
CONVENTIONAL	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Light and Medium	704	653	622	593	567	555	544	528	507	487	467	448	430	413	393	373	354	337	320	304
Net Conventional Heavy to Market	463	443	418	395	379	368	353	337	323	308	294	280	263	246	226	207	189	172	155	140
TOTAL CONVENTIONAL	**1 166**	**1 097**	**1 041**	**988**	**946**	**924**	**897**	**865**	**829**	**795**	**761**	**729**	**694**	**659**	**619**	**580**	**543**	**508**	**475**	**443**
NGL Mix	37	37	30	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
OIL SANDS																				
Upgraded Light (Synthetic)	377	465	492	560	495	615	605	705	737	748	1 026	1 196	1 351	1 482	1 569	1 688	1 816	1 943	1 970	1 958
Heavy Equivelant																				
Dil Bit Blend and Synthetic Heavy	435	446	531	587	669	753	769	805	805	983	1 299	1 304	1 284	1 424	1 391	1 492	1 630	1 676	1 691	1 680
Syn-Bit	6	5	7	69	87	104	316	371	581	729	599	635	881	890	891	873	719	651	676	772
Total Heavy Equivelant	441	451	538	656	756	857	1 085	1 176	1 387	1 712	1 898	1 939	2 164	2 314	2 283	2 365	2 349	2 326	2 367	2 452
Synthetic Used as Diluent			*3*	*31*	*39*	*47*	*142*	*167*	*262*	*328*	*270*	*286*	*396*	*401*	*401*	*393*	*324*	*293*	*304*	*347*
TOTAL OIL SANDS AND UPGRADERS	**818**	**917**	**1 030**	**1 216**	**1 251**	**1 472**	**1 690**	**1 882**	**2 123**	**2 460**	**2 925**	**3 135**	**3 516**	**3 796**	**3 852**	**4 054**	**4 164**	**4 269**	**4 337**	**4 410**
Total Light Supply	1 118	1 156	1 144	1 175	1 084	1 192	1 171	1 255	1 266	1 256	1 515	1 666	1 804	1 917	1 984	2 083	2 192	2 302	2 312	2 284
Total Heavy Supply	904	895	956	1 051	1 135	1 225	1 438	1 514	1 709	2 020	2 192	2 220	2 427	2 561	2 509	2 572	2 538	2 498	2 522	2 592
WESTERN CANADA OIL SUPPLY	**2 021**	**2 051**	**2 100**	**2 226**	**2 219**	**2 418**	**2 609**	**2 769**	**2 975**	**3 277**	**3 708**	**3 886**	**4 231**	**4 478**	**4 493**	**4 656**	**4 730**	**4 800**	**4 834**	**4 876**

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 4

Summary of Western Canadian Supply and Pipeline Capacity ex Western Canada

Supply Scenario with Synthetic Crude Used as Diluent

Thousand Barrels Per Day

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Light Crude Supply	1 080	1 190	1 170	1 260	1 270	1 170	1 300	1 480	1 620	1 740	1 810	1 860	1 920	2 030	2 050	2 020
Non Enbridge Demand	690	710	720	720	760	770	770	770	770	770	770	770	770	770	770	770
Supply to Enbridge	390	490	450	530	510	410	540	720	860	980	1 050	1 100	1 160	1 270	1 280	1 250
Enbridge Light Capacity (Line 2 & Line 13)	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
Capacity Surplus / (Shortfall)	190	90	130	50	80	170	40	(140)	(280)	(390)	(470)	(520)	(580)	(690)	(700)	(670)
Heavy Crude Supply	1 140	1 230	1 440	1 510	1 710	2 060	2 290	2 280	2 490	2 620	2 560	2 650	2 640	2 600	2 630	2 700
Non Enbridge Demand	320	330	370	370	380	380	380	380	380	380	380	380	380	380	380	380
Supply to Enbridge	810	890	1 070	1 140	1 330	1 690	1 910	1 900	2 110	2 240	2 190	2 280	2 270	2 230	2 250	2 320
Enbridge Heavy Capacity (L3 & L4)	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120
Capacity Surplus / (Shortfall)	300	220	50	(30)	(220)	(570)	(790)	(790)	(1 000)	(1 130)	(1 070)	(1 160)	(1 150)	(1 110)	(1 130)	(1 200)
Total Supply to Enbridge	1 200	1 380	1 520	1 670	1 840	2 100	2 450	2 620	2 970	3 220	3 240	3 380	3 430	3 500	3 530	3 570
Total Enbridge Capacity	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700
Net Surplus / (Shortfall)	500	320	180	30	(140)	(400)	(750)	(920)	(1 270)	(1 520)	(1 540)	(1 680)	(1 730)	(1 800)	(1 830)	(1 870)
Planned Western Canadian Capacity Expansion Projects:																
Enbridge Southern Access			120	268	315	315	315	315	315	315	315	315	315	315	315	315
Trans Canada Keystone					170	340	340	340	340	340	340	340	340	340	340	340
Total Capacity Added			120	268	485	655	655	655	655	655	655	655	655	655	655	655
Net Surplus / (Shortfall)	500	320	300	298	345	255	(95)	(265)	(615)	(865)	(885)	(1 025)	(1 075)	(1 145)	(1 175)	(1 215)

Notes:

Enbridge capacities reflect Terrace III annual capacity

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020 Table 5

Summary of Western Canadian Supply and Pipeline Capacity ex Western Canada

Supply Scenario with Condensate Used as Diluent

Thousand Barrels Per Day

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Light Crude Supply	1 080	1 190	1 170	1 260	1 270	1 260	1 520	1 670	1 800	1 920	1 980	2 080	2 190	2 300	2 310	2 280
Non Enbridge Demand	690	710	720	720	760	770	770	770	770	770	770	770	770	770	770	770
Supply to Enbridge	390	490	450	530	510	490	750	900	1 040	1 150	1 220	1 320	1 430	1 540	1 550	1 520
Enbridge Light Capacity (Line 2 & Line 13)	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580	580
Capacity Surplus / (Shortfall)	190	90	130	50	80	90	(170)	(320)	(460)	(570)	(640)	(740)	(850)	(960)	(970)	(940)
Heavy Crude Supply	1 140	1 230	1 440	1 510	1 710	2 020	2 190	2 220	2 430	2 560	2 510	2 570	2 540	2 500	2 520	2 590
Non Enbridge Demand	320	330	370	370	380	380	380	380	380	380	380	380	380	380	380	380
Supply to Enbridge	810	890	1 070	1 140	1 330	1 640	1 820	1 840	2 050	2 180	2 130	2 200	2 160	2 120	2 150	2 210
Enbridge Heavy Capacity (L3 & L4)	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120	1 120
Capacity Surplus / (Shortfall)	300	220	50	(30)	(220)	(530)	(700)	(730)	(940)	(1 070)	(1 020)	(1 080)	(1 050)	(1 010)	(1 030)	(1 100)
Total Supply to Enbridge	1 200	1 380	1 520	1 670	1 840	2 130	2 570	2 740	3 090	3 330	3 350	3 520	3 590	3 660	3 700	3 730
Total Enbridge Capacity	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700	1 700
Net Surplus / (Shortfall)	500	320	180	30	(140)	(430)	(870)	(1 040)	(1 390)	(1 630)	(1 650)	(1 820)	(1 890)	(1 960)	(2 000)	(2 030)
Planned Western Canadian Capacity Expansion Projects:																
Enbridge Southern Access			120	268	315	315	315	315	315	315	315	315	315	315	315	315
Trans Canada Keystone					170	340	340	340	340	340	340	340	340	340	340	340
Total Capacity Added			120	268	485	655	655	655	655	655	655	655	655	655	655	655
Net Surplus / (Shortfall)	500	320	300	298	345	225	(215)	(385)	(735)	(975)	(995)	(1 165)	(1 235)	(1 305)	(1 345)	(1 375)

Notes:

Enbridge capacities reflect Terrace III annual capacity

May, 2006

Table 6

CAPP CANADIAN CRUDE OIL PRODUCTION FORECAST 2006 - 2020

	Thousand m3 per day			Actuals		Forecast														
CONVENTIONAL	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Light & Medium																				
Alberta	76	70	66	62	59	58	57	55	53	51	49	47	45	43	41	39	37	35	34	32
B.C.	7	7	6	6	5	5	5	4	4	4	4	4	4	3	3	3	3	3	3	3
Saskatchewan	23	22	22	22	22	22	21	21	20	19	18	18	17	16	15	15	14	13	13	12
Manitoba	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1
N.W.T.	4	4	4	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2
Total Conv. Light and Medium	**112**	**104**	**99**	**94**	**92**	**90**	**88**	**85**	**82**	**79**	**76**	**73**	**70**	**67**	**64**	**60**	**57**	**54**	**52**	**49**
Heavy																				
Alberta Conv. Heavy	38	35	34	34	31	31	30	29	28	27	26	26	25	24	22	21	20	19	18	17
Saskatchewan Conv. Heavy*	45	45	45	45	44	43	42	41	40	38	37	36	35	33	32	30	29	27	26	24
Total Conventional Heavy	83	80	79	79	76	74	72	70	68	66	64	62	59	57	54	51	49	46	44	42
TOTAL CONVENTIONAL	**195**	**184**	**178**	**173**	**167**	**164**	**160**	**155**	**150**	**144**	**139**	**134**	**129**	**124**	**118**	**112**	**106**	**101**	**96**	**91**
PENTANES/CONDENSATE	30	26	26	26	25	25	25	25	25	25	25	25	24	24	24	24	24	24	24	24
OIL SANDS																				
Oil Sands Mining	55	70	82	97	88	111	119	131	144	162	188	201	235	270	278	303	317	337	349	361
Oil Sands In-Situ	49	48	55	61	70	83	107	126	152	180	218	240	267	276	277	279	278	277	275	274
TOTAL OIL SANDS	**105**	**118**	**137**	**158**	**157**	**193**	**227**	**257**	**296**	**342**	**406**	**441**	**503**	**546**	**555**	**582**	**596**	**614**	**624**	**635**
WESTERN CANADA OIL PRODUCTION	**329**	**328**	**341**	**357**	**350**	**382**	**412**	**438**	**471**	**511**	**569**	**600**	**656**	**694**	**697**	**718**	**726**	**738**	**743**	**750**
TOTAL CANADIAN OIL PRODUCTION	**353**	**373**	**395**	**407**	**399**	**433**	**472**	**494**	**523**	**562**	**617**	**645**	**698**	**733**	**734**	**752**	**757**	**768**	**771**	**775**

Notes:

* Re-allocates Saskatchewan Area III "Medium" into medium and heavy. Reserves data shows about 17% of Area III is > 900 kg/m3

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 7

BLENDED SUPPLY to Trunk Pipelines and Markets

Supply Scenario with Synthetic Crude Used as Diluent

	Thousand m3 per day				Actual	Forecast														
CONVENTIONAL	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Light and Medium	112	104	99	94	90	88	86	84	81	77	74	71	68	66	62	59	56	53	51	48
Net Conventional Heavy to Market	74	70	66	63	60	59	56	54	51	49	47	45	42	39	36	33	30	27	25	22
TOTAL CONVENTIONAL	**185**	**174**	**165**	**157**	**150**	**147**	**143**	**138**	**132**	**126**	**121**	**116**	**110**	**105**	**98**	**92**	**86**	**81**	**75**	**70**
NGL Mix	6	6	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
OIL SANDS																				
Upgraded Light (Synthetic)	60	74	78	89	79	98	96	112	117	105	129	161	186	207	222	233	246	266	271	269
Heavy Equivelant																				
Dil Bit Blend and Synthetic Heavy	69	71	84	93	106	120	122	128	128	128	133	140	139	162	159	159	164	172	175	174
Syn-Bit	1	1	1	11	14	17	50	59	92	151	184	178	215	215	213	230	227	215	218	232
Total Heavy Equivelant	70	72	85	104	120	136	172	187	220	279	317	318	353	377	372	389	390	386	393	406
Synthetic Used as Diluent	*0*	*0*	*1*	*5*	*6*	*7*	*23*	*27*	*42*	*68*	*83*	*80*	*97*	*97*	*96*	*103*	*102*	*97*	*98*	*105*
TOTAL OIL SANDS AND UPGRADERS	**130**	**146**	**164**	**193**	**199**	**234**	**269**	**299**	**337**	**384**	**446**	**479**	**540**	**584**	**594**	**622**	**636**	**653**	**664**	**675**
Total Light Supply	178	184	182	187	172	189	186	199	201	186	207	235	258	277	288	296	305	323	325	321
Total Heavy Supply	144	142	152	167	180	195	228	241	272	328	363	363	395	416	408	422	420	414	417	428
WESTERN CANADA OIL SUPPLY	**321**	**326**	**334**	**354**	**353**	**384**	**415**	**440**	**473**	**514**	**570**	**598**	**653**	**693**	**696**	**718**	**726**	**737**	**743**	**749**

May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 8

BLENDED SUPPLY to Trunk Pipelines and Markets

Supply Scenario with Condensate Used as Diluent

	Thousand m3 per day				Actual	Forecast														
CONVENTIONAL	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Light and Medium	112	104	99	94	90	88	86	84	81	77	74	71	68	66	62	59	56	53	51	48
Net Conventional Heavy to Market	74	70	66	63	60	59	56	54	51	49	47	45	42	39	36	33	30	27	25	22
TOTAL CONVENTIONAL	**185**	**174**	**165**	**157**	**150**	**147**	**143**	**138**	**132**	**126**	**121**	**116**	**110**	**105**	**98**	**92**	**86**	**81**	**75**	**70**
NGL Mix	6	6	5	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
OIL SANDS																				
Upgraded Light (Synthetic)	60	74	78	89	79	98	96	112	117	119	163	190	215	235	249	268	289	309	313	311
Heavy Equivelant																				
Dil Bit Blend and Synthetic Heavy	69	71	84	93	106	120	122	128	128	156	206	207	204	226	221	237	259	266	269	267
Syn-Bit	1	1	1	11	14	17	50	59	92	116	95	101	140	141	142	139	114	103	107	123
Total Heavy Equivelant	70	72	85	104	120	136	172	187	220	272	302	308	344	368	363	376	373	370	376	390
Synthetic Used as Diluent	*0*	*0*	*1*	*5*	*6*	*7*	*23*	*27*	*42*	*52*	*43*	*45*	*63*	*64*	*64*	*62*	*51*	*47*	*48*	*55*
TOTAL OIL SANDS AND UPGRADERS	**130**	**146**	**164**	**193**	**199**	**234**	**269**	**299**	**337**	**391**	**465**	**498**	**559**	**603**	**612**	**644**	**662**	**678**	**689**	**701**
Total Light Supply	178	184	182	187	172	189	186	199	201	200	241	265	287	305	315	331	348	366	367	363
Total Heavy Supply	144	142	152	167	180	195	228	241	272	321	348	353	386	407	399	409	403	397	401	412
WESTERN CANADA OIL SUPPLY	**321**	**326**	**334**	**354**	**353**	**384**	**415**	**440**	**473**	**521**	**589**	**618**	**672**	**712**	**714**	**740**	**752**	**763**	**768**	**775**

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 9

Summary of Western Canadian Supply and Pipeline Capacity ex Western Canada

Supply Scenario with Synthetic Crude Used as Diluent

Thousand m3 Per Day

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Light Crude Supply	172	189	186	200	202	186	207	235	257	277	288	296	305	323	326	321
Non Enbridge Demand	110	113	114	114	121	122	122	122	122	122	122	122	122	122	122	122
Supply to Enbridge	62	78	72	84	81	65	86	114	137	156	167	175	184	202	203	199
Enbridge Light Capacity (Line 2 & Line 13)	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Capacity Surplus / (Shortfall)	30	14	21	8	13	27	6	(22)	(44)	(62)	(75)	(83)	(92)	(110)	(111)	(106)
Heavy Crude Supply	181	195	229	240	272	327	364	362	396	416	407	421	420	413	418	429
Non Enbridge Demand	51	52	59	59	60	60	60	60	60	60	60	60	60	60	60	60
Supply to Enbridge	129	141	170	181	211	269	304	302	335	356	348	362	361	354	358	369
Enbridge Heavy Capacity (L3 & L4)	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Capacity Surplus / (Shortfall)	48	35	8	(5)	(35)	(91)	(126)	(126)	(159)	(180)	(170)	(184)	(183)	(176)	(180)	(191)
Total Supply to Enbridge	191	219	242	265	292	334	389	416	472	512	515	537	545	556	561	567
Total Enbridge Capacity	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
Net Surplus / (Shortfall)	79	51	29	5	(22)	(64)	(119)	(146)	(202)	(242)	(245)	(267)	(275)	(286)	(291)	(297)
Planned Western Canadian Capacity Expansion Projects:																
Enbridge Southern Access	0	0	19	43	50	50	50	50	50	50	50	50	50	50	50	50
Trans Canada Keystone	0	0	0	0	27	54	54	54	54	54	54	54	54	54	54	54
Total Capacity Added	0	0	19	43	77	104	104	104	104	104	104	104	104	104	104	104
Net Surplus / (Shortfall)	79	51	48	47	55	41	(15)	(42)	(98)	(137)	(141)	(163)	(171)	(182)	(187)	(193)

Notes:

Enbridge capacities reflect Terrace III annual capacity
May, 2006

CAPP WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST 2006 - 2020

Table 10

Summary of Western Canadian Supply and Pipeline Capacity ex Western Canada

Supply Scenario with Condensate Used as Diluent

Thousand m3 Per Day

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Light Crude Supply	172	189	186	200	202	200	242	265	286	305	315	331	348	365	367	362
Non Enbridge Demand	110	113	114	114	121	122	122	122	122	122	122	122	122	122	122	122
Supply to Enbridge	62	78	72	84	81	78	119	143	165	183	194	210	227	245	246	242
Enbridge Light Capacity (Line 2 & Line 13)	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
Capacity Surplus / (Shortfall)	30	14	21	8	13	14	(27)	(51)	(73)	(91)	(102)	(118)	(135)	(153)	(154)	(149)
Heavy Crude Supply	181	195	229	240	272	321	348	353	386	407	399	408	404	397	400	412
Non Enbridge Demand	51	52	59	59	60	60	60	60	60	60	60	60	60	60	60	60
Supply to Enbridge	129	141	170	181	211	261	289	292	326	346	338	350	343	337	342	351
Enbridge Heavy Capacity (L3 & L4)	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Capacity Surplus / (Shortfall)	48	35	8	(5)	(35)	(84)	(111)	(116)	(149)	(170)	(162)	(172)	(167)	(160)	(164)	(175)
Total Supply to Enbridge	191	219	242	265	292	338	408	435	491	529	532	559	570	582	588	593
Total Enbridge Capacity	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
Net Surplus / (Shortfall)	79	51	29	5	(22)	(68)	(138)	(165)	(221)	(259)	(262)	(289)	(300)	(311)	(318)	(323)
Planned Western Canadian Capacity Expansion Projects:																
Enbridge Southern Access	0	0	19	43	50	50	50	50	50	50	50	50	50	50	50	50
Trans Canada Keystone	0	0	0	0	27	54	54	54	54	54	54	54	54	54	54	54
Total Capacity Added	0	0	19	43	77	104	104	104	104	104	104	104	104	104	104	104
Net Surplus / (Shortfall)	79	51	48	47	55	36	(34)	(61)	(117)	(155)	(158)	(185)	(196)	(207)	(214)	(219)

Notes:

Enbridge capacities reflect Terrace III annual capacity
May, 2006

June 15, 2006

Long Range Forecast (2006-2015)

Introduction

This document summarizes the results of Enbridge's 2006 Long Range forecast. In the fourth quarter of 2005, Enbridge surveyed western Canadian crude oil producers, pipelines and provincial governments to determine future crude oil supply out of the Western Canadian Sedimentary Basin (WCSB). Refiners were also approached for information on crude demand for their respective facilities. The respondents were asked to provide information for a period of 10 years, from 2006 to 2015.

Supply data was balanced against refinery demands to determine the likely production and disposition of western Canadian crude. A preliminary forecast consisting of two scenarios, a market unconstrained and a market constrained supply, was developed and presented at a series of meetings with industry participants. Feedback from these meetings was compiled and incorporated into the final Long Range Forecast detailed in this document.

Mainly as a result of significantly higher crude oil price expectations, the unconstrained and constrained supply cases for the 2006 Long Range Forecast expect greater future production from the 2005 Long Range Forecast. In the market constrained case the limiting factor for production growth is the downstream market and its ability to process incremental blended bitumen (Dilbit and Synbit) and the availability of sufficient export pipeline capacity – primarily to the west coast (China and California) and US Gulf Coast. The market unconstrained supply case has three key assumptions that differentiate it from the market constrained supply case: significant new access and demand for western Canadian heavy crude to the US Gulf Coast by 2010, considerable growth in export volumes to the west coast starting in 2010, and incremental imported condensate supply available for blending in 2009. For the unconstrained supply case to occur, a combination of incremental heavy crude demand and lower cost diluent available to bitumen producers, and significant new pipeline infrastructure will be required.

MARKET UNCONSTRAINED SUPPLY CASE

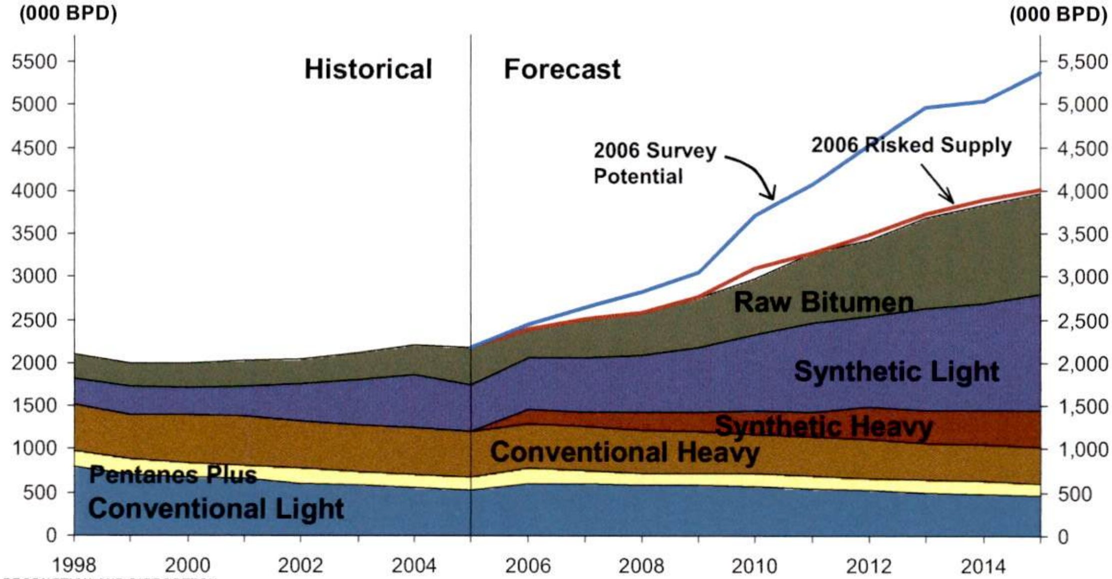
Western Canadian Sedimentary Basin Production and Disposition

- Steady production growth is anticipated in the WCSB. Production is expected to grow from 2.18 MMBPD in 2005 to 3.97 MMBPD (excluding imported condensate) by 2015, an increase of 82 percent.

- Conventional light crude production is expected to continue to decline, from 526 kBPD in 2005 to 464 kBPD in 2015. Light crude production is expected to grow modestly for 2006 and stay level in 2007, as drilling activity responds to high prices. In 2008, it is forecast that production will revert to the long-term historical average decline rate of approximately 3-4 percent.

- Conventional heavy crude production is expected to continue to decline at an average rate of approximately 3 percent per year through the forecast period.

- Through 2015, PADD II, the US Gulf Coast and West Coast Exports are the major growth markets for western Canadian crude. PADD II is expected to increase runs by 1046 kBPD from 2005 to 2015 and movements off the West Coast are expected to reach over 500 kBPD.



PRODUCTION AND DISPOSITION
MARKET UNCONSTRAINED CASE (KBPD)

Western Canada Crude Oil Production	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Conventional Light	798	711	681	654	604	572	550	526	599	597	583	580	571	548	521	501	483	464
Pentanes Plus (excluding recycled)	174	171	165	157	182	189	145	144	179	154	145	145	144	144	144	144	143	143
New Condensate	-	-	-	-	-	-	-	12	31	50	52	101	125	184	221	270	300	301
Conventional Heavy (unblended)	544	521	560	572	537	565	544	526	518	506	491	477	464	452	442	429	420	408
Synthetic Heavy (mined only)	-	-	-	-	-	-	-	-	162	169	213	230	256	277	376	370	401	423
Synthetic Light (mined only)	303	324	314	344	435	521	627	546	603	634	659	754	894	1,037	1,060	1,186	1,244	1,352
Bitumen (unblended)	287	265	279	300	281	293	347	440	345	458	493	563	648	811	882	1,051	1,137	1,182
	2,106	**1,992**	**2,000**	**2,027**	**2,038**	**2,140**	**2,213**	**2,194**	**2,438**	**2,568**	**2,636**	**2,849**	**3,102**	**3,454**	**3,646**	**3,951**	**4,127**	**4,273**
Western Canada Crude Oil Disposition																		
Western Canada	446	461	460	459	453	562	609	574	620	650	642	685	643	641	647	609	617	606
Ontario	382	330	233	213	220	219	225	212	281	257	279	301	306	396	409	404	406	406
PADD IV	160	195	218	228	243	216	234	274	279	266	276	280	265	270	269	282	294	318
PADD V	105	66	64	75	67	54	93	83	92	95	106	145	67	67	51	105	128	101
PADD II Total	1,013	940	1,025	1,052	1,056	1,020	1,026	1,042	1,131	1,250	1,282	1,378	1,522	1,605	1,676	1,866	1,964	2,088
PADD III	-	-	-	-	-	49	27	9	35	50	50	60	100	100	184	239	239	239
West Coast Exports (Gateway)	-	-	-	-	-	-	-	-	-	-	-	-	200	375	410	445	480	515
	2,106	**1,992**	**2,000**	**2,027**	**2,038**	**2,120**	**2,213**	**2,194**	**2,438**	**2,568**	**2,636**	**2,849**	**3,102**	**3,454**	**3,646**	**3,951**	**4,127**	**4,273**

- Demand in Ontario for western Canadian crude increases in 2011 from 2010 by approximately 90 kBPD as a result of declining Atlantic imports and replacement with WCSB crude.

- Synthetic light crude, synthetic heavy crude and raw bitumen are able to more than offset the production decline in conventional crude, thereby increasing total WCSB production.

- Mined light synthetic production is expected to more than double in the next 10 years from 603 kBPD to 1.35 MMBPD. By 2015, approximately 248.5 kBPD of light synthetic crude is forecast to be used as diluent for bitumen blending purposes.

- Mined synthetic heavy and sour production (e.g. Albian Heavy Synthetic and Suncor OSE) grows from 162 kBPD in 2006 to 423 kBPD in 2015.[1]

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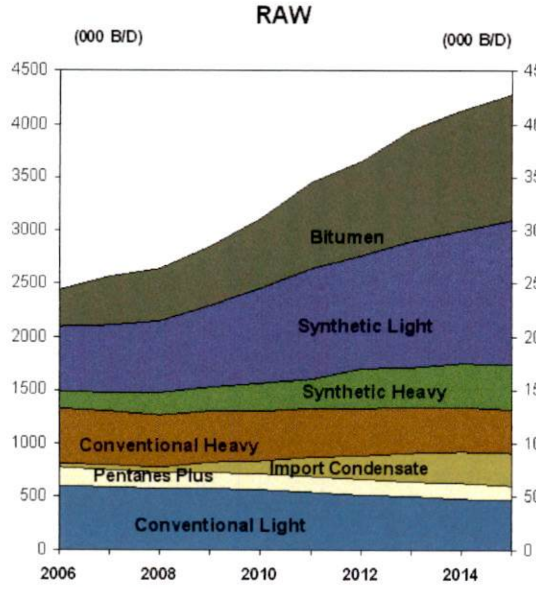
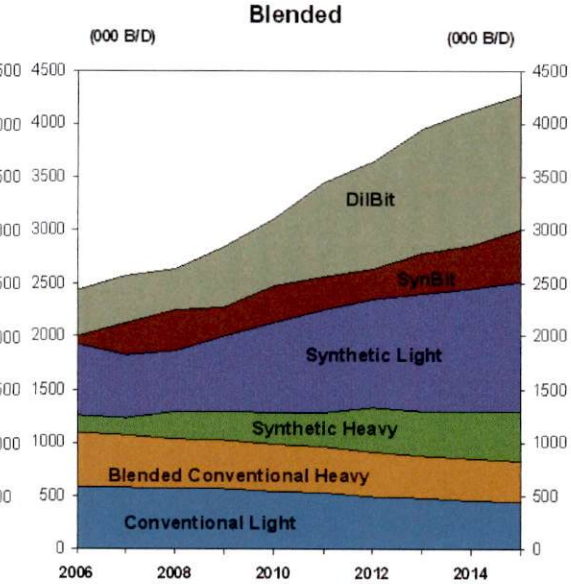
[1] With the inclusion of output from the stand-alone upgraders, synthetic light and blended volumes differ from the raw synthetic heavy and light production volumes as these include only mined production.





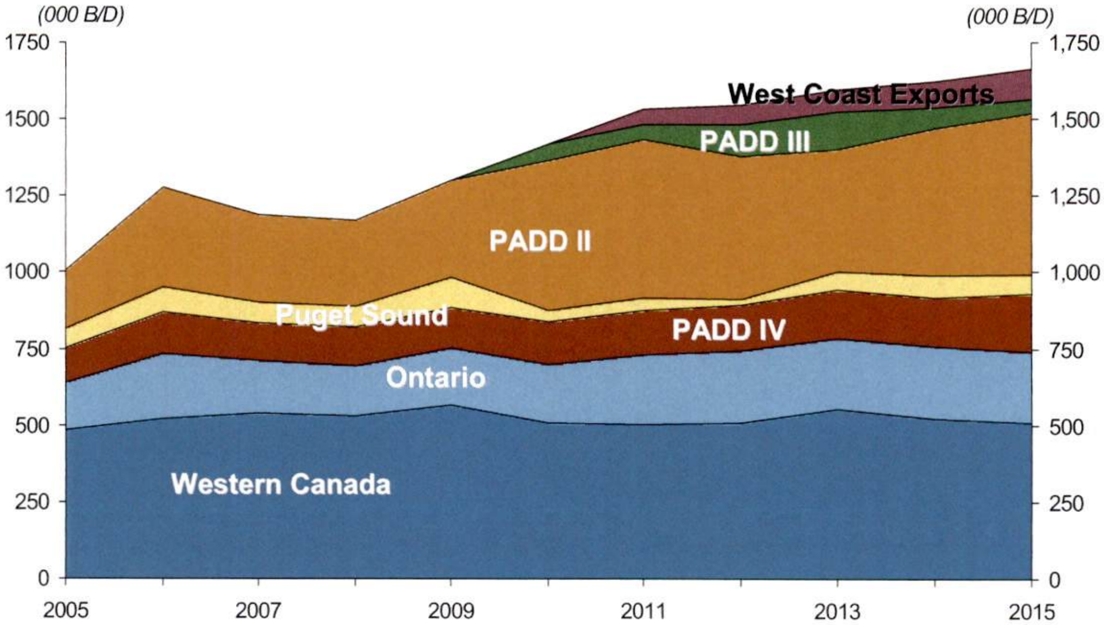
MARKET UNCONSTRAINED CASE (KBPD)

RAW PRODUCTION	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Bitumen (unblended)	345	458	493	563	648	811	882	1,051	1,137	1,182
Synthetic Light (mined only)	603	634	659	754	894	1,037	1,060	1,186	1,244	1,352
Synthetic Heavy (mined only)	162	169	213	230	256	277	376	370	401	423
Conventional Heavy (unblended)	518	506	491	477	464	452	442	429	420	408
New Condensate	31	50	52	101	125	184	221	270	300	301
Pentanes Plus (excluding recycled)	179	154	145	145	144	144	144	144	143	143
Conventional Light	599	597	583	580	571	548	521	501	483	464
	2,438	**2,568**	**2,636**	**2,849**	**3,102**	**3,454**	**3,646**	**3,951**	**4,127**	**4,273**

BLENDED PRODUCTION										
DilBit	435	445	391	568	626	891	1,018	1,166	1,272	1,272
SynBit	72	298	372	278	351	310	277	383	407	497
Synthetic Light	674	584	577	700	839	970	1,013	1,104	1,150	1,209
Synthetic Heavy	162	169	259	276	302	323	422	416	447	469
Blended Conventional Heavy	510	491	469	460	437	434	418	406	395	386
Conventional Light	585	581	567	566	547	526	498	477	457	440
	2,438	**2,568**	**2,636**	**2,849**	**3,102**	**3,454**	**3,646**	**3,951**	**4,127**	**4,273**

- Raw bitumen production will increasingly require synthetic as diluent (depicted in the chart above and included as SynBit). The new condensate supply available in 2009 relieves some of the pressure on synthetic crude used for diluent but demand for synthetic-bitumen blend is still forecast to grow.

Light and Equivalent Disposition – Market Unconstrained Supply



MARKET UNCONSTRAINED CASE (KBPD)

Supply of Light and Equivalent	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Light Sweet	335	321	308	309	296	286	270	259	245	235
Light Sour	250	260	260	257	250	240	227	218	212	204
Synthetic (mined only)	567	484	473	614	742	882	923	994	1,041	1,104
Upgraded Heavy	116	120	125	120	128	122	125	125	125	122
Pentanes Plus (excluding diluent)	11	4	4	3	3	3	2	2	2	2
	1,279	**1,189**	**1,169**	**1,303**	**1,419**	**1,533**	**1,547**	**1,598**	**1,625**	**1,667**

Disposition of Light and Equivalent										
West Coast	-	-	-	-	-	50	63	75	88	100
PADD III	-	-	-	-	53	52	104	121	64	45
PADD II	325	287	282	318	488	517	468	400	482	530
PADD V	85	67	66	98	39	39	18	60	71	61
PADD IV	136	125	127	132	138	145	151	158	160	189
Ontario	210	171	165	186	191	229	237	232	238	233
Western Canada	523	539	529	568	509	501	506	552	520	508
	1,279	**1,189**	**1,169**	**1,303**	**1,419**	**1,533**	**1,547**	**1,598**	**1,625**	**1,667**

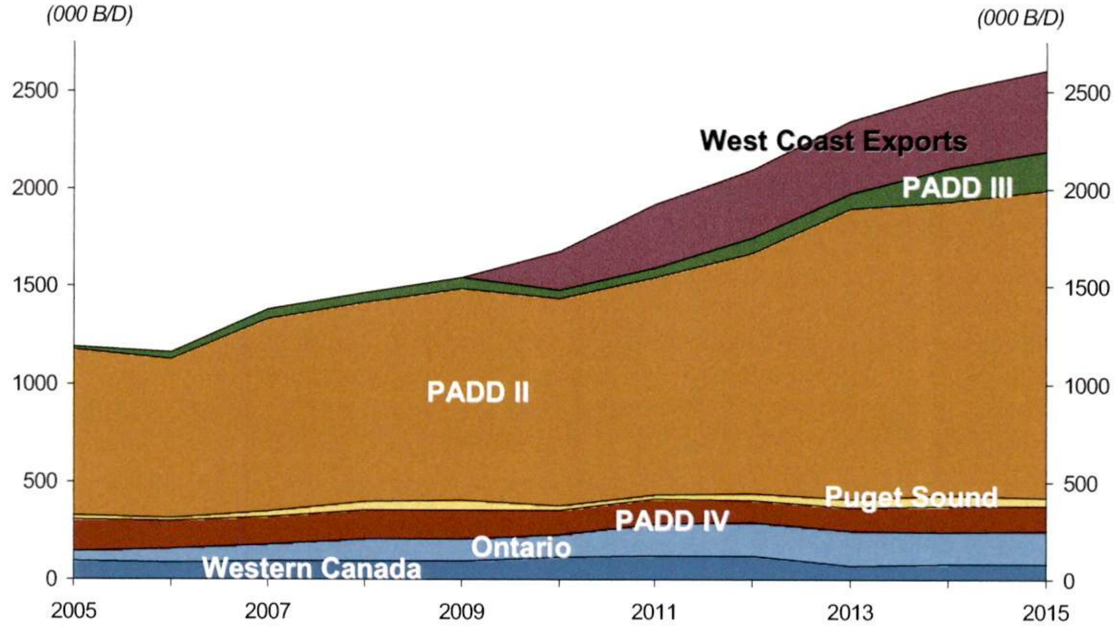
- Total demand of light crude and equivalent grows by approximately 388 kBPD through the forecast period. The timing and magnitude of differences between new synthetic projects and synthetic required as diluent for bitumen blending translates into an uneven pattern of growth/decline disposition for light and equivalent crude.
- Both PADD III (Gulf Coast) and the west coast will demand Canadian light crude in levels up to approximately 50-100 kBPD each between 2010 and 2015.

- There is an increase of approximately 40 kBPD in light demand in Ontario in 2011 with deliveries remaining at those levels to 2015 due to the expected displacement of Atlantic barrels by WCSB production.

- The PADD IV market will continue to represent an important, relatively stable demand region for Canadian light crude. Demand growth in PADD IV is to some extent limited by continued strength from local production.

- During the period 2009 through 2012, PADD V will have a preference for tidewater crude given the tight market in conventional light crude, significant volumes of synthetic light exported off the West Coast and the need for synthetic light crude to be used for bitumen blending. Post 2012, the continued growth of synthetic production combined with rising levels of new imported condensate will ultimately allow for more western Canadian crude to flow back into the region.

Blended Heavy Disposition – Market Unconstrained Supply



MARKET UNCONSTRAINED CASE (KBPD)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Blended Heavy Supply	1,159	1,379	1,467	1,546	1,683	1,921	2,100	2,352	2,503	2,606
Disposition of Blended Heavy*										
West Coast Exports	-	-	-	-	200	325	347	370	392	415
PADD III	35	50	50	60	47	48	80	80	174	194
PADD II	813	979	1,020	1,082	1,055	1,110	1,230	1,488	1,503	1,579
PADD V	8	28	40	47	28	28	33	45	57	40
PADD IV	143	142	149	148	127	125	118	125	134	129
Ontario	70	86	114	115	115	167	172	172	167	172
Western Canada	89	94	93	95	111	118	119	74	75	77
	1,159	1,379	1,467	1,546	1,683	1,921	2,100	2,352	2,503	2,606

*(excludes upgrader feed)

- Demand for heavy crude oil more than doubles from 1.16 MMBPD to 2.61 MMBPD over the forecast period.

- Deliveries to PADD II grow until 2010 when it is assumed that supply is diverted to support shipper commitments on a newly constructed west coast market occurs. Heavy crude disposition to PADD II is slightly lower in 2010 and then recovers with a strong growth pattern in 2011 and beyond.

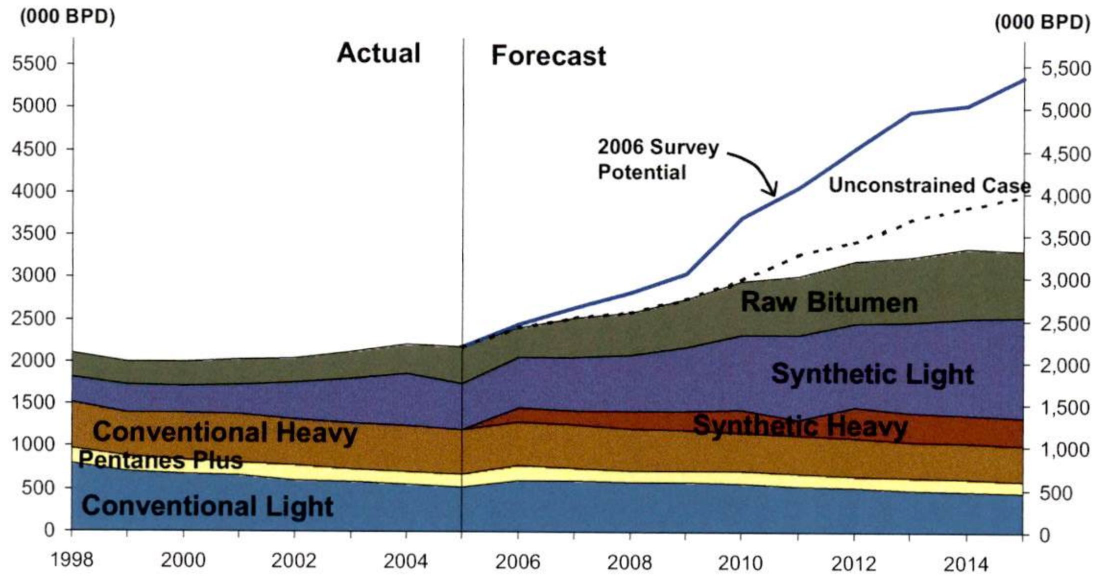
- Disposition of heavy crude to PADD III, represented primarily by the Gulf Coast region, shows strong growth from 35 kBPD in 2006 to 194 kBPD in 2015.

- Demand in Ontario grows by approximately 50 kBPD in 2011 and remains level to 2015 as WCSB production is expected to replace declining Atlantic production.

MARKET CONSTRAINED SUPPLY CASE

Western Canadian Sedimentary Basin Production and Disposition

- Production out of western Canada for the constrained supply case is 17 kBPD less than the market unconstrained supply case in 2010. By 2015, the difference in production between the two cases widens to 653 kBPD. Approximately 164 kBPD of the difference is in synthetic light production, while 395 kBPD is in raw bitumen production. The remainder of the total difference is caused by relatively small changes throughout the other crude types.



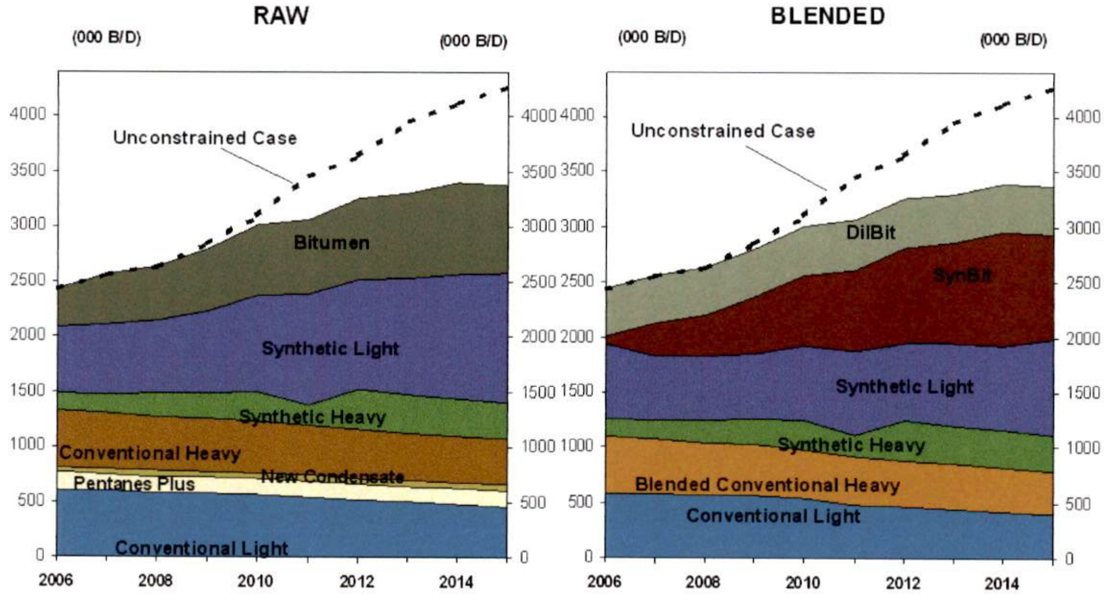
PRODUCTION AND DISPOSITION
MARKET CONSTRAINED CASE (KBPD)

Western Canada Crude Oil Production	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Conventional Light	799	711	679	654	604	579	554	526	599	597	583	580	571	548	521	501	483	464
Pentanes Plus (excluding recycled)	176	170	164	157	182	151	145	144	178	153	145	145	144	144	143	143	143	143
Imported Condensate	-	-	-	-	-	-	-	12	31	49	52	52	52	53	52	52	52	53
Conventional Heavy (unblended)	541	522	560	572	535	547	541	526	518	506	491	477	464	452	442	429	420	408
Synthetic Heavy (mined only)	302	327	314	346	434	522	629	546	603	169	213	230	269	184	361	341	340	330
Synthetic Light (mined only)	-	-	-	-	-	-	-	-	162	634	659	754	877	1,003	996	1,071	1,133	1,188
Bitumen (unblended)	289	264	277	302	283	321	346	440	345	458	493	563	635	686	743	760	826	787
	2,107	**1,994**	**1,994**	**2,032**	**2,038**	**2,120**	**2,214**	**2,194**	**2,437**	**2,566**	**2,635**	**2,800**	**3,012**	**3,069**	**3,258**	**3,298**	**3,398**	**3,372**
Western Canada Crude Oil Disposition																		
Western Canada	446	461	460	459	453	562	609	574	619	648	642	684	643	638	649	610	600	607
Ontario	382	330	233	213	220	219	225	212	261	248	261	264	260	263	264	267	263	265
PADD IV	160	195	218	228	243	216	234	274	279	266	276	265	285	295	299	308	321	345
PADD V	105	66	64	75	67	54	93	83	92	95	106	111	155	150	136	155	155	155
PADD II Total	1,013	940	1,025	1,052	1,056	1,020	1,026	1,042	1,150	1,259	1,299	1,416	1,599	1,642	1,829	1,878	1,976	1,918
PADD III	-	-	-	-	-	49	27	9	35	50	50	60	70	81	80	80	83	82
West Coast Exports (Gateway)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2,106	**1,992**	**2,000**	**2,027**	**2,038**	**2,120**	**2,213**	**2,194**	**2,437**	**2,566**	**2,635**	**2,800**	**3,012**	**3,069**	**3,258**	**3,298**	**3,398**	**3,372**

- The main difference between crude oil disposition in the constrained case versus the unconstrained case is the absence of significant exports off the west coast and expected significant growth in volumes delivered to PADD III. PADD II is the most important growth market in the constrained case with crude demand of 1.04 MMBPD in 2005 growing to 1.92 MMBPD in 2015.

- Ontario refinery runs of WCSB essentially remain flat in contrast to the displacement of Atlantic origin barrels assumed in the unconstrained case.

- The conventional light and heavy supply forecast is essentially unchanged in the unconstrained and constrained cases.



[1] includes New Condensate

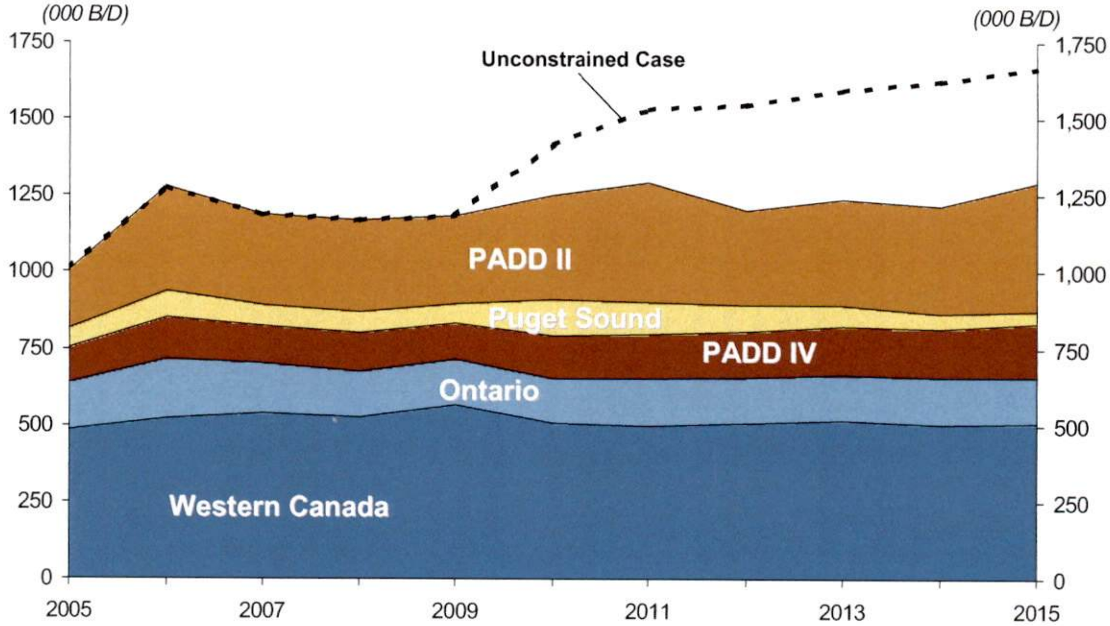
MARKET CONSTRAINED CASE (KBPD)

RAW PRODUCTION	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Bitumen (unblended)	345	458	493	563	635	686	743	760	826	787
Synthetic Light (mined only)	603	634	659	754	877	1,003	996	1,071	1,133	1,188
Synthetic Heavy (mined only)	162	169	213	230	269	184	361	341	340	330
Conventional Heavy (unblended)	518	506	491	477	464	452	442	429	420	408
Imported Condensate	31	49	52	52	52	53	52	52	52	53
Pentanes Plus (excluding recycled)	178	153	145	145	144	144	143	143	143	143
Conventional Light	599	597	583	580	571	548	521	501	483	464
	2,437	**2,566**	**2,635**	**2,800**	**3,012**	**3,069**	**3,258**	**3,298**	**3,398**	**3,372**
BLENDED PRODUCTION										
DilBit	433	443	437	428	452	454	440	432	432	436
SynBit	72	298	372	520	635	742	877	915	1,043	959
Synthetic Light	674	584	577	595	680	767	693	756	762	860
Synthetic Heavy	162	169	213	230	269	184	361	341	340	330
Blended Conventional Heavy	510	491	469	460	437	434	418	406	395	387
Conventional Light	585	581	567	566	539	489	469	448	425	401
	2,437	**2,566**	**2,635**	**2,800**	**3,012**	**3,069**	**3,258**	**3,298**	**3,398**	**3,372**

- The main difference between the two market demand cases is reflected in the size of the DilBit and SynBit blended crude streams. In the constrained case, in the absence of a new source of condensate diluent, there is 174 kBPD less DilBit in 2010 and 836 kBPD in 2015. Consequently, in the constrained case, there is approximately 284 kBPD more SynBit in 2010 and 462 kBPD more in 2015 in the constrained case, a significant difference caused by the relatively flat levels of SynBit production forecast in the unconstrained case.

- Primarily as a result of the greater size of the Synbit stream in the constrained case, the quantity of light synthetic delivered to markets in 2015 is approximately 349 kBPD lower than in the unconstrained case in 2015. Total synthetic heavy production delivered to markets in the constrained case is lower than the unconstrained case by 139 kBPD in 2015.

Light and Equivalent Disposition – Market Constrained Supply



MARKET CONSTRAINED CASE (KBPD)

Supply of Light and Equivalent	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Light Sweet	335	321	308	309	289	248	242	230	213	197
Light Sour	250	260	260	257	250	240	227	218	212	204
Synthetic (mined only)	567	484	473	493	583	679	604	662	665	767
Upgraded Heavy	116	120	125	120	128	122	125	125	125	122
Pentanes Plus (excluding diluent)	11	4	4	3	3	3	2	2	2	2
	1,279	1,189	1,169	1,182	1,252	1,293	1,200	1,237	1,216	1,292

Disposition of Light and Equivalent										
PADD III	-	-	-	-	-	-	-	-	-	-
PADD II	341	296	300	284	342	392	307	345	348	416
PADD V	86	67	66	65	118	103	84	67	52	42
PADD IV	136	125	127	117	138	145	151	158	160	177
Ontario	192	162	148	148	145	153	149	152	153	150
Western Canada	523	539	528	568	509	499	509	516	503	508
	1,279	1,189	1,169	1,182	1,252	1,293	1,200	1,237	1,216	1,292

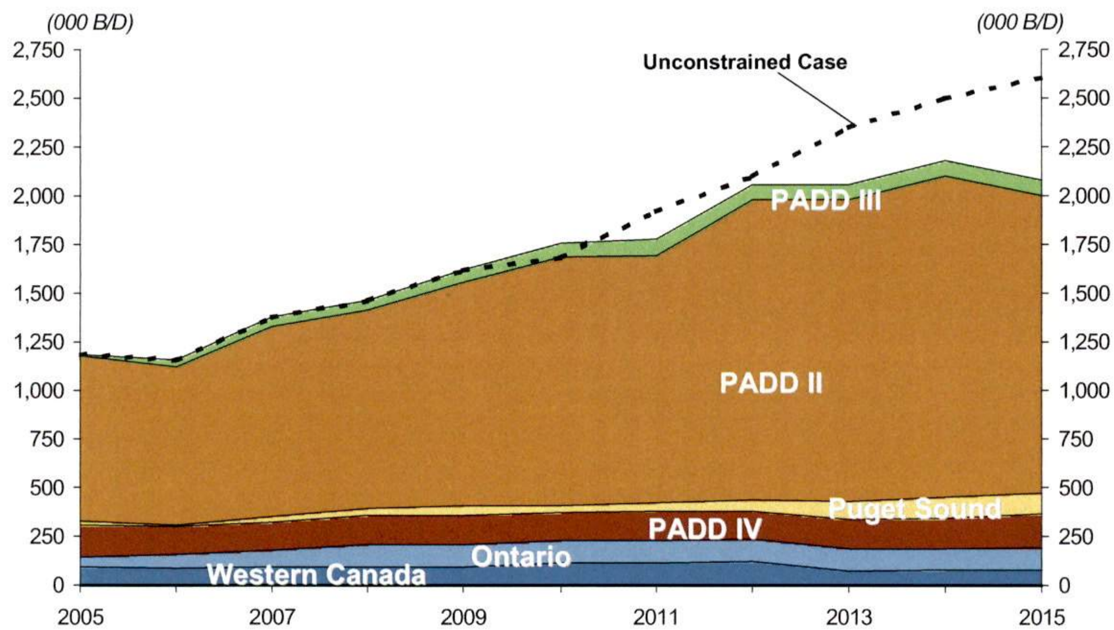
- Total demand of light crude and equivalent is essentially flat, growing by only 13 kBPD throughout the forecast period with demand in western Canada and PADD IV essentially the same in both cases.

- Given the forecast declines in conventional light crude and the expected strong demand for synthetic used as diluent, the Puget Sound refining region is not expected to be able to compete for the light barrel past 2011 and replaces it with synthetic heavy. This is further described in the following section in the following section.

Blended Heavy Disposition – Market Constrained Supply

- Blended heavy crude demand grows by 922 kBPD from 2006 to 2015; that is 525 kBPD less than in the unconstrained supply case. For the constrained case, currently connected markets and a moderate level of new access to the Cushing and Gulf Coast refining regions starting in 2006 are expected to absorb all of the growth in heavy crude production.

- The PADD II refining market is the main growth area with an 87% demand increase over the forecast period. As previously mentioned, some synthetic heavy is run in PADD V, making up for the conventional light and synthetic light lost to competing demand areas.



MARKET CONSTRAINED CASE (KBPD)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Blended Heavy Supply	1,158	1,377	1,466	1,618	1,760	1,776	2,058	2,061	2,181	2,080
Disposition of Blended Heavy*										
PADD III	35	50	50	60	70	81	80	80	83	82
PADD II	816	979	1,020	1,155	1,280	1,272	1,544	1,555	1,650	1,524
PADD V	6	28	40	47	36	47	52	88	103	114
PADD IV	143	142	149	148	147	150	148	150	160	169
Ontario	69	86	114	115	115	110	115	115	110	115
Western Canada	89	92	92	94	111	117	118	72	75	77
	1,158	1,377	1,466	1,618	1,760	1,776	2,058	2,061	2,181	2,080

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National Energy Board
Office national de l'énergie

Canada's Oil Sands

OPPORTUNITIES AND CHALLENGES TO 2015: AN UPDATE

AN ENERGY MARKET ASSESSMENT JUNE 2006

Canada

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Canada's Oil Sands

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LIST OF ACRONYMS AND ABBREVIATIONS

AENV	Alberta Environment
AESO	Alberta Electric System Operator
ANS	Alaskan North Slope
CBM	coal bed methane
CEMA	Cumulative Environmental Management Association
CERI	Canadian Energy Research Institute
CHOPS	Cold Heavy Oil Production with Sand
CHP	Combined Heat and Power
CONRAD	Canadian Oilsands Network for Research and Development
CSS	Cyclic Steam Stimulation
EMA	Energy Market Assessment
EOR	enhanced oil recovery
EUB	Alberta Energy and Utilities Board
GDP	Gross Domestic Product
GHG	greenhouse gases
LLB	Lloydminster Blend
MSAR	Mulitphase Superfine Atomized Residue
MSW	Mixed Sweet (crude oil)
NEB	National Energy Board
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
PADD	Petroleum Administration for Defense District
RAS	Remedial Action Schemes
RIWG	Regional Issues Working Group
SAGD	Steam Assisted Gravity Drainage
SCO	synthetic crude oil
SGL	synthetic gas liquids
SOR	steam-to-oil ratio
THAI	Toe-to-Heel Air Injection
U.S.	United States
VAPEX	Vapour Extraction Process
VGO	vacuum gas oil
WBEA	Wood Buffalo Environmental Association
WCS	Western Canadian Select
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

UNITS

b	barrel(s)
b/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Btu	British thermal units
Btu/cf	British thermal unit per cubic feet
cf	cubic feet
GW	gigawatt
GW.h	gigawatt hour
m^3	cubic metres
m^3/d	cubic metres per day
Mcf	thousand cubic feet
Mb/d	thousand barrels per day
MMb	million barrels
MMb/d	million barrels per day
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MW	megawatt
scf	standard cubic feet

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines. The Board regulates pipeline tolls and tariffs for pipelines under its jurisdiction. In terms of specific energy commodities, the Board regulates the exports and imports of natural gas as well as exports of oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration, development and production in Frontier lands and offshore areas not covered by provincial or federal management agreements. The Board's advisory function requires keeping under review matters over which Parliament has jurisdiction relating to all aspects of energy supply, transmission and disposal of energy in and outside Canada.

The NEB collects and analyzes information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. In addition, policy makers are informed of the regulatory and related energy issues. On this note, the Board has received feedback from a wide range of energy market participants across the country indicating that the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA is an update to a previous oil sands EMA released by the Board in May 2004, entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*. Audiences requiring a detailed review of the background surrounding the oil sands resource and its development are encouraged to read the previous publication. The key objective of this report is to highlight the major changes to the supply and market analysis resulting from developments in the last two years.

In preparing this report, the NEB conducted a series of informal meetings and discussions with a cross-section of oil sands stakeholders including producers, refiners, marketers, pipeline companies, electricity and petrochemical officials, industry associations, consultants, government departments and agencies, and environmental groups. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

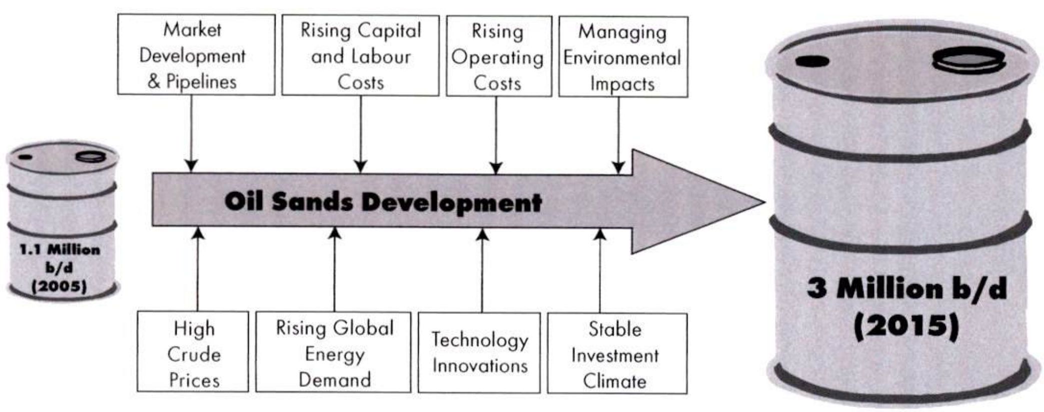
Executive Summary

Introduction

In May 2004, the Board released an Energy Market Assessment (EMA) entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*, which contained detailed discussions on the major aspects of the oil sands industry and assessed the opportunities and challenges facing the development of the resource. Since then, the conditions surrounding oil sands development have changed significantly. As a result, the Board decided to provide an update to this report, highlighting major changes and developments.

The diagram below shows the major influences on oil sands development as production grows from 175 000 m³/d (1.1 MMb/d) in 2005 to a projected 472 000 m³/d (3.0 MMb/d) by 2015.

Influences on Oil Sands Development



A comparison of key assumptions between the current analysis (2005 dollars) and the 2004 report (2003 dollars) is as follows:

Assumptions	June 2006 Report	May 2004 Report
WTI crude oil price	US$50 per barrel	US$24 per barrel
NYMEX natural gas price	US$7.50 per MMBtu	US$4.00 per MMBtu
Light/heavy price differential	US$15 per barrel	US$7 per barrel
Canadian dollar exchange rate	US$0.85	US$0.75

Key Findings

Supply Costs

The table below provides estimates of operating and supply costs for various types of oil sands recovery methods.

Estimated Operating and Supply Costs by Recovery Type

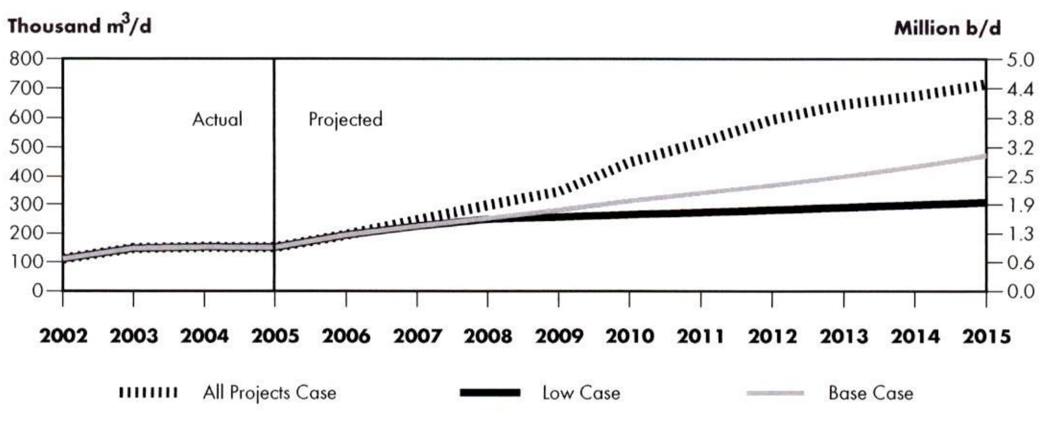
C$(2005) per barrel at the Plant Gate	Crude Type	Operating Cost	Supply Cost
Cold Production - Wabasca, Seal	Bitumen	6 to 9	14 to 18
Cold Heavy Oil Production with Sand (CHOPS) - Cold Lake	Bitumen	8 to 10	16 to 19
Cyclic Steam Stimulation (CSS)	Bitumen	10 to 14	20 to 24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10 to 14	18 to 22
Mining/Extraction	Bitumen	9 to 12	18 to 20
Integrated Mining/Upgrading	Synthetic	18 to 22	36 to 40

Integrated mining and SAGD operations are estimated to be economic at US$30 to $35 per barrel WTI. Continued escalation in material and labour costs pose a risk to this outlook. Higher natural gas prices and blending costs would also increase this estimate. On the other hand, advancement in recovery and upgrading technologies hold potential to reduce supply costs.

Crude Oil Supply

About C$125 billion in capital expenditures have been publicly announced for the period 2006 to 2015; however, it is unlikely that all publicly announced development plans will be completed in the declared timeframe. The Base Case projection, shown in the chart below, assumes capital expenditures of C$94 billion and indicates oil sands production will almost triple from 175 000 m^3/d (1.1 MMb/d) in 2005 to 472 000 m^3/d (3.0 MMb/d) by 2015.

Projected Total Bitumen Production



Markets and Pipelines

Based on industry consultations and the Board's internal analysis, potential scenarios for market expansion for the growing oil sands production could unfold as outlined in the following table.

Potential Markets for Oil Sands Production

Steps	Potential Markets
1	Existing core markets in Ontario, Western Canada, northern PADD II (see map in Introduction, page 1), PADD IV and Washington State
2	Southern PADD II, PADD III, new cokers and/or refinery expansions in PADDs II, IV and V
3	New markets in California and the Far East

With increasing production from the oil sands, total pipeline capacity out of the Western Canada Sedimentary Basin (WCSB) could be near full utilization starting in 2007. The pace of pipeline expansion will depend on decisions with respect to the markets to be served and the necessary regulatory approvals.

Environmental and Socio-economic Impacts

There is now a clearer understanding that large water withdrawals from the Athabasca River for mining operations during the winter could impact the ecological sustainability of the river. As well, it is uncertain if land reclamation methods currently employed will be successful. These issues have moved to the forefront of environmental concerns. Regions associated with oil sands development enjoy several economic benefits but at costs to the social well-being of the communities, including a shortage of available housing and stress on public infrastructure and services. There is currently a limited supply of skilled workers in Alberta, and this tight labour market is expected to continue in the near future.

Electricity and Petrochemical Opportunities

The potential for building cogeneration capacity has decreased somewhat since the 2004 report. The recent trend has been for oil sands producers to build for self-sufficiency with little excess electricity generated for sale to the grid. However, factors that could alter the trend include: advancement in gasification technology that could reduce the reliance on natural gas for fuel; access to a higher priced electricity market; and a premium payment for clean power.

Given the outlook for synthetic crude oil production, the Alberta petrochemical industry may have an opportunity to supplement declining ethane feedstock supply with synthetic gas liquids extracted from upgrader off-gas.

Outlook

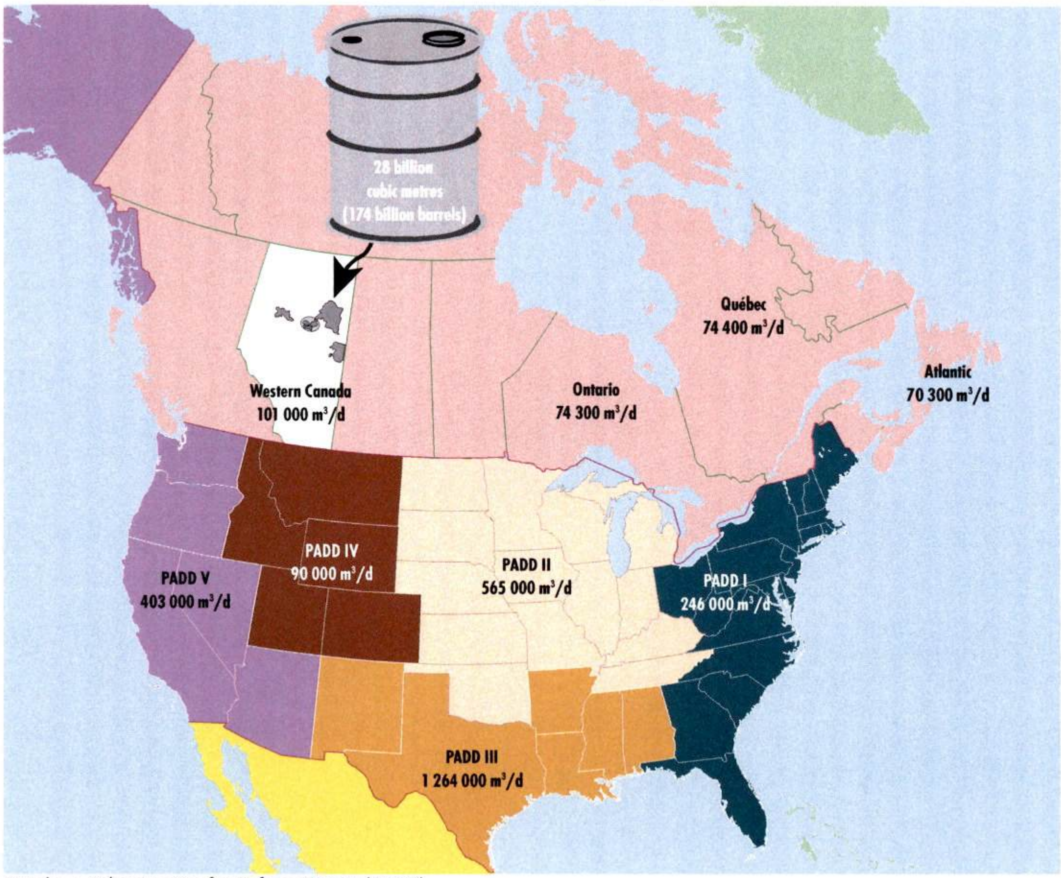
It is expected that there will continue to be rapid growth in the development of Canada's oil sands. There are, however, issues and uncertainties associated with the development of the resource. The rate of development will depend on the balance that is reached between the opposing forces that affect the oil sands. High oil prices, international recognition, geopolitical concerns, global growth in oil demand, size of the resource base and proximity to the large U.S. market, and potentially other markets, encourage development. On the other hand, natural gas costs, the high light/heavy oil price differential, management of air emissions and water usage, insufficient labour, infrastructure and services are concerns that could potentially inhibit the development of the resource.

Introduction

In May 2004, the Board released a comprehensive Energy Market Assessment (EMA) entitled *Canada's Oil Sands: Opportunities and Challenges to 2015*. It contained detailed discussions on major aspects of the oil sands industry and assessed the opportunities and issues facing development of the resource. Since then, there have been significant changes. In recognition of the need for current information, the Board decided to provide this update for stakeholders, which highlights the major changes and new developments. The main purpose of this report remains the same—to provide an objective assessment of the current state of the oil sands and the potential for growth. It is assumed that readers are familiar with the topic but those readers seeking additional background information are encouraged to refer to the previous report which is available on the Board's website at www.neb-one.gc.ca.

FIGURE 1.1

Oil Sands Reserves and Canada and U.S. Refinery Capacities



Petroleum Administration for Defense District (PADD)

Canada's oil sands are a substantial resource. According to the Alberta Energy and Utilities Board (EUB), Alberta's oil sands contain an ultimately recoverable crude bitumen resource of 50 billion cubic metres (315 billion barrels), with remaining established reserves of almost 28 billion cubic metres (174 billion barrels) at year-end 2004[i].

The rapid pace of development continues to be driven by several factors, including:

- higher oil prices;
- concerns surrounding the global supply of oil;
- market potential in the U.S. and Asia; and
- stable generic fiscal terms for producers.

Key assumptions that underlie the current analysis compared to the May 2004 report are as follows:

Assumptions	June 2006 Report	May 2004 Report
West Texas Intermediate (WTI) crude oil price	US$50 per barrel	US$24 per barrel
NYMEX natural gas price	US$7.50 per MMBtu	US$4 per MMBtu
Light/heavy crude oil price differential	US$15 per barrel	US$7 per barrel
Canadian dollar exchange rate	US$0.85	US$0.75

As in the previous report, sensitivities around the oil price, natural gas price, exchange rate and other cost components were used for the supply cost estimates.

This report can broadly be considered as having four key components:

- economic potential and development of the resource base;
- markets and pipelines;
- environmental and socio-economic impacts; and
- potential opportunities in the electricity and petrochemical industries.

The outline of the report is as follows:

- Chapter 1 is an introduction to the report;
- Chapter 2 analyzes supply costs;
- Chapter 3 discusses crude oil production and supply;
- Chapter 4 provides a synopsis of the potential markets for the rising oil sands supply;
- Chapter 5 describes the major crude oil pipeline network and expansion plans;
- Chapter 6 highlights the environmental concerns over water, air quality, by-product and waste production from oil sands activity and related socio-economic impacts;
- Chapter 7 assesses the opportunity for electricity generation; and
- Chapter 8 concludes with a discussion on the potential opportunities for the petrochemical industry.

Supply Costs

2.1 Introduction

Since the Board's May 2004 report, the economic environment, particularly with respect to energy, has changed significantly. For the oil sands sector, this has meant a substantial escalation in the costs to develop and operate projects, but also greater revenues with currently higher oil prices and a general view that higher prices will endure into the foreseeable future.

Capital costs have risen dramatically due to higher prices for steel, cement and equipment. The rising pace of development has also led to a shortage of skilled tradespersons and a reduction in the overall productivity of labour. These cost escalations and the challenge in attracting skilled labour are being felt all across the world, but are particularly severe in the oil sands region because of its relatively remote location, the high pace of development, and the scope and complexity of the projects being undertaken.

The rise in energy prices has been the most dominant factor influencing project economics and the oil sands development drive. Higher oil prices have boosted revenues; however, operating costs have also increased significantly with the rise in electricity and natural gas prices. The latter is of particular importance with an estimated 1 Mcf required to produce each barrel of bitumen. For in situ producers, the availability and price of diluent for blending has become a more pressing issue, as has the market value of heavy versus light crude oil (the differential) in traditional markets.

Table 2.1 provides a summary of current oil sands operating costs and supply costs for major recovery methods. Operating costs can generally be considered as reflecting the cash costs of operation while supply costs include all costs associated with production, including operating cost, capital cost, taxes, royalties and a rate of return on investment. Supply costs are stated as a range, reflecting variables such as: reservoir quality, depth of the producing formation, project size, recovery method and operating parameters.

TABLE 2.1

Estimated Operating and Supply Costs by Recovery Type

C$(2005) per barrel at the Plant Gate	**Crude Type**	**Operating Cost**	**Supply Cost**
Cold Production - Wabasca, Seal	Bitumen	6 to 9	14 to 18
Cold Heavy Oil Production with Sand (CHOPS) - Cold Lake	Bitumen	8 to 10	16 to 19
Cyclic Steam Stimulation (CSS)	Bitumen	10 to 14	20 to 24
Steam Assisted Gravity Drainage (SAGD)	Bitumen	10 to 14	18 to 22
Mining/Extraction	Bitumen	9 to 12	18 to 20
Integrated Mining/Upgrading	Synthetic	18 to 22	36 to 40

Compared with the last report, most of the costs in this table are significantly higher. The primary reasons for the changes are higher natural gas prices and increasing capital costs for project construction.

2.2 Project Economics

This section provides an update to the Board's project economic work that was completed as part of the 2004 report. The reader is encouraged to review the previous work for more information on methodology and for a greater understanding on how project economics have changed.

The Board decided to examine the economics of Steam Assisted Gravity Drainage (SAGD) and integrated mining as it is anticipated that these operations will form the bulk of supply growth through 2015. Although Cyclic Steam Stimulation (CSS) has been employed successfully in the Cold Lake oil sands region for over 20 years, it is not anticipated that its application will be expanded significantly over the timeframe of this report.

In this report, as in the previous one, the Board developed a discounted cash flow model to determine supply cost. This resulting supply cost is defined as the constant dollar crude oil price required over the life of the project to cover all costs, except land acquisition costs that can vary widely, and provide a 10 percent real rate of return (12 percent nominal) on investment.

Economic and market assumptions are available in Appendix 1 and major modelling assumptions are available in Appendices 2 and 3. The following are the key assumptions used in the analysis (2005 dollars):

- WTI at Cushing, Oklahoma is US$50 per barrel;
- NYMEX natural gas is US$7.50 per MMBtu;
- U.S./Canada exchange rate is 0.85; and,
- light/heavy crude oil differential (Par versus Lloydminster Blend) is US$15 per barrel (30 percent).

2.2.1 *Integrated Mining/Extraction and Upgrading*

An update to the economic evaluation for a 31 700 m^3/d (200 Mb/d) integrated mining/extraction and upgrading operation has been performed. This model is intended to emulate a greenfield project with construction beginning in 2006 and first production in 2010. The mining project evaluated is assumed to produce synthetic crude oil (SCO) of similar quality and value to conventional light oil.

FIGURE 2.1

Supply Cost Sensitivities: 200 Mb/d Athabasca Mining/ Extraction and Upgrading Project

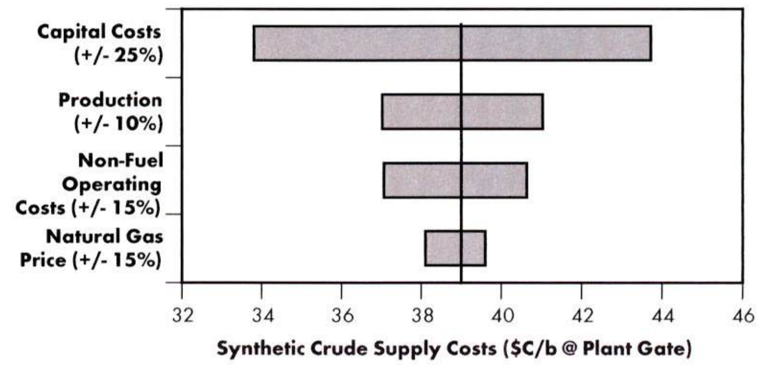


Figure 2.1 shows a supply cost for SCO at the plant gate of about $39 per barrel. This compares to a supply cost of $26 in the 2004 report. The main reasons for the increase are higher capital costs (up 37 percent), higher natural gas prices (up 88 percent), and increased non-gas operating costs (up 20 percent). In addition, supply costs include royalties and taxes which increase under higher oil prices.

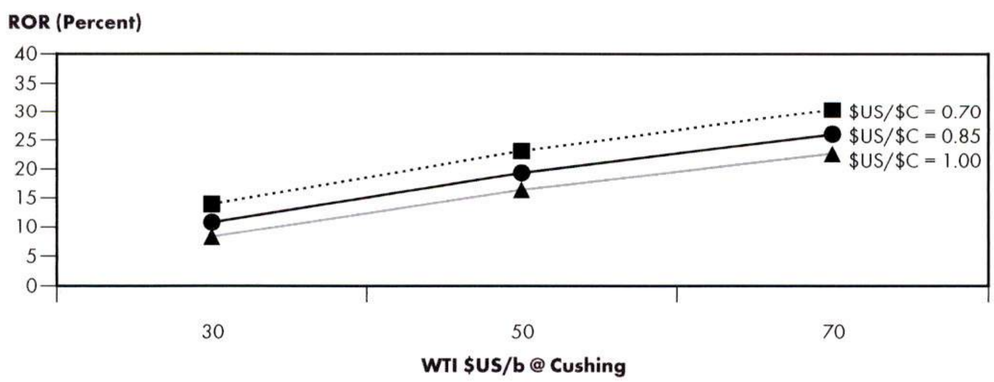
The supply cost continues to be most sensitive to changes in capital costs. A 25 percent increase or decrease in capital costs results in a nearly $5 per barrel change in supply cost. Also important to note is the sensitivity to overall production levels vis-à-vis design rates. Improving operational reliability and minimizing unplanned maintenance continues to be a major focus of integrated mining operations today.

Figure 2.2 illustrates the economic performance of the hypothetical integrated mining project for different combinations of the oil price and the exchange rate. At US$50 per barrel for WTI, the project is estimated to provide a rate of return of 16 to 23 percent.

It is estimated that US$30 to $35 per barrel for WTI is required to provide a 10 percent real rate of return to the producer. Continued escalation in material and labour costs pose a risk to this outlook. Each 10 percent increase in capital costs is estimated to increase the required WTI price by US$2 per barrel.

FIGURE 2.2

After-tax Nominal Rate of Return: 200 Mb/d Athabasca Mining/Extraction and Upgrading Project



2.2.2 SAGD

An update to the economic evaluation for a 19 000 m^3/d (120 Mb/d) Athabasca SAGD operation has been performed. The SAGD project is assumed to produce a condensate-bitumen blend (dilbit) of similar quality and value to Lloydminster Blend (LLB).

FIGURE 2.3

Supply Cost Sensitivities: 120 Mb/d Athabasca SAGD Project – High-Quality Reservoir

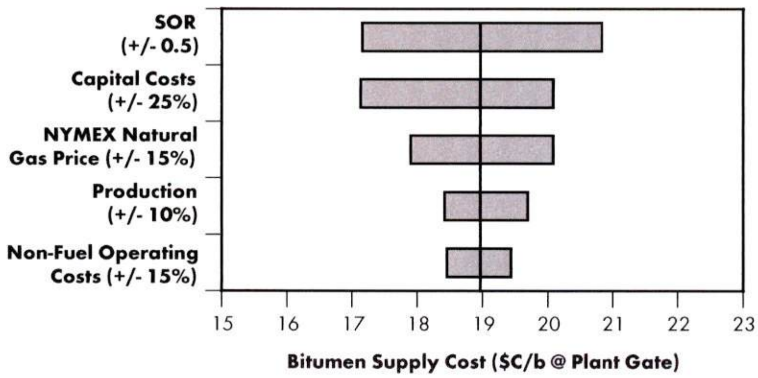


Figure 2.3 shows a supply cost for bitumen at the plant gate of about $19 per barrel. This compares with a supply cost of about $13 in the 2004 report. As with the integrated mining case, one of the main reasons for the increase is higher capital costs, which are up 45 percent. This increase is driven not only by the escalation of material and labour costs, but also by more conservative assumptions regarding reservoir performance resulting in more wells being drilled over the life of the project. Higher natural gas prices (up 88 percent) also contribute significantly to higher supply costs, since purchased natural gas requirements are estimated at approximately 1 Mcf per barrel. Non-gas operating costs have been reduced from $5.00 per barrel to $3.50 reflecting operator progress and estimates from the most recent project plans.

Over the past number of years, Western Canada Sedimentary Basin (WCSB) supply of the traditional blending agent, pentanes plus (C5+), has been flat to declining while, at the same time, demand from bitumen producers has been increasing. As a result of these market conditions, prices have been rising. Historically, C5+ in western Canada has had a market value of about five percent above Edmonton Par crude. In 2005 and in the first quarter of 2006, however, this premium has increased to an average of about 10 percent. At present, there exists no means of importing large quantities of blend stock into Alberta; therefore, it is not anticipated that this price premium will ease in the near term. For this reason, a 10 percent premium of C5+ over Edmonton Par crude has been incorporated into the SAGD project economics.

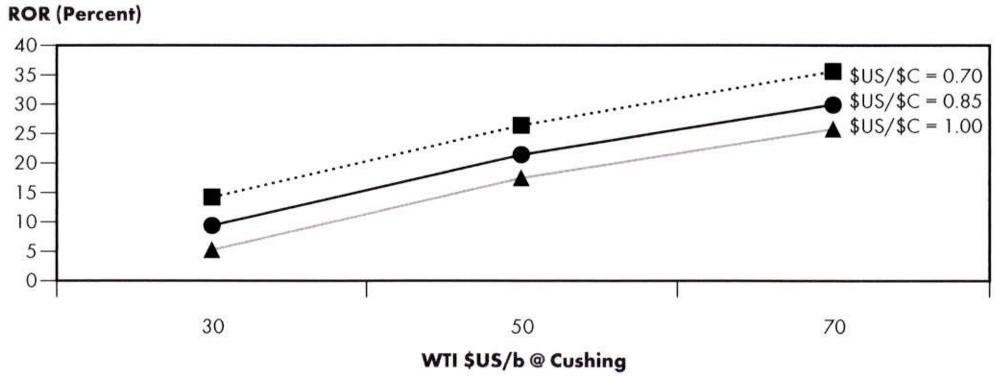
The supply cost is highly sensitive to the steam-to-oil ratio (SOR), a measure of how much energy must be applied to the reservoir to induce bitumen to flow into the well bore. For dry steam (100 percent), an increase of 0.5 in SOR translates into approximately 200 standard cubic feet (scf) in added natural gas consumption and increased water handling costs. Together, these amount to a nearly $2 per barrel increase in supply cost.

Figure 2.4 illustrates the economic performance of the hypothetical Athabasca SAGD project for different combinations of the oil price and the exchange rate. At US$50 per barrel for WTI, the project is estimated to provide a rate of return of 16 to 27 percent.

It is estimated that US$30 to $35 per barrel for WTI is required to provide a 10 percent real rate of return to the producer. As in the integrated mining case, continued escalation in material and labour costs pose a risk to this outlook. Each 10 percent increase in capital costs is estimated to increase the required WTI price by US$1.50 per barrel.

FIGURE 2.4

After-tax Nominal Rate of Return: 120 Mb/d Athabasca SAGD Project – High-Quality Reservoir (Canada–U.S. Exchange Rate Sensitivity)

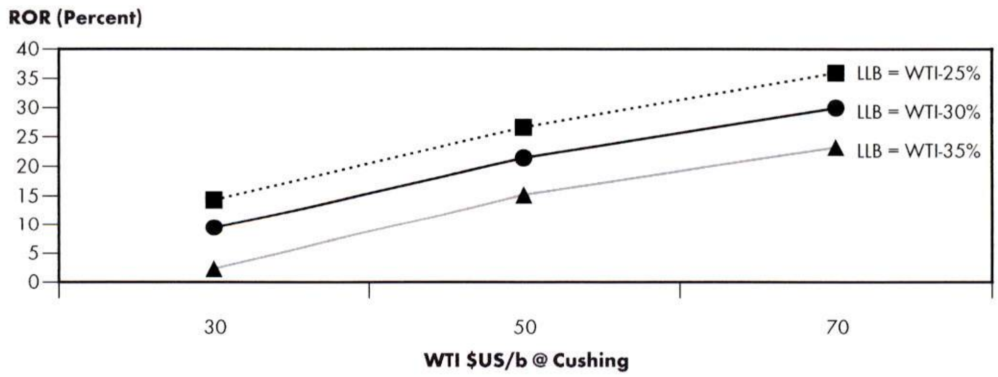


Recently, oil sands supply growth has outpaced demand in traditional markets for Canadian heavy oil. This situation has resulted in deep price discounting for heavy blends and substantially wider light/heavy oil differentials, both on a dollar and percentage basis. Figure 2.5 shows that a long-term widening (narrowing) of the differential has a significant negative (positive) impact on project economics.

Although there are likely to be periods where markets are unbalanced, resulting in a widening or narrowing of the differential, wide differentials provide refiners with an economic incentive to build heavy oil conversion capacity, while narrow differentials lessen the need to construct conversion capacity. For this reason, it is expected that the historical relationship of Lloydminster Blend at about a 30 percent discount to Edmonton Par crude will prevail over the longer term.

FIGURE 2.5

After-tax Nominal Rate of Return: 120 Mb/d Athabasca SAGD Project – High Quality Reservoir (Light/Heavy Differential Sensitivity)



2.3 Outlook: Issues and Uncertainties

Under today's market conditions, integrated mining and SAGD are estimated to be economic at US$30 to $35 per barrel for WTI. In recent years, higher oil prices have bolstered the economics of prospective projects. On the downside, however, higher energy costs, higher capital costs, a rising Canadian dollar relative to the U.S. dollar, and widening light/heavy differentials have proved to be significant challenges.

The supply cost projections and project economic analysis presented in this chapter are based on operational and market assumptions. Significant changes to these underlying assumptions may alter the results of the analysis materially. The following are the key risks and uncertainties to the outlook:

- **Crude oil prices:** Oil sands are relatively expensive to produce; a significant drop in oil prices may lead to poor economics for many existing and potential projects. The persistence of wider than average light/heavy differentials will negatively affect project economics for those producers marketing heavy blends.
- **Capital costs:** Oil sands projects, particularly those involving upgrading facilities, are very capital intensive and project economics are extremely sensitive to capital costs. Continued escalation in raw material and labour costs will have a material impact on supply costs and project economics.
- **Natural gas costs:** Both integrated mining and thermal in situ operations are intensive users of natural gas. Over the past several years, the price of natural gas has increased substantially. The future price of natural gas and the development of alternatives, including fuel substitutes and gasification, will have a material impact on supply costs and project economics.
- **Diluent availability:** With WCSB supply of the traditional blending agent, pentanes plus, flat to declining, and demand from bitumen producers increasing, prices for diluent are rising. There are pipeline proposals to import diluent into Alberta. The future cost of blend stock will affect project economics.
- **Technology:** In the past, technology has enabled step-wise reductions in supply costs. Technology currently under development such as mobile crushing equipment and "at-the-face" slurrying for mining projects, and solvent-aided production (SAP) and low-pressure SAGD for in-situ projects, have the potential to reduce operating costs significantly. In addition, improvements in upgrading costs are anticipated as new or modified upgrading technologies are employed.

CRUDE OIL SUPPLY

3.1 Introduction

Since the Board's 2004 report, activity in the oil sands has ramped up sharply. This has been primarily due to:

- sustained higher oil prices since 2004, which have resulted in increased cash flows and profitability for oil sands operators;
- an outlook for sustained high oil prices in the future; and,
- increased recognition that the oil sands represent a very large, economically attractive accumulation of oil in a politically stable country.

Companies have been aggressively accelerating plans for expansion of existing projects and initiating new projects. Many new players have been attracted to the oil sands, with several of the world's multi-national oil companies now represented, as well as several subsidiaries of foreign national oil companies.

Relatively wide light/heavy oil price differentials over the past several years have made the prospect of adding local upgrading capacity more attractive. As a result, most plans for large-scale mining and in situ projects now include consideration of upgrading. As well, one "merchant" or third-party upgrader has been approved and two more are in early planning stages.

These aggressive expansion plans are countered by a number of significant constraints, including a shortage of skilled labour, lack of adequate infrastructure, rapidly escalating construction costs and uncertainty regarding the scope and cost of managing environmental impacts.

3.2 Crude Bitumen Reserves

According to the Alberta Energy and Utilities Board (EUB), Alberta's oil sands areas contain an ultimately recoverable crude bitumen resource of 50 billion cubic metres (315 billion barrels), with remaining established reserves of almost 28 billion cubic metres (174 billion barrels) at year-end 2004[ii].

In Saskatchewan, exploration efforts to define unconventional oil resources are ongoing in two areas. The first involves crude bitumen deposits located in northwest Saskatchewan, across the border from the Firebag area in Alberta. The second involves oil shale deposits in the Pasquia Hills region of east-central Saskatchewan. Official estimates of the size of these resources are not yet available.

3.3 Expansion Plans

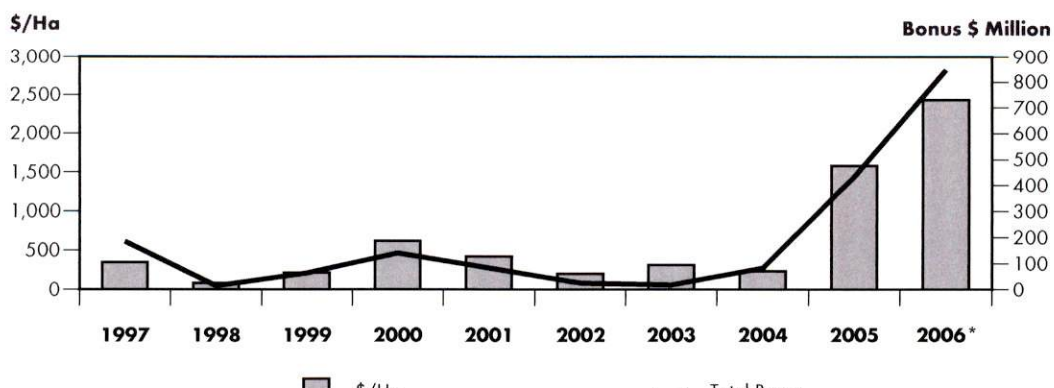
The fees paid to the Alberta government for the right to explore and develop oil sands leases provide a good indicator of the heightened interest in the oil sands over the last several years. Land sale "bonuses" reached record levels in 2005 and early 2006, with prices paid averaging $2,200 per hectare. In 2005, total bonuses reached $450 million, more than double any previous year (Figure 3.1).

Another indicator of the rising interest over the past two years is the plethora of announcements regarding new projects or expansion plans for existing projects. Major project plans include:

- Suncor Energy (Suncor) announced its Voyageur growth strategy, a multi-phased plan designed to increase the company's oil sands production capacity to a range of 79 500 m^3/d to 87 300 m^3/d (500 Mb/d to 550 Mb/d) by 2010 to 2012;
- EnCana Corporation (EnCana) will utilize SAGD technology to expand production from its leases to 79 500 m^3/d (500 Mb/d) by 2016;
- Canadian Natural Resources Limited (CNRL) announced additional phases to its Horizon Oil Sands mining project to expand production to 79 500 m^3/d (500 Mb/d) by 2018, plus plans to expand in situ production by 47 700 m^3/d (300 Mb/d);
- Imperial Oil Limited (Imperial) and Exxon Mobil Canada (ExxonMobil) filed a regulatory application for a three-phase 47 700 m^3/d (300 Mb/d) mining project at Kearl;
- Shell Canada Limited (Shell) announced expansion plans at both its Peace River and Jackpine Lake properties;
- Petro-Canada, partnered with UTS Energy Corporation (UTS) and Teck Cominco Ltd., received regulatory approval for the 16 000 m^3/d (100 Mb/d) Phase 1 of the Fort Hills mining project;
- Husky Energy (Husky) received regulatory approval for its Sunrise project, with capacity of 31 800 m^3/d (200 Mb/d) over four phases, and disclosed plans to expand its Lloydminster upgrader to 23 800 m^3/d (150 Mb/d) of synthetic crude oil (SCO) and diluent production capacity;

FIGURE 3.1

Oil Sands Land Sales



* January and February data only.

- BA Energy Inc. (BA) received approval for its three-phase 23 800 m^3/d (150 Mb/d) SCO production capacity Heartland Upgrader project, to be built in Strathcona County northeast of Edmonton, Alberta;
- North West Upgrading Inc. (North West) has disclosed plans for its North West Upgrader, a three-phase 31 800 m^3/d (200 Mb/d) merchant upgrader to be located in Sturgeon County, near Edmonton;
- Total E&P Canada has acquired Deer Creek Energy and its Joslyn oil sands operations and leases;
- Shell EP Americas, a subsidiary of Royal Dutch Shell Plc, recently purchased 10 properties in northern Alberta targeting bitumen deposits situated in carbonate formations and formed a new company, SURE Northern Energy Ltd., to develop its new holdings; and
- Chevron Corporation (Chevron) recently acquired five heavy oil leases in the Athabasca region and anticipates developing these leases using SAGD technology.

Examples of participation by foreign national oil companies include:

- SinoCanada Petroleum (SinoCanada), a subsidiary of China-based Sinopec Group, has partnered with Synenco Energy Inc. (Synenco) to develop the proposed Northern Lights project, an integrated mining, extraction and upgrading project, with the upgrader to be located in Sturgeon County near Edmonton;
- China National Offshore Oil Corporation (CNOOC) bought a 17 percent stake in MEG Energy Corporation (MEG), the developer of the Christina Lake project, which is designed to produce 4 000 m^3/d (25 Mb/d); and
- Enbridge Inc. (Enbridge) has entered into a memorandum of understanding with PetroChina International Company Limited (PetroChina) to cooperate on the development of the Gateway Pipeline and supply crude oil from Canada to China.

The number of major mining, upgrading and thermal in situ projects has grown to include some 46 existing and proposed projects, encompassing 135 individual project expansion phases in various stages of execution, from those announced to those already under construction. A list of these projects is presented in Appendix 4. More detail on Alberta's oil sands projects can be found at the Alberta Economic Development website at: http://www.alberta-canada.com/oandg/oilsands.cfm. A comprehensive list of projects can also be found at: http://www.strategywest.com.

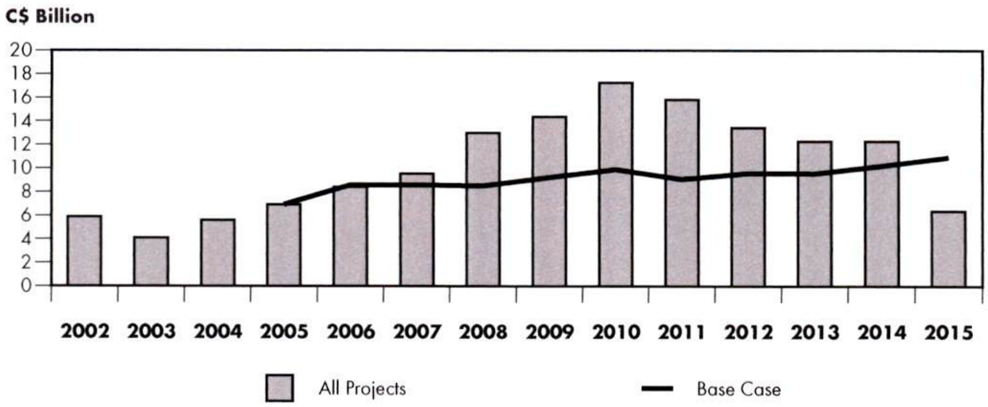
Primary, or non-thermal in situ production, is still an important component of the total oil sands picture, accounting for nearly 10 percent of total bitumen production in 2005. There are isolated regions within the oil sands areas, such as at Seal, near Peace River, and Brintnell and Pelican Lake in the Wabasca region, where primary production levels are growing significantly and where operators are reporting success with secondary recovery via waterflooding.

3.4 Capital Expenditures

Indicated total capital expenditures for oil sands projects have increased substantially since the 2004 report. Estimates of capital expenditures to construct all announced projects over the period 2006 to 2015 total C$(2005) 125 billion (Figure 3.2). This level of capital expenditure is roughly twice that indicated in the Board's previous report.

FIGURE 3.2

Estimated Capital Expenditures



There is a logjam of announced projects in the 2008 to 2012 period. It is expected that not all projects will proceed as originally scheduled; some will be delayed and some may be cancelled. Figure 3.2 also illustrates an adjusted capital spending profile, which is based on the Board's "Base Case" projection of oil sands production discussed in the following section. A discounting of about 35 percent below the "All Projects" case is indicated, with expenditures over the period 2006 to 2015 estimated to be about C$95billion.

3.5 Oil Sands Production

Crude bitumen is produced by mining and extraction, in situ thermal recovery and in situ non-thermal recovery. Currently, about 60 percent of crude bitumen is transformed by upgrading into various grades of SCO or upgraded products. Figure 3.3 illustrates the projected oil sands supply in terms of upgraded and non-upgraded bitumen. The supply projections indicate a relatively aggressive ramp-up in capacity that extends to 2015. In the present high oil price environment, lease owners are keen to realize the value associated with typically large resource holdings. In general, the companies involved are large Canadian companies or multi-national companies with significant capital and considerable experience in developing heavy oil resources, both in Canada and abroad. However, many smaller companies are also able to take advantage of favourable capital markets to initiate project plans.

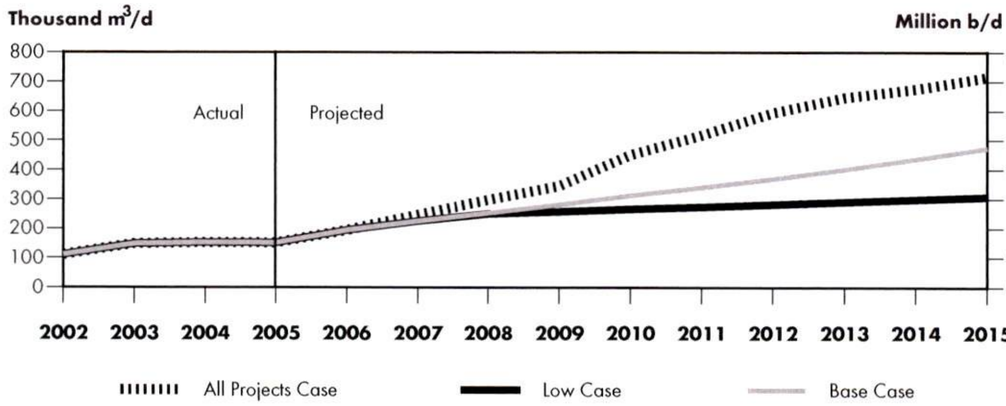
The All Projects case assumes that all projects publicly announced to date commence operation at their name-plate volume and start date. This would result in production of about 699 500 m^3/d (4.4 MMb/d) by 2015, which is considered to be beyond the limits of capacity growth that could be reasonably expected within that time period.

The lower bound or "Low Case" projection is shown to directionally illustrate what might happen if the economic viability of oil sands projects is compromised, perhaps by sharply lower prices. An outlook for sustained oil prices below US$35 per barrel would lead to marginal economics for many projects in the present business environment and would slow development. It is anticipated that production growth would decline to about four percent, or about half the growth rate of the "Base Case".

The development of the Base Case projections is based on a sustained high oil price and an economically attractive environment. Several companies have adopted a continuous construction philosophy; that is, to keep a workforce on hand dedicated to the construction of a series of company

FIGURE 3.3

Projected Oil Sands Production



projects or project expansions in succession. There is also a wealth of experience throughout the industry that bodes well for future development. While there may be constraints, such as labour shortages and lack of infrastructure, it is anticipated that the industry's ability to add capacity will gradually increase year-over-year.

A review of projects currently under construction and those in various stages of planning and execution reveals that there is a surplus of projects sponsored by experienced and credible proponents; the challenge becomes one of defining the limits of growth that can reasonably be expected. With the rapid escalation of construction and material costs over the last two years, and with industry's greater ability to finance large projects, defining a limit to growth based on capital expenditure seems a less appropriate approach.

Because of the long lead times associated with oil sands projects, the production outlook for the period 2006 to 2010 is already largely defined by projects currently under construction or substantially advanced in their project planning. On the assumption these projects will be built, a review of the resultant growth profile over the period 2000 to 2010 should provide a good indication of industry's ability to ramp up capacity.

TABLE 3.1

Capital Spending Requirement

Project Type	Capex per daily flowing barrel
CSS	\$20,000
SAGD	\$15,000
Mining & Extraction	\$20,000
Upgrading	\$32,000

Over the period 2006 to 2010, annual production additions will be in the order of 30 200 m^3/d (190 Mb/d). Beyond 2010, this rate of additions increases (plus one percent per year is assumed for the projection) and expands to 31 700 m^3/d (200 Mb/d) by 2015. Projects are assigned from the list of available projects and timelines adjusted to match this growth profile. The associated capital expenditure is in the order of C$8 billion per year over the course of the projection. This is based on estimates of the capital spending requirement, per unit of daily capacity, for each type of project as set out in Table 3.1.

In the Base Case projection, supply of upgraded and non-upgraded bitumen rises from about 175 000 m^3/d (1.1 MMb/d) in 2005 to 472 000 m^3/d (3.0 MMb/d) in 2015. Compared with the 2004 report, projections for upgraded bitumen are up 43 percent and are up 13 percent for non-upgraded bitumen. Non-thermal in situ production is up by five percent, as opposed to no growth in the last report.

3.5.1 Production by Type

Currently, about 60 percent of crude bitumen is upgraded into various grades of SCO or other upgraded products within the Fort McMurray and Edmonton regions. Note that there is generally some shrinkage of bitumen volumes through the upgrading process, depending on the type of process used. Overall, this loss is estimated to be about 11 percent.

There have been a number of recent announcements regarding new mining projects with associated upgraders and expansion of upgrading capacity at existing projects. As well, three third-party or merchant upgraders have been announced with one, the BA Heartland Upgrader, already under construction. The OPTI/Nexen Long Lake SAGD project is the first to feature the on-site upgrading of in situ production. These various projects have added a significant amount of potential upgrading capacity. Further discussion of upgrading projects can be found in *Chapter 4 - Markets.*

In the Base Case projection, the net bitumen volumes produced from mining operations, thermal in situ, and primary (non-thermal) in situ operations account for 52 percent, 44 percent and four percent, respectively, by 2015 (Figure 3.4). The bitumen feedstock for upgrading is sourced from both mining and in situ types of recovery operations. By 2015, upgraded crude oil (synthetic or SCO) production is projected to be 306 000 m^3/d (1.9 MMb/d), or about 65 percent of total oil sands production.

3.6 Western Canada Sedimentary Basin Crude Oil Supply

Figure 3.5 provides a projection of production of crude oil and equivalent in the WCSB to 2015. The oil sands components of this chart are based on the Base Case projections discussed earlier, while the conventional light oil, conventional heavy oil and condensate projections are based on the 2003 NEB Supply and Demand Report Techno-Vert scenario, and exhibit long-term decline trends. As a result of rapidly growing oil sands production, total WCSB production will rise from 365 000 m^3/d (2.4 MMb/d) in 2005 to 613 000 m^3/d (3.9 MMb/d) by 2015, an increase of 68 percent.

FIGURE 3.4

Oil Sands Production by Type – Base Case

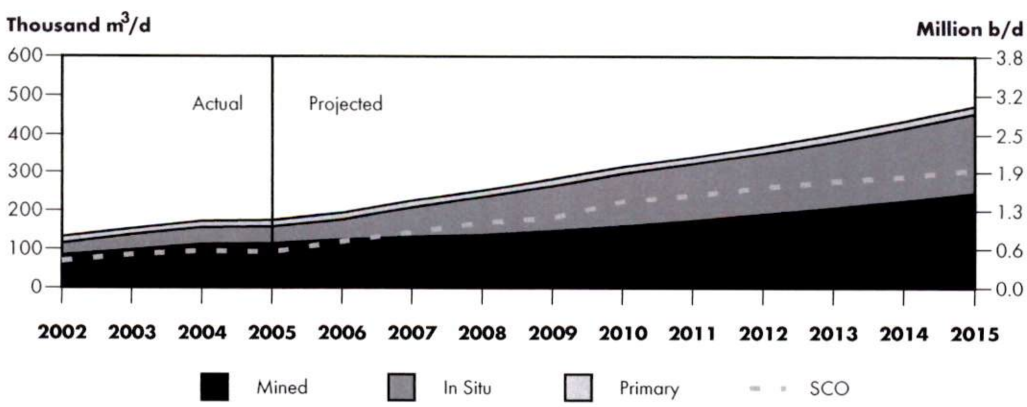
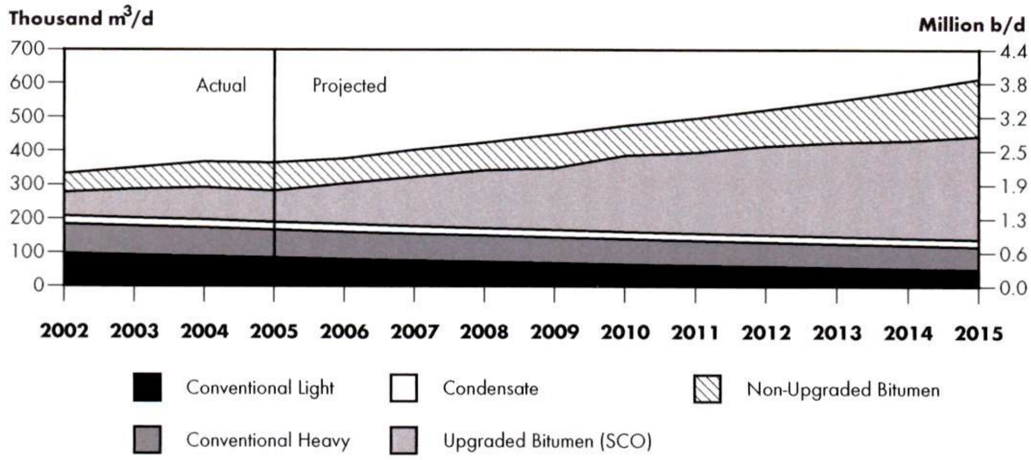


FIGURE 3.5

Projected Crude Oil Production - WCSB



3.6.1 Net Available Supply

Non-upgraded bitumen and heavy conventional crude oil need some degree of blending with a light hydrocarbon diluent to create a bitumen blend or heavy blend that is suitable for pipeline transportation. Gas condensate has been the traditional source of diluent for blending purposes, but increasing volumes of non-upgraded bitumen have outpaced available condensate supplies, putting upward pressure on prices and forcing producers to develop alternate strategies.

The projections of available supply take into account the diluent requirements for blending heavy oil and non-upgraded bitumen, recycled volumes of diluent, product losses during upgrading and volumes of condensate not available for blending. There are a number of potential solutions to deal with anticipated shortfalls of condensate for blending purposes, such as offshore imports, long-haul recycle by truck or rail, diluent-return pipelines from the U.S., specifically refined diluents, and blending with light crude oil or SCO. If the proposed Mackenzie Valley Gas Pipeline is built, another 2 850 m^3/d (18 Mb/d) of condensate could be available.

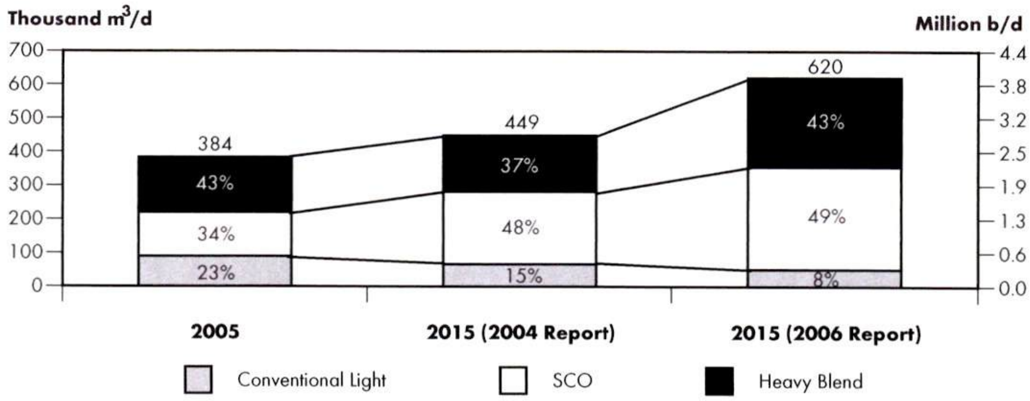
Figure 3.6 provides a view of the projected available supply by 2015, consistent with the Base Case projection. The relative volumes of conventional light crude oil, heavy blend and SCO are shown. The projections of available supply contained in this report total 620 000 m^3/d (3.9 MMb/d) in 2015, or about 38 percent higher than the 2004 report. The proportionate share of SCO increases slightly to 49 percent from 48 percent, while the share of blended heavy increases from 37 percent to 42 percent of total supply.

The volume of heavy blend indicated in the far right column, 260 000 m^3/d (1.6 MMb/d), would require approximately 40 000 m^3/d (250 Mb/d) of diluent beyond what is anticipated to be available from traditional domestic sources. The calculated demand for condensate is reduced if it is assumed that SCO or light crude are used as a diluent or additional upgrading capacity is built.

Further discussion of the issues facing oil sands producers regarding the types of crude oil produced, the degree and type of blending and other market choices can be found in *Chapter 4 - Markets.*

FIGURE 3.6

Net Available Supply - WCSB



3.7 Natural Gas Requirement

Oil sands projects are very energy intensive operations and require significant amounts of natural gas. The total oil sands related natural gas demand is determined by reviewing the projected production levels and gas usage factors for each of the major oil sands projects.

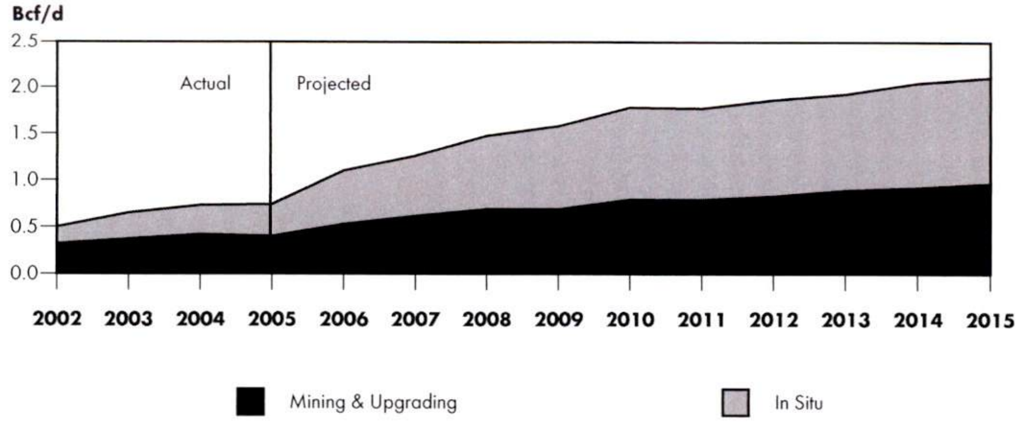
Figure 3.7 illustrates the total purchased gas requirement for the Base Case for in situ and for mining and upgrading projects. These values include purchased gas required to generate electricity on site. It does not include any requirements for stand-alone or merchant upgraders. By 2015, the total gas requirement is projected to be 2.1 Bcf/d.

Figure 3.8 illustrates the amount of purchased gas used per unit of bitumen recovery, or gas intensity, required for both oil sands mining and in situ projects, and includes gas used in on site cogeneration facilities to produce electricity for plant operations.

For in situ projects, the steam-to-oil ratio (SOR) is a measure of how efficiently energy is used in recovery of bitumen from the oil sands. An SOR of 2.5 equates to a gas intensity of 1.1 Mcf/b.

FIGURE 3.7

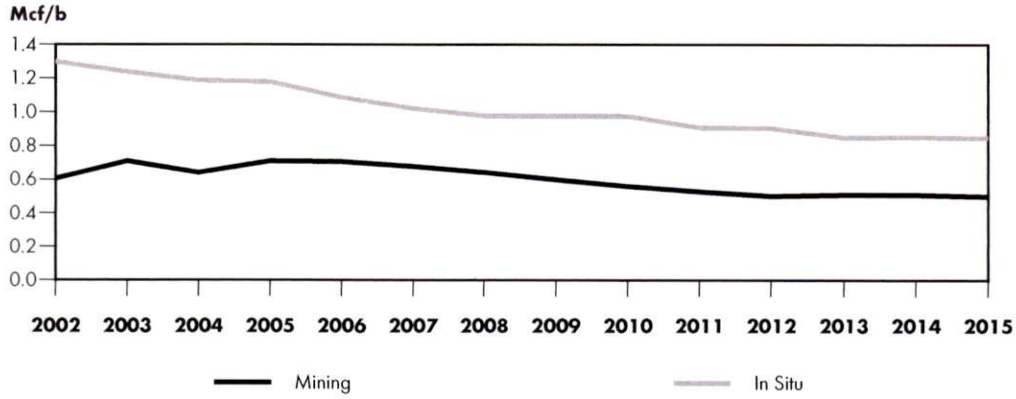
Total Purchased Gas Requirement



Source: EUB and NEB

FIGURE 3.8

Average Gas Intensity – Oil Sands Projects



A review of the performance of major steam-stimulation projects in operation reveals that very few have achieved that target, but this is expected to improve as operators make efficiency improvements. This applies especially to SAGD, still a relatively new technology. The Long Lake SAGD project, currently being constructed by Nexen and OPTI Canada, will be introducing a technology new to the oil sands—using bitumen gasification to create a synthetic gas (syngas) for process and fuel use, and thus reducing the need for external gas supply.

Another alternative to natural gas use for fuel is currently being pilot tested. Multiphase Superfine Atomized Residue (MSAR) features the clean and complete combustion of bitumen or refinery residue.

If these alternatives prove successful, it will lead to implementation in other projects, but probably not before the 2010–2012 timeframe. Efficiency improvements in SAGD and CSS operations are also anticipated through technological innovation, such as low-pressure SAGD or solvent aided production. However, going forward, as existing projects expand and new projects are initiated, it is likely that operators will be facing declining quality of bitumen reservoirs, with a resultant increase in energy required. The combination of these factors, including gas substitution, yields an overall improvement in average gas intensity to 0.9 Mcf/b by 2015.

For integrated mining projects, the natural gas intensity increases as the upgraders move to producing higher quality SCO, which requires more hydrogen. Some general improvements in energy efficiency are anticipated, and after about 2010–2012, it is predicted that newer technologies such as bitumen or coke gasification will be implemented, leading to significant improvement in average gas intensity. Some projects will use only natural gas, some will use gasification and others will use a combination of these. By 2015, the overall gas intensity for both in situ and mining/upgrading combined equates to an average of 0.7 Mcf/d.

3.8 Outlook: Issues and Uncertainties

The crude oil supply projections defined as the Base Case in this chapter are based on a "business as usual" outlook with oil and gas prices generally at or above the US$50 per barrel (WTI) and US$7.50 per MMBtu range, respectively. While the outlook is for a fairly quick ramp-up in oil sands production, there are issues that could impede the pace of capacity development. These include:

- **Crude oil prices:** It is believed that sustained lower oil prices below about US$35 per barrel would slow oil sands production growth and result in a material difference in projected volumes.
- **Natural gas usage:** High natural gas prices have encouraged oil sands operators to use gas more efficiently and to look for alternative fuels. The extent to which bitumen gasification or other alternatives to natural gas use prove successful and are adopted in additional operations will materially affect the purchased gas requirement in the oil sands.
- **Infrastructure:** The many projects proposed for the Fort McMurray area will put pressure on available infrastructure, such as housing, hospitals, schools and highways to transport the required materials, heavy equipment and modularized components. These issues could lead to delays in construction schedules.

Markets

4.1 Introduction

High oil prices coupled with robust global oil demand growth in the past several years have been key drivers in the expansion of the oil sands. In this regard, producers will be faced with a number of hurdles including choosing pipeline proposals to deliver these growing supplies to new and existing markets. In addition to market options, producers are assessing what they will be producing in the future. Will it be synthetic-bitumen blend (synbit), condensate-bitumen blend (dilbit), bitumen or synthetic crude oil (SCO)? As well, which markets can process those crude types and provide the best netback? These factors will determine which markets hold the greatest potential for oil sands producers.

The light/heavy differential is expected to remain wide for the next several years until sufficient upgrading capacity has been added. In addition to the large growth forecasted in oil sands bitumen production, international heavy crude oil output is also rising and, therefore, Canadian heavy crude oil may continue to be heavily discounted to ensure marketability. This is currently being exacerbated by increased crude oil production in the Rocky Mountain area and North Dakota.

The core market (i.e., Canada, upper PADD II, PADD IV and Washington State shown in Figure 5.1) can take increased volumes of crude oil, and pipeline expansions have taken place to facilitate this increase. In addition, expansion and extension into markets such as Wood River, Illinois; Cushing, Oklahoma; Washington State; the U.S. Gulf Coast; California and perhaps Asia are being considered through the various pipeline proposals.

Refiners in PADD II and PADD IV will continue to look to Canadian producers for their crude oil requirements, while producers will look for more options to market their supplies. This chapter reviews the Canadian and export markets for crude oil and examines the potential for market expansion to 2015.

4.2 Domestic Markets

Canada is a small refining market with nineteen refineries and a capacity of 320 000 m^3/d (2.0 MMb/d) (Table 4.1). In 2005, the refineries in Canada operated above 90 percent of capacity, primarily to meet the needs of the domestic market. Due to the age and lack of complexity of Canadian refineries, the domestic market does not hold tremendous growth opportunities for oil sands producers.

The refineries located in eastern Canada, including Ontario, import crude oil for their refining needs and process some eastern and western Canadian volumes. In 2005, less than 50 percent of Ontario's crude oil requirements were sourced from western Canada and of the total only 22 percent was SCO

TABLE 4.1

Receipts of Western Canadian Crude Oil – 2005 (m^3/d)

Market	Refining Capacity	Refining Runs	Conventional Light[1]	Conventional Heavy	Synthetic	Blended Bitumen	Total
W. Canada	100 529	91 526	37 232	18 082	31 868	3 787	90 969
E.Canada - Ontario	74 300	64 184	13 419	1 891	7 030	7 024	29 364
E. Canada - all	219 050	204 032	13 419	1 891	7 030	7 024	29 364
Total Canada	319 579	295 558	50 651	19 972	38 898	10 812	120 333

1 Includes condensates and pentanes plus.

FIGURE 4.1

Ontario Receipts of Western Canadian Crude Oil – 2005

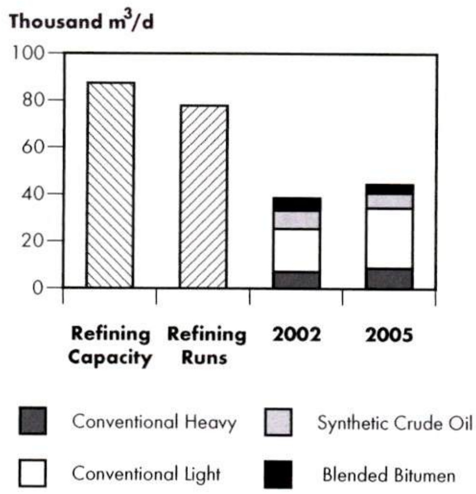
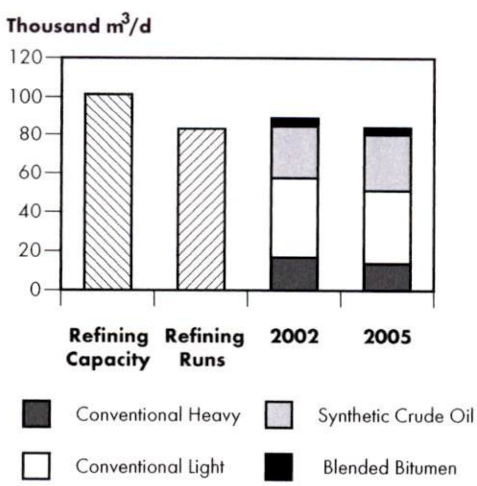


FIGURE 4.2

Western Canada Receipts of Western Canadian Crude Oil – 2005



and blended bitumen (Figure 4.1). Although there are few growth opportunities for western Canadian crude oil in Ontario and Québec, it has been suggested by some industry stakeholders that Enbridge could re-reverse Line 9. This would allow SCO to penetrate refineries located in Québec. It is expected that Imperial Oil Limited (Imperial), Suncor (Sunoco) and Shell Canada Limited (Shell) will look for opportunities to integrate their oil sands production with their downstream facilities located in Ontario.

The refineries located in western Canada process exclusively western Canadian production, including oil sands derived crude oil (Figure 4.2). In 2005, almost 40 percent of crude oil refined was SCO and blended bitumen. It is expected that the integrated companies such as Husky, Imperial, Petro-Canada and Shell who own refineries and have oil sands production will look for opportunities to integrate their upstream production with their downstream operations.

In 2003, Petro-Canada announced that it would convert its Edmonton refinery to refine exclusively oil sands feedstock. By 2008, the refinery will process 100 percent or 21 400 m^3/d (135 Mb/d) of oil sands feedstock. This will displace about 13 500 m^3/d (85 Mb/d) of conventional crude oil that Petro-Canada currently processes in its refinery. It will obtain these supplies through an agreement with Suncor who will process bitumen from Petro-Canada's MacKay River in situ facility into sour synthetic crude oil.

Recently, Husky announced that it is considering doubling the capacity of its upgrader at Lloydminster from its current 12 700 m^3/d (80 Mb/d) to 23 800 m^3/d (150 Mb/d) by 2009.

It would enable Husky to capture full value from increased production at its Cold Lake and Athabasca oil sands projects.

There are a number of proposals to upgrade bitumen, particularly with respect to mining projects with associated upgraders. As well, there have been three merchant upgrader proposals announced. The BA Heartland Upgrader project with a capital cost estimate of $900 million began site clearing and preparation for the first phase in September 2005. It will be located in Strathcona County, near Edmonton. Development will take place in three phases, with the start-up of the first phase scheduled for early 2008. The first phase will process 12 200 m^3/d (77 Mb/d) of bitumen blend. Once the project is fully expanded it will have a total processing capacity of 39 700 m^3/d (250 Mb/d).

North West Upgrading Inc. (North West) is planning to construct a heavy oil upgrader in Sturgeon County, near Edmonton. The first phase pending project approval in 2007 is expected to come on stream in early 2010 and will upgrade 8 000 m^3/d (50 Mb/d) of bitumen to SCO. Up to three additional phases are planned. The total processing capacity of the project when fully operational in 2015 would be 36 700 m^3/d (231 Mb/d) and would produce 28 600 m^3/d (180 Mb/d) of SCO and 6 700 m^3/d (42 Mb/d) of diluent.

Peace River Oil Upgrading Inc. has proposed a small scale upgrading facility to be located near McLennan, Alberta. Its proposal calls for an initial phase of 3 740 m^3/d (20 Mb/d) of bitumen processing capacity.

In addition to upgraders, there is a publicly announced proposal for a new refinery complex in Alberta. A C$7 to $8.5 billion integrated upgrader, petrochemical and electrical generation complex near Edmonton is being studied by Alberta Energy and 19 stakeholders. The refinery would initially be 47 700 m^3/d (300 Mb/d) and expandable to 71 500 m^3/d (450 Mb/d) and would include a petrochemical facility and a 500 megawatt coal-fired power generation plant. It could be completed as early as 2011. Some emerging concerns are that such a mega project could jeopardize other announced upgrading projects and expansions already underway.

4.3 Export Markets

In the Board's consultations with industry it was clear that refiners and producers have differing views on market expansion and extension. Not surprisingly, and consistent with the opinions expressed in the Board's previous report, many believe that in the short-term the industry should maximize its volumes in its traditional markets of PADD II, PADD IV and Washington State, with further market expansions and extensions later in the decade into California, PADD III and the Far East.

4.3.1 United States

The United States with a refining capacity of almost 2.6 million m^3/d (16 MMb/d) is Canada's largest market for crude oil exports and continues to possess the greatest potential for increased penetration of oil sands derived crude oil (Table 4.2). In 2005, exports declined 10 percent largely as a result of declining light conventional production and the outages at the three integrated oil sands facilities. Last year, Canada supplied almost 10 percent of U.S. crude oil refining needs, making it one of the largest crude oil exporters to that country. Continuing concerns about geopolitical events and security of supply are expected to be key drivers, as the U.S. looks to Canada as a secure source of supply.

TABLE 4.2

Export Receipts of Western Canadian Crude Oil – 2005 (m³/d)

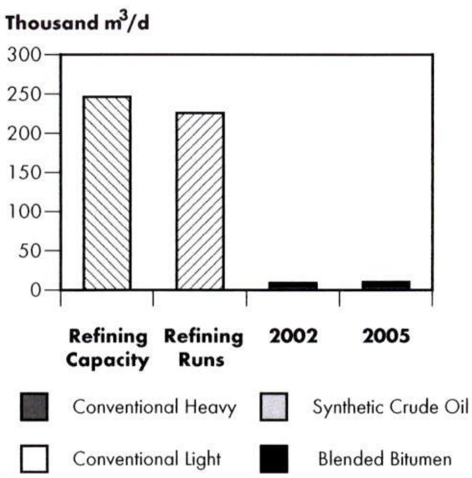
	Refining Capacity	Refining Runs	Conventional Light[1]	Conventional Heavy	Light Synthetic	Heavy Synthetic	Blended Bitumen	Total
PADD I	246 524	225 810	2 312	4 838	2 121	0	829	10 099
PADD II	564 740	525 714	11 345	88 737	16 849	15 730	30 416	163 078
PADD III	1 263 979	1 128 254	149	67	0	197	1 127	1 539
PADD IV	89 794	89 524	8 195	23 106	8 471	446	2 775	42 993
PADD V	403 317	459 841	8 744	750	2 308	1 631	972	14 406
Total U.S.	2 561 248	2 457 143	30 744	117 498	29 749	18 004	36 120	232 115
Other			0	0	0	315	70	385
Asia			0	0	0	0	0	0

1 Includes condensates and pentanes plus.

Source: NEB

FIGURE 4.3

PADD I Receipts of Western Canadian Crude Oil – 2005



4.3.1.1 PADD I

PADD I has a refining capacity of 246 500 m³/d (1.6 MMb/d) and is not viewed as a large growth market for oil sands crude oil (Figure 4.3). Although not illustrated in Table 4.2, many of the refineries located in the U.S. northeast import crude oil from offshore eastern Canada.

The United refinery located in Warren, Pennsylvania is the exception and processes western Canadian crude oil. In 2005, it processed 21 percent SCO and eight percent blended bitumen. It is expected that United Refining will process an increasingly heavy crude slate as it moves ahead with the construction of a 2 200 m³/d (14 Mb/d) coker. It is slated to be in service by 2009. As well, with the addition of the coker, refinery capacity is expected to increase by 790 m³/d (5 Mb/d) to 11 000 m³/d (70 Mb/d). Post-2009, United Refining will process 100 percent heavy crude oil.

United Refining receives western Canadian crude oil from Enbridge's Line 10 at Westover, Ontario, which has a capacity of 11 100 m³/d (70 Mb/d). With future volumes expected to increase, there may be a requirement to expand that line.

4.3.1.2 PADD II

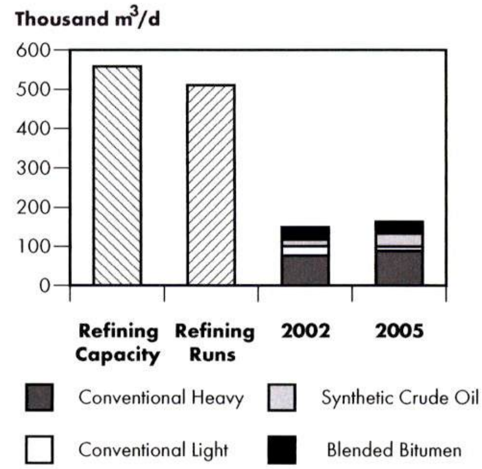
PADD II is the largest market for western Canadian crude oil with a refining capacity of 567 000 m³/d (3.6 MMb/d) (Figure 4.4). In 2005, 70 percent of western Canada's crude oil exports were delivered to PADD II. Twenty percent of those volumes were SCO and 19 percent were blended bitumen. PADD II continues to hold tremendous potential for western Canadian producers as deliveries represent only 31 percent of that region's total crude runs. As well, the core markets of northern

PADD II, including St. Paul and Chicago, are heavy and medium sour markets, which are a good fit for oil sands producers.

With the reversal of the Spearhead pipeline in March 2006, producers have the ability to deliver crude into southern PADD II. Deliveries into Cushing, Oklahoma open up several options to other locations that typically did not have access to Canadian crude oil in the past. By using existing underutilized pipelines and/or building new pipelines in southern PADD II, extension to other markets is possible. It is expected that this could result in better prices for western Canadian crude oil by extending the core market. Industry sees southern PADD II including Wood River, Cushing and Ponca City as good markets for synthetic and blended bitumen.

FIGURE 4.4

PADD II Receipts of Western Canadian Crude Oil – 2005



Western Canadian crude oil deliveries into Cushing have resulted in talks with the New York Mercantile Exchange (NYMEX) to create a futures contract for Western Canadian Select (WCS) at the Cushing hub. Introduced in 2004, WCS is a blend of 19 crude oil streams amounting to about 39 700 m^3/d (250 Mb/d) with an average of 19–21 API. The goal is to deliver 39 700 m^3/d to 79 500 m^3/d (250 Mb/d to 500 Mb/d) into Cushing, where Canadian crude oil could compete with foreign sour grades or U.S. Gulf Coast sour that would be delivered against it. A NYMEX contract is likely a year away as crude volumes need to increase.

Northern PADD II is well positioned to run increased volumes of bitumen blends and SCO because of the complexity of the refineries. Recently, heavy oil producers have been faced with an especially wide light/heavy differential. This reflects, in part, rising output from the oil sands and increased conventional production from North Dakota, Wyoming and Montana. This is further exacerbated by increased competition for limited pipeline space to deliver crude into the U.S. Midwest and limited facilities to process the heavier oil sands crude oil. This could be alleviated in the future as a number of companies identified an interest in constructing a coker or developing refinery expansion plans that would allow them to process heavier crude oil to take advantage of the wide light/heavy differential and the expected increase in oil sands production. Some U.S. companies, for example Marathon Oil, that have a number of refineries in PADD II, have publicly stated that they would like a stake in the oil sands to have an "integrated" arrangement between their refineries and production. The announced refinery projects are listed in Table 4.3.

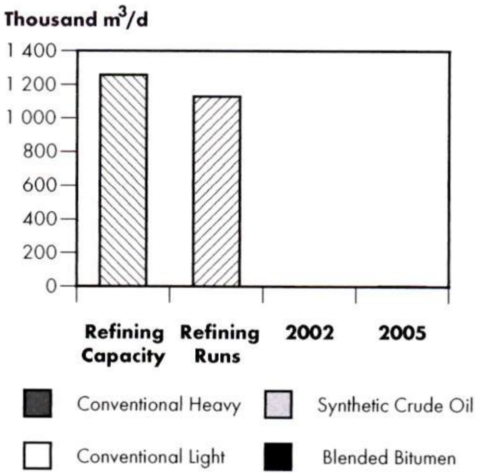
In May 2006, Enbridge announced its Southern Lights project, which includes a return diluent line from the Chicago area, as well as additional light crude oil capacity out of western Canada and a new light sour crude oil pipeline between Cromer, Manitoba and Clearbrook, Minnesota. For more information see *Chapter 5 - Major Crude Oil Pipelines.*

4.3.1.3 PADD III

PADD III has a refining capacity of 1 265 000 m^3/d (8.0 MMb/d) and approximately 475 000 m^3/d (3.0 MMb/d) is heavy crude refining capacity (Figure 4.5). At one time, this market was not seen as one that held potential for western Canadian crude oil producers. However, recent interest has been generated with the reversal of the Mobil pipeline that will transport western Canadian crude

FIGURE 4.5

PADD III Receipts of Western Canadian Crude Oil – 2005



oil from Patoka, Illinois to Corsicana, Texas. In the first quarter 2006, deliveries on the Mobil line are expected to be 7 900 m^3/d (50 Mb/d) versus its 10 300 m^3/d (65 Mb/d) capacity. In April, the line was operating at capacity. During our consultations, producers were of the view that 63 600 m^3/d (400 Mb/d) of heavy crude could possibly move into this market in the longer-term, possibly later this decade or post 2010.

PADD III is particularly attractive given the size and complexity of the refineries. Western Canadian crude oil, particularly bitumen blends, could compete in this market with imports from Venezuela and Mexico, particularly since it has recently been heavily discounted in the U.S. Midwest. Increased demand in this market would likely result in higher netbacks for Canadian heavy producers for two reasons: first, it would take volumes away from the Midwest market; and second, it could move the pricing parity point of heavy sour further south where Canadian heavy crudes would compete against other heavy oil imports.

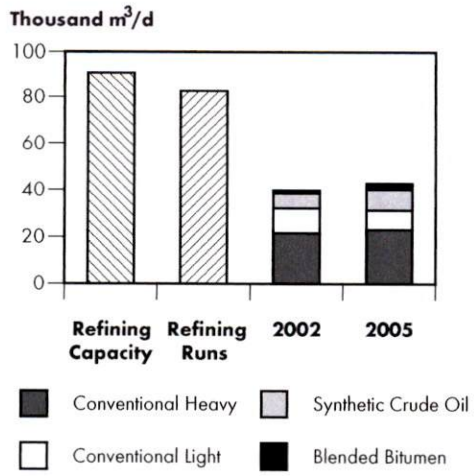
To ship the increased oil sands production to the U.S. Gulf Coast, Altex Energy Ltd. (Altex) announced in October 2005, the Altex Pipeline system, which would be a new direct-route, stand-alone oil pipeline that would deliver crude oil from northern Alberta to the U.S. Gulf Coast. This is discussed further in *Chapter 5 – Pipelines.*

4.3.1.4 PADD IV

PADD IV, with a refining capacity of 90 000 m^3/d (567 Mb/d), has traditionally been a good market for western Canadian producers (Figure 4.6). Recently, however, the pricing dynamics in this market have changed. Refiners in this area have always been price takers because they have few supply alternatives. With the very high crude oil price, producers in PADD IV have been drilling at a record pace. As well, to extract additional oil, they are using CO_2 floods and horizontal drilling. This has resulted in an increase in crude production and pressure from domestic producers in PADD IV to process this production in local refineries. Subsequently, refiners in PADD IV are taking less western Canadian crude supplies in order to run the readily available and heavily discounted Wyoming sweet and sour crudes. The large discount is in reaction to aggressive Canadian crude pricing, shortage of refinery capacity and the lack of pipeline capacity to move the crude oil to other markets. Producers in this region will continue to be aggressive provided that crude oil prices remain above US$50 per barrel.

FIGURE 4.6

PADD IV Receipts of Western Canadian Crude Oil – 2005



In March 2006, Holly Corp. announced the sale of its Montana Refining Company, a partnership, to a subsidiary of Connacher Oil and Gas Limited. Montana Refining, located in Great Falls, Montana, operates a 1 300 m^3/d (8 Mb/d) refinery. It is anticipated that the refinery will provide Connacher with an outlet for the SAGD production from its Great Divide oil sands project, as well as, provide it with some protection against wide light/heavy differentials.

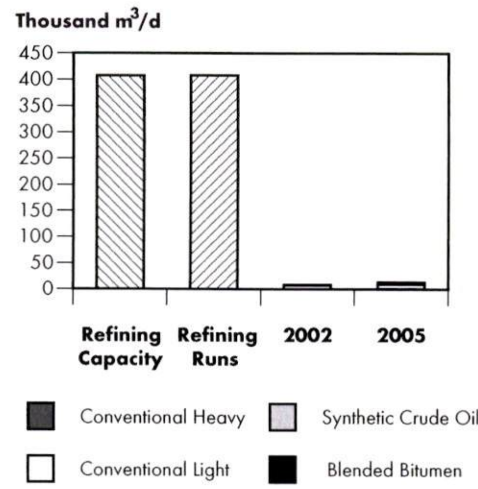
Due to its size and the complexity of the refineries, PADD IV will continue to be a marginal growth market for western Canadian crude oil, particularly SCO and blended bitumen.

4.3.1.5 PADD V

PADD V has a refining capacity of 403 000 m^3/d (2.5 MMb/d) and is a growth market for western Canadian crude oil. Consultations with industry indicated a strong consensus that this market, particularly Washington State, is eager for increased volumes of western Canadian crude oil. This is evident by the number of cokers and refinery conversions being contemplated in that market.

FIGURE 4.7

PADD V Receipts of Western Canadian Crude Oil – 2005



Refineries located in Puget Sound, such as ConocoPhillips, Tesoro and British Petroleum (BP) all have plans to run a heavier slate, which would include oil sands crude oil. Currently, Washington State processes only 11 percent of its crude oil requirements from Canada, and this is largely due to the availability of Alaskan North Slope (ANS) crude oil and capacity constraints on Kinder Morgan's Terasen Pipeline (Trans Mountain) Inc. (TPTM). A likely scenario in PADD V is that with the continuing decline in ANS crude oil production, western Canadian crude oil will push into the Puget Sound market, and ANS production will move farther south into California. The latest forecast of ANS is that production in 2006 is down almost seven percent from last year. The decline rate is higher this year as a result of the natural decline of maturing fields coupled with unanticipated field maintenance problems and unexpected delays in some development projects. Between 2008 and 2015, the production decline is expected to be 1.2 percent per year.

The California market could be an excellent market for heavier Canadian grades, but this would likely not occur until the end of the decade and would also depend on how the above scenario regarding the disposition of ANS production unfolds. This market could give Canadian producers another option and would also help to narrow the light/heavy differential by moving volumes away from northern PADD II.

4.3.2 Other Export Markets

In recent years, China's demand for oil has had a tremendous impact on global oil markets. It is now the world's second largest consumer of oil and the third largest importer. This is a result of strong growth in all sectors, but particularly transportation. In 2004, Chinese oil demand rose by 159 000 m^3/d (1.0 MMb/d), and this represents a 15 percent increase year-on-year. The reasons for this increase in oil demand include a strong GDP growth of around 10 percent; a strong industrial output estimated to be around 15 percent; an electricity shortage that supported domestic

TABLE 4.3

Announced Refinery Expansions

Company	Location	Increase Crude	Coker or Expansion	Completion Date
Holly Corp.	Woods Cross, UT	10 Mb/d	Expansion	4Q2006
Coffeyville	Coffeyville, KS	15 Mb/d	Expansion	1Q2006
Tesoro	Anacortes, WA	15 Mb/d	Coker	2Q2007
Cenex	Laurel, MT	No increase	Coker (15 Mb/d)	1Q2008
Sunoco	Toledo, OH	50 Mb/d	Expansion	2008
Flint Hills Resources	St. Paul, MN	50 Mb/d	Expansion	1Q2008
Frontier Oil	El Dorado, KS	11 Mb/d	Expansion	2008
Frontier Oil	Cheyenne, WY	N/A	Coker	2008
Sinclair	Sinclair, WY	13 Mb/d	Coker	2008
United Refining	Warren, PA	5 Mb/d	Coker	2009
ConocoPhillips	Wood River, IL	55 Mb/d	Coker	2012-2015
ConocoPhillips	Borger, TX	25 Mb/d	Coker	2012-2015
ConocoPhillips	Ferndale, WA	25 Mb/d	Coker	2012-2015
ConocoPhillips	Billings, MO	N/A	Expansion	2012-2015

N/A - Not Available

oil use through increased utility use of fuel oil and off-grid/stand-alone generator use; increased petrochemical capacity; and strong growth in vehicle sales.

China will increasingly rely on oil imports because of its continued robust oil demand growth. Currently, about half of China's oil needs are met through imports of 556 400 m^3/d (3.5 MMb/d) and some analysts forecast this to rise to 1 589 800 m^3/d (10 MMb/d) by 2025. With the increased development of the oil sands, and the need for new markets, Canada would be in a position to export oil to China. Some analysts project that the light/heavy differential could narrow to the benefit of all Canadian producers, by moving crude oil to China. Enbridge's proposed Gateway pipeline which would deliver crude oil to the west coast of British Columbia, is trying to tap, amongst other markets, the Far East market, including China. Enbridge and state-controlled PetroChina have signed a memorandum of understanding to ship up to 31 800 m^3/d (200 Mb/d) on the Gateway pipeline, and it has been suggested that PetroChina could purchase a stake in the line. Industry is generally of the view, however, that filling up existing markets in the U.S. in the short-term makes sense and that the Far East has potential in the longer-term.

While much of the attention has been focused on China, a senior researcher at the Institute of Energy Economics in Japan estimated that Canada could export as much as 131 300 m^3/d (825 Mb/d) of sweet synthetic to Japan by 2015. Historically, Japanese refiners imported some bitumen, but found that it did not yield the lighter products they desired. It is likely that if Japanese refiners choose to import SCO it would have to be less expensive than the sour grades that they currently import from the Middle East.

Two state-run companies from India, Oil and Natural Gas Corp. and Indian Oil Corp. Ltd., have expressed an interest in spending one billion dollars on early-stage oil sands projects.

In addition, spot shipments of Canadian crude oil have been delivered to other markets. Most recently, there have been shipments to Italy. In the second quarter 2006, the Italian refiner, ENI, will begin construction on a 3 200 m^3/d (20 Mb/d) "Super Hydrocracker". It will have the ability to process residuals from heavy crude oil such as Russian Urals or Canadian heavy into high quality diesel. It should come on stream between 2007 and 2009 at ENI's largest mainland refinery at Sannazzaro, Italy. ENI has installed a smaller unit at its Taranto refinery that has tested Canadian oil sands crude oil.

4.4 Outlook: Issues and Uncertainties

It is expected that high oil prices, coupled with robust global oil demand, will continue to drive oil sands expansion. In this regard, producers will be faced with a number of hurdles including choosing among proposed pipelines to deliver the growing supplies to new and existing markets.

To penetrate new markets, there will likely be periods when substantial price discounts are required, particularly as new oil sands production comes on stream in large volumes and the market adjusts to the incremental supply.

Based on industry consultations and the Board's internal analysis, potential scenarios for market expansion for growing oil sands production could unfold in the following way:

Step One: Fill up existing markets, including Washington State, PADD II and PADD IV and some additional volumes in Canada.

Step Two: Further penetrate southern PADD II and PADD III and refinery expansions and conversions in northern PADD II, PADD IV and PADD V.

Southern PADD II could take an additional 6 400 m^3/d (40 Mb/d) with an expansion of the Spearhead pipeline and the U.S. Gulf Coast could take up to 63 600 m^3/d (400 Mb/d) of western Canadian crude if there were pipeline capacity to deliver those volumes. It is estimated that in the next 10 years, PADD II could take an additional 79 500 m^3/d (500 Mb/d). As well, in the near term, PADDs IV and V could take an incremental 6 400 and 7 900 m^3/d (40 and 50 Mb/d), respectively.

These increases to U.S. markets could take place in unison with expansions to offshore markets, as discussed in Step Three.

Step Three: The industry would have to branch out and develop new markets. In this connection, a new pipeline or a major pipeline expansion to the west coast would be required to deliver crude oil to California and the Far East.

With the expected increase in SCO production, there is also the opportunity of processing increased volumes in refineries in Ontario and reversing Enbridge Line 9 to supply Montreal refineries.

In addition to potential market opportunities, there are a number of issues and challenges through to 2015. They include:

- **Crude oil prices:** Very high crude oil prices have drawn a significant amount of attention to the oil sands, particularly from China, Japan, India and the U.S. Softening demand and falling prices could slow investment and hinder market development.
- **Bitumen blend versus synthetic:** The need for diluent to transport bitumen, and the uncertainty surrounding which market is best for producers continues to impact the pipeline selection process. There have been many announcements of upgrader projects which begs the question, when the North American refining industry appears to be moving toward processing heavier crudes, why is the industry moving to producing more light

synthetic crude oil? The uncertainty concerning the type of crude oil the industry will produce is causing delays in the decision-making process, leading to the likelihood that there will be extended periods of apportionment on the major pipelines. In other words, who should do the upgrading—the producer or the refiner?

- **Partnerships:** Those companies that are not integrated (i.e. upstream assets and downstream facilities) need to either enter into a supply contract or be in an ownership position in the corresponding asset. With the increased volumes that are expected to come on stream later in the decade, these arrangements are critical to market development to avoid large discounts.
- **Pipeline expansion:** Currently the major export pipelines are at or near capacity and at times in apportionment. The industry needs to decide which markets hold the greatest potential and move forward on pipeline expansions or new pipelines.
- **Light/heavy differential:** The light/heavy differential is expected to remain wide for the next several years until upgraders are built either upstream or at the refinery. Furthermore, growing international heavy crude oil production could have an affect on Canadian heavy crude oil prices.

Major Crude Oil Pipelines

5.1 Introduction

As discussed in *Chapter 3: Crude Oil Supply*, rapid expansion of the oil sands is expected to occur within the next decade while *Chapter 4: Markets* highlighted that markets will need to be determined. Pipeline infrastructure will need to be addressed to accommodate the increase in supply and market requirements. This chapter focuses on the major export pipelines and feeder pipelines, including announced expansions of existing pipelines and new greenfield projects.

In some instances, oil pipelines are embarking on a new era of contractual arrangements. Historically, oil pipelines, with the exception of Express, operated under common carriage. With the intense competition between announced pipeline proposals and refiners' need for security of supply, some pipeline companies are moving toward "take-or-pay" agreements with shippers to ensure there is support for these initiatives.

The number of proposed pipeline expansions and new proposals are causing delays within the industry's decision-making process. This coupled with environmental, Aboriginal and landowner concerns could delay pipeline development.

5.2 Crude Oil Pipelines

Canada delivers crude oil to the export market through three major Canadian trunklines (Figure 5.1):

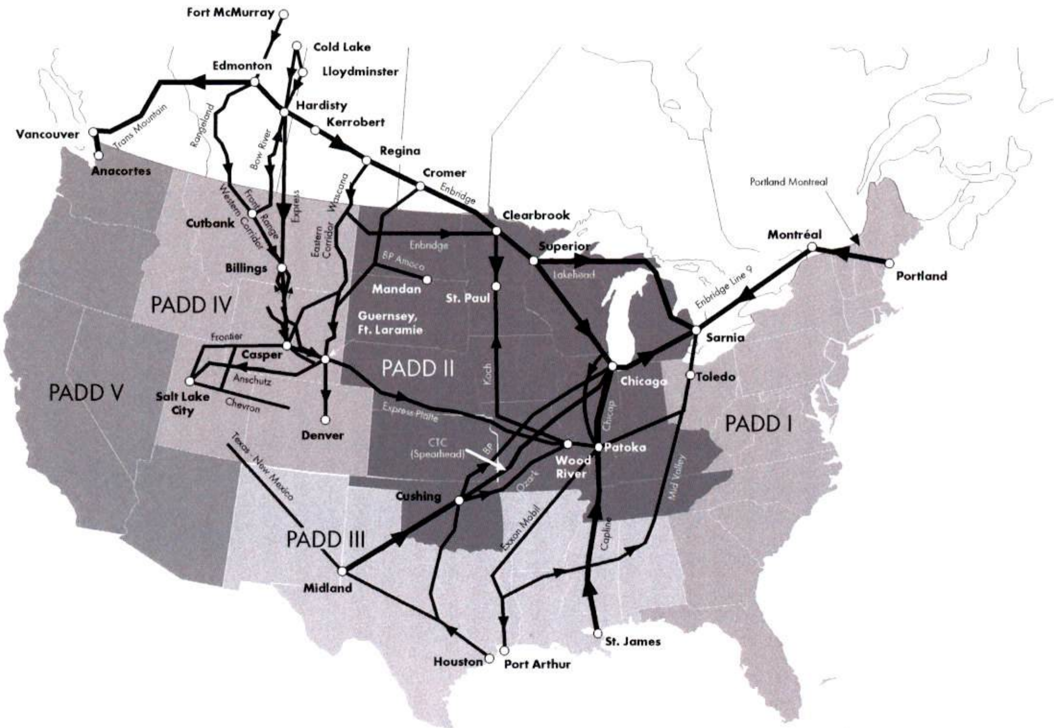
- Enbridge's mainline originates at Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba. At the U.S. border, it connects with the Lakehead system to deliver crude to the U.S. Midwest and north to Sarnia, Ontario.
- Kinder Morgan's Trans Mountain (formerly Terasen) pipeline originates at Edmonton, Alberta and extends west across British Columbia for delivery to Burnaby, British Columbia, the Westridge Dock and Washington State.
- Kinder Morgan's Express pipeline originates at Hardisty, Alberta and delivers crude to locations in PADD IV and connects to the Platte system in Casper, Wyoming for delivery to southern PADD II.

Enbridge Pipeline

The Enbridge system in Canada and the Lakehead system in the U.S. represent the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The system delivers approximately 333 000 m^3/d (2.1 MMb/d) of crude oil. In the third quarter 2005, to facilitate growth in heavy crude oil, Enbridge completed the Terrace Phase III expansion project. By converting Line 2 from heavy to light service, and Line 3

FIGURE 5.1

Major Canadian and U.S. Crude Oil Pipelines and Markets



from light to heavy service, it increased its capacity to move heavy crude by 39 000 m³/d (245 Mb/d). In doing so, Enbridge reduced light capacity by 18 400 m³/d (116 Mb/d). Recently, Enbridge has been operating at or near capacity and in some instances certain lines have been under apportionment.

To accommodate growing oil sands production and the need for additional markets, Enbridge received approval for a non-routine adjustment for tolls to reverse two pipelines in the U.S. The Spearhead and Mobil 20-inch reversal projects will provide access to southern PADD II and the U.S. Gulf Coast, respectively. It is estimated that Spearhead will deliver 19 900 m³/d (125 Mb/d) versus signed commitments of 9 500 m³/d (60 Mb/d). Enbridge has indicated that it would respond to shipper requirements on Spearhead in the near-term to increase capacity to 30 200 m³/d (190 Mb/d), and in the longer-term, it has proposed a looping program with the first phase providing a further increase of 15 900 m³/d (100 Mb/d). The Mobil line made its first crude oil deliveries to the U.S. Gulf Coast in the first quarter 2006.

Kinder Morgan Express Pipeline

In April 2005, Express completed its expansion of 17 500 m³/d (110 Mb/d) to bring its capacity to 44 800 m³/d (282 Mb/d). Recently, the Express system has been operating at capacity and, at times, there has been apportionment on the Platte system. Kinder Morgan is assessing expansion plans to deal with capacity issues on the Platte system.

Kinder Morgan Canada Terasen Pipelines (Trans Mountain) Inc.

Trans Mountain pipeline transports crude oil and petroleum products from Edmonton to Vancouver, Washington State and offshore via the Westridge Dock. In November 2005, Kinder Morgan purchased Terasen Inc., making it a major oil pipeline player in Canada. Its current capacity is

35 700 m^3/d (225 Mb/d) and it has been operating at or near capacity for several years and, on many occasions, has been under apportionment. Kinder Morgan has carried forward Terasen's plans to expand the scale and the scope of the Trans Mountain system. The TMX project announced in 2004 comprises three phases, including an initial Anchor Loop expansion, followed by a southern or northern option. On 10 November 2005, part of TMX1, which included a capacity increase of 5 600 m^3/d (35 Mb/d), received approval from the NEB. This will increase the capacity from 35 700 m^3/d (225 Mb/d) to 41 300 m^3/d (260 Mb/d). On 17 February 2006, Kinder Morgan filed an application with the Board for the Anchor Loop project. The project involves twinning a 158 kilometre section of the existing line between Hinton, Alberta to a location near Rearguard, British Columbia. If approved, the Anchor Loop would add 6 400 m^3/d (40 Mb/d) of incremental capacity, bringing the Trans Mountain system to 47 700 m^3/d (300 Mb/d) by the end of 2008.

It is expected that Kinder Morgan could file the next phase of the TMX project in the first quarter 2007. TMX2 would involve the looping of the Trans Mountain pipeline from Edmonton to the Anchor Loop expansion (Hinton) and from the anchor loop (Rearguard) increasing capacity by 15 900 m^3/d (100 Mb/d) to 63 600 m^3/d (400 Mb/d). The in-service date is estimated to be January 2010.

The final phase of the project, TMX3, involves the completion of a south leg and/or a north leg. For both legs, capacity out of Edmonton would be 175 000 m^3/d (1.1 MMb/d). The south leg from Kamloops to Vancouver would add 47 600 m^3/d (300 Mb/d) and have a total capacity of 111 000 m^3/d (700 Mb/d). The north leg from Rearguard to Kitimat would have a capacity of 63 600 m^3/d (400 Mb/d). The in-service date for both legs is proposed for 2011.

Enbridge Southern Access

Enbridge has proposed the Southern Access program to expand and extend service on the mainline system. It would provide incremental capacity to Chicago, Wood River and Patoka and access to Cushing. In May 2006, Enbridge filed an application with the Board for Phase 1 of its Southern Access program to increase capacity by 19 000 m^3/d (120 Mb/d) with a scheduled in-service date of Fall 2006. The expansion would consist of debottlenecking and pump additions on Lines 3 and 4 from Edmonton and Hardisty, respectively. In the U.S., industry has decided to increase the pipe diameter from Superior to Flanagan/Chicago to 42 inches from the original proposal of 30 inches to reduce power costs and allow for future expansion. The initial capacity on the U.S. system would be 63 600 m^3/d (400 Mb/d) by early 2010 and expandable to 127 000 m^3/d (800 Mb/d). Enbridge continues to look at extending Southern Access to either or both Wood River or Patoka. Patoka offers more storage and better access to other pipelines and refineries.

Enbridge is assessing several other pipeline options from the Patoka area. They include expanding existing lines, such as Spearhead as well as reversing lines which could include, Seaway pipeline (Cushing to Houston); Ozark pipeline (Cushing to Wood River); and Mid Valley (Longview to Toledo).

Enbridge Southern Lights

The industry has been looking at alternatives to increase its diluent supply in Alberta. One initiative that Enbridge has been studying is the potential for diluent return service from the Midwest. Supply sources from this area could come from refineries, the U.S. Gulf Coast/Midcontinent, Rocky Mountain volumes and imports. In addition, the Southern Lights project would include an expansion of light crude oil capacity on the Enbridge mainline.

The Southern Lights Pipeline (diluent line) would include the reversal of Line 13 from Clearbrook, Minnesota to Edmonton, Alberta and new pipeline construction between Clearbrook and Manhattan, Illinois (near Chicago). The pipeline would have a total capacity of 28 600 m^3/d (180 Mb/d).

The expansion of light crude oil capacity on the Enbridge mainline would occur in parallel with the diluent return line. It would include an expansion of Line 2 between Edmonton and Superior, Wisconsin to 70 300 m^3/d (440 Mb/d) and construction of a light sour line from Cromer to Clearbrook of 29 500 m^3/d (185 Mb/d). This would eliminate the need for breakout storage tanks at Cromer.

Enbridge plans to synergize this project with the Southern Access Program. The project if approved could be in-service by the first quarter of 2009.

TransCanada Keystone Pipeline

In February 2005, TransCanada announced its Keystone Pipeline project. This is a 2 800 kilometre, 69 200 m^3/d (435 Mb/d) crude oil pipeline that would extend from Hardisty, Alberta to markets in the U.S. Midwest. TransCanada intends to convert one gas line in Canada to oil service and construct a new pipeline from the Canada/United States border to Wood River/Patoka, Illinois. On 31 January 2006, TransCanada announced that it had received long-term contractual commitments of 54 000 m^3/d (340 Mb/d). ConocoPhillips Pipe Line Company has signed a memorandum of understanding with TransCanada to acquire up to a 50 percent participating interest in the project, and ConocoPhillips has committed to ship crude oil on the pipeline. The proposal includes an expansion to 93 800 m^3/d (590 Mb/d) with the addition of pump stations.

Enbridge Alberta Clipper Pipeline

In February 2006, Enbridge unveiled its newest pipeline initiative, the Alberta Clipper. The proposal is for a 36-inch contract carrier crude oil pipeline that would have an initial capacity of 63 600 m^3/d (400 Mb/d), expandable to 127 200 m^3/d (800 Mb/d). The Alberta Clipper would run alongside Enbridge's mainline right-of-way from Hardisty, Alberta to Superior, Wisconsin and connect into existing infrastructure delivering crude oil into the Chicago area. The proposed in-service date would be 2010 or 2011.

Altex

Altex Energy is proposing to construct an oil pipeline from northeastern Alberta to the U.S. Gulf Coast by the fourth quarter 2010. It would have a minimum capacity of 39 700 m^3/d (250 Mb/d) with significant expansion potential. Altex has said that utilizing proprietary pipeline technology it could eliminate the need for condensate thereby greatly reducing the cost of transporting bitumen.

Enbridge Gateway Pipeline

Enbridge's proposed Gateway Pipeline would consist of two elements, a 63 600 m^3/d (400 Mb/d) crude oil pipeline and a 23 800 m^3/d (150 Mb/d) return condensate line. The crude oil line would originate in Edmonton for delivery to Kitimat and the condensate line would operate in the reverse direction, providing transportation for imported condensate. The crude oil and condensate lines could have ultimate capacities of 87 400 m^3/d and 39 800 m^3/d (550 Mb/d and 250 Mb/d), respectively. Both lines have a target in-service date of first half 2010.

Following the successful open seasons of both pipelines, Enbridge announced plans to increase the diameter of the condensate line to 20 inches and the crude oil line to 36 inches. Non-binding interest in excess of 63 600 m³/d (400 Mb/d) was received for the crude oil line. Enbridge has signed a memorandum of understanding with PetroChina to supply 31 800 m³/d (200 Mb/d) of crude oil to China. There have also been discussions that PetroChina may purchase a stake in the line.

Pembina Spirit Pipeline

In October 2005, Pembina Pipeline Income Fund (Pembina) and Terasen Pipelines Inc. announced a proposal to import 15 900 m³/d (100 Mb/d) of condensate into Kitimat and deliver it by pipeline to Edmonton. The proposal would utilize existing infrastructure and some new pipeline construction would be required. The proposed in-service date would be April 2009.

In February 2006, Pembina announced that it would pursue the Spirit Pipeline on its own, without the support of Kinder Morgan Canada (formerly Terasen Pipelines Inc.). Pembina announced in April 2006 that it has entered into a development support agreement with a group of shippers.

Conclusion

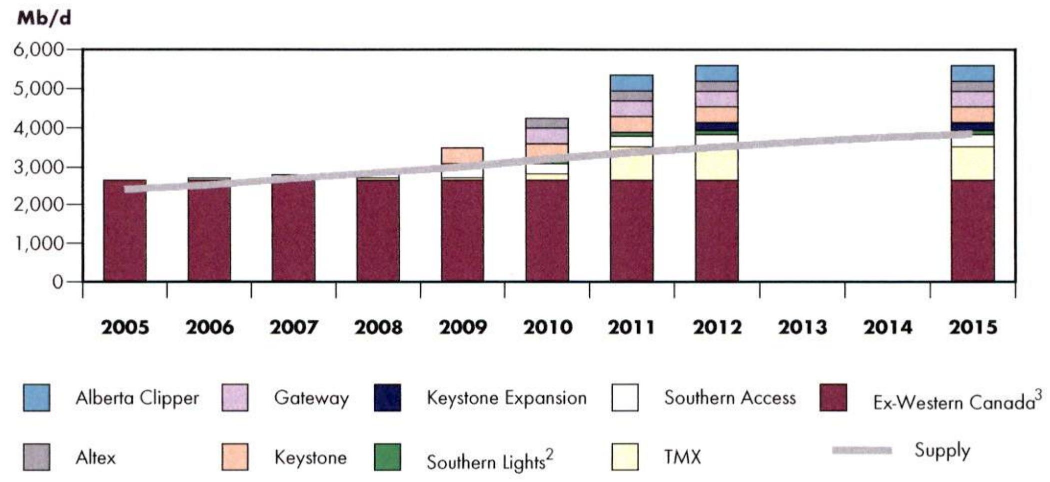
Figure 5.2 illustrates the production forecast for the Western Canada Sedimentary Basin (WCSB), the proposed pipeline projects, and the proponents estimated completion date. Based on the number of pipeline projects being proposed and the production that is forecast to come out of the WCSB, it is apparent that not all projects will move forward. However, as mentioned in *Chapter 4 – Markets* and as evident in the chart, pipeline capacity is expected to be tight starting in 2007.

5.3 Feeder Pipelines

In addition to the proposed expansions and greenfield projects announced by the major export lines, feeder pipelines within Alberta are expanding to transport growing oil sands volumes to the major hubs of Edmonton and Hardisty. These proposed expansions are described below.

FIGURE 5.2

NEB Supply Forecast and Proposed Pipeline Projects and Timing[1]



1 The pipeline projects are listed alphabetically.

2 Edmonton to Cromer.

3 Total pipeline capacity out of the WCSB.

Enbridge Waupisoo Oil Sands Pipeline

Enbridge announced in September 2005 that it will proceed with its proposed Waupisoo oil pipeline. The line would originate at Enbridge's Cheecham terminal on the Athabasca system and terminate adjacent to Enbridge's mainline Edmonton terminal. Initial capacity would be 55 600 m^3/d (350 Mb/d) with a maximum capacity of 95 400 m^3/d (600 Mb/d). It would also include a 16-inch return diluent line from Edmonton to the Fort McMurray area. If approved, the expected in-service date would be mid-2008.

The Waupisoo pipeline would be operated by Enbridge and shippers include, ConocoPhillips Canada, Petro-Canada, Suncor Energy and Total E&P Canada Ltd.

Kinder Morgan Corridor Pipeline

In August 2005, Terasen Pipelines (now Kinder Morgan Canada) announced plans to expand the Corridor pipeline. Currently, the Corridor pipeline system includes a 24-inch bitumen blend line and a 12-inch diluent return line. The proposed expansion includes building a new 42-inch bitumen line and upgrading pump stations along the existing system from the Muskeg River Mine north of Fort McMurray to Shell's Scotford upgrader near Edmonton. It would increase dilbit capacity to 79 500 m^3/d (500 Mb/d) by 2009 and would be designed to further support expansions in the future. It is estimated that future expansions of this system could lead to a capacity of 174 900 m^3/d (1.1 MMb/d).

Pembina Horizon Pipeline

In August 2005, Pembina Pipeline Corporation (Pembina) announced that it would twin the existing Alberta Oil Sands Pipeline resulting in two parallel, commercially segregated lines. One would be dedicated to Canadian Natural Resources (CNRL) and would transport synthetic crude oil from CNRL's Horizon project. The new line would connect with the existing infrastructure. It could be in-service by July 2008 and have a capacity of 39 700 m^3/d (250 Mb/d).

Pembina Cheecham Pipeline

In January 2006, Pembina announced that it had reached an agreement with ConocoPhillips Surmont Partnership, Total E&P Canada Ltd., Nexen Inc. and OPTI Long Lake L.P. for the construction of the Cheecham lateral pipeline. Pembina has entered into transportation agreements with shippers for up to 21 600 m^3/d (136 Mb/d). Construction is underway and the line is expected to be in-service by November 2006. It will transport synthetic crude oil for delivery to a terminal facility located near Cheecham, Alberta.

5.4 Outlook: Issues and Uncertainties

It is clear that increasing western Canadian production, driven largely by the oil sands has resulted in several proposed pipeline expansions or greenfield pipeline projects. The industry has some challenging times ahead with the increase in production and the resulting lack of capacity on the major export pipelines. The pace of pipeline expansion will largely depend on market conditions and the necessary regulatory approvals. In this regard, pipelines may be looking to shippers for financial support in the form of take-or-pay agreements.

It is expected that, if high prices continue and the market remains strong, apportionment on export pipelines will be an issue. In the short-term, the industry will add smaller incremental capacity expansions in an attempt to alleviate some of these capacity issues. Table 5.1 illustrates current expansion proposals that are either before the Board, have been publicly announced or are being considered by industry.

The next decade will be a critical period in terms of pipeline development. There are a number of issues and uncertainties that will impact the pace of expansion to 2015 including:

- **Crude oil prices:** See Chapters 3 and 4.
- **Bitumen blend, bitumen or synthetic:** Pipelines will need to be developed based on the type of oil sands crude oil that is produced and required by the market.
- **Cost of projects:** With the cost of labour and materials rising to unprecedented levels, project costs are rising at alarming rates. It is estimated that the costs of some pipeline projects have risen 25 percent since they have been announced.
- **Type of carriage:** Historically, oil pipelines have generally been common carriers, but there may be a desire by the project proponents to seek take-or-pay commitments.

TABLE 5.1

Announced and Potential Expansions by Canadian Pipelines

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TMPL)		75		PADD V
(Phase One TMX1)	Filed July 2005	35	April 2007	Offshore/Far East
(Phase Two TMX1)	Filed February 2006	40	Nov 2008	
Southern Option		700		PADD V
(TMPL TMX2)	01Q2007	100	Jan 2010	Offshore/Far East
(TMPL TMX3)	N/A	300	2011	
Northern Option (TMX)	N/A	400	2011	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	June 2006	400/150	Mid 2010	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights				
Southern Lights (diluent)		180		Alberta
Line 2 Expansion (oil)	N/A		2009	
Edmonton to Cromer		103		PADD II
Cromer to Clearbrook		33		PADD II
Clearbrook to Superior		33		PADD II
New sour line Cromer to Clearbrook		185		PADD II
TCPL (Keystone)	June 2006	400	2009	Southern PADD II/ PADD III
Alberta Clipper	N/A	400	2010/11	Southern PADD II
Altex Energy	N/A	250	4Q2010	PADD III
Enbridge (Southern Access)		315		Midwest/Southern PADD II
Phase I	May 2006	120	Oct 2006 and Feb 2007	
Phase II	N/A	148	2008/09	
Phase III	N/A	47	N/A	

N/A - Not Available

ENVIRONMENT AND SOCIO-ECONOMIC

6.1 Introduction

The economic potential of Canada's oil sands is undisputed, but the fast pace and large scale of its development has considerable environmental and social impacts. This chapter provides an update on the major challenges oil sands operators must confront, including: water conservation, greenhouse gas (GHG) emissions, land disturbance and waste management. From a socio-economic perspective, one major issue of concern is an overwhelming demand on a limited population of skilled labourers. Regions associated with oil sands development enjoy several economic benefits but these benefits are accompanied by costs to the social well-being of the communities.

A variety of regional multi-stakeholder groups have been established to address the socio-economic and environmental impacts related to oil sands development. Table 6.1 shows a representation of these major groups. Many subcommittees have also been formed to address issues under their jurisdictions. These groups include industry, government and local community partnerships that work to create policies and programs for the best management of the resource.

6.2 Environment

The concern around the management of environmental impacts related to developing the oil sands has reached new highs. In March 2006, the Parkland Institute released a report calling for a moratorium on oil sands development for five years, citing the need for Canadians to discuss and understand all the implications.

TABLE 6.1

Multi-Stakeholder Summary

Stakeholder	Focus
Wood Buffalo Environmental Association (WBEA)	• Air quality monitoring in the Wood Buffalo Region • Ecological and health effects monitoring
Cumulative Environmental Management Association (CEMA)	• Addresses cumulative effects of regional development in northern Alberta
Canadian Oilsands Network for Research and Development (CONRAD)	• Research and development in responsible environmental activities and emission reduction opportunities for mining and in situ projects
Athabasca Regional Issues Working Group (RIWG)	• Provide a proactive process that promotes the responsible, sustainable development of resources within the Regional Municipality of Wood Buffalo for the benefit of all stakeholders

6.2.1 Water Use and Conservation

Both mining and in situ operations use large volumes of water for extracting bitumen from the oil sands. Between 2 to 4.5 barrels of water[iii] are withdrawn, primarily from the Athabasca River, to produce each barrel of synthetic crude oil (SCO) in a mining operation. Currently, approved oil sands mining projects are licensed to divert 370 million cubic metres (2.3 billion barrels) of freshwater per year from the Athabasca River[iv]. Planned oil sands mines would push the cumulative withdrawal to 529 million cubic metres (3.3 billion barrels) per year[v]. Despite some recycling, almost all of the water withdrawn for oil sands operations ends up in tailings ponds.

Stakeholders agree that the Athabasca River does not have sufficient flows to support the needs of all planned oil sands mining operations. Adequate river flows are necessary to ensure the ecological sustainability of the Athabasca River. In winter, river flows are naturally lower[vi] with low rates of precipitation, and therefore, water withdrawal during this period is of particular concern.

In January 2006, Alberta Environment (AENV) issued *An Interim Framework: Instream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River* to address this issue. This document describes certain actions to be taken under various flow conditions. Under conditions where there could be potential short-term impacts on the ecosystem, project owners are asked to target their diversion rate to less than 10 percent of available flow. Recent and new licenses may include conditions with mandatory incremental reductions. In cases where flows are so low that withdrawal would have expected impacts on the aquatic ecosystem, water use reductions and the use of water storage would be mandatory.

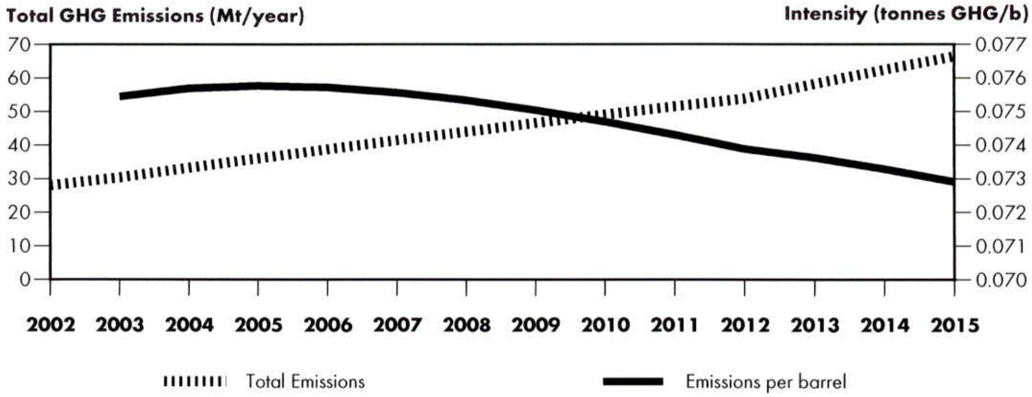
Oil sands mining operations have direct impacts on groundwater levels. Once the mine pit is excavated, it is essential to reduce groundwater levels in the area to prevent flooding of the pit. Withdrawal of groundwater from large areas of the landscape can lower the groundwater level in adjacent areas, which can result in reduced groundwater flows to peatlands, wetlands and other surface waterbodies.

About 82 percent[vii] of Alberta's remaining established oil sands reserves can only be accessed using in situ extraction technologies, and there is also a growing demand for freshwater for these projects. The demand for fresh water for in situ oil sands projects is projected to more than double between 2004 and 2015 from 5 million (31.5 million barrels) to 13 million cubic metres (82 million barrels) per year[viii]. In SAGD operations, 90 to 95 percent of the water used for steam to recover bitumen is reused, but for every cubic metre (6.3 barrels) of bitumen produced, about 0.2 cubic metres (1.3 barrels) of additional groundwater must be used[ix]. SAGD projects minimize the use of freshwater aquifers by using some freshwater mixed with saline groundwater. However, treating saline groundwater for the steam generators produces large volumes of solid waste. The disposal of this waste to landfills is another long-term concern because it could impact nearby soil and groundwater. This waste has a high concentration of acids, hydrocarbon residues, trace metals and other contaminants.

AENV is currently developing a new Water Conservation and Allocation Policy to reduce or eliminate the use of freshwater for in situ projects. Water allocation licenses will be issued for a two-year period with subsequent licenses issued for a five-year term, if the renewal is allowed. This is a reduction from the previous 10-year renewal period. License holders must apply for renewal under section 59 of the *Water Act*. AENV will approach the holders of permanent licenses to undertake a voluntary review of their licence.

FIGURE 6.1

Projected GHG Emission from Oil Sands to 2015



Source: Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush*

6.2.2 Air Emissions

While there remains a controversy over our ability to manage global climate impacts of greenhouse gas (GHG) emissions, many Canadians are concerned about GHG emissions. The production of bitumen and SCO emits higher GHG emissions than the production of conventional crude oil and has been identified as the largest contributor to GHG emissions growth in Canada.

Although significant progress has been made toward decreasing the intensity of GHG emissions produced by oil sands operators, additional production offsets these gains and total emissions are expected to rise. Figure 6.1 shows projected emissions, with total emissions estimated to be 67 megatonnes (Mt) per year by 2015 under Pembina Institute's second best scenario[x].

Carbon Dioxide

Innovative technology applied to increasing energy production has the potential to both reduce GHG emissions and create an economic opportunity. Research is being conducted to determine the feasibility of CO_2 capture and storage in Canada. According to the Alberta Geological Survey, the cumulative capacity of oil and gas reservoirs located in western Canada with an estimated CO_2 sequestration capacity greater than 1.0 Mt each is 3.2 gigatonnes CO_2 for gas reservoirs and 560 Mt for oil reservoirs[xi].

Carbon dioxide flooding in mature oil reservoirs for enhanced oil recovery (EOR) could increase production from mature Canadian oil reserves by between 8 and 25 percent, which means increasing potential recovery by between 0.5 and 1.4 billion cubic metres (3 and 9 billion barrels) of oil[xii]. At current oil prices, there is renewed interest in EOR projects but the economics are still marginal. Carbon dioxide injection for enhancing coal bed methane (CBM) recovery has also generated much interest but is currently much less economic than for EOR.

The oil sands projects are a major source of CO_2, but a dedicated CO_2 pipeline from Fort McMurray to the large light oil or CBM pools in central Alberta will be needed to encourage the capture, storage and use of large volumes of CO_2. A number of provincial and federal government incentives are in place to promote the development of CO_2 capture and storage, but the uncertainty of policy regarding long-term storage is an obstacle.

6.2.3 Land Disturbance and Reclamation

The Athabasca oil sands deposit is situated wholly within Canada's boreal forest. Individual mine sizes range from 150 to 200 square kilometers (58 to 77 square miles). The proposed future reclaimed landscape will be significantly different—with 10 percent less wetlands, more lakes, and no peatlands. There are currently divergent views regarding the ultimate the success of reclamation methods. The in situ process requires no excavation and less surface area for operation but is associated with fragmentation of the forest from the construction of new roads in the area, seismic lines and exploration well sites. As well, there is still some debate about whether the tailings ponds can become biologically productive ecosystems.

6.2.4 Sulphur By-product

Elemental sulphur is a major by-product of the oil sands. There have been notable efforts focused on the management of sulphur. The stockpiling of sulphur is a physical problem. By 2015, sulphur recovery could generate as much as five million tonnes of sulphur per year. To address this issue, China and India have been identified as potential markets since sulphur can be used to make fertilizer. Shell Canada has made investments to market Canadian sulphur as a replacement for the process of burning pyrite to extract sulphur. Since 1996, 40 of China's 600 fertilizer plants have been converted to use Canadian sulphur, as opposed to burning pyrite to extract sulphur, thereby releasing 250,000 fewer tonnes of CO_2 to the atmosphere each year[xiii]. Sulphur is also currently used in road asphalt and potentially in concrete or other construction materials.

6.3 Socio-Economic

The Athabasca deposit is the largest of the three oil sands deposits in northern Alberta and has undergone the most intensive oil sands development. Development in the Cold Lake and Peace River regions has been less extensive to date; however, this is starting to change. These regions will likely face socio-economic impacts similar to the Athabasca region in the future. It will require a concerted effort from all of the stakeholders to effectively address socio-economic concerns as the oil sands enter into a period of unprecedented growth.

Industry, government and local organizations are working to improve the social well-being of Aboriginal and non-Aboriginal communities in the region. These efforts must continue in order to keep pace with the increasing demands that will be placed on the existing social infrastructure. This should be supplemented with careful planning to ensure that no irreparable damage is done to people or the environment and that natural resources are developed in a responsible manner taking into account the needs of future generations.

6.3.1 Socio-Economic Setting

The 2005 Municipal Census results indicate that the Regional Municipality of Wood Buffalo[xiv] has a population of 73,176. This figure represents an increase of 6,071 residents or nine percent since the municipal census in 2004. The Sustainability Community Indicators Summary Report indicated that the population of Fort McMurray and the Regional Municipality of Wood Buffalo has a higher growth rate, a higher net migration rate, a higher proportion of males, and is generally younger than the selected comparator communities/regions of Alberta. This steady population growth has the potential to exacerbate socio-economic impacts.

According to NEB estimates, $41 billion has already been invested in Canada's oil sands, $7 billion is projected to be spent on construction in 2006, and another $85 billion worth of projects are forecasted for completion by 2015. Presently, oil companies and developers are engaged in or have proposed 46 oil sands related projects with 135 project expansion phases. This magnitude of growth and expansion of the oil sands is not possible without a corresponding increase in the number of workers.

Labour

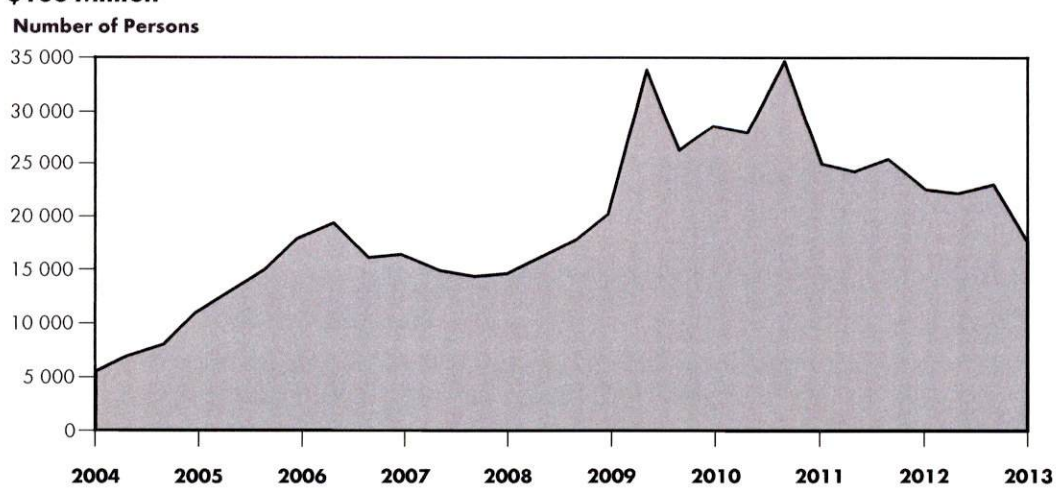
There is currently a limited supply of skilled workers in Alberta, and this tight labour market is expected to continue in the near future. The Construction Owners Association of Alberta states that labour supply and demand forecasts show increased construction activity in Alberta, especially in the oil sands, which will cause severe shortages of construction labour in the years ahead[xv]. Figure 6.2 illustrates the expected increase in the number of construction personnel that will be required for Alberta industrial projects with a planned capital expenditure greater than $100 million. Major industrial projects in Alberta will be competing for labour, and this competition has the potential to drive up construction costs and pull workers from other parts of Canada.

A labour shortage occurs when the demand for workers exceeds the supply of those qualified, available and willing to do the job at existing market conditions, including prevailing wages and locations. The challenge for the oil sands sector is not only one of finding the right skills—process operators, heavy equipment operators, mechanics and plant maintenance personnel—but also attracting these people to the Wood Buffalo region[xvi].

To address the current pressure on labour supply from several industries in Alberta, the Government of Alberta released a preliminary strategy in January 2006, *Building and Educating Tomorrow's Workforce: A Framework to enhance Alberta's People Capacity*. This 10-year strategy is currently in the consultation phase but outlines various proposed actions to address Alberta's labour force challenges. The strategic framework is built around four themes—inform (education, career, workplace and labour market information), attract (immigrants and inter-provincial migrants), develop (education and training investment) and retain (community and work attractiveness)[xvii]. Addressing the labour force shortages faced by the oil sands industries is a priority for the Government of Alberta, and as a result, the

FIGURE 6.2

Construction Personnel Required for Alberta Industrial Projects Costing Over $100 Million



Source: Construction Owners Association of Alberta (COAA)

10-year strategy includes an Oil Sands Industry Sub-Strategy. The Alberta Government has also signed an agreement with the federal government that will allow for the targeted entry of temporary foreign workers to meet the urgent skilled labour needs of oil sands employers for key projects in Fort McMurray[xviii].

6.3.2 Positive Socio-Economic Impacts

There are numerous positive socio-economic impacts on the communities and regions associated with oil sands development, including employment, economic benefits, economic stability, government revenue, and investment in research and development. This update will highlight employment, and government revenue and national economic benefits.

Employment

In addition to the 33,000 direct, indirect and induced jobs already created by oil sands development, it is expected that there will be a total of 240,000 new jobs created across Canada by 2008[xix]. Roughly 60 percent of these jobs will be in Alberta, with the majority in the manufacturing sector.

Oil sands companies in the Wood Buffalo region have projected that they will be hiring approximately 6,000 new permanent positions from 2005 to 2014. An additional 9,000 will be required to replace workers lost due to attrition. In 2004, over 1,300 Aboriginal people were directly employed by oil sands developers or have been engaged by contractors, and more than $250 million was spent on contracts to source goods and services from businesses owned by Aboriginal people.

Government Revenue and National Economic Benefits

Oil sands industry expansion is a major driver of economic activity in Alberta, which in turn generates economic benefits for the regional, provincial and national economies. Oil sands royalties and taxes generated for the Alberta government between 1996 and 2005 totalled $6 billion. The Athabasca Regional Issues Working Group[xx] forecasts the following:

- by 2015, the Alberta government is expected to receive $2.4 billion annually in royalties, Alberta corporate tax and personal income tax from existing and new oil sands projects; and
- by 2015, the federal corporate and personal tax revenue associated with the oil sands industry is estimated to be $3.5 billion per year.

6.3.3 Negative Socio-Economic Impacts

There are also negative socio-economic effects associated with this rapid growth. These negative effects include a shortage of affordable housing, increased regional traffic, increased pressures on government services such as health care and education systems, alteration to the traditional way of life, impacts on traditional lands, municipal infrastructure that lags behind population growth, drug and alcohol abuse, and increased dependence on non-profit social service providers. The following highlights housing, and infrastructure and services issues:

Housing

The growing population of Fort McMurray creates a demand for housing, resulting in high accommodation costs, low availability and a lack of subsidized housing. A key finding in the Sustainable Community Indicators Summary report[xxi] regarding the availability of housing is that housing is generally less available in Fort McMurray than the communities of Grande Prairie, Medicine Hat, Calgary and Edmonton. The report also found that the housing situation is worsening (i.e., the availability of housing in Fort McMurray is decreasing).

In the Wood Buffalo region, and especially in Fort McMurray, this affordability and availability issue is acute because:

- housing prices are high relative to Edmonton and elsewhere, with the average price of a single family dwelling costing $430,000 for the month of March 2006[xxii] compared to $256,000 in Edmonton[xxiii] and $363,000 in Calgary[xxvi]; and
- rents are high with a two-bedroom apartment costing on average $1,400 per month[xxv] in February 2006. In addition, vacancies are extremely low, and recent new project announcements have resulted in notices of further rental increases.

The affordability and availability of housing in Fort McMurray is detrimental to recruitment for oil sands companies. In order to address these issues, several companies have applied for fly-in and fly-out permission for their projects, which would allow workers to live in larger centres (e.g., Edmonton, Calgary and other centres in Canada) and commute to the worksite via airplane. This approach has the potential to assist companies with recruitment and reduce stress on accommodation, infrastructure and services; however, in the long-term this approach may compromise the sustainability of communities (i.e., Fort McMurray and other centres in Canada).

Infrastructure and Services

The Wood Buffalo Business Case 2005 offers a comprehensive overview of the urgent public infrastructure needs of the region as determined by industry, the municipality and public service providers. A capital investment of $1.2 billion is required to address the full range of public sector infrastructure needs in the region over the next five years[xxvi]. The $1.2 billion includes:

- $353 million in municipal projects, including water, waste water, road and recreation facilities;
- $236 million in primary, secondary and post-secondary education facilities;
- $500 million in highway projects; and
- $136 million in health facilities and affordable (low income) housing.

6.4 Outlook: Issues and Uncertainties

The original goal of producing one million barrels per day of oil from the oil sands by 2020 was surpassed in 2004. In light of such rapid growth, the question arises as to whether the balance between resource development and environmental protection and social interests can be maintained. The following are the key environmental and socio-economic challenges to be addressed.

- **Water policies:** The amount of water used in oil sands mining operations is significant and the limited available supply from the Athabasca River could be a constraint on future expansion plans. Continued development of water policies beyond AENV's Interim Framework can be expected. Some newer approved oil sands mines have up to 30 days of on-site water storage incorporated into their project designs to limit withdrawals during periods of low river flows. Building water storage[xxvii] upstream of the oil sands mine operations to help supplement periods of low river flows is another option.
- **Labour requirements:** Both short-term and long-term solutions have been proposed to help meet the labour needs of oil sands industry employers. It remains uncertain if the

short-term solutions will be able to increase the supply of skilled workers in order to match the demand created by the rapid expansion of the oil sands industry. A limited supply of skilled labour has the potential to restrict the pace of development.

- **Infrastructure and services:** As a result of rapid population growth, the Wood Buffalo region has experienced deficiencies in community service delivery and infrastructure development. This jeopardizes the ability of the Regional Municipality of Wood Buffalo to maintain a reasonable quality of life standard, which is essential for all employers in the region that seek to attract and retain employees.
- **Air emissions:** GHG emissions are a major concern for Canadians. Oil sands operators have taken steps to significantly reduce the emissions intensity of their operations but total emissions have still increased due to higher production levels. The use of CO_2 for enhanced oil recovery could potentially reduce GHG emissions and create an economic opportunity.
- **Cumulative environmental impacts:** The accumulation of changes to the air, land and water, which results from oil sands development, is a major area of concern. Environmental groups contend that there is currently inadequate scientific information to understand how the ecosystem will react to the impacts of development and that stricter environmental performance targets are needed. Industry continues to look at technological innovation that could be used to reduce environmental impacts.
- **Technology:** With continued high oil prices, the oil sands industry could be motivated to focus their innovative capacity on technological breakthroughs for the environment. In terms of waste management, gasification could potentially turn petroleum coke into fuel gas and a source of hydrogen. CO_2 sequestration (injecting CO_2 from oil sands into conventional oil fields) promises to both capture emissions and add new crude production. There are many areas for companies to devote their capital, depending on the incentives.

ELECTRICITY OPPORTUNITIES

7.1 Introduction

Cogeneration plants, also known as a combined heat and power (CHP) facilities, are the primary source of power for most oil sands operations. CHP facilities typically use natural gas as fuel to run a combustion turbine that turns a generator to produce electricity. A heat recovery steam generator then captures the heat that would normally be wasted and uses it to produce steam, hot water or a mixture of the two for use in an industrial process such as bitumen production. This combined process is more cost and fuel efficient than generating equivalent amounts of electricity and steam separately.

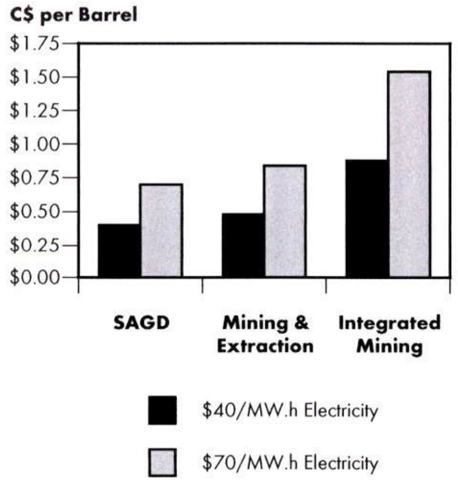
Developments in the oil sands industry since 2004 have led the majority of oil sands producers to continue to install cogeneration plants at their facilities to:

- increase the reliability of steam and power in order to maximize oil production;
- capture environmental and economic efficiencies, and;
- potentially increase revenues with the sale of excess power.

However, the current trend has shifted to building only sufficient cogeneration to ensure the facility can meet its own energy needs, but with little surplus available for sale to the grid.

FIGURE 7.1

Estimated Electricity Costs by Recovery Type



Source: CERI and AESO

7.2 Electricity Requirements

Increased prices for natural gas have raised the Alberta average electricity pool price in 2005 to $70/MW.h from the $40/MW.h used in the Board's 2004 report, as shown in Figure 7.1. While this represents a 75 percent increase in electricity costs, the resulting increase to production costs is small in comparison to the increase in oil prices. Consequently, more weight is placed on maximizing production than in generating revenue from excess electricity sales or reducing electricity costs.

7.3 Cogeneration Opportunities

Total Alberta generating capacity, as of March 2006, is about 11 400 MW, while the peak demand, set in December 2005, was 9 580 MW[xxviii].

Installed total cogeneration capacity increased by about 150 MW in 2005, of which about 25 MW is available for sale to the grid. The latest Athabasca Regional Issues Working Group cogeneration forecast (mid-range) is illustrated in Figure 7.2. The capacity forecast in 2015 lies in a range between 2 900 MW and 3 000 MW.

This forecast is significantly lower (projected total generation capacity in 2015 is 22 percent lower) than in the Board's 2004 report because of higher natural gas prices and concerns about the uncertainty surrounding the amount of energy the Alberta electricity market can absorb. These factors have led to a trend for oil sands producers to build cogeneration for self-sufficiency, not for grid sales. Specifically, instead of building cogeneration to the steam requirements of a project, facilities are sized based on the project's electricity requirements with the addition of less capital-intensive steam boilers for additional steam needs.

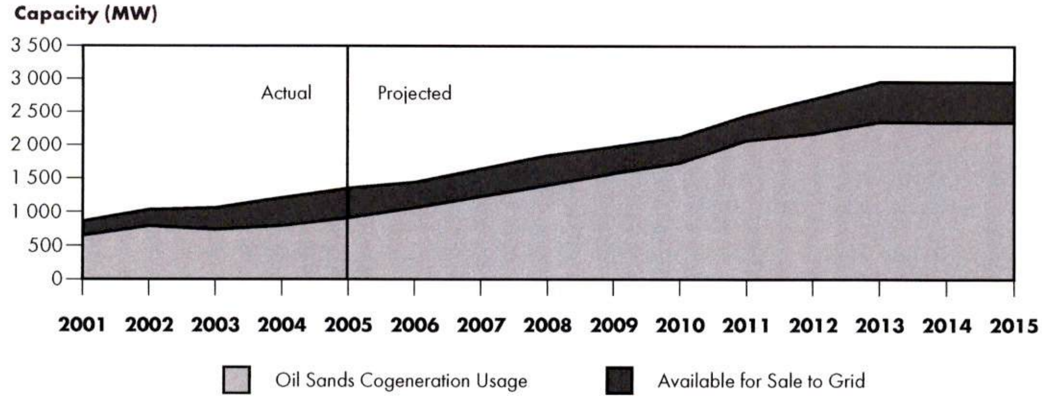
Higher natural gas prices have led to a heightened interest in coal-fired generation in southern Alberta as well as increased interest in alternative fuels such as coal and bitumen. The direct combustion of coal and bitumen can be used to fuel boilers but is not suitable for cogeneration. Recent developments in in situ recovery technologies such as low pressure SAGD or solvent assisted production, or new recovery methods such as VAPEX or THAI, could also reduce the need for steam generation. Any technology that reduces the need for steam will decrease the potential for cogeneration, as cogeneration is only economic when there is a need for the steam produced.

However, renewed interest in cogeneration could result if:

- the potential market in power attributes[xxix] became more favorable—specifically if the market was willing to pay a premium for clean power;
- an alternative fuel to natural gas, such as syngas[xxx] (produced from the gasification of coal, bitumen or petroleum coke) can be used since it would remove the uncertainty associated

FIGURE 7.2

Oil Sands Based Cogeneration



Source: Athabasca Regional Issues Working Group. *2006 Oil Sands Co-generation Report.*

with high natural gas prices; and

- Alberta electricity could gain access to larger, higher priced markets, such as California.

Farther out on the horizon is the possibility of using nuclear energy in the oil sands. Higher natural gas prices would favour the development of this technology; however, certain issues will have to be addressed before nuclear energy could be part of the oil sands industry. These include the large size of a typical nuclear generator compared with a typical oil sands plant, the oil sands producers' lack of experience with the technology, and public concerns about safety and the disposal of nuclear waste.

Research continues and, while it is unlikely to see commercial development in the time frame of this report, it may be possible to develop smaller, low maintenance modular nuclear reactors that would address some of these concerns.

7.4 Transmission

The Alberta Transmission Development Policy, announced in December 2003, has generally been seen as successful in addressing many of the concerns regarding the development of new transmission in a timely manner.

The addition of a third 240 kV transmission line in the Fort McMurray region has raised transmission capacity to 610 MW and has enabled the removal of Remedial Action Schemes (RAS), which were previously required to deal with the possibility of a line fault. Oil sands producers have welcomed this addition since it reduces the risk of service interruption, which could result in lost production, and it has allowed access to the Alberta market for cogeneration surpluses. If more cogeneration surplus becomes available in the future, further transmission expansion will be required in order to reach the market.

Work continues on the development of the proposed Northern Lights project to connect Fort McMurray cogeneration to markets in California. The consensus remains that while the project has great potential there are also a number of questions that must be answered, such as:

- How big is the potential market? Will nuclear and coal plants in California and the Pacific Northwest be retired or refurbished? Will there be competition from coal-fired generation in the U.S. states east of the Rockies?
- Who will take the risk of being the first company to commit to the project? Will it be the transmission provider or a producer?

7.5 Outlook: Issues and Uncertainties

There are many factors that will affect the future of oil sands related cogeneration. Some of the most important are:

- **Natural gas costs:** Rising natural gas prices have caused increased interest in coal-fired generation in southern Alberta, which can present serious competition for natural gas-fired cogeneration.
- **Technology:** Natural gas prices have given impetus to the development of new technologies for oil sands production. Alternate fuels such as syngas, that can be used to produce electricity and steam, will favour cogeneration. However, fuels that can be used in

a boiler but not in a combustion turbine, such as bitumen and coal, or oil sands production technologies that reduce the demand for steam such as THAI or the use of solvents, will reduce the potential for cogeneration.

- **Availability of markets:** The Alberta electricity market has relatively low cost generation and is small compared to the potential for cogeneration in the Fort McMurray region. Access to larger, higher priced markets in California would make a major difference in how much cogeneration is built.
- **Power attributes:** If consumers are willing to pay a premium for clean power, this would favour development of cogeneration. Natural gas-fired cogeneration uses a clean fuel very efficiently. The production of syngas has more environmental costs but is still cleaner than coal fired generation and (due to higher efficiencies) almost as clean as combined cycle natural gas generation.

Petrochemical Feedstock Opportunities

8.1 Introduction

Alberta's petrochemical industry is based on ethane (which is produced from processing natural gas) as feedstock for the production of ethylene. In response to flattening natural gas production from the WCSB and rising demand, natural gas prices, and therefore ethane prices, have increased significantly since the late 1990s. Since feedstock costs account for over two-thirds of the total cost of producing ethylene, they have a strong influence on operating profitability. Going forward, with natural gas prices expected to remain high and volatile (over US$7 per MMBtu), natural gas-based feedstock costs are also expected to remain high.

The Alberta petrochemical industry has suggested that current ethane feedstock supply falls short of ethane cracker capacity by about 4 800 m^3/d (30 Mb/d). Given the expected outlook for conventional natural gas supply, the ethane supply shortfall could intensify if WCSB conventional natural gas production declines or if domestic gas demand in the province increases. In addition, North American ethylene derivative demand is forecast to grow to the point where new ethylene capacity will likely be required within five to ten years. In order for the Alberta ethylene sector to expand, additional, secure and cost-competitive feedstock supply will be required. These feedstock challenges have highlighted the need to consider future ethane supply and feedstock flexibility.

Over the past few years, market signals have indicated that Alberta's oil sands resource could provide a secure, substantial and stable-priced feedstock for the petrochemical industry. Currently, most of this potential feedstock is not recovered but is used as fuel in upgrading and refinery operations.

8.2 Synthetic Gas Liquids (SGL) from Upgrader Off-gas

When bitumen is upgraded to produce SCO, the upgrading processes produce a by-product off-gas, which is a mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and, using the coking process, olefins ethylene, propylene and butylenes). The paraffinic light hydrocarbon components of off-gas, ethane in particular, could be a potential source of feedstock for the Alberta ethylene plants. The olefin portion could be feed for petrochemical derivative plants. This mix of paraffinic and olefinic hydrocarbons is referred to as "synthetic gas liquids" or "SGL". They currently remain, for the most part, in the off-gas and are consumed as fuel.

Upgrading bitumen also represents potential petrochemical feedstock in the form of heavier intermediary products recovered from upgrader and refinery processes. The intermediary products include naphtha, aromatics and vacuum gas oil (VGO). Access to oil sands intermediary hydrocarbon feedstock would likely require association with an integrated upgrader/refinery/petrochemical complex. Development of such a complex is expected to be beyond the timeframe of this report. Consequently, intermediary feedstocks will not be discussed in this report.

8.2.1 Ethane and Ethylene ($C_2/C_{2=}$)

Based on production from existing and currently proposed upgrading expansions, it is estimated that by 2012, up to at least 16 000 m^3/d (100 Mb/d) of SGL mix could be entrained in upgrader off-gas. About 50 percent of this stream would be ethane. Existing and proposed upgrading expansions (for the purpose of determining this supply) would include Syncrude Canada Ltd., Shell Canada Ltd. and Suncor Energy Inc. (Suncor), as well as two other upgraders in operation by 2012. Tying in SGL streams from refinery processes could further increase the potential.

Alberta currently has upgrader off-gas C_{3+} extraction facilities near Fort McMurray, as well as a propane/propylene splitter facility located at Redwater, Alberta. A portion of the province's currently available olefinic C_{3+} mix is extracted from Suncor's upgrader off-gas. The Suncor off-gas stream could also provide about 1 900 m^3/d (12 Mb/d) of $C_2/C_{2=}$ mix; however, it is not economic to recover at this time. As a result, $C_2/C_{2=}$ mix is left in the off-gas stream to be burned as fuel.

Large-scale SGL recovery would require new infrastructure, particularly to access off-gas from the Fort McMurray region and deliver it to the Heartland region near Edmonton, Alberta. For example, additional extraction and $C_2/C_{2=}$ fractionation capacity as well as separate product pipelines would be required. On the other hand, given the outlook for SCO production by 2012, it is expected that upgrader capacity will increase to the point where upgraders may produce up to 600 MMcfd of off-gas. Consequently by 2010 to 2012, off-gas volumes could reach a level where upgraders should be considering the value-added synergies of recovering available SGL. Cokers will reach this point faster than hydrogen addition upgraders, as the coking process produces greater volumes of SGL.

Merchant upgraders may be more open to taking advantage of SGL recovery opportunities compared with integrated oil companies. For example, BA Energy Inc. (BA) is in the process of constructing a merchant upgrader in Fort Saskatchewan, Alberta. Phase 1 of its project will have a capacity to upgrade 12 200 m^3/d (77 Mb/d) of bitumen blend; upon completion of Phase 3, the capacity would triple to about 39 700 m^3/d (250 Mb/d). BA is also evaluating access to long-term off-gas extraction and fractionation service (to produce $C_2/C_{2=}$ and C_{3+} cuts) from a proposed third-party facility on a fee-for-service basis. Both prospective partners would be located in the Heartland region and would have access to various nearby infrastructure.

8.2.2 Propane/Propylene ($C_3/C_{3=}$)

About 682 000 tonnes (1.5 billion pounds) per year of propylene has been identified in Alberta as available from upgrader/refinery off-gas and ethylene cracker processes—enough feedstock to supply a worldscale poly-propylene plant. Propylene is the main driver behind the Redwater $C_3/C_{3=}$ fractionation facility as propylene is a high value component. These facilities commenced operation in 2002 with the expectation of accessing propylene from several sources in Alberta. The Redwater splitter is currently not fully utilized and could accommodate additional olefinic feedstocks. Presently, olefinic C_{3+} mix from Suncor's upgrader is the only feed to the $C_3/C_{3=}$ splitter.

Over the past few years many factors have changed such as improved economic growth leading to increased propylene and propylene derivative product prices. With North American propylene demand growth increasing at a rate of three to four percent per annum and a future shortfall expected, there is an opportunity to utilize propylene in Alberta. The question of how to capture this opportunity remains. With this in mind, the Alberta Government, along with other industry parties, is presently examining the cost competitiveness of a propylene derivative plant in Alberta.

8.3 Outlook: Issues and Uncertainties

While not currently feasible, there may be an opportunity to recover ethane (up to about 9 500 m^3/d or 60 Mb/d, depending on upgrader configuration) and other SGL from off-gas within the 2010 to 2012 time frame. There are several uncertainties that could impact the development of this supply. These include:

- The building of SGL infrastructure will compete with oil sands infrastructure requirements.
- A capital incentive or credit against royalty payments on enhanced ethane production being considered by the Alberta Government, if approved, may apply to incremental, conventional gas liquids sources only. That is, it may not apply to SGL available from upgrader or refinery off-gas. This would suggest that incremental ethane derived from taking a deeper cut from conventional natural gas would be the most likely next tranche of ethane supply. However, with a similar royalty credit, ethane from bitumen upgrader off-gas may be cost competitive with incremental conventional ethane.
- In order for the Alberta ethylene sector to expand, substantial additional, secure long-term and cost-competitive feedstock supply will be required.
- The natural gas make-up requirement (i.e., to replace removed gas liquids content) currently used by the midstream sector has been a deterrent to ethane production from off-gas. The natural gas replacement requirement is, in effect, tying SGL recovery costs to natural gas. Consequently, a replacement requirement of somewhat less than 100 percent of natural gas content, a percent of proceeds arrangement, or tying the replacement of heat content cost to a lower-valued bitumen product could be suitable alternatives.
- Aggregation of all propylene identified as available in Alberta would be capital intensive, requiring construction of new infrastructure and may require a financial incentive.

In conclusion, some questions need to be addressed. If SCO production reaches the level projected in this report, will associated off-gas volumes reach a point where recovering SGL would be economic? On the other hand, is there an alternative use for off-gas in addition to process fuel?

GLOSSARY

Apportionment	The method of allocating the difference between the total nominated volume and the available pipeline operating capacity, where the latter is smaller.
Aquifer	An underground geological formation, or group of formations, that contain water.
Aromatics	A term referring to compounds containing one or more six-carbon rings, with alternating (or resonating) carbon-hydrogen double bonds. Benzene, toluene and xylene are examples of common aromatic hydrocarbons.
Barrel	One barrel is approximately equal to 0.159 cubic metres or 158.99 litres or approximately 35 Imperial gallons.
Bitumen or crude bitumen	A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Blended bitumen	Bitumen to which light oil fractions have been added in order to reduce its viscosity and density to meet pipeline specifications.
Brackish water	Water with a total dissolved solids concentration greater than 4,000 milligrams per litre. It is not suitable for consumption or agricultural use. Also known as saline water.
C_2	Ethane.
$C_{2=}$	Ethylene.
$C_2/ C_{2=}$	Ethane/Ethylene Stream.
C_{2+}	Ethane plus refers to a mixture of natural gas liquids consisting of ethane and heavier hydrocarbons.
C_3	Propane.
C_{3+}	Propane plus refers to a mixture of natural gas liquids consisting of propane and heavier hydrocarbons.
$C_3/ C_{3=}$	Propane/propylene stream.

Cogeneration	A facility that produces process heat and electricity. Also known as combined heat and power (CHP) facility.
CO_2	Carbon dioxide.
Coke	A solid black carbon residue remaining after valuable hydrocarbons are extracted from bitumen.
Coker	A vessel in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil. The lighter fractions, primarily naphtha and gas oils, become the main ingredients of the final blend.
Condensate	A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a natural gas processing plant before the gas is processed.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Cracking	The process of breaking down larger, heavier more complex hydrocarbon molecules into smaller, lighter molecules.
Cyclic Steam Stimulation (CSS)	A method of recovering bitumen from a reservoir using steam injection to heat the reservoir to reduce the viscosity of the oil and provide pressure support for production. Oil production occurs in cycles, each of which begins with a period of steam injection followed by the same well being used as a producer.
Deep-cut plant	Refers to a plant that extracts ethane and heavier hydrocarbons from natural gas streams.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.
Distillate	Fraction of crude oil; a term generally used for naphthas, diesel, kerosene and fuel oils.
DilSynBit	A blend of bitumen, condensate and synthetic crude oil that has similar properties to medium sour crude.
Ecosystem	A biological community of interacting organisms and their physical environment.

Ethane	The simplest straight-chain hydrocarbon structure with two carbon atoms.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from the oil sands.
Groundwater	Water beneath the earth's surface, often between saturated soil and rock, that supplies wells and springs.
Heat rate	The amount of input energy used to generate electricity, commonly expressed in gigajoules per gigawatt hour (GJ/GW.h).
Heavy crude oil	Generally, a crude oil having a density greater than 900 kg/m^3.
Horizontal well	A well that deviates from the vertical and is drilled horizontally along the pay zone. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.
Hydrocarbons	Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, gaseous or solid.
Hydrocracking	The breaking of hydrocarbon chains into smaller molecules in the presence of hydrogen and a catalyst such as platinum. The end result is a high quality gasoline and other light hydrocarbons.
Hydrotreating	A process used to saturate olefins and improve hydrocarbon stream quality by removing unwanted materials such as nitrogen, sulphur, and metals utilizing a selected catalyst in a hydrogen environment.
Integrated mining plant	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
In situ recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Light crude oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.
Lloyminster Blend	LLB is a heavy crude oil, produced in Canada, which is the benchmark grade of crude oil for Canadian price quotations.
Merchant upgrader	Processing facilities that are linked not to any specific extraction project, but designed to accept raw bitumen on a contract basis from producers.

Natural gas liquids	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Off-gas	A mixture of hydrogen and light hydrocarbon gases (including paraffins ethane, propane and butanes; and olefins ethylene, propylene and butylenes) produced when bitumen is upgraded to synthetic crude oil.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Olefins	Refers to any open-chain hydrocarbon such as ethylene, propylene and butylenes, having the general formula C_nH_{2n} with a carbon-to-carbon double bond.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Paraffin	A straight-chain hydrocarbon without double bonds; also called an alkane.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Real price	The price of a commodity after adjusting for inflation. In this report most real energy prices are expressed in 2005 dollars.
Reclamation	Returning disturbed land to a stable, biologically-productive state.
Recovery - Primary	The extraction of crude oil from reservoirs utilizing the natural energy available in the reservoirs and pumping techniques.
Remedial action scheme	A system to prevent a cascading blackout of a power system by taking generation out of service if part of the transmission system fails.
Reserves - Established	The sum of the proven reserves and half probable reserves.
Reserves - Initial established	Established reserves prior to deduction of any production.
Reserves - Proven	Reserves recoverable under current technology and present and anticipated economic conditions, specifically demonstrated by drilling, testing or production.
Reserves - Remaining	Initial reserves less cumulative production at a given time.
Reservoir	A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil that is confined by impermeable rock or water barriers.

Resources - Recoverable	That portion of the ultimate resources potential recoverable under expected economic and technical conditions.
SAGD	Steam Assisted Gravity Drainage is a steam stimulation technique using horizontal wells in which the bitumen drains, by gravity, into the producing wellbore. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Straddle plant	A reprocessing plant located on a gas pipeline. It extracts natural gas liquids from previously processed gas before the gas leaves or is consumed within the province.
Supply cost	Expresses all costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
Surface water	Lakes and rivers.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude.
Synthetic gas liquids	Refers to the liquids (ethane, ethylene and propylene in particular) produced from upgrading bitumen to synthetic crude oil.
Synthetic crude oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Unconventional crude oil	Crude oil that is not classified as conventional crude oil (e.g., bitumen).
Upgraded crude oil	Generally refers to crude bitumen and heavy crude oil that have undergone some degree of upgrading, but is commonly synonymous with synthetic crude oil.
Upgrading	The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
VAPEX™	Vaporized Extraction is a process similar to SAGD but using a vaporized hydrocarbon solvent, rather than steam, to reduce the viscosity of crude oil in the reservoir.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

ECONOMIC AND MARKET ASSUMPTIONS FOR SUPPLY COST MODELS

TABLE A1.1

Economic Assumptions

Rate of Return	10 percent real, 12 percent nominal
Royalty	Alberta oil sands regime
Federal Taxes	Current oil sands terms
Provincial Taxes	Current Alberta rates
Inflation - constant (percent)	2.0
Exchange Rate US$/C$	0.85

TABLE A1.2

Market Pricing Assumptions

Natural gas NYMEX (US$ per MMBtu)	7.50
Natural gas AECO (C$/GJ)	8.25
NYMEX - AECO Natural Gas (US$ per MMbtu)	0.50
WTI @ Cushing, OK (US$ per barrel)	50.00
Condensate premium over MSW @ Edmonton (percent)	10.00
MSW @ Edmonton - Syncrude @ Edmonton (US$ per barrel)	0.00
MSW @ Edmonton - Lloydminster Blend @ Hardisty (US$ per barrel)	15.00
Heavy crude transportation differential to Chicago: Hardisty vs. Cushing (US$ per barrel)	1.25
Light crude transportation differential to Chicago: Edmonton vs. Cushing (US$ per barrel)	1.00

ASSUMPTIONS FOR ATHABASCA SAGD MODEL

TABLE A2.1

Project Assumptions: High-Quality SAGD

(costs in per barrel of bitumen produced)	
Steam-to-oil ratio (dry)	2.5
Natural gas consumption (Mcf/b)	1.05
Non-gas cash operating costs[a] (C$ per barrel)	3.50
Reduction in operating costs (percent per year)	0
Required diluent – percent of blend volume	33.3
Project start date	2006
Project end date	2047
Kyoto compliance cost (C$ per barrel)	0.00
Capital expenditures to first oil (millions C$ 2005)	450
Capital expenditures over project life (billions C$ 2005)	2.7
Condensate transportation to Plant (C$ per barrel)	0.80
Bitumen blend transportation differential: Plant vs. Hardisty (C$ per barrel)	1.15

a Other non-gas cash operating costs include purchased power, administration, environmental and other direct costs associated with the operation.

TABLE A2.2

Phase Schedule: High-Quality SAGD

	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2009	4 800	30,000
Phase 2	2012	9 600	60,000
Phase 3	2015	14 400	90,000
Phase 4	2018	19 200	120,000

TABLE A2.3

Reservoir Assumptions: High-Quality SAGD

Oil sands area	Athabasca
Oil sands deposit	McMurray
API°	8
Continuous pay thickness (m)	35
Porosity (percent)	35
Effective vertical permeability (Darcies)	5

Assumptions for Athabasca Mining/Extraction and Upgrading Model

TABLE A3.1

Project Assumptions

	Mining Extraction & Upgrading
External natural gas consumption (Mcf/b)	0.75
Non-gas cash operating costs[a] (C$ per barrel)	12.00
Reduction in operating costs (percent per year)	0.00
Kyoto compliance cost (C$ per barrel)	0.00
Capital maintenance cost (C$ per barrel)	1.25
Capital expenditure excluding maintenance capital (billions C$)	10.0
Project start date	2006
Project end date	2050
Transportation differential: Plant vs. Edmonton (C$ per barrel)	0.70

a Other non-gas cash operating costs include purchased power, administration, environmental and other direct costs associated with the operation.

TABLE A3.2

Phase Schedule

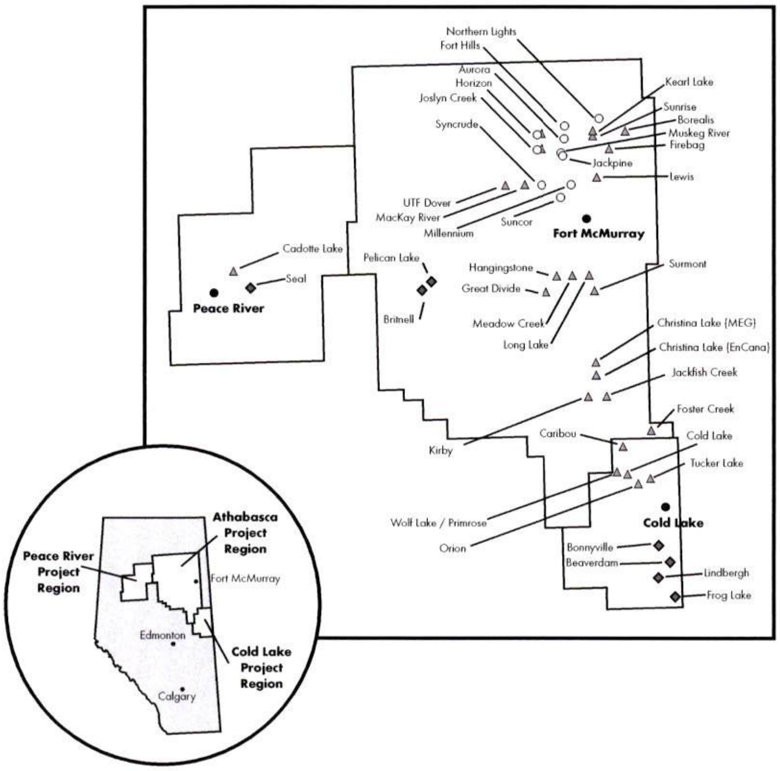
	First Oil	Cumulative Production (m^3/d)	Cumulative Production (b/d)
Phase 1	2010	15 873	100,000
Phase 2	2012	31 746	200,000

TABLE A3.3

Reservoir Assumptions

Oil Sands Area	Athabasca
Oil Sands Deposit	McMurray
API°	8
Bitumen grade - weight percent	11

Oil Sands Projects



LEGEND

In Situ Projects △	***Operator***
Orion	BlackRock Ventures
Kirby	Canadian Natural Resources
Wolf Lake/Primrose	Canadian Natural Resources
Surmont	ConocoPhillips/Total
Great Divide	Connacher Oil and Gas
UTF (Dover)	Devon Energy
Jackfish Creek	Devon Energy
Borealis	EnCana
Christina Lake	EnCana
Foster Creek	EnCana
Caribou	Husky Energy
Sunrise	Husky Energy
Tucker Lake	Husky Energy
Cold Lake	Imperial Oil
Hangingstone	Japan Canada Oil Sands (JACOS)
Christina Lake	MEG
Long Lake	OPTI/Nexen
Lewis	Petro-Canada
MacKay River	Petro-Canada
Meadow Creek	Petro-Canada/Nexen
Cadotte Lake	Shell Canada
Firebag	Suncor Energy
Joslyn Creek	Total E&P Canada

Mining Projects ○	***Operator***
Muskeg River	Albian Sands (Shell/Chevron/Western Oil Sands)
Jackpine Mine	Albian Sands (Shell/Chevron/Western Oil Sands)
Horizon*	Canadian Natural Resources
Kearl Lake	Imperial Oil
Suncor Base Mine	Suncor Energy
Millennium	Suncor Energy
Syncrude Base Mine	Syncrude Joint Venture
Aurora	Syncrude Joint Venture
Northern Lights	Synenco
Fort Hills	Petro-Canada/UTS Energy/Teck Cominco
Joslyn Creek	Total E&P Canada

Major Primary Production Areas ◆

SEAL
Pelican Lake
Lindbergh
Frog Lake
Brintnell
Bonnyville
Beaverdam

* Includes plans for both in situ and mining

Mining/Extraction and Upgrading Projects

Company/Project Name	Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m³/d)
Athabasca Oil Sands Project				
Muskeg River Mine				
Existing Facilities	Operating	2002	155,000	24 600
Expansion and Debottleneck	Application	2010	115,000	18 300
Jackpine Mine				
Phase 1A	Approved	2010	100,000	15 900
Phase 1B	Approved	2012	100,000	15 900
Phase 2	Disclosure	2014	100,000	15 900
Scotford Upgrader				
Phase 1	Operating	2003	155,000	24 600
Debottleneck	Application	2007	45,000	7 100
Expansion	Application	2009	90,000	14 300
CNRL				
Horizon Mine & Upgrader				
Phase 1	Construction	2008	135,000	21 400
Phase 2	Approved	2011	45,000	7 100
Phase 3	Approved	2011	90,000	14 300
Phase 4	Announced	2015	145,000	23 000
Phase 5	Announced	2017	162,000	25 700
Primrose Upgrader				
Phase 1	Announced	2012	145,000	23 000
Phase 2	Announced	2015	58,000	9 200
Fort Mackay First Nation				
Fort Mackay Mine				
Phase 1	Announced	TBD	TBD	TBD
Husky				
Lloydminster Upgrader				
Existing Operations	Operating	1992	71,000	11 300
Debottleneck	Construction	2006	12,000	1 900
Expansion	Announced	TBD	67,000	10 600
Imperial/ExxonMobil				
Kearl Mine				
Phase 1	Application	2010	100,000	15 900
Phase 2	Application	2012	100,000	15 900
Phase 3	Application	2018	100,000	15 900

Mining/Extraction and Upgrading Projects (continued)

Company/Project Name	Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
OPTI/Nexen				
Long Lake Upgrader				
Phase 1	Construction	2007	72,000	11 400
Phase 2 (South)	Approved	2011	72,000	11 400
Phase 3	Announced	2013	72,000	11 400
Phase 4	Announced	2015	72,000	11 400
Petro-Canada/UTS/Teck Cominco				
Fort Hills Mine				
Phase 1/2	Approved	2011	100,000	15 900
Phase 3/4	Approved	2014	90,000	14 300
Fort Hills Upgrader				
Phase 1/2	Announced	2011	100,000	15 900
Phase 3/4	Announced	2014	90,000	14 300
Suncor				
Steepbank & Millennium Mine				
Steepbank & N.Steepbank Extension	Operating	1967	276,000	43 800
Steepbank Debottleneck	Construction	2006	25,000	4 000
Millennium Debottleneck	Construction	2008	23,000	3 700
Tar Island Upgrader				
Base U1 and U2	Operating	1967	281,000	44 600
Millennium Vacuum Unit	Operating	2005	43,000	6 800
Millennium Coker Unit	Construction	2008	116,000	18 400
Voyageur Upgrader				
Phase 1	Application	2010	156,000	24 800
Phase 2	Application	2012	78,000	12 400
Syncrude				
Mildred Lake & Aurora Mining and Upgraders				
Existing Facilities	Operating	1978	290,700	46 100
Stage 3 Expansion	Construction	2006	116,300	18 500
Stage 3 Debottleneck	Announced	2011	46,500	7 400
Stage 4 Expansion	Announced	2015	139,500	22 100
Synenco				
Northern Lights Mine				
Phase 1	Disclosure	2009	50,000	7 900
Phase 2	Disclosure	2011	50,000	7 900
Northern Lights Upgrader				
Phase 1	Disclosure	2010	50,000	7 900
Phase 2	Disclosure	2012	50,000	7 900

Mining/Extraction and Upgrading Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity	
					(b/d)	(m^3/d)
Total E&P (formerly Deer Creek)						
	Joslyn Mine					
		Phase 1 (North)	Application	2010	50,000	7 900
		Phase 2 (North)	Application	2013	50,000	7 900
		Phase 3 (South)	Announced	2016	50,000	7 900
		Phase 4 (South)	Announced	2019	50,000	7 900
	Joslyn/Surmont Upgrader					
		Phase 1	Announced	2010	50,000	7 900
		Phase 2	Announced	2013	50,000	7 900
Value Creation						
	North Joslyn Upgrader					
		Phase 1	Announced		40,000	6 300

Merchant Upgraders

Company/Project Name			Project Status	Startup Date	Bitumen Capacity	
					(b/d)	(m^3/d)
BA Energy						
	Heartland Upgrader					
		Phase 1	Construction	2008	54,400	8 600
		Phase 2	Approved	2010	54,400	8 600
		Phase 3	Approved	2012	54,400	8 600
BA Energy North West Upgrading						
	North West Upgrade					
		Phase 1	Application	2010	50,000	7 900
		Phase 2	Application	2013	54,400	7 900
		Phase 3	Application	2016	54,400	7 900
Peace River Oil Upgrading						
	Bluesky Upgrader					
		Phase 1	Announced	2010	25,000	4 000
		Phase 2	Announced	TBD	25,000	4 000
		Phase 3	Announced	TBD	25,000	4 000
		Phase 4	Announced	TBD	25,000	4 000

IN SITU PROJECTS

Athabasca Oil Sands Area In Situ Projects				
Company/Project Name	**Project Status**	**Startup Date**	**Bitumen Capacity**	
			(b/d)	**(m^3/d)**
CNRL				
Birch Mountain				
Phase 1	Announced	2013	30,000	4 800
Phase 2	Announced	2015	30,000	4 800
Gregoire Lake				
Phase 1	Announced	2016	30,000	4 800
Phase 2	Announced	2018	30,000	4 800
Phase 3	Announced	2020	30,000	4 800
Phase 4	Announced	2023	30,000	4 800
Kirby				
Phase 1	Approved	2011	30,000	4 800
Connacher				
Great Divide				
Phase 1	Application	2006	10,000	1 600
ConocoPhillips				
Surmont				
Phase 1	Construction	2006	25,000	4 000
Phase 2	Approved	2008	25,000	4 000
Phase 3	Approved	2011	25,000	4 000
Phase 4	Approved	2014	25,000	4 000
Devon				
Jackfish				
Jackfish 1	Construction	2008	35,000	5 600
Jackfish 2	Disclosure	2010	35,000	5 600
EnCana				
Borealis				
Phase 1	Announced	2010	20,000	3 200
Phase 2	Announced	2011	20,000	3 200
Phase 3	Announced	2012	20,000	3 200
Phase 4	Announced	2013	20,000	3 200
Phase 5	Announced	2014	20,000	3 200

Athabasca Oil Sands Area In Situ Projects (continued)

Company/Project Name	Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Christina Lake				
Phase 1A	Operating	2002	10,000	1 600
Phase 1B	Approved	2008	30,000	4 800
Phase 1C	Approved	2009	30,000	4 800
Phase 1D	Announced	2010	30,000	4 800
Unnamed Expansion 1	Announced	2011	30,000	4 800
Unnamed Expansion 2	Announced	2012	30,000	4 800
Unnamed Expansion 3	Announced	2013	30,000	4 800
Unnamed Expansion 4	Announced	2014	30,000	4 800
Unnamed Expansion 5	Announced	2015	30,000	4 800
Foster Creek				
Phase 1A	Operating	2001	24,000	3 800
Phase 1B - Debottleneck	Operating	2003	6,000	1 000
Phase 1C - Stage 1	Operating	2005	10,000	1 600
Phase 1C - Stage 2	Construction	2006	20,000	3 200
Phase 1D	Announced	2006	20,000	3 200
Phase 1E	Announced	2007	20,000	3 200
Unnamed Expansion 1	Announced	2009	25,000	4 000
Unnamed Expansion 2	Announced	2011	25,000	4 000
Husky				
Sunrise				
Phase 1	Approved	2008	50,000	7 900
Phase 2	Approved	2010	50,000	7 900
Phase 3	Approved	2012	50,000	7 900
Phase 4	Approved	2014	50,000	7 900
JACOS				
Hangingstone				
Pilot	Operating	2002	10,000	1 600
Phase 1	Disclosure	2010	25,000	4 000
Phase 2	Disclosure	2012	25,000	4 000
MEG				
Christina Lake				
Pilot	Construction	2007	3,000	500
Commercial	Application	2008	22,000	3 500

Athabasca Oil Sands Area In Situ Projects (continued)						
Company/Project Name			**Project Status**	**Startup Date**	**Bitumen Capacity**	
					(b/d)	**(m^3/d)**
North American						
	Kai Kos Dehseh					
		Phase 1	Announced	2008	10,000	1 600
		Phase 2	Announced	2010	30,000	4 800
		Phase 3	Announced	2011	40,000	6 300
		Phase 4	Announced	2013	40,000	6 300
		Phase 5	Announced	2015	40,000	6 300
OPTI/Nexen						
	Long Lake					
		Pilot	Operating	2003	2,500	400
		Phase 1	Construction	2006	72,000	11 400
		Phase 2 (South)	Disclosure	2010	72,000	11 400
		Phase 3	Announced	2012	72,000	11 400
		Phase 4	Announced	2014		
Orion						
	Whitesands					
		Pilot	Startup	2006	2,000	300
Petro-Canada						
	Chard					
		Phase 1	Announced	TBD	40,000	6 300
	Dover					
		SAGD Pilot	Operating	2001	1,400	200
		VAPEX Pilot	Operating	2003	100	16
	Lewis					
		Phase 1	Disclosure	TBD	40,000	6 300
		Phase 2	Disclosure	TBD	40,000	6 300
	MacKay River					
		Phase 1	Operating	2002	33,000	5 200
		Phase 2	Application	2009	40,000	6 300
	Meadow Creek					
		Phase 1	Approved	TBD	40,000	6 300
		Phase 2	Approved	TBD		
	Lewis					
		Phase 1	Disclosure	TBD	40,000	6 300
		Phase 2	Disclosure	TBD	40,000	6 300

Athabasca Oil Sands Area In Situ Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Suncor						
	Firebag					
		Phase 1	Operating	2004	33,000	5 200
		Phase 2	Operating	2006	35,000	5 600
		Cogeneration and Expansion	Construction	2009	25,000	4 000
		Phase 3	Approved	2008	35,000	5 600
		Phase 4	Approved	2009	35,000	5 600
		Phase 5	Announced	2012	50,000	7 900
		Phase 6	Announced	2013	50,000	7 900
		Phase 7	Announced	2014	50,000	7 900
		Phase 8	Announced	2015	63,000	10 000
Total E&P (Deer Creek)						
	Joslyn					
		Phase 1	Operating	2004	2,000	300
		Phase 2	Construction	2006	10,000	1 600
		Phase 3a	Disclosure	2009	15,000	2 400
		Phase 3b	Disclosure	2011	15,000	2 400
Value Creation						
	Halfway Creek					
		Phase 1	Announced	2009	10,000	1 600
	North Joslyn					
		Phase 1	Announced	TBD	40,000	6 300

Cold Lake Oil Sands Area In Situ Projects

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
BlackRock						
	Orion (Hilda Lake)					
		Pilot	Operating	1997	500	100
		Phase 1	Approved	2007	10,000	1 600
		Phase 2	Approved	2009	10,000	1 600
CNRL						
	Primrose					
		Primrose South	Operating	1985	50,000	7 900
		Primrose North	Construction	2006	30,000	4 800
		Primrose East	Application	2009	30,000	4 800

Cold Lake Oil Sands Area In Situ Projects (continued)

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Husky						
	Tucker Lake					
		Phase 1	Construction	2006	30,000	4 800
Imperial Oil						
	Cold Lake					
		Phases 1-10: Leming, Maskwa, Mahikan	Operating	1985	110,000	17 500
		Phases 11-13: Mahkeses	Operating	2003	30,000	4 800
		Phases 14-16: Nabiye, Mahikan North	Construction	2006	30,000	4 800

Peace River In Situ Projects

Company/Project Name			Project Status	Startup Date	Bitumen Capacity (b/d)	Bitumen Capacity (m^3/d)
Shell						
	Cadotte Lake					
		Pilot	Operating	1979	1,000	200
		Phase 1	Operating	1986	11,000	1 700
	Carmon Creek					
		Phase 1	Disclosure	2009	18,000	2 900
		Phase 1 Expansion	Announced	2012	35,000	5 600
		Phase 2	Announced	2015	35,000	5 600

Source: Strategy West Inc., Alberta Economic Development, NEB

Conversion Factors and Energy Contents

Abbreviation Table

Prefixes		Equivalent
K	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Imperial/Metric Conversion Table

Physical Units		Equivalent
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil, LPG)
		35.3 cubic feet (gas)
L	litre	0.22 imperial gallon
b	barrel (oil, LPG)	0.159 m^3

Energy Content Table

Energy Measures		Energy Content
GJ	gigajoules	0.95 million Btu

Electricity		Energy Content
MW	megawatt	
GW.h	gigawatt hour	3600 GJ
TW.h	terawatt hour	3.6 PJ

Natural Gas		Energy Content
MMBtu	million British thermal units	1.05 GJ
Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ

Energy Content Table

Natural Gas Liquids		Energy Content
m^3	Ethane	18.36 GJ
m^3	Propane	25.53 GJ
m^3	Butanes	28.62 GJ

Crude Oil		Energy Content
m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes Plus	35.17 GJ

End Notes

i Alberta Energy and Utilities Board (EUB). *Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014.* Statistical Series (ST) 2005-98. Calgary, Alberta, September 2005. p. 2.

ii Alberta Energy and Utilities Board (EUB). *Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014.* Statistical Series (ST) 2005-98. Calgary, Alberta, September 2005. p. 2.

iii Pembina Institute. *Troubled Waters, Troubling Trends - Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta.* May 2006. p 16.

iv Communications with Alberta Environment and NEB. March 9, 2006. This includes allocations for the CNRL's Horizon project and the Shell Jackpine project.

v Golder Associates Ltd. A compilation of information and data on water supply and demand in the lower Athabasca River Reach (2005). Prepared for the CEMA Surface Water Group.

vi River flows are lowest between November and March. The mean flow is about 169 cubic metres (44,600 US gallons) per second.

vii Alberta Energy and Utilities Board (EUB). *Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014.* Statistical Series (ST) 2005-98. Calgary, Alberta, September 2005 p. 2.

viii Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush.* November 2005. p. 35.

ix Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush.* November 2005. p. 33.

x The Pembina Institute's created four scenarios to project future GHG emission growth. The second best scenario for GHG emission projections is used. Source: Pembina Institute. *Oil Sands Fever - The Environmental Implications of Canada's Oil Sands Rush.* November 2005. p. 20.

xi Bachu and Shaw. "Evaluation of the CO2 sequestration capacity in Alberta's oil and gas reservoirs at depletion and the effect of underlying aquifers." *Journal of Canadian Petroleum Technology*, v. 42. no. 9 p. 51-61, 2003.

xii Government of Canada, *Moving Forward on Climate Change – A Plan for Honouring our Kyoto Commitment* (2005). p. 5. Available at: http://www.climatechange.gc.ca/kyoto_commitments.

xiii *Sustainability: The Dollars and Sense.* Clive Mather, Shell Canada Limited presentation to Vancouver Board of Trade. 2 March, 2006.

xiv The Regional Municipality of Wood Buffalo is located in northeastern Alberta, and includes the communities of Fort McMurray, Anzac, Conklin, Draper, Fort Chipewyan, Fort Fitzgerald, Fort MacKay, Gregoire Lake Estates, Janvier, Mariana Lake and Saprae Creek Estates.

xv Construction Owners Association of Alberta. *COAA on Labour Shortages: Key Messages.* December 2005.

xvi Nichols Applied Management. *Understanding Alberta's Labour Force: Looking to the Future.* A discussion document for Alberta Human Resources and Employment. September 2005.

xvii Alberta Human Resources and Employment, *Building and Educating Tomorrow's Workforce: A framework to enhance Alberta's people capacity, 10-Year Strategy.* Consultation Version. January 27, 2006.

xviii Alberta Learning Minister, Federal Minister of Human Resources and Skills Development Canada, Minister of Citizenship and Immigration Canada, *"Memorandum of Understanding for the Entry of Temporary Foreign Workers for Projects in the Alberta Oil Sands".*

xix Athabasca Regional Issues Working Group, Fact Sheet, June 2005.

xx Athabasca Regional Issues Working Group, Fact Sheet, June 2005.

xxi Nichols Applied Management. "Sustainable Community Indicators Summary Report". Revised Version, January 2006.

xxii Fort McMurray Real Estate Board.

xxiii Edmonton Real Estate Board.

xxiv Calgary Real Estate Board.

xxv Fort McMurray Landlord and Tenants Advisory Board.

xxvi Athabasca Regional Issues Working Group (RIWG) in conjunction with: Regional Municipality of Wood Buffalo, Fort McMurray Public Schools, Fort McMurray Catholic Board of Education, Northland School Division, Keyano College and Northern Lights Health Region. *Wood Buffalo Business Case 2005: A Business Case for Government Investment in the Wood Buffalo Region's Infrastructure.* March 2005.

xxvii This would entail constructing a small dyke in a low-lying area and then pumping water from the Athabasca River during periods of high flow to create a stockpile of water. This stockpile could then be re-released during periods of low flow to increase river flows and allow oil sands mine operations to continue water withdrawals. Source: Golder Associates. *Water supply security for oil sands mines by upstream offsite storage.* http://www.conrad.ab.ca/seminars. water_usage/Water_supply securityfor_oil_sands_mines_Sawatsky.pdf.

xxviii AESO.

xxix Power attributes refers to the environmental and social attributes associated with the way the electricity is generated.

xxx Syngas, or synthesis gas, is a mixture of hydrogen and carbon monoxide that can be produced from a number of sources, including coal, or more commonly for the oil sands, heavy bitumen or asphaltenes produced in the upgrading process.


EXHIBIT H

RIGHT-OF-WAY REQUIREMENTS FOR ALBERTA CLIPPER PROJECT

Background Information

The Alberta Clipper Project will be constructed within the same construction footprint as the Applicant's 20-inch diameter liquid petroleum pipeline, referred to as the "LSr Project," that is the subject of Docket No. PU07-75. Both pipelines will generally be located adjacent to the existing Lakehead System right-of-way, which extends southeasterly in a contiguous manner from the Manitoba-North Dakota border near Neche, North Dakota to the Minnesota-North Dakota border near Bowesmont, North Dakota. The Alberta Clipper Project will extend the length of this corridor, approximately 28 miles, through Pembina County from the Manitoba-North Dakota border to the North Dakota-Minnesota border.

The existing right-of-way corridor consists almost exclusively of undefined permanent easements. Where the right-of-way is held through these undefined ("blanket") easements that do not limit the width of the right-of-way, new easements will not be required to install the pipeline. However, the Applicant will negotiate compensation with the landowner for exercising the existing multiple pipeline rights.

In limited situations where the Applicant's existing right-of-way is held through defined easements that limit the width of the corridor to 125 feet (2 landowners) or where the proposed pipeline route deviates substantially from the existing Lakehead System to accommodate design requirements or environmental features on blanket easements, the Applicant will obtain new easements to install the pipeline. These easements will be negotiated on a tract-by-tract basis with each landowner. The actual right-of-way requirement for each tract will be determined on the basis of field surveys and final engineering designs.

Right-of-Way Requirements

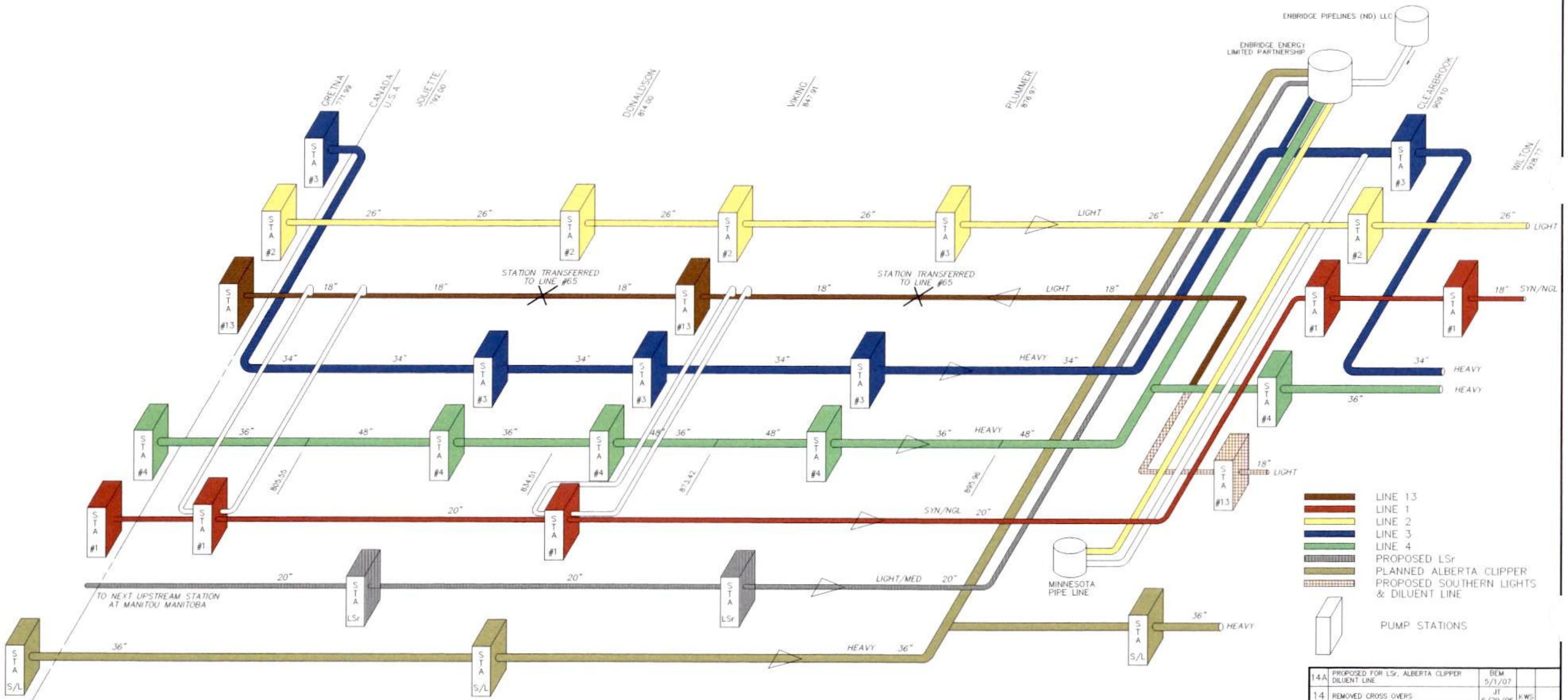
Given the Alberta Clipper pipeline will generally be installed in the same construction footprint as the LSr pipeline in parallel adjacent to the southern boundary of the existing right-of-way corridor, the design configuration and anticipated construction execution methods are intended to take advantage of the proximity of the pipelines to each other to minimize right-of-way requirements. This typically results in a maximum construction footprint of 140 feet for the combined projects for standard pipeline construction, which consists typically of establishing up to 75 feet of additional permanent right-of-way for both pipelines and 65 feet of temporary workspace for construction purposes. In limited situations, such as at road crossings, additional temporary workspace beyond 65 feet will be required to facilitate construction. This will be negotiated and obtained on an as needed basis. Both the permanent easement and the temporary workspace areas may be returned to uses by the landowners that do not impact the pipelines. 75 feet of additional permanent right-of-way is necessary to accommodate a 25 foot offset between the existing and new pipelines and a 25 foot buffer zone to the southern boundary of the maintained right-of-way corridor.

The Applicant currently anticipates that right-of-way requirements for the defined easement tracts will be between 40 and 60 feet of additional permanent easement and 65 feet of temporary workspace. The proposed route will also require the Applicant to obtain 50 feet of permanent easement on one parcel of land that is not presently encumbered by the Applicant's existing easements.

Right-of-Way Requirements – Acquisition Program

To achieve the right-of-way requirements of all proposed pipelines in a timely manner, the Applicant has implemented a right-of-way acquisition program that is intended to meet the needs of the previously filed LSr Project and the Alberta Clipper Project in a coordinated and cost-effective manner. The intent of the program is to achieve this acquisition goal while at the same time simplify the process for affected landowners through one set of negotiations, which should reduce the complexity of the negotiations and minimize time and resource commitments on the landowners' part. To that end, acquisition efforts are directed at establishing a contiguous 140 foot construction corridor along the existing corridor for typical standard construction methods. Regardless of the nature of the existing easements involved (defined or blanket), acquisition of the required permanent easement and temporary workspace will be on the basis of fair market value per acre.

The Applicant acknowledges that any approvals issued in conjunction with this application will not include the LSr right-of-way requirements.



NO	REVISION	BY DATE	APPR	
14A	PROPOSED FOR LSr, ALBERTA CLIPPER DILUENT LINE	BEM 5/1/07		
14	REMOVED CROSS OVERS	JT 6/29/06	KWS	
13	ADDED 36"/48" TIE-IN MILE POSTS	KWS 10/02/03	DAC	
12	REVISED AS BUILT FOR TERRACE EXPANSION 99-8-822	NLL 9/9/03	DAC	

ENBRIDGE Enbridge Energy, Limited Partnership

GRETNA TO CLEARBROOK

PIPELINE SYSTEM
SCHEMATIC DIAGRAM
With PROPOSED LSr* & ALBERTA CLIPPER PROJECTS

PROJECT:					
SCALE:	NONE	DATE:	6/15/88	DRAWN:	KWS
CHECK:	JAJ	APPR:	KAB	DATE:	7/11/01
APPR:	DWK	D-0.4-10155A-14A-0			
APPR:	RCT				

LSr* Project was filed in MN Docket No. PL9/CN-07-464

MUSE
STANCIL

MARKET ASSESSMENT FOR THE ALBERTA CLIPPER PROJECT

2010 – 2020

prepared for

ENBRIDGE

March 2007

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INTRODUCTION

Enbridge is developing a pipeline project to expand its existing crude pipeline system that delivers much of Western Canada's crude production into the in Ontario and U.S. Midwest markets. The project, referred to as the Alberta Clipper Pipeline, involves the construction of a 1,590-kilometer (km) of 914-millimeter (mm) pipeline with an initial capacity of 71,500 cubic meters per day (m^3/d) [450 thousand barrels per day (kb/d)]. The pipeline can be expanded up to 163,000 m^3/d (800 kb/d) at a relatively low cost via the installation of additional pumping capacity.

Muse, Stancil & Co. (Muse) has been engaged to provide an assessment of the markets for and the benefits of the Alberta Clipper Pipeline Project. Muse is an independent consulting firm that specializes in assisting clients in the downstream sector of the oil and gas industry. Muse provides an integrated combination of economic, marketing, and technical consulting services to the global refining industry. Our clients include major and independent oil companies, pipeline companies, petrochemical concerns, trading houses, engineering and construction companies, government agencies, and financial institutions. Typical assignments have involved feasibility and market studies, performance evaluation and operations optimization, asset valuations for mergers and acquisitions, and project development. Headquartered in the Dallas area, Muse has additional offices in London, Houston, and Singapore.

EXECUTIVE SUMMARY

Western Canadian crude production exceeded 380,000 m^3/d (2,400 kb/d) in 2006, and it is widely anticipated that production will continue to climb over the next decade. Based on a crude production forecast developed by the Canadian Association of Petroleum Producers (CAPP), total Western Canadian crude supply will reach 770,000 m^3/d (4,900 kb/d) by 2020. Accordingly, the need for additional crude pipeline capacity to delivery these rising flows of Western Canadian crude to the market is compelling.

Total crude demand in the Ontario and U.S. Midwest markets accessible via the Alberta Clipper pipeline exceeds 650,000 m^3/d (4,000 kb/d). There is also the likely possibility that the very large U.S. Gulf Coast market, and perhaps the U.S. East Coast market, can be accessed using the Alberta Clipper pipeline via one or more high-capacity pipeline projects currently in commercial development. The U.S. Gulf Coast market is roughly twice the size of the markets initially accessible through the Alberta Clipper pipeline.

Demand prospects for Canadian crude are bright within the markets that the Alberta Clipper pipeline can initially access. Western Canadian crude represents an economically attractive feedstock for the refiners in these markets and, accordingly, the refiners are actively pursuing various upgrading and expansion projects to further increase their ability to process Western Canadian crude. In addition, there is a significant volume of competing crudes that currently flow into Ontario and the Midwest that can be displaced by Western Canadian crude grades.

The Alberta Clipper pipeline promises to provide significant benefits, both to the Canadian crude producer and to the Canadian and U.S. refiners that consume Western Canadian crude. The two key Alberta Clipper Pipeline Project benefits are:

- Improved access to refining customers within Ontario and the Midwest
- Avoidance of shut-in of Western Canadian crude production

The Project benefits are summarized in Table I, and are further detailed in the body of the report.

TABLE I
ESTIMATED ALBERTA CLIPPER BENEFITS
(Millions of Dollars per Year)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Improved Access	-	367	139	441	301	277	180	320	263	159	304
Avoided Shut-in Cost	-	473	1,812	4,570	158	315	1,655	2,206	2,758	3,073	3,309
Total	**-**	**839**	**1,951**	**5,011**	**458**	**592**	**1,834**	**2,526**	**3,021**	**3,233**	**3,613**

The economic benefits related to improved access to the customers for Western Canadian crude have been assessed using Muse's Crude Market Optimization Model. This tool is a distribution model of the entire Western Canadian crude market place that considers pipeline capacities and tariffs, refinery capacities and capabilities, and individual crude grade refining values. The model uses linear programming (LP) techniques to develop the optimal disposition for Western Canadian crude production, such that the netback prices for the producers are maximized. The model includes the markets in the Rockies, the West Coast, and Northeast Asia that are not supplied via the Alberta Clipper pipeline. The estimated incremental shipments on Enbridge's eastbound system to Superior, Wisconsin, using the Crude Market Optimization Model, are shown in Table II.

TABLE II
ESTIMATED INCREMENTAL EASTBOUND ENBRIDGE SHIPMENTS
(Units as Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Thousands of Cubic Meters per day	20	33	52	92	66	73	104	113	97	114	115
Thousands of Barrels per day	128	206	329	578	415	459	655	709	610	717	722

The estimated volume of Western Canadian crude that the Alberta Clipper pipeline enables to be produced (or not be shut-in) is sizable. To develop the estimated volume, the following assumptions have been made:

- A new pipeline to the coast of British Columbia has been constructed by 2014 with an ultimate capacity of 127,200 m3/d (800 kb/d)
- TransCanada's Keystone Pipeline Project has proceeded with a ultimate capacity of 96,800 m3/d (590 kb/d) of crude oil, with an in-service date of 2010
- Kinder Morgan Canada proceeds with a 6,400 m3/d (40 kb/d) expansion of its Trans Mountain pipeline by 2009

The estimated shut-in production, absent the Alberta Clipper pipeline, is shown in Table III. To estimate the cost of the shut-in production, Muse

TABLE III
ESTIMATED SHUT-IN WESTERN CANADIAN CRUDE PRODUCTION
(Units as Noted)

	2010	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*
Thousands of Cubic Meters per day	-	9.5	36.6	92.2	3.2	6.4	33.4	44.5	55.6	62.0	66.8
Thousands of Barrels per day	-	60	230	580	20	40	210	280	350	390	420

has assumed that the shut-in production is an Athabasca bitumen, which tends to have the highest production cost but receive the lowest market price. The estimated market price for a blended Athabasca bitumen is obtained from the Crude Market Optimization Model, and adjusted for the diluent content to determine the market price for the Athabasca bitumen. From the Athabasca bitumen price, a production cost of $CN19.00 per barrel (/bbl) is subtracted. The resultant bitumen value is multiplied by the annual shut-in volume to estimate the net economic benefit, in terms of avoided shut-in crude production, of the Alberta Clipper pipeline.

Western Canadian Crude Supply Forecast

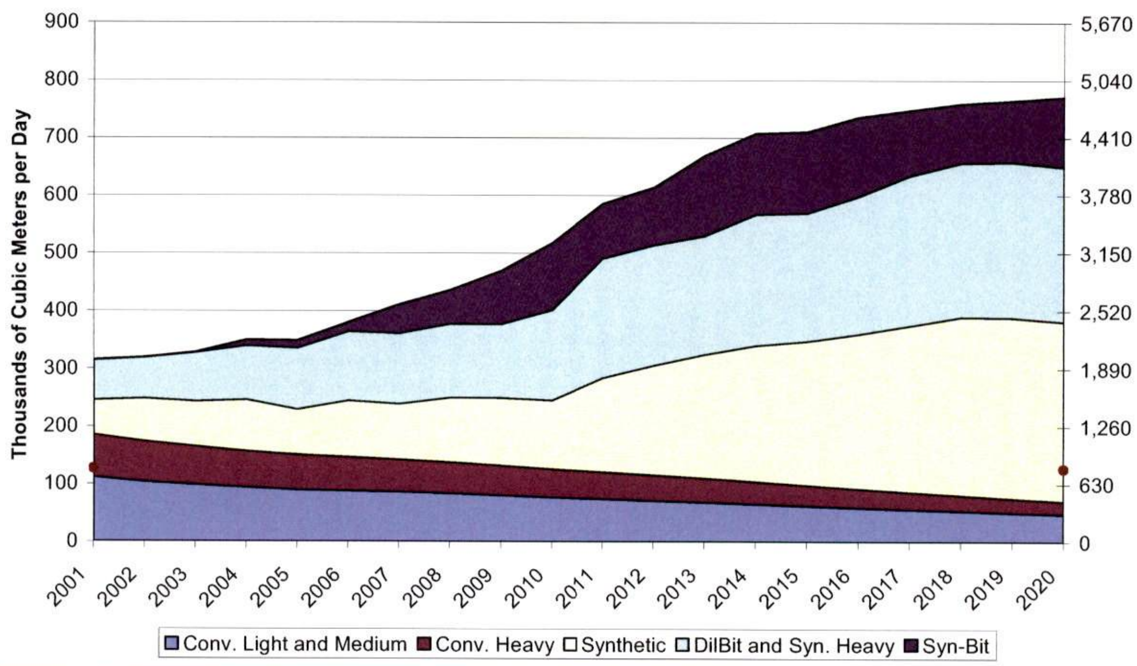
Western Canadian crude production exceeded 380,000 m^3/d (2,400 kb/d) in 2006, and it is widely anticipated that production will continue to climb over the next decade. For purposes of this study, the Western Canadian crude production forecast developed by CAPP has been used. CAPP periodically develops a crude production forecast to provide its members with information to evaluate the need for new pipeline capacity from Western Canada to various markets. CAPP's most recent forecast was publicly released in May 2006.[1] The forecast is based upon a combination of a survey of CAPP's member companies regarding their plans for Oil Sands production and an extrapolation of historical trends for conventional crude production. CAPP represents the upstream oil and gas industry in Canada, and its approximately 150 member-companies collectively produce more than 95 percent of Canada's natural gas and crude oil.

Supply from the Oil Sands and upgraders is projected to grow at an annual average 8 percent rate to reach some 700,000 m^3/d (4,400 kb/d) by 2020. Total Western Canadian crude supply will reach 770,000 m^3/d (4,900 kb/d), which is about a two-fold increase from the 2006 volume. The total supply of heavy crude is forecast to increase from today's total of roughly 195,000 m^3/d (1,200 kb/d) to 410,000 m^3/d (2,600 kb/d) by 2020.[2]

Figure 1 illustrates CAPP's forecast of the total supply of Western Canadian crude. The heavy conventional crude and bitumen produced in Western Canada must be blended with a diluent, such as condensate, before they can be transported via pipeline. The CAPP forecast shown in Figure 1 assumes that a condensate import pipeline has been commissioned with initial imports of 23,800 m^3/d

(150 kb/d), growing to 31,800 m^3/d (200 kb/d) by 2020. There are at least two condensate import pipeline projects currently in the commercial development phase, including Enbridge's Southern Lights Project, which is presently awaiting regulatory approval. CAPP also has a crude supply forecast based upon the use of synthetic crude as the bitumen diluent, rather than condensate. The total volumes are substantially the same, as they differ only by the volume of imported condensate.

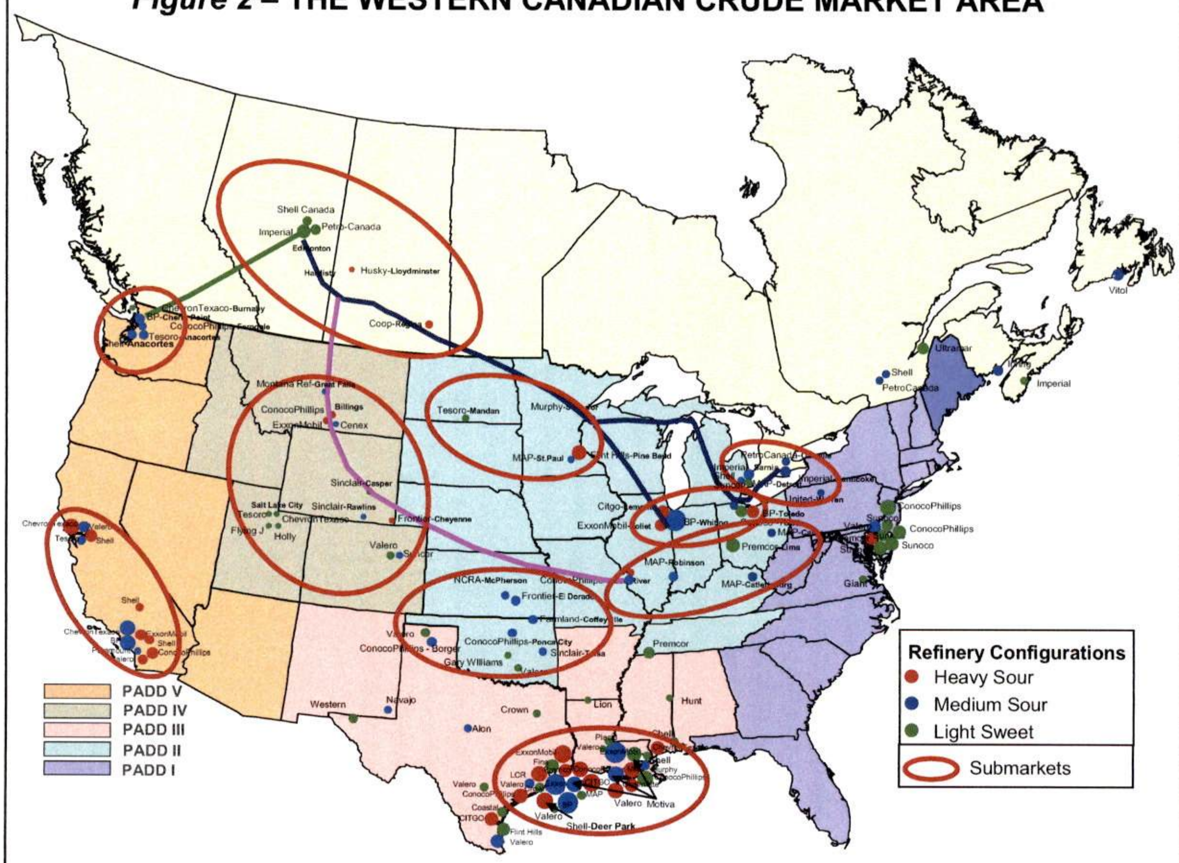
FIGURE 1
CAPP WESTERN CANADIAN CRUDE SUPPLY FORECAST



CHARACTERIZATION OF WESTERN CANADIAN CRUDE MARKET

The current Western Canadian crude market area encompasses an area that ranges from the Puget Sound area in the west, as far south as Oklahoma, and east to Pennsylvania. Figure 2 displays a number of the attributes of this market area: regional submarkets; relative refinery size (distinguished by diameter of the circles); and refinery configuration, which strongly influences the type of crude (light sweet, heavy sour, etc.) preferred by the refiner.

***Figure 2* – THE WESTERN CANADIAN CRUDE MARKET AREA**



The Alberta Clipper pipeline facilitates access to a broad region within the current Western Canadian market area, including Ontario, which contains over 20 percent of Canada's total refining capacity. In addition, using existing pipeline infrastructure, almost every refinery in PADD II can be accessed with crude deliveries made through the Alberta Clipper pipeline.[3] Total refining capacity in Ontario and PADD II is over 660,000 m^3/d (4.0 million b/d), and this refining capacity comprises roughly 70 percent of the total refining capacity within the current market area. Longer term, the target market for crude shippers on Alberta Clipper may well include the very large U.S. Gulf Coast market and perhaps the U.S. East Coast, via one or more pipeline projects currently under commercial development. Table IV provides a summary of the crude distillation capacities of the Ontario and U.S. refineries accessible through the Alberta Clipper pipeline, as well as the pipeline route (or routes) by which the refineries can be reached from Canada. All but three of the U.S. refineries shown in Table IV are in PADD II.[4]

TABLE IV

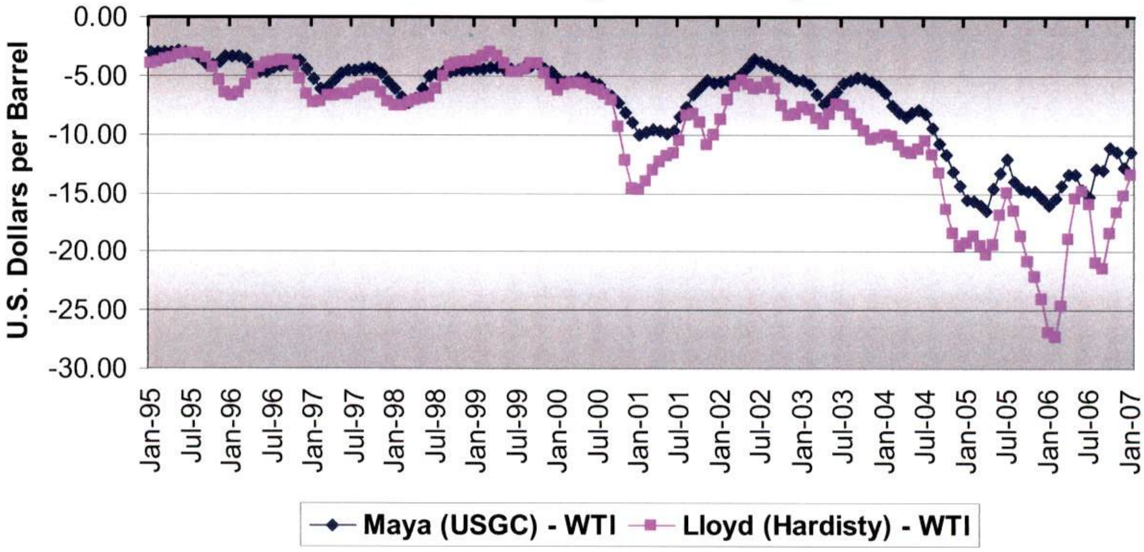
REFINERIES ACCESSIBLE VIA ALBERTA CLIPPER PIPELINE
(Units as Noted)

Refinery	*Pipeline Routing From Superior*	*m^3/cd*	*kb/cd*
Ontario/Pennsylvania			
Imperial Nanticoke	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	17,800	112.0
Imperial Sarnia	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	19,200	120.8
Nova Corunna	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	12,700	80.0
Shell Sarnia	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	11,400	71.4
Suncor Sarnia	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	11,100	70.0
United Warren	Lakehead Line 5, Lines 6A/B to Sarnia/Local Connections	10,300	65.0
Subtotal		**82,500**	**519.2**
Northern Tier			
Flint Hills Pine Bend	Direct at Clearbrook/Minnesota PL	42,100	265.0
Marathon St. Paul	Direct at Clearbrook/Minnesota PL	11,100	70.0
Murphy Superior	Direct at Superior	5,200	33.0
Tesoro Mandan	None presently	9,200	58.0
Subtotal		**67,600**	**426.0**
Upper Midwest			
BP Toledo	Lakehead Line 5, 6B/Local Connections	20,800	131.0
BP Whiting	Lakehead Line 6A, 14, Southern Access	65,200	410.0
CITGO Lemont	Lakehead Line 6A, 14, Southern Access	26,600	167.0
ExxonMobil Joliet	Lakehead Line 6A, 14, Southern Access	37,900	238.5
Marathon Detroit	Lakehead Line 5, 6B/Local Connections	15,900	100.0
Sunoco Toledo	Lakehead Line 5, 6B/Local Connections	25,400	160.0
Subtotal		**191,800**	**1,206.5**
Lower Midwest	**(Connections from Chicago)**		
COP/EnCana Wood River	Southern Access Extension or Mustang/CapWood	48,700	306.0
Valero Lima	Southern Access Extension or Mustang/Marathon	23,400	146.9
Marathon Robinson	Southern Access Extension or Mustang/Marathon	30,500	192.0
Marathon Canton	Southern Access Extension or Mustang/Marathon	11,600	73.0
Marathon Catlettsburg	Southern Access Extension or Mustang/Marathon	35,300	222.0
Subtotal		**149,500**	**939.9**
Mid-Continent	**(Connections from Chicago)**		
Coffeyville Resources, Coffeyville	Spearhead/Plains	17,800	112.0
ConocoPhillips/EnCana Borger	Spearhead/ConocoPhillips	23,200	146.0
ConocoPhillips Ponca City	Spearhead/ConocoPhillips	30,800	194.0
Frontier El Dorado	Spearhead/Jayhawk	16,900	106.0
NCRA McPherson	Spearhead/Jayhawk	12,900	81.2
Sinclair Tulsa	Spearhead/Local Connections	11,200	70.3
Sunoco Tulsa	Spearhead/Local Connections	13,500	85.0
Valero Ardmore	None presently	13,300	83.6
Valero Sunray	None presently	25,200	158.3
Gary-Williams Wynnewood	Spearhead/Local Connections	8,600	54.0
Subtotal		**173,400**	**1,090.5**
U.S. Gulf Coast(1)	Southern Access Extension or Mustang/Pegasus	**10,500**	**66.0**
Grand Total		**675,300**	**4,248.1**

Notes: (1) Access to the U.S. Gulf Coast currenly limited by the capacity of the Pegasus pipeline.

Demand prospects for Canadian crude are bright, as Western Canadian crude represents an economically attractive feedstock for North American refiners. The increasing supply of Canadian heavy crude, and to a lesser extent Canadian synthetic crude, has applied downward pressure in recent years on Canadian crude pricing relative to similar grades from elsewhere. As an example of these recent trends, Figure 3 illustrates the pricing relationships for Lloydminster Blend versus Maya, both heavy sour crudes from Canada and Mexico, respectively.

Figure 3
Crude Pricing Relationships



Both pricing series are expressed as a differential to West Texas Intermediate (WTI) crude, thus eliminating the effect that changes in the absolute crude price has upon the price of the two heavy grades. The Maya differential provides a benchmark of the global pricing relationships between heavy sour crude and light sweet crudes. Lloydminster Blend, since about 2001, has frequently traded at a greater differential to WTI than does Maya, although in previous years its differential to WTI was similar to that of Maya. This widening Lloydminster Blend differential is a consequence of the increased supply of Canadian heavy crude within the markets to which the Canadian crudes have access. Consequently, North American refineries that can access and process Canadian heavy crude have found it to be increasingly attractive in the last several years, relative to their heavy sour crude alternatives available from elsewhere.

Future crude demand for Western Canadian crude within the current market area also will be influenced by the extent to which refiners act to reconfigure their facilities to process additional Canadian crude, particularly the heavy sour grades. In almost all of the submarkets within the overall Canadian market area, there is little demand for heavy fuel oil and asphalt demand is finite. Demand growth prospects for asphalt are low and negative for heavy fuel oil. High transportation costs preclude refiners from shipping excess production of either to other regions of North America. Thus, since refiners in the Canadian market area cannot sell more heavy fuel oil and asphalt, they must convert the heavy fractions (frequently referred to as resid) of the crude barrel into light products within the refinery.[5] As the refinery process units that convert resid are routinely operated at their maximum capacity, most refineries have a limited ability to further increase their runs of heavy crude, irrespective of the degree of attractiveness of the heavy crude pricing. Moreover, some refineries are not well equipped to process any significant volumes of heavy crude, as they lack the desulfurization capabilities required to accommodate the heavy crude grades. Essentially all of the heavy crude grades produced in Western Canada have a high sulfur content.

The marketing issues associated with Canadian synthetic crudes are somewhat less acute than is the case for the heavy sour grades. Most refineries can process some amount of synthetic crude, and the volume that they can process tends to be driven as much by the pricing of the synthetic grades, relative to other conventional crude grades available to the refiner, as by technical considerations. In addition, the synthetic crude producers generally have been improving the quality of their crude grades so that refiners can process more before the technical limits on synthetic crude rates are reached.

Refiners are also interested in upgrading their facilities to process more Western Canadian crude for reasons other than price. These reasons include: the recognition that the supply of Western Canadian crude is increasing significantly and, therefore, will be available for the long term; improved security of supply; shorter delivery times; and, for some, a desire to integrate their Canadian upstream crude production business with their downstream refining business. The relative importance of these reasons varies among refiners but, in the aggregate, they are prompting refiners to propose an unprecedented number of upgrading projects. However, these upgrading projects are all predicated upon being able to receive Canadian crude, as only Canada offers a combination of supply availability and security, delivery time, crude cost, and upstream-downstream integration possibilities that makes these upgrading projects attractive. It is exceedingly unlikely that any sizable upgrading project in Ontario or PADD II would proceed absent assured transportation capacity for crude from Western Canada. The Alberta Clipper Project provides the Ontario and PADD II refineries with just such access.

To forecast the utilization of the Alberta Clipper, as well as the associated economic benefits for the crude producers and refiners, Muse has employed its Crude Market Optimization Model (details of the model are provided later in this report). The model allocates all of the Western Canadian crude production among a number of refinery configurations within the various submarkets within North America as well as

Northeast Asia. Figure 4 illustrates the forecast disposition of Western Canadian crude, assuming that the Alberta Clipper pipeline is in operation. This figure also highlights that flows to the markets not served by Alberta Clipper pipeline, i.e., the Rockies and West Coast/Asia, are not reduced as a result of the Alberta Clipper pipeline, but are in fact increasing.

Figure 4
Disposition of Total Western Canadian Crude

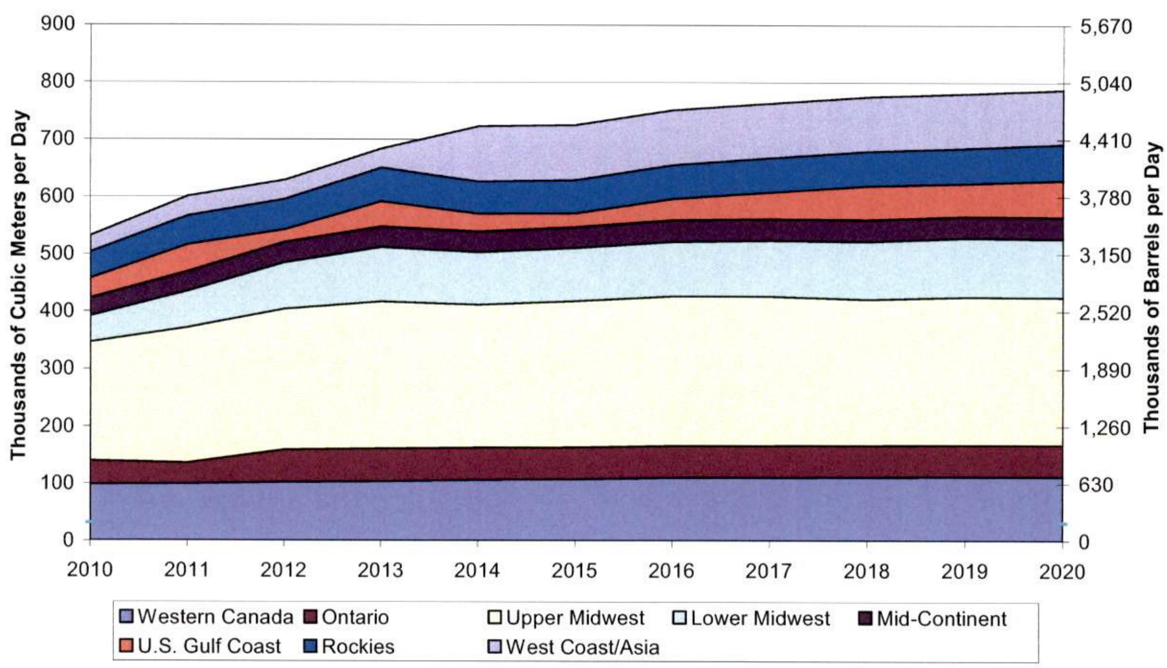
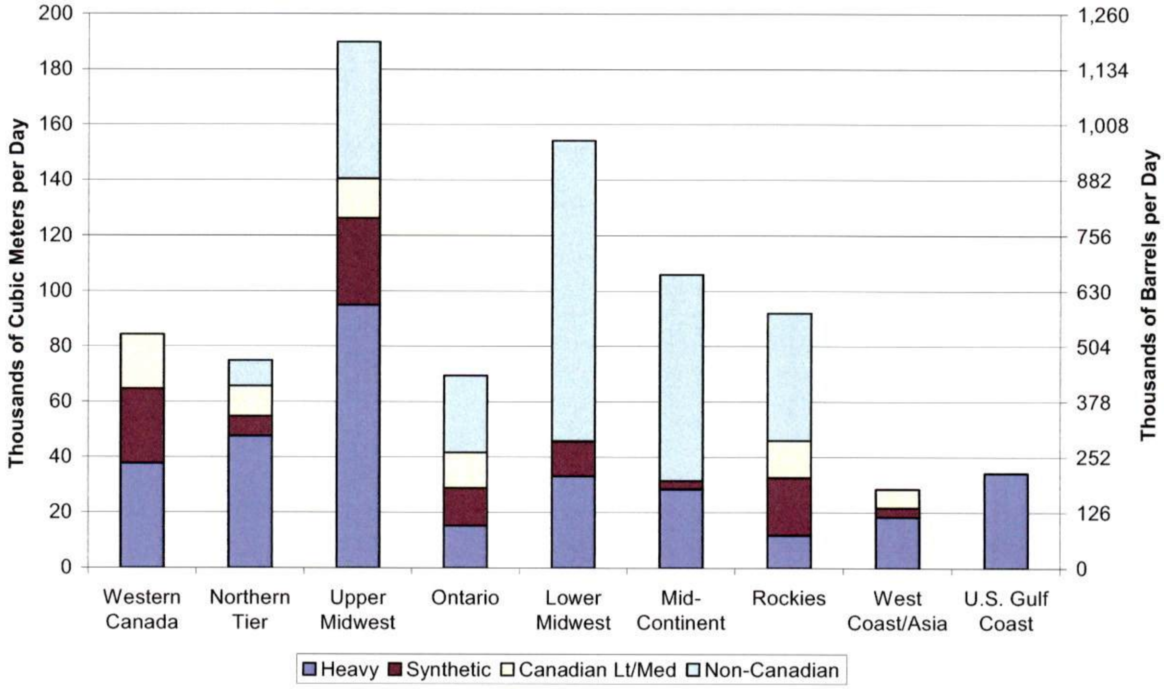


Figure 5 provides further detail of the estimated distribution of Western Canadian crude by crude grade, and by regional submarket, for the year 2010. All of the regional submarkets will be discussed, with a greater level of detail offered for those market areas serviced by the Alberta Clipper Pipeline Project. Figure 5 also provides a sense of the relative size of the inland submarkets. The comparison is not valid for the West Coast/Asia and U.S. Gulf Coast submarkets, as in these two submarkets the non-

Canadian receipts are not shown because they total millions of barrels per day. For the Ontario submarket, the volume identified as Non-Canadian may include crude produced offshore of Atlantic Canada.

Figure 5
Year 2010 Western Canadian Crude Distribution



WESTERN CANADA

The Western Canadian submarket includes the three refineries in the Edmonton area; the Husky Lloydminster asphalt refinery, and the Husky Prince George and Gibson Moose Jaw refineries.[6] The Husky upgrader at Lloydminster and the Consumers' Cooperative Regina refinery are also included in this submarket, and are modeled as both a consumer of Canadian heavy and a producer of sweet synthetic. Accordingly, Figure 5 shows the net consumption of synthetic in Western Canada (submarket refinery synthetic consumption less the Husky upgrader and Consumers'

Cooperative synthetic production). The announced configuration changes for the area refineries, particularly for the Petro-Canada Edmonton refinery, are considered, although a shift in the crude grades processed in Edmonton does not change the total volume of crude that must be transported from Western Canada to the broader market. Other than the announced projects, crude consumption in Western Canada is projected to increase at the rate of approximately 0.5 percent per year, reflecting capacity creep.

NORTHERN TIER

As shown in Table V, the Northern Tier submarket is dominated by the large Flint Hills Pine Bend refinery, which is one of the largest consumers of heavy sour crude in the entire market area for Western Canadian crude, based upon public records available from the EIA.[7] In addition to refinery capacity, Table V also provides the refinery configuration, which strongly influences the refiner's desired crude mix. The Marathon St. Paul and Murphy Superior refineries primarily process a combination of light sweet crudes and heavy sour crudes. The Tesoro Mandan refinery primarily processes local North Dakota crudes.

TABLE V

2006 NORTHERN TIER REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	*m^3/cd*	*kb/cd*
Flint Hills Pine Bend	Hvy Sour Coking	42,100	265.0
Marathon St. Paul	Lt. Swt Cracking/Hvy Sour Asphalt	11,100	70.0
Murphy Superior	Lt. Swt Cracking/Hvy Sour Asphalt	5,200	33.0
Tesoro Mandan	Lt. Swt Cracking	9,200	58.0
Total		**67,600**	**426.0**

Prospects for increased consumption of Canadian crude are rather limited, as essentially all of the crude consumed in this submarket is either Canadian or local crude grades, as illustrated in Figure 5. Other than capacity creep, the only anticipated capacity increase is at the Pine Bend refinery, where capacity is projected to increase by 7,900 M^3/d (50 kb/d) by 2008. Most of this capacity increase, if not all of it, will likely be for heavy sour crude.

The primary means of external crude supply to this submarket is via the Enbridge system. For the Murphy Superior refinery, Enbridge is the only avenue of crude supply. The Flint Hills and Marathon refineries have a pipeline connection to the Enbridge Clearbrook terminal, where they receive most of their Western Canadian crude deliveries. These two refineries can also receive Western Canadian crude from the South, however, the route is considerably longer and more expensive.

UPPER MIDWEST

The Upper Midwest is the largest submarket in North America until the U.S. Gulf Coast is reached. Individual refinery capacities are shown in Table VI. The refineries are concentrated in the Chicago area (BP Whiting, CITGO Lemont, and ExxonMobil Joliet) and in the Detroit/Toledo area, both heavily populated areas that have sizable local demand for petroleum products. Total crude capacity exceeds 190,000 m^3/d (1,200 kb/d) and much of the refining capacity is configured to process Canadian heavy sour crude, making the region a key demand center for Canadian heavy crude. Moreover, the Sunoco Toledo refinery has emerged as a sizable customer for Canadian synthetic crude.

TABLE VI

2006 UPPER MIDWEST REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	*m^3/cd*	*kb/cd*
BP Toledo	Hvy Sour Coking	20,800	131.0
BP Whiting	Lt. Swt Cracking/Hvy Sour Coking/Asphalt	65,200	410.0
CITGO Lemont	Hvy Sour Coking	26,600	167.0
ExxonMobil Joliet	Hvy Sour Coking	37,900	238.5
Marathon Detroit	Lt. Swt Cracking/Hvy Sour Asphalt	15,900	100.0
Sunoco Toledo	Lt. Swt Cracking	25,400	160.0
Total		**191,800**	**1,206.5**

Prospects for increased consumption of Canadian crude are strong. In 2005, BP announced that it will begin repositioning its refining portfolio to provide additional Canadian heavy crude processing capabilities at its Whiting and Toledo refineries, although details were not offered at that time.[8] In September 2006 the details were provided, as BP disclosed a $US3 billion project at Whiting that is now in the final planning stages and is tentatively scheduled for completion by 2011. The project will increase Canadian heavy crude processing capability by about 41,300 m^3/d (260 kb/d) via the addition of a world-scale coking unit, a hydrogen plant, and various revamps and enhancements to other existing units and refinery infrastructure.[9] As total refinery crude capacity is not being significantly increased as part of this project, the higher throughput of Canadian crude will likely displace some of the U.S. and waterborne light sweet crude grades that the Whiting refinery currently processes.

Marathon has announced that it is exploring the addition of a coker at its Detroit refinery with a potential completion date of 2009 or 2010. At Detroit, the installation of a 3,200 m^3/d (20 kb/d) coker and concurrent ancillary modifications will allow the refinery to increase its heavy crude throughput by up to 10,300 m^3/d (65 kb/d), and to boost its overall refining capacity to 17,900 m^3/d (113 kb/d). Marathon is currently engaged in a detailed engineering and design study of the project, which is expected to be completed by late 2007.[10] Finally, Sunoco has also disclosed that it is adding 7,900 m^3/d (50 kb/d) of crude capacity to its Toledo refinery, increasing its capacity by roughly one-third.[11] The modification is in response to Sunoco's desire to increase its utilization of Canadian synthetic crudes.

The Enbridge system, including the Alberta Clipper pipeline, is the most economic and practical means to supply the Upper Midwest submarket with Western Canadian crude. It is also physically possible to deliver Western Canadian crude into Patoka, Illinois, via either the Express-Platte or Keystone pipelines, and then up the

ChiCap pipeline to Chicago. However, this route is considerably longer, more expensive, and fraught with logistical complexities concerning crude grade segregation and pipeline scheduling. Other than perhaps the occasional opportunistic purchase, the refiners in the Upper Midwest submarket generally would not be interested in Western Canadian crude receipts via this southern route versus the Enbridge alternative.

ONTARIO / WESTERN PENNSYLVANIA

The Ontario submarket encompasses a number of refineries that have a wide range of crude processing capabilities. Although the regional heavy sour crude runs are not immaterial, this submarket predominately processes synthetic and various grades of conventional light and medium crudes. This submarket definition also includes the United Warren refinery in western Pennsylvania, as it can only receive crude via the Enbridge pipelines that transit Ontario, other than perhaps some local trucked barrels. The individual refinery capacities and configurations are shown in Table VII below.

TABLE VII

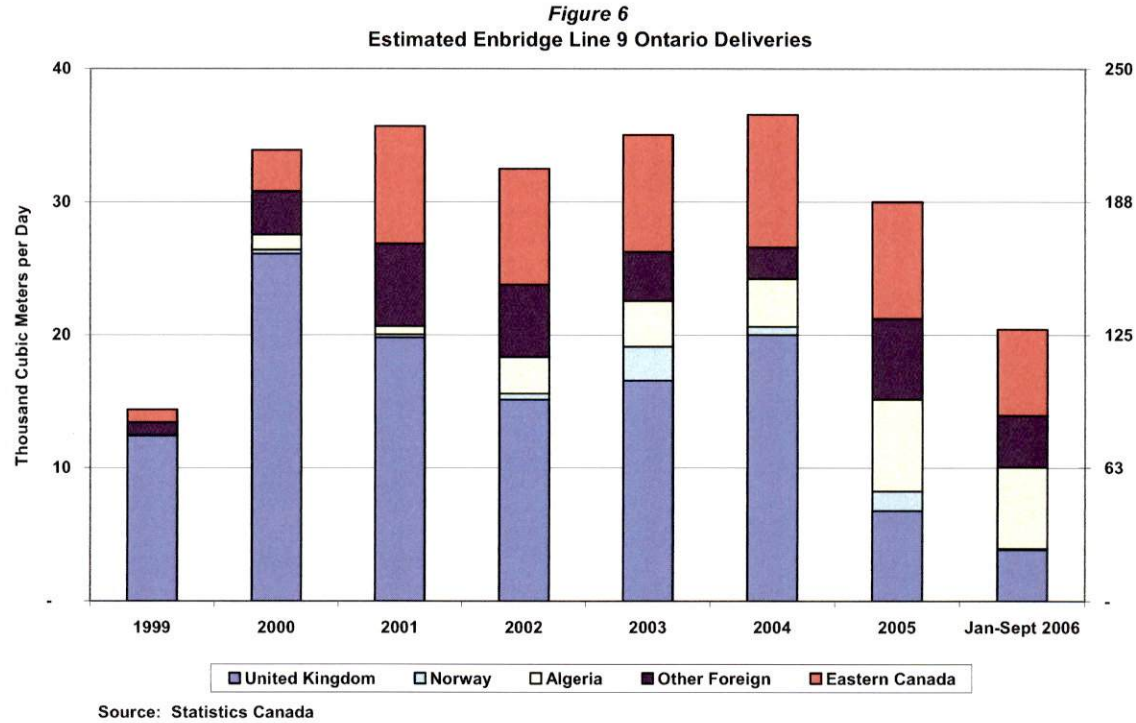
2006 ONTARIO / WESTERN PENNSYLVANIA REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	m^3*/cd*	*kb/cd*
Imperial Nanticoke	Medium Sour Cracking	17,800	112.0
Imperial Sarnia	Medium/Hvy Sour Coking	19,200	120.8
Nova Corunna	Petrochemical	12,700	80.0
Shell Sarnia	Lt. Sour Cracking	11,400	71.4
Suncor Sarnia	Lt. Sour Cracking	11,100	70.0
United Warren	Medium Sour Cracking	10,300	65.0
Total		**82,500**	**519.2**

Prospects for increased consumption of Western Canadian crude are strong for three reasons: the potential construction of a new Ontario refinery; the need to replace decreasing crude flows received via the Enbridge Line 9 pipeline from Montréal; and, capacity increases at existing refineries. Of these three reasons, the first two likely will have the greatest impact upon future Western Canadian crude demand in the Ontario submarket, although capacity increases at existing refineries via various debottlenecking projects also may be material over time.

In November 2006, Shell Canada announced that it was engaged in the pre-development and front-end engineering for a new 23,800 to 39,700 m^3/d (150 to 250 kb/d) heavy oil refinery to be located near Sarnia.[12] The refinery will be primarily designed to process heavy crude from Western Canada, as Shell indicated that it is seeking downstream solutions to maximize the value from its growing Oil Sands production. The decision to proceed will be made in the next 2 to 3 years.

Through September 2006, the Ontario crude receipts via the Enbridge Line 9 pipeline averaged an estimated 20,400 m^3/d (125 kb/d) of crude from the Atlantic Basin. The historical pattern of the estimated Line 9 shipments is illustrated by Figure 6. Through September 2006, these shipments comprised roughly 35 percent of the total crude runs in the province, down somewhat from the proportion in previous years. The crude received, via Line 9, is mostly production from offshore Atlantic Canada, the North Sea, and Algeria.



Until recently, Ontario refiners have enjoyed a modest cost advantage for their North Sea crude receipts, relative to crude receipts from Western Canada. However, declining crude production in the North Sea, combined with rising production in Western Canadian, promises to permanently eliminate the cost advantage for North Sea crude deliveries. By 2012, North Sea crude production will have dropped to a level, with a concomitant increase in price, such that Ontario refiners likely will find other Atlantic Basin crude grades more economically attractive. As the alternatives are more distant than the North Sea, the declining North Sea production will erode the cost advantage that Ontario refiners have historically enjoyed for crude receipts via Line 9. Over the same time period, rising Western Canadian crude production will be applying downward price pressure on Western Canadian crude grades, also acting to erode the cost advantage for crude supply from the Atlantic Basin. Such shifts in crude pricing will reduce flows on Line 9 and, thus, open up market space for increased crude receipts from Western Canada. In addition, the Oil Sands ownership positions held by most of the Ontario refiners acts to enhance the prospects for various Ontario refinery upgrading projects that will increase runs of Western Canadian crude.

As is the case for the Upper Midwest submarket, the Enbridge system is the most practical and economic means to supply the Ontario submarket with Western Canadian crude. It is physically possible to deliver Western Canadian crude into Patoka via either the Express-Platte or Keystone pipelines, and then up the ChiCap pipeline to Chicago, and then through Enbridge Line 6B to Ontario. However, Ontario refiners and the United Warren refinery likely will have little interest in this route

LOWER MIDWEST

Today, refineries in the Lower Midwest submarket primarily process various grades of conventional light sweet, light sour, and medium sour crudes. However, Canadian crude runs in the Lower Midwest submarket are projected to increase significantly over the forecast period from a combination of better pipeline connectivity to Western Canada, more attractive Canadian crude pricing relative to the refiners' alternatives, and refinery upgrading plans that are directed towards increasing Canadian crude runs. Table VIII displays the current refinery capacities and configurations in this submarket.

TABLE VIII

2006 LOWER MIDWEST REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	*m^3/cd*	*kb/cd*
COP/EnCana Wood River	Lt. Swt Cracking/Hvy Sour Asphalt	48,700	306.0
Valero Lima	Lt. Swt Coking	23,400	146.9
Marathon Robinson	Lt. Sour Coking	30,500	192.0
Marathon Canton	Lt. Swt Cracking/Hvy Sour Asphalt	11,600	73.0
Marathon Catlettsburg	Lt. Sour Cracking	35,300	222.0
Total		**149,500**	**939.9**

As of January 2, 2007, the Wood River refinery became part of a joint venture between ConocoPhillips and Encana. The owners of the new joint venture have disclosed that the Wood River refinery will undergo a $US1.9 billion upgrading project to add an estimated 11,100 m^3/d (70 kb/d) of bitumen (before blending with diluent) capacity by 2009 via the construction of a new 10,300 m^3/d (65 kb/d) coker. A second phase of the expansion is a $US2.0 billion crude unit and coker expansion that will add another 15,900 m^3/d (100 kb/d) of bitumen capacity by 2013.

Marathon has also announced that it is exploring the addition of a coker to its Catlettsburg refinery. The 5,900 m^3/d (37 kb/d) coker project at the Catlettsburg facility will permit the utilization of up to an additional 20,700 m^3/d (130 kb/d) of medium and heavy sour crudes, increasing their proportion of the refinery's crude slate to about 90 percent once the upgrades are completed.[13] The feasibility study phase of this project is expected to be completed by late 2007. Marathon has further commented that some type of expansion or upgrading program to increase Canadian crude runs at its Robinson refinery is also possible.

Canadian crude can be supplied to this submarket via the Enbridge Southern Access Extension Pipeline (which connects the Chicago area with Patoka), Express-Platte, or via the proposed Keystone pipeline. Some of the new Canadian crude demand, particularly at the Wood River refinery, can be expected to be satisfied via the Keystone pipeline, as ConocoPhillips has publicly disclosed its status as a committed shipper on the Keystone pipeline. Nevertheless, the delivery of Canadian crude via the Enbridge system is cost competitive with the alternatives.

MID-CONTINENT

Refineries tend to be configured to process the crudes that are abundant in their local market area. In the case of the Mid-Continent, the crudes produced in Oklahoma and Kansas, as well as in West Texas, are predominately light sweet and medium sour grades. Accordingly, most of the refineries in the Mid-Continent are configured to run light sweet or medium sour crudes, or some combination. However, with the start up of the Enbridge Spearhead pipeline in 2006 (which connects the Chicago area with Cushing, Oklahoma), interest among the local refiners in Canadian crude supply has increased. Table IX displays the current refinery capacities and configuration for the Mid-Continent region.

TABLE IX

2006 MID-CONTINENT REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	*m^3/cd*	*kb/cd*
Coffeyville Resources, Coffeyville	Medium Sour Coking	17,800	112.0
ConocoPhillips/EnCana Borger	Medium/Hvy Sour Coking	23,200	146.0
ConocoPhillips Ponca City	Lt/Medium Sweet Coking	30,800	194.0
Frontier El Dorado	Medium Sour Coking	16,900	106.0
NCRA McPherson	Medium Sour Coking	12,900	81.2
Sinclair Tulsa	Lt./Med Sour Cracking	11,200	70.3
Sunoco Tulsa	Lubes	13,500	85.0
Valero Ardmore	Lt./Med Sour Cracking	13,300	83.6
Valero Sunray	Lt. Sweet Cracking	25,200	158.3
Gary-Williams Wynnewood	Lt. Sweet Cracking	8,600	54.0
Total		**173,400**	**1,090.5**

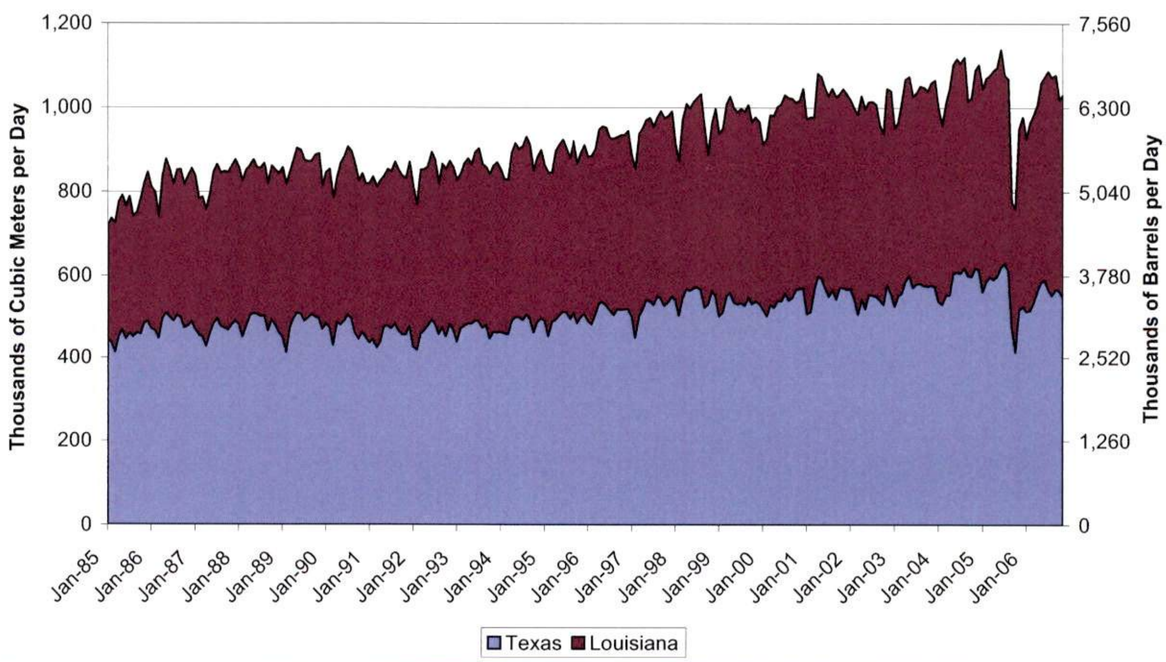
For example, Frontier has announced that it is investing $US140 million to increase both its heavy crude capacity and total crude capacity at the El Dorado refinery by the end of 2008. The project will expand the crude and vacuum distillation units to increase the refinery's overall capacity by 1,600 m^3/d (10 kb/d) and will provide for greater utilization of heavy crudes, from 1,900 to 6,300 m^3/d (12 to 40 kb/d).[14] The ConocoPhillips/EnCana Borger refinery expects to commission a coker in 2007, which will enable the refinery to shift to a heavier, more sour, crude slate. The partnership has plans to expand capability of Borger to process Canadian bitumen to 11,900 m^3/d (75 kb/d) by 2012.

Crude flows on the Alberta Clipper pipeline for a Mid-Continent destination would be routed through Chicago, and then down the Enbridge Spearhead pipeline to Cushing, Oklahoma. The Spearhead pipeline, with additional power, is capable of up to 30,200 m^3/d (190 kb/d). Enbridge also has developed preliminary plans for a looping project, the first phase of which will provide another 15,900 m^3/d (100 kb/d) of capacity.

U.S. GULF COAST

At over 1,100,000 m^3/d (7,300 kb/d), the refining capacity located on the U.S. Gulf Coast exceeds that of any single country in the world, other than the United States itself. Figure 7 illustrates the actual crude runs for the U.S. Gulf Coast over the last 20 years, and crude throughput has been steadily rising over this period (except for the hurricane-related outages in 2005). This trend can be expected to continue both via debottlenecking projects and potential large-scale refinery expansions.

Figure 7
Monthly U.S. Gulf Coast Crude Runs



The current consumption of heavy sour crude on the U.S. Gulf Coast is approximately 350,000 m^3/d (2,200 kb/d), which makes it the largest demand center for heavy sour crude in the world. Consumption of waterborne light sweet exceeds 150,000 m^3/d (1,000 kb/d), and the refineries that process such grades would be interested in the Canadian sweet synthetics as long as the Canadian synthetic is price competitive.

Access to the U.S. Gulf Coast is currently limited to approximately 10,300 m^3/d (65 kb/d) via the Pegasus pipeline (which delivers crude from Patoka to Beaumont, Texas). Several pipeline projects that will provide better connectivity to the U.S. Gulf Coast are in the commercial development phase, and the prospects of one or more of these projects proceeding is regarded as high by Muse. Although the precise destination of the next pipeline to reach the U.S. Gulf Coast is not yet known, it is Muse's view that the refineries in the Houston area, to at least the refineries in the Lake Charles, Louisiana area, will be connected to Canada via high capacity pipelines. Connectivity to most of the large Louisiana refineries along the Mississippi River is also a distinct possibility. Total refinery capacity in the area just described is approximately 1,000 m^3/d (6,500 kb/d).

ROCKIES

Relative to other refineries in North America, the refineries in this submarket are small, and tend to focus on processing light sweet crude. Refinery capacity is shown in Table X. Crude capacity expansion is expected to be limited to debottlenecking projects. The region is in approximate supply and demand balance for finished petroleum products, and alternative product demand centers are too distant for a major refinery expansion project to make economic sense. This submarket does not receive crude via the Enbridge system (other than crude transported from Edmonton to Hardisty for delivery into the Express pipeline).

TABLE X

2006 ROCKIES REFINING CAPACITY
(Units as Noted)

Refinery	*Configuration Type*	m^3*/cd*	*kb/cd*
Cenex Laurel	Hvy Sour Coking	8,700	55.0
ConocoPhillips Billings	Hvy Sour Coking	9,200	58.0
ExxonMobil Billings	Hvy Sour Coking	9,500	60.0
Montana Refining Great Falls	Hvy Sour Cracking	1,300	8.2
Flying J Salt Lake City	Lt. Sweet Cracking	4,700	29.4
Chevron Salt Lake City	Med Sour Coking	7,200	45.0
Holly Woods Cross	Lt. Sweet Cracking	3,900	24.7
Silver Eagle Woods Cross	Lt. Sweet Cracking	1,600	10.3
Tesoro Salt Lake City	Lt. Sweet Cracking	9,200	58.0
Frontier Cheyenne	Hvy Sour Coking	7,500	47.0
Silver Eagle Evanston	Lt. Sweet Cracking	500	3.0
Sinclair Caspar	Lt. Sweet Cracking	3,900	24.5
Sinclair Sinclair	Med Sour Cracking	10,500	66.0
Suncor Commerce City	Lt/Med/Hvy Sour Cracking	13,800	87.0
Wyoming Refining Newcastle	Lt. Sweet Cracking	2,000	12.5
Total		**93,500**	**588.6**

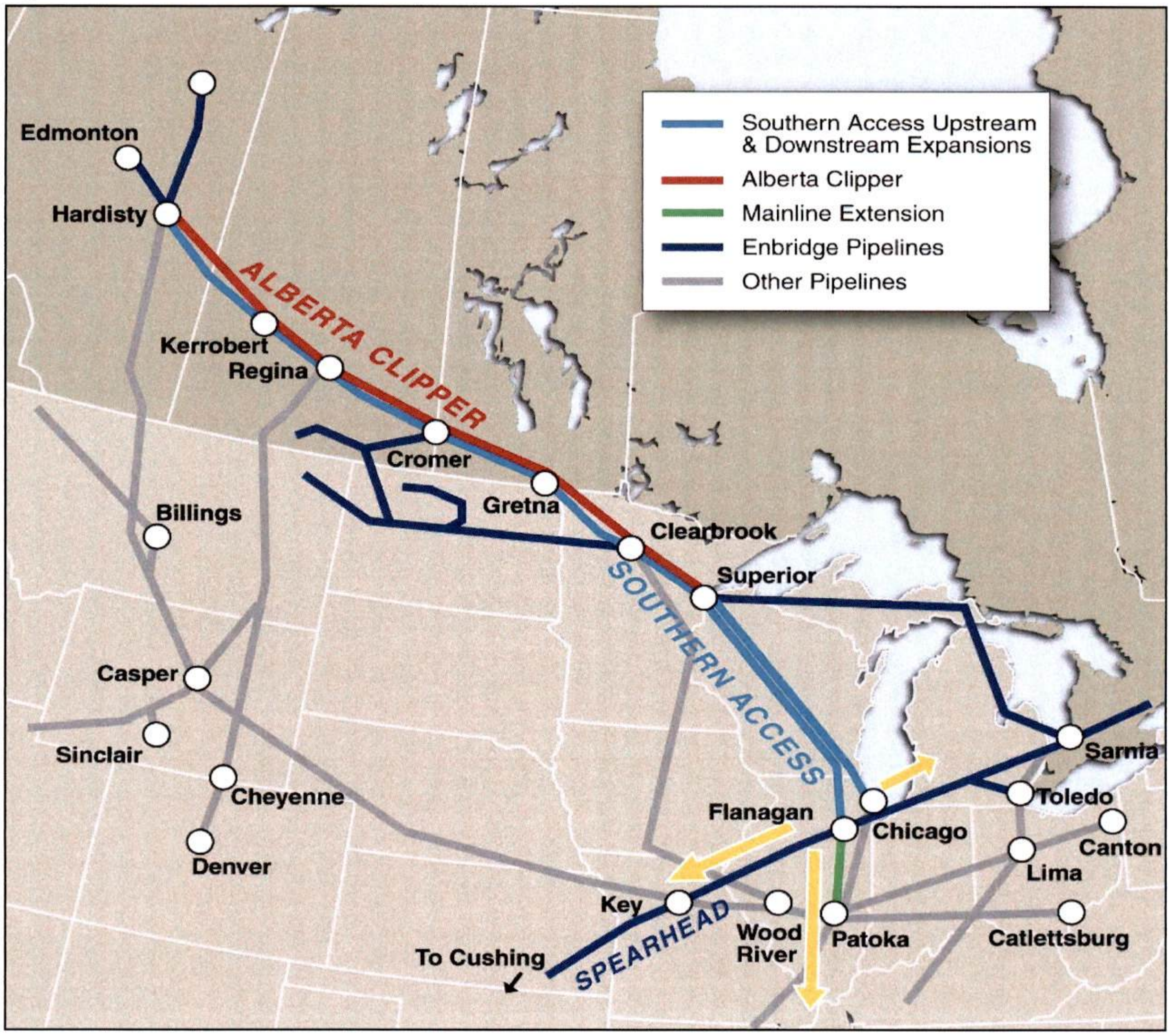
WEST COAST/ASIA

As the Alberta Clipper Pipeline Project does not directly or indirectly service the West Coast and/or the Northeast Asia markets, these markets are not discussed in any detail in this report. However, in the aggregate, the West Coast/Asia markets are very large and will be an attractive market for Western Canadian crude. For purposes of this report, a new crude pipeline that connects Edmonton to a port on the coast of British Columbia, where ocean-going tankers can be loaded to deliver crude to the U.S. West Coast and Northeast Asia markets, has been assumed to be in service in 2014. The assumed pipeline capacity is 63,600 m^3/d (400 kb/d).

ALBERTA CLIPPER PIPELINE PROJECT OVERVIEW

The Alberta Clipper Project will extend from Hardisty, Alberta, to Superior, Wisconsin. The pipeline will integrate with and form part of Enbridge Pipelines Inc.'s mainline crude pipeline system. The project will have an annual capacity of 71,500 m^3/d (450 kb/d). A map of the project is provided as Figure 8. The pipeline will originate at the Enbridge Hardisty terminal. At Superior, the Alberta Clipper pipeline will connect to Enbridge's Lakehead mainline pipelines that extend south to the Chicago, Illinois, area and southeast to the Sarnia, Ontario, area.

Figure 8



The Canadian portion of the project will entail the construction of approximately 1,070 km of new 914 mm (36-inch) diameter pipeline to the U.S. border at Gretna, Manitoba; new receipt tankage, pumping units, and other terminalling facilities at Hardisty; and new pump units between Hardisty and Gretna. The U.S. segment will entail the construction of approximately 520 km of new 914 mm diameter pipeline between Gretna and Superior, as well as pumping units along the pipeline and breakout tankage at Superior.

Lakehead's mainline pipelines that extend south from Superior to the Chicago area are further connected, at Chicago, to several pipelines in addition to the local Chicago area refineries. These pipelines are: Line 6B that extends to the Detroit/Toledo/Sarnia area; Southern Access Extension to Patoka, Illinois; the Mustang pipeline that also runs to Patoka; and the Spearhead pipeline that extends to Cushing, Oklahoma. Appendix 1 provides a map that illustrates these connections. Appendix 2 provides further detail regarding the various pipelines that transport crude from Western Canada to the market.

EXPECTED ALBERTA CLIPPER UTILIZATION

To analytically assess the expected distribution of Western Canadian crude, Muse has constructed a crude distribution model of the Canadian market area. The key model inputs are the volume of Canadian and inland U.S. crude grades, refinery capacities, pipeline capacities and tariffs, and crude refining values. The overall market is broken up into a number of submarkets and individual refineries within each submarket are assigned to a refinery configuration class (light sweet cracking, heavy sour coking, etc.). Thus, within each submarket there may be as few as one refinery configuration or as many as four or five configurations. Pipeline capacities and tariffs for Canadian crudes, and their crude competitors to each submarket, are defined within the model. The model seeks to optimize the distribution of Western Canadian crude by maximizing the aggregate crude value of all Western Canadian crude production at Edmonton, or, in other words, attempts to replicate the individual efforts of Canadian crude producers and their refiner customers to maximize their profit.

An important component of the optimization technique is the determination of the value of the Canadian crude grades to the refiners (the crude's refining value). Muse uses the AspenTech PIMS™ LP modeling system to determine the refining value of crudes. For purposes of this study, Muse developed 20 detailed LP models of different refinery configurations in the Midwest, California, Rockies, U.S. Gulf Coast, and Northeast Asia. The LP models include such details as refinery process unit capacities, finished product specifications, and process unit yields and yield properties that are a function of the quality of the crude being processed.

These 20 LP models were then used to estimate the refining values of five grades of Canadian heavy sour crude and a Canadian synthetic grade over a range of throughput levels. These six grades reasonably cover the variety of Canadian crudes available to the marketplace. The refining value is always assessed relative to the refiner's non-Canadian crude alternative, which typically is a waterborne foreign crude. For the inland submarkets, the refiner's alternative is still a waterborne crude, but its delivered cost also includes the pipeline tariffs necessary to transport the crude inland.

The understanding of the refining value of Canadian crude, from the refiner's perspective, is necessary to determine the optimal disposition of the Canadian crude. Absent the refiner's perspective on crude valuation, an optimization model could only distribute crude on the basis of minimizing total transportation cost (which mostly consists of pipeline tariffs). Refineries, even if in the same location, for a variety of technical reasons, can have quite different refining values for the same grade of crude. Accordingly, the optimal distribution of Western Canadian crude is as much a function of its value to individual refineries as it is of the total cost to transport it to the refineries. In summary, the optimization model mimics the efforts of the crude producers to seek out, and sell to, those refiners that see the greatest value for the particular grades of crude that the producer has for sale, and the attempts by the refiner to simultaneously obtain those particular grades of Canadian crude that best fit its refinery capabilities and product market attributes.

The key Crude Market Optimization Model outputs are the aggregate value of all crude grades (as well as individual grades), identification of available capacity in all crude pipelines (or the size of the incentive to expand a pipeline that is at capacity), and the volume of all crude grades assigned to each refinery configuration in each submarket. As the input variables can be easily changed, the model provides the capability to analyze the market implications of: adding, or subtracting, crude pipeline capacity; changing the production volume of synthetic and bitumen blends; changing the production volume of conventional inland crudes; and downstream developments, such as additional coker unit construction.

As a way of illustrating some of the capabilities of the Crude Market Optimization Model, Figure 9 displays the projected disposition of Canadian heavy crude over the forecast period. The increase in flow to the Ontario submarket in 2012 is the result of the start up of a new Ontario heavy crude refinery. The increase in crude shipments to the West Coast/Asia markets in 2014 is due to the commissioning of a new export pipeline to a British Columbia port.

Figure 9
Disposition of Canadian Heavy Crude

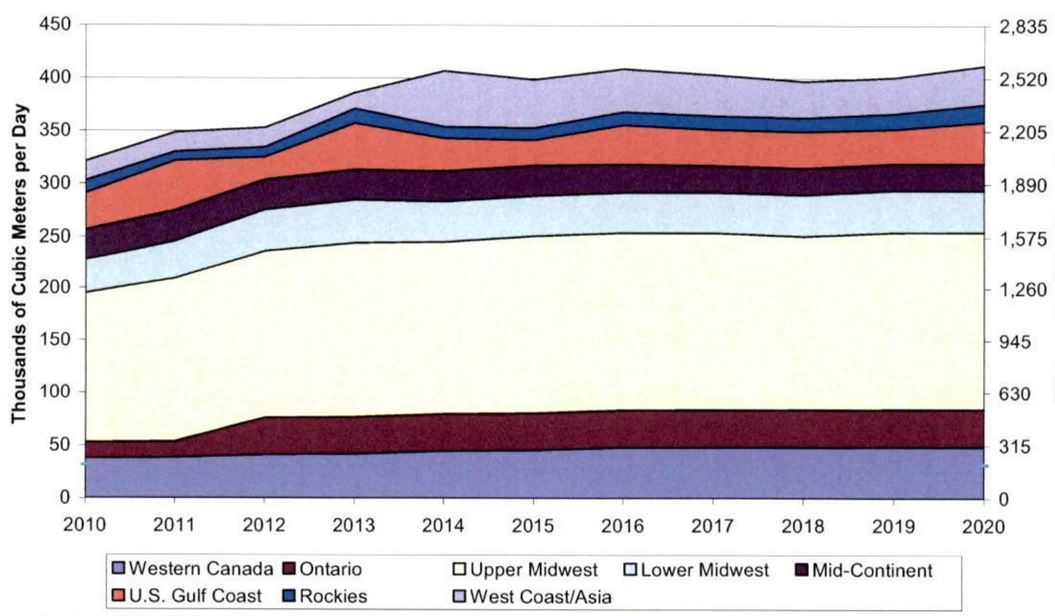


Table X shows the expected incremental throughput on all of the Enbridge eastbound pipelines starting with the first full year that the Alberta Clipper pipeline is in service. The year-to-year variations in throughput are influenced by the volume and crude grade mix produced in Western Canada, the start up of new pipeline projects, such as a new export pipeline to British Columbia, and refinery upgrades and expansions. Due to its multiple pipelines, the Enbridge system has considerable flexibility to transfer crude grades between the individual eastbound pipelines to optimize total system throughput and aggregate crude quality. The Crude Market Optimization Model does not attempt to model the individual pipelines within Enbridge's system.

TABLE X
ESTIMATED INCREMENTAL EASTBOUND ENBRIDGE SHIPMENTS
(Units as Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Thousands of Cubic Meters per day	20	33	52	92	66	73	104	113	97	114	115
Thousands of Barrels per day	128	206	329	578	415	459	655	709	610	717	722

Alberta Clipper Benefits

BENEFIT OF IMPROVED ACCESS TO CRUDE CONSUMERS

Once the minimum crude export pipeline capacity is in place that is required to avoid shut-in crude production, there are significant additional economic benefits that can flow from a pipeline project that provides better access to just a subset of the total array of potential consumers of Western Canadian crude.

For example, if pipeline capacity to Superior is full, then the balance of the Western Canadian crude production must flow into the Rockies and the West Coast markets, even though the refiners in these areas may be reaching the upper limits on their capacity to process Canadian crude. In contrast, the Ontario and Midwest refiners may have considerable unused capacity to handle Canadian crude, but are unable to process more because of upstream pipeline constraints. In general, the value to the refiner of any specific grade of crude drops as the volume processed at an individual refinery is increased. This particularly tends to be the case for the Western Canadian synthetic and heavy sour crude grades, as their properties differ somewhat from that of the typical conventional crude grades for which most refineries have been designed.

The benefits of improved marketplace crude distribution arising from the Alberta Clipper pipeline are quantified in a multi-step process:

1. The Crude Market Optimization Model is run with the Alberta Clipper pipeline capacity set to zero and the aggregate crude value is determined (the Base Case).

2. The Crude Market Optimization Model is rerun with the Alberta Clipper pipeline in operation, and the overall model aggregate crude value is determined (the Change Case).

3. For the Base Case years, which require the operation of the Alberta Clipper pipeline to avoid crude shut-in, pipeline capacity is provided to the U.S. Gulf Coast so as to eliminate shut-in, therefore measuring just the benefits of improved marketplace distribution, and not the benefit of preventing shut-in.

4. The aggregate crude value difference between the two Crude Market Optimization Model runs is calculated.

5. This exercise is repeated for each year of the forecast period (2010 to 2020).

The aggregate crude value provided by the Crude Market Optimization Model is essentially equivalent to the value of all Western Canadian crudes to the refiners, less the cost required to transport the crude from Western Canada to the refiners. Said differently, the aggregate crude value defines the total economic rent available between the refiners and the crude producers, and the split of the rent between the two will be a function of the commercial dynamics of the Canadian crude marketplace, although, in general, much of any uplift in economic rent will flow to the crude producer over time. Table XI illustrates the difference in the aggregate crude value with and without the Alberta Clipper Pipeline Project. This represents the value to the total oil value chain (crude producers and refiners combined) of optimizing the distribution of Western Canadian crude.

TABLE XI
ESTIMATED CHANGE IN AGGREGATE CRUDE MARKET VALUE
(Millions of Canadian Dollars per Year)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Aggregate Crude Value	-	367	139	441	301	277	180	320	263	159	304

The impact of the Alberta Clipper pipeline varies from year to year. This is due to the size and nature of crude supply increases in Western Canada and the timing of other pipeline projects that may also alleviate inefficiencies in marketplace distribution. The impact in 2010 is zero as the existing Enbridge mainline to Superior is not quite full. The Keystone pipeline is assumed to be operational in 2010, and an export pipeline to the British Columbia coast is assumed to be operational in 2014. On a per-barrel basis, the benefit varies from zero in 2010 to slightly over $CN0.28/bbl in 2013. The benefit drops in 2014 due to the assumed start up of the export pipeline to British Columbia, which acts to provide an additional market outlet for Canadian crude. The average over the period 2011 to 2020 is $CN0.18/bbl. Since the volume of Western Canadian crude is enormous, the total economic benefits are also correspondingly large.

An analysis of the model results indicates that, absent the Alberta Clipper pipeline, the refineries in Ontario and the Upper Midwest are not receiving all of the Canadian crude that they would prefer. The construction of the Alberta Clipper pipeline enables Canadian crudes to flow to the Ontario and U.S. refineries that are capable of processing them. Consequently, some portion of the total Western Canadian crude production is shifted into markets that provide a better Edmonton netback price for the Canadian crude producer. The refiners also benefit, as they are also receiving a crude grade that they prefer, relative to their alternatives.

ELIMINATION OF SHUT-IN CRUDE PRODUCTION

The crude pipeline capacity that is available to transport Canadian crude from Western Canada to the crude markets is finite. Moreover, the existing crude export pipelines from Western Canada currently operate at close to capacity. Western Canadian crude production is widely forecast to increase and the point will be reached when the available export pipeline capacity is completely full and, consequently, the Western Canadian crude producers will have to shut-in crude production.[15]

Absent the Alberta Clipper pipeline, sizable volumes of Canadian crude will not be able to reach Ontario and the U.S. and, conversely, Canadian and U.S. refiners will not be able to receive the Canadian crude that they desire. Table XII displays the estimated volume of Canadian crude that will not be able to reach the marketplace.

TABLE XII
ESTIMATED SHUT-IN WESTERN CANADIAN CRUDE PRODUCTION
(Units as Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Thousands of Cubic Meters per day	-	10	37	92	3	6	33	45	56	62	67
Thousands of Barrels per day	-	60	230	580	20	40	210	280	350	390	420

The analytical results shown in Table IX presumes that other sizable export pipeline projects from Alberta have been commissioned. Muse has assumed that an export pipeline to British Columbia has proceeded with a capacity of 127,200 m^3/d (800 kb/d) by 2014.

Muse has further assumed that TransCanada's Keystone Pipeline Project has proceeded. The Keystone pipeline is assumed to be capable of transporting up to 96,800 m^3/d (590 kb/d) of crude oil from Alberta to southern

Illinois, with an in-service date of 2010. As of February 2007, TransCanada was still seeking regulatory approval from the relevant state and national regulatory bodies in Canada and the U.S., and key engineering and material procurement activities have yet to be completed. Should TransCanada not proceed with the Keystone Project, an even greater capacity expansion will be required on Enbridge to avoid the shut-in of Western Canadian crude production.

Muse has also assumed that Kinder Morgan Canada proceeds with a 6,400 m^3/d (40 kb/d) expansion of its Trans Mountain pipeline, for which it has received National Energy Board approval. Construction is scheduled to be completed in 2008. The Trans Mountain pipeline connects Alberta with the Vancouver, British Columbia area.

Table XIII displays the estimated shut-in cost if the Alberta Clipper Pipeline Project is not constructed. For purposes of this analysis, the crude grade that is assumed to be shut-in is an Athabasca bitumen. This particular grade generally has the highest production cost but receives the lowest market price.

TABLE XIII
ESTIMATED WESTERN CANADIAN CRUDE SHUT-IN COST
(Units as Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Shut-in Production (Millons of Barrels)	-	21.9	84.0	211.7	7.3	14.6	76.7	102.2	127.8	142.4	153.3
Heavy Crude Price at Edmonton, CN$/bbl	40.59	40.59	40.59	40.59	40.59	40.59	40.59	40.59	40.59	40.59	40.59
Heavy Crude Production Cost, CN$/bbl	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00
Shut-in Cost, Millions of CN Dollars	**-**	**473**	**1,812**	**4,570**	**158**	**315**	**1,655**	**2,206**	**2,758**	**3,073**	**3,309**

The market price for the Canadian heavy is estimated to be equal to 69 percent of the WTI price. This estimate is obtained from the Crude Market Optimization Model for an Athabasca DilBit grade. The light sweet crude benchmark price (WTI) is assumed to equal US$50/bbl. The shut-in cost is further adjusted to account for the Canadian crude producer's production cost. Considerable cash operating costs are eliminated if crude production is shut-in, particularly for the heavy crude grades which tend to have high production costs. The Canadian heavy crude production cost of $CN19.00/bbl is obtained from a National Energy Board report.[16] This cost of production estimate includes the capital required to bring the heavy crude production online.

The economic implications of shut-in crude production are twofold. First, there is clearly a direct economic impact to the Western Canadian crude producer as their crude is shut-in and revenue is lost (or their crude production projects are not developed in the first place). Secondly, the Ontario and U.S. refiner is also impacted by the loss of Western Canadian crude, because the Canadian crude will only be bought by the refiner if the purchase is more economically advantageous than the refiner's alternatives.

ENDNOTES

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[1] CAPP, *Canadian Crude Oil Production and Supply Forecast 2006-2020*, May 2006. This projection is based on CAPP's "Supply Scenario with Condensate Used as Diluent", which assumes that condensate is readily available for use as a bitumen diluent.

[2] The values provided refer to the blended volume of heavy crude, as much of the Oil Sands crude is too heavy to be transported via pipeline and must be diluted with lighter grades of crude oil.

[3] The U.S. is divided into five Petroleum Administration for Defense Districts (PADDs). The Energy Information Administration, a department of the U.S. Department of Energy, provides the greatest amount of energy statistical detail at the PADD level and, accordingly, the PADD designations are commonly used by industry to refer to specific regions in the U.S. Figure 2 illustrates the PAD districts.

[4] The United Warren refinery is in PADD I, and the ConocoPhillips/EnCana Borger and the Valero McKee refineries are in PADD III.

[5] The primary means to convert resid into light products is via the use of a delayed coker, which is a refinery process unit that thermally cracks the resid into light liquid products and a solid material known as petroleum coke.

[6] The Chevron Burnaby refinery is included in the West Coast market area.

[7] (EIA) Energy Information Administration.

[8] BP Presentation, Enbridge Conference, *Canadian Crude: A Global Refiner's View*, June 8, 2005.

[9] BP Press Release, September 20, 2006.

[10] Marathon Press Release, November 6, 2006.

[11] *Platt's Oilgram News*, Volume 83, Number 214, November 4, 2005

[12] Shell Canada News Release, 23 November 2006.

[13] Marathon Oil Presentation, Bank of America 2005 Energy Conference, Clarence Cazalot, Jr., President and CEO, November 15, 2005.

[14] Frontier Oil, Investor Teleconference, December 1, 2005.

[15] Alternative means of transportation is not generally available to crude producers. Long distance crude transportation by rail or truck, even if the crude loading facilities exist, is rarely economic in North America.

[16] National Energy Board, *Canada's Oil Sands, Opportunities and Challenges to 2015: An Update*, June 2006.

EES103 – 2006

Submerged-Arc-Welded Steel Pipe Specification
Supplementary to API 5L

Revision: 0
Prepared By: Vincent Chou
Approval Date: August 4, 2006

1 Scope

1.1 PURPOSE AND COVERAGE

1.1.1

This Specification is prepared to be used in conjunction with API Specification 5L, Specification for Line Pipe, Forty-third Edition, March 2004, for the manufacture, qualification, inspection, and testing of submerged-arc welded steel line pipe for use in transportation of sweet service hydrocarbon fluids, and covers the requirements that are in addition to those specified in API 5L.

All pipe shall meet the minimum requirements of API 5L, Forty-third Edition.

In the event that conflict exists between this Specification and the requirements in API 5L, Forty-third Edition, the more stringent of the requirements shall apply.

The numbering of clauses in this Specification corresponds, where possible, to that in API 5L, Forty-third Edition when the subject is covered in that specification, and any additional clauses are numbered sequentially.

The requirements of the Appendices to this Specification shall also be met when applicable.

1.1.2

Pipe shall be supplied to meet the additional requirements outlined on the Specification Data Sheet(s) issued as applicable to each order, and on purchase order documentation applicable to each order.

1.2 PRODUCT SPECIFICATION LEVEL (PSL)

Pipe shall meet the level of technical requirements (product specification level) designated as PSL 2.

3 Definitions

For the purposes of this Specification, the following additional definitions shall also apply:

3.9 manufacturer: a pipe manufacturer who proposes to, or has been contracted to provide to the purchaser, pipe manufactured to this Specification.

3.20 purchaser: that company, which is stated on the Specification Data Sheet(s) as purchaser, and shall include their engineering agencies, and other designated authorized representatives.

3.21 Specification Data Sheet(s): information issued to the prospective manufacturer in a format as outlined in Appendix B of this Specification, including information issued to the manufacturer on purchase order documentation or on any request-for-quotation documentation associated with a specific project.

3.22 crack: a stress-induced separation of the metal which, without any other influence, may be insufficient in extent to cause complete rupture of the material

3.23 single-jointer: two pieces of pipe welded together to make a length shorter than 50 ft. (15.2 m)

3.24 double-jointer: two pieces of pipe welded together to make a length 50 ft. (15.2 m) or longer

3.25 triple-jointer: three pieces of pipe welded together to make a length 50 ft. (15.2 m) or longer

4 Information to be Supplied by the Purchaser

4.4 Specification Data Sheet(s) supplied for each order shall include applicable information outlined in Clauses 4.1, 4.2, and 4.3 of API 5L. It shall remain the responsibility of the manufacturer to clarify and submit as part of each specific quotation for supply, any proposed specific requirements of Clauses 4.1, 4.2, and 4.3 of API 5L not issued in the request for quotation.

5 Process of Manufacture and Material

5.1 PROCESS OF MANUFACTURE

Pipe furnished to this specification shall be submerged-arc welded as defined in Clauses 5.1.2.2.1, 5.1.3.5, and 5.1.3.11 of API 5L as applicable.

5.1.2 Welding Processes

5.1.2.3 Welding Procedure Qualification

Welding procedures for the longitudinal, helical, skelp end, and circumferential jointer welds, whichever are applicable, shall be qualified in accordance with the requirements of the latest edition of ASME Boiler and Pressure Vessel Code, Section IX for each welding process, and for each flux trade name/designation and electrode designation combination employed.

5.1.2.3.1

Material grade shall be included as an essential variable for qualification of welding procedures in accordance with ASME Boiler and Pressure Vessel Code, Section IX.

5.1.2.3.2

For pipe ordered with proven notch toughness properties, procedure qualification testing shall include Charpy V-notch impact tests of the weld and heat-affected zone. The absorbed energy requirements shall be as outlined on Specification Data Sheets.

5.1.2.3.3

Procedure qualification tests shall include at least three microhardness traverses across the weld, heat-affected zones, and parent material. One traverse shall be within 1/8" (3 mm) of the outside surface, one traverse shall be at the mid-wall point, and one traverse shall be within 1/8" (3 mm) of the inside surface. All readings in each zone shall be performed on the hardest-appearing structure. All hardness tests shall meet requirements outlined in clause 6.2.7 of this specification.

5.1.2.3.4

Utilization of pre-qualified welding procedures shall be permitted, if qualification documentation meets requirements of this Specification, and is submitted to the Purchaser and approved prior to start of production. Welding procedures qualified as part of production shall be documented and submitted to the Purchaser not later than seven days after the start of production.

5.1.5 Repair Welding

Defects in the longitudinal, helical , or circumferential seams, or in skelp end welds of submerged-arc welded pipe, shall be subjected to weld repair in accordance with requirements in Appendix B of API 5L. In addition to requirements outlined in B.3 of Appendix B of API 5L, the following requirements shall apply:

- The maximum length of any repair shall be 10 in. (250 mm).
- The minimum distance of a repair weld from the pipe end shall be 12 in. (300 mm).
- The minimum distance between any two repaired weld locations shall be 12 in. (300 mm).
- There shall not be more than 2 repairs in any 20 ft. (6 m) of weld.
- Back-to-back repairs shall not be permitted.
- Additional repair to a previously-repaired area shall not be permitted.

5.1.5.1 Repair Welding Procedure Qualification – Additional Tests

Repair welding procedure qualifications shall be carried out in accordance with requirements outlined in ASME Section IX, and in accordance with requirements outlined in Appendix C of API 5L.

Hardness tests shall be performed in general accordance with, and meet the requirements of Clause 6.2.7 of this specification.

For pipe ordered with proven notch toughness properties, repair welding procedure qualification tests shall include Charpy V-notch tests of the weld and heat affected zone. Energy absorption requirements and test temperature for notch toughness tests shall be as specified for pipe welds.

5.3 MATERIAL

5.3.3 Steel Deoxidation Practice

All pipe shall be made from killed steel.

5.3.4 Plate or Skelp Inspection

Coincident with submission of quotation, the Manufacturer shall provide details of procedures to be utilized for the ultrasonic inspection of skelp or pipe for the detection of laminar discontinuities in the steel. Acceptance criteria relating to defect size shall be included with the procedure, and shall be approved by the Purchaser prior to commencement of production.

5.7 Manufacturing Procedure Specification (MPS)

As part of the quotation for supply of line pipe under this Specification, the Manufacturer shall submit a Manufacturing Procedure Specification (MPS) providing the information including, but not limited to, that listed in Appendix A of this Specification. The Manufacturing Procedure Specification shall be approved by the Purchaser prior to commencement of production, and any subsequent changes to the Manufacturing Procedure Specification shall be approved by the Purchaser in writing prior to implementation.

6 Material Requirements

6.1 CHEMICAL PROPERTIES

6.1.1 Chemical Composition

6.1.1.1 Heat and Product Analysis

In addition to requirements outlined in API 5L, heat and product analysis shall conform to the requirements of Table 1 following:

Table 1

Element	Symbol	Maximum % Element
Carbon	C	0.13
Manganese	Mn	**
Phosphorus	P	0.020
Sulphur	S	0.008
Silicon	Si	0.40
Copper	Cu	0.40
Nickel	Ni	0.70
Chromium	Cr	0.30
Molybdenum	Mo	0.40
Niobium	Nb	0.10
Titanium	Ti	0.030
Aluminum (total)	Al	0.12
Vanadium	V	0.09
Nitrogen	N	**
(Niobium + Vanadium)	(Nb + V)	0.12
(Manganese+Chromium+Molybdenum)	(Mn+Cr+Mo)	**

**** limitations on constituents Mn, (Mn+Cr+Mo), & N:**

Carbon (C) Content	Manganese (Mn) Maximum	(Mn+Cr+Mo) Maximum	Nitrogen (N) Maximum
≥.09	1.75	2.15	0.012
.08	1.80	2.20	0.012
.07	1.95	2.35	0.012
.06	1.95	2.35	0.013
.05	2.00	2.40	0.014
≤.04	2.00	2.40	0.015

6.1.3 Carbon Equivalent

6.1.3.2 Maximum Carbon Equivalent

For all pipe, the carbon equivalent shall not exceed CE (*Pcm*) of 0.22%, or CE(*IIW*) of 0.38%, whichever is applicable.

6.2 MECHANICAL PROPERTIES

6.2.1 Tensile Properties

6.2.1.1 Body Tensile Range

The range of actual yield strengths based on laboratory qualification testing shall not exceed 15,000 psi (104 MPa) for each pipe order of a specific diameter, wall thickness and grade.

6.2.1.2 Yield Ratio

The ratio of yield strength to ultimate tensile strength (Y/T ratio) shall not exceed .90.

6.2.5 Fracture Toughness Tests

6.2.5.3 Supplementary Fracture Toughness Tests

6.2.5.3.1 Supplementary Fracture Toughness Tests – Pipe Body

For pipe ordered with proven notch toughness properties, the following requirements shall apply:

(i) Pipe shall be tested to requirements of SR5, SR6, and SR19 of API 5L, Forty-third Edition, as outlined on Specification Data Sheets.

(ii) Pipe material shall exhibit an absorbed energy (full size equivalent) as outlined in SR19, and also as outlined on Specification Data Sheets.

(iii) Drop-weight tear tests shall exhibit a fracture shear area of 60% minimum for any test, with no individual test specimen exhibiting less than 50% shear, except that for each order of a specific diameter, wall thickness and grade supplied using material from five or more heats of steel, the all-lot average shear area shall not be less than 85%. Shear area shall be reported for each individual Drop-weight Tear Test specimen.

6.2.5.4 Supplementary Fracture Toughness Tests - Weld Metal and Heat Affected Zones

For pipe ordered with proven notch toughness properties, longitudinal, helical, skelp end welds and circumferential mill welds, as well as heat affected zones, shall exhibit absorbed energies as outlined on the Specification Data Sheet(s).

6.2.7 Hardness Tests

Unless specified otherwise on the Specification Data Sheet(s), the hardness in the weld, heat affected zone and base metal shall not exceed 350 HV_{500}, as determined using test methods in accordance with ASTM E384.

The results of all hardness tests shall be reported.

7 Dimensions, Weights, Lengths, Defects, and End Finishes

7.2 DIAMETER

Tolerances for diameter of the pipe body and for diameter of the pipe ends shall be in accordance with requirements of Table 7 and Table 8 respectively of API 5L, except that the diameter tolerances shall not exceed minus 1/32" (0.8 mm) or plus 1/8" (3.2 mm) at any location along the length of the pipe.

7.2.1 Out-of-Roundness

For all pipe sizes and D/t ratios, the maximum difference between the lengths of the major and minor axes at any point along the pipe shall not exceed the lesser of 2% of the nominal outside diameter or 0.500" (12.7 mm).

7.3 WALL THICKNESS

The under-tolerance on wall thickness shall be 5% of the specified nominal wall thickness.

7.5 LENGTH

Length tolerances shall be as outlined on the Specification Data Sheet(s).

7.6 STRAIGHTNESS

Deviation from a straight line shall not exceed 0.2% of the length, as applied along any 10 ft. (3 m) section of each pipe.

7.7 JOINTERS

It shall be acceptable to furnish mill jointers, subject to requirements of Appendix A of API 5L, and to requirements of this Specification.

7.7.1 Transverse Weld Tensile Tests – Jointer Welds

For circumferential mill jointer welds, tests shall be conducted at a frequency of one test per lot of 500 welds, and shall meet the ultimate tensile strength requirements of Table 3B of API 5L for the applicable grade of pipe.

7.7.2 Guided Bend Tests – Jointer Welds

For circumferential mill jointer welds, face and root guided-bend tests shall be conducted in accordance with Clause 9.10.3 of API 5L, at a frequency of one test per lot of 500 welds.

7.7.3 Single-jointers

It shall be permissible to furnish single-jointers as defined in Clause 3.23 of this specification to a maximum of 5% of each order item.

7.7.4 Double-jointers

It shall be permissible to furnish double-jointers as defined in Clause 3.24 of this specification for an entire order or any portion thereof.

7.7.5 Triple-jointers

It shall be permissible to furnish triple-jointers as defined in Clause 3.25 of this specification to a maximum of 5% of each order item.

7.8 WORKMANSHIP AND DEFECTS

7.8.1 Dents

Plain dents deeper than ¼" (6.4 mm) and located in the pipe body, measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe, or having a length in any direction exceeding one-half the pipe diameter, or both, shall be considered to be defects and shall be cut out as a cylinder.

All cold-formed dents deeper than 1/8 in. (3.2 mm) with a sharp bottom gouge shall be considered as defects, and shall be cut out as a cylinder or shall be removed by grinding.

Dents on welds shall not be permitted, and shall be cut out as a cylinder.

7.8.9 Cracks, Sweats, and Leaks

All cracks, sweats and leaks shall be considered defects. Cracks as defined in this Specification shall be considered to be defects regardless of dimensions, and shall be cut out as a cylinder.

7.8.14 Other Defects

Any imperfection on either of the external wall or internal wall surfaces of the pipe, and having a depth that results in a remaining wall thickness at any point of less than 95 per cent of the specified nominal wall thickness, shall be considered to be a defect.

7.8.14.1

Surface scores (sharp notches, gouges, scores, slivers, etc.) and all stress raising imperfections shall be removed by grinding even though they may be less than the maximum depth permissible for imperfections.

7.8.14.2

Pipe ordered to this Specification may be externally coated utilizing fusion bond epoxy or similar methods. Slivers, scabs, bristles or other surface imperfections that could result in an unacceptable applied coating shall be considered to be surface defects, and shall be removed by grinding or by other means acceptable to the purchaser.

7.8.15 Geometric Deviations

Geometric deviations from the normal cylindrical contour of the pipe which occur as a result of the pipe forming process or manufacturing operations (e.g. flat spots, peaks) shall not exceed 1/8" (3 mm), measured as the gap between the extreme point of the deviation and the prolongation of the normal contour of the pipe.

7.8.16 Grinding

The minimum remaining wall thickness at any point after grinding shall not be less than 95 per cent of the specified nominal wall thickness.

7.9 PIPE ENDS

7.9.3 Plain Ends

Unless otherwise specified on Specification Data Sheet(s), the root face dimension shall be 1/16" (1.6 mm) plus 1/32" (0.8 mm) minus 0" (0.0 mm) for 95 per cent of the circumference of each pipe end.

Both ends of submerged-arc welded pipe shall have the inside weld reinforcement removed for a minimum distance of 3" (75 mm) from the end of the pipe, such that the inside weld bead does not extend above the inside surface of the pipe by more than 0.020" (0.5 mm).

Where specified on Specification Data Sheet(s), both ends of submerged-arc-welded pipe shall have the outside weld reinforcement removed for a distance of at least 5" (125 mm) from the end of the pipe, such that the outside weld bead does not extend above the outside surface of the pipe by more than 0.010" (0.25 mm)

9 Inspection and Testing

9.3.5 Fracture Toughness Tests

9.3.5.4 Charpy Testing Frequency – Welds

For pipe ordered with proven notch toughness properties, Charpy V-notch impact tests shall be conducted on the weld and heat affected zone of longitudinal, helical, skelp end welds and circumferential welds. For longitudinal, helical and skelp end welds, the test frequency shall be the same as that required for weld tensile tests in Table 13 of API 5L. For circumferential mill jointer welds, the test frequency shall be once per 500 welds completed.

9.3.6 Hardness Tests

Microhardness testing shall be performed at applicable frequencies as follows:

a) For longitudinal and helical welds: one test per welding day per O.D. welder, and at least once for each heat of material supplied for an order;
b) For skelp end welds: one test per lot of 100 lengths containing skelp end welds;
c) For circumferential mill welds: one test per lot of 500 welds.

Microhardness tests shall be performed in accordance with ASTM E384, at locations identical to those as outlined in clause 5.1.2.3.3 above, and shall meet requirements of Clause 6.2.7 of this Specification.

9.4 HYDROSTATIC TESTS

9.4.1 Hydrostatic Test Requirements

The pressure of the hydrostatic test medium shall stress the pipe wall to at least 95% of the specified minimum yield strength (SMYS). Test pressure shall be held constant for not less than 10 seconds.

9.4.2 Verification of Hydrostatic Test

9.4.2.1

The individual pressure recordings shall be unambiguously traceable to each pipe section tested.

9.4.2.2

Hydrostatic test gages shall be calibrated with a device approved by the Purchaser, and shall be calibrated prior to commencement of production, weekly thereafter, and after all hydrostatic bursts.

9.4.3 Test Pressures

9.4.3.1

Any proposals to determine test pressure by applying end load compensation in accordance with the requirements of Appendix K of API 5L, shall be indicated at the time of submission of proposals for supply.

9.4.5 Investigation of Test Failure

Each hydrostatic test failure shall be investigated, and the cause of each failure determined and fully documented. Documented failure investigation results shall be forwarded to the Purchaser.

9.6 SURFACE INSPECTION

Visual inspection shall include, but not be limited to, examination of:

a) The entire external surface including the weld zone, by the inspector(s) walking the full length of the pipe;
b) the internal surface by crawling each pipe, except that for pipe of diameter 20" (508 mm) and smaller, internal surface inspection may be performed from each end using adequate lighting; and
c) the pipe ends.

9.6.1

All pipe shall be visually inspected.

9.6.2

The external and internal surfaces of the pipe shall be presented for final visual inspection free of oil, grease, lubricant, flux, loose mill scale or other foreign matter.

9.8 NONDESTRUCTIVE INSPECTION

9.8.3 Methods of Inspection

Longitudinal and helical weld seams shall be inspected for internal and external longitudinal and transverse imperfections by ultrasonic methods, in accordance with requirements of API 5L and this Specification.

Skelp end welds shall be inspected for longitudinal and transverse imperfections by radiological methods in accordance with API 5L, by ultrasonic methods utilizing procedures approved by the Purchaser, or by a combination of radiological and ultrasonic methods. Fluoroscopic inspection shall not be accepted for specification compliance.

Repair welds shall be inspected by radiological methods in accordance with Clause 9.8.4 of API 5L, except that fluoroscopic inspection shall not be accepted for specification compliance.

Circumferential jointer welds produced by double submerged arc welding shall be inspected for longitudinal and transverse imperfections by radiological methods in accordance with Clause 9.8.4 of API 5L, by ultrasonic methods in accordance with requirements of API 5L and this Specification, or by a combination of radiological and ultrasonic methods, except that fluoroscopic inspection shall not be accepted for specification compliance. Standards of acceptability for circumferential jointer welds shall be in accordance with the requirements of the latest edition of API 1104.

The junctions of jointer welds and other submerged-arc-welds shall be inspected by film radiography or non-film radiological imaging techniques, or by ultrasonic inspection methods. Fluoroscopic inspection shall not be accepted for specification compliance. Standards of acceptability for the junctions of jointer welds and other submerged arc welds shall be in accordance with the requirements of Clause 9.8.4.6 of API 5L, or Clause 9.8.5.4 of this Specification, whichever is applicable, and shall also be in accordance with requirements of Clause 7.8.12 of API 5L.

The location of equipment in the manufacturer's facility shall be such that all nondestructive inspection for compliance to specification requirements shall be performed after final hydrostatic testing.

9.8.3.3 Removal of Markings from Nondestructive Inspection

For all nondestructive inspection applied for specification and production control purposes, any paint markings applied to the pipe to mark locations where alarm limits were exceeded, or where imperfections were noted, shall be removed or painted over with black paint, as an indication that imperfections have been investigated for compliance to all requirements of this Specification.

9.8.3.4 Nondestructive Inspection Procedure Documentation

All nondestructive inspection procedures to be applied for specification compliance and for production control purposes shall be documented and submitted by the Manufacturer as part of the quotation for supply, and shall be approved by the Purchaser prior to implementation.

9.8.3.5 Additional Nondestructive Inspection of Pipe Ends

The finished bevel of all pipe ends shall be inspected for seams and laminations using an ultrasonic, liquid penetrant, or magnetic particle inspection method. Acceptance criteria shall be as outlined in Clause 7.8.10 of API 5L.

9.8.5 Ultrasonic Inspection

9.8.5.2 Ultrasonic Inspection Reference Standards

Reference standards shall contain machined calibration reflectors as follows:

- 1/16" (1.6 mm) radially drilled hole, for application of acceptance limits and for setting of alarm levels applicable to longitudinal and transverse defect inspection;

- rectangular notches; ID and OD, longitudinal orientation, depth 5.0% of specified wall thickness, dimensional tolerances as specified in Table 26 of API 5L, for the verification that the sound beam for longitudinal defect inspection is being directed perpendicular to the weld line

9.8.5.4 Acceptance Limits

For inspection of the pipe welds, imperfections that produce a signal greater than the applicable acceptance limit signal given in Table 23 of API 5L for the 1/16" (1.6 mm) radially drilled hole shall be considered defects, and shall be dispositioned in accordance with Clause 9.9 of API 5L.

9.8.7 Residual Magnetism Measurement Requirements

In addition to the requirements of Clause 9.8.7 of API 5L, the Manufacturer shall ensure that the measured flux density from residual magnetism induced into the pipe as a result of forming, welding, inspection, or any other aspect of the manufacturing process does not exceed 30 Gauss (3 mT).

9.12 RETESTS

9.12.7 Hardness Retests

In the event of a hardness test failure, a documented proposal for the location and number of retests shall be prepared by the Manufacturer and submitted for approval by the Purchaser.

9.14 RIGHT OF REJECTION

Where more than 50% of the pipe from any heat, heat treat lot or qualification lot is rejected due to a combination of defects in the steel, skelp or finished pipe, mechanical test failures, nondestructive inspection rejects or other deficiencies, the Purchaser reserves the right to reject all remaining pipe supplied from the affected lot.

10 Marking

10.1 GENERAL

10.1.3 Additional Markings and Method Of Application

The pipe number, length, and heat number (or code traceable to the heat number) shall be legibly stenciled on the inside of both ends of each pipe.

Any additional requirements for marking shall be outlined on the Specification Data Sheet(s).

12 Documents

12.1 CERTIFICATION

12.1.2 PSL 2 Certification Requirements

The Manufacturer shall, within seven days of completion of each mill run, supply material test certificates in a format approved by the Purchaser, and in accordance with requirements of this Specification.

12.1.2.1

Supply of material test certificates shall be a condition of acceptance and payment for pipe.

12.1.2.2

The reports and certificates shall provide information as specified in SR 15.1 of API 5L, and shall include the following additional information:

j) Tensile test results applicable to Y/T ratio and transverse weld tensile tests,

k) Qualification pipe number for each test;

l) Deoxidation practice for steel;

m) Certification of hydrostatic test including duration and pressure;

n) Certification of completion of guided bend tests;

o) Certification that nondestructive inspection was performed in accordance with, and met the requirements of this Specification and the approved Manufacturing Procedure Specification (MPS);

p) Certification correlating pipe number to heat number and plate number; and,

q) Certification that the pipe has been manufactured in accordance with the Manufacturing Procedure Specification (MPS), API 5L, and this Specification.

14 Purchaser Inspection

14.1

The provisions of Appendix H of API 5L shall apply.

14.2

The Manufacturer shall allow free access to the Purchaser to all steelmaking and rolling mill facilities providing skelp for the pipe order.

14.3

The Purchaser may arrange under separate contract with one or more third party agencies to conduct supervisory, visual, mechanical, electromagnetic, ultrasonic or other types of inspection in the pipe mill, rolling mill, or steel mill. The Manufacturer shall supply acceptable space to the Purchaser as may be necessary for the performance of this work.

14.4

The Manufacturer shall permit access by the Purchaser to all specimens and test records applicable to specification-compliance testing and production control testing during the manufacture of steel, skelp and pipe.

APPENDIX A – MANUFACTURING PROCEDURE SPECIFICATION REQUIREMENTS

The Manufacturing Procedure Specification submitted shall include, as a minimum, the following detailed information:

i) steel source, including steelmaking method, heat size, deoxidation practice, inclusion shape control practices, and casting method;

ii) aim chemistries and chemical limits for all elements referenced in Clause 6.1.1.1 of this Specification, and as applicable to pipe of each diameter, wall thickness and material grade to be made for the order;

iii) skelp rolling source, specific rolling and forming practices, including where applicable, typical reduction schedules, final finishing temperatures, and facilities for thermo-mechanical controlled rolling and on-line accelerated cooling;

iv) skelp inspection procedures;

v) details of forming procedures;

vi) pipe manufacturing location, and any plant limitations on wall thickness, diameter, and material grade;

vii) typical welding parameters and consumable combinations applicable to longitudinal, helical, skelp end, repairs, and circumferential jointer welds;

viii) a description of the quality organization applicable to steelmaking, casting, skelp rolling and pipe manufacturing facilities, including identification of reporting practices, verification mechanisms to assure product traceability in accordance with requirements of SR 15.2 of API 5L, and responsibility for customer contact related to commercial and quality matters;

ix) a flow chart for pipe manufacturing, finishing, and qualification processes;

x) normal mill control tolerances on all specification dimensions for pipe;

xi) laboratory test equipment present at the manufacturing plant for testing of material properties for the order;

xii) all nondestructive inspection procedures utilized for specification compliance and for production control, as applicable to skelp, pipe body, and welds

xiii) method and typical amount of cold expansion as applicable;

xiv) facilities available for external or internal coating in-house or by a third party;

xv) yard handling, storage, and shipping procedures, including drawings of proposed methods of stacking and securing pipe for shipment and method of end protection; and,

xvi) facilities available for the Purchaser or his representative.

APPENDIX B
SPECIFICATION DATA SHEET
SUBMERGED-ARC-WELDED STEEL PIPE

PROJECT:____________________________________

PURCHASER:____________________________________

A. PIPE REQUIREMENTS:

Item No.	O.D. (in.)	W.T. (in.)	Grade	Product Specification Level (PSL)	Pipe Test Temperature (˚F)	Manufacturing Method

B. APPLICABLE SPECIFICATIONS:

(i) API 5L, Specification for Line Pipe, 43rd Edition
(ii)

C. FLUID: Analysis attached

D. MIN./MAX. OPERATING TEMPERATURE (°F) ____________

E. MAXIMUM FIELD TEST PRESSURE: ____________

F. FIELD TEST MEDIUM: ____________

G. FIELD TEST DURATION: ____________

H. LENGTH REQUIREMENTS:

Item #	Nominal Length (ft.)	Specified lengths in entire shipment (ft.)		
		Minimum any Section	Maximum any Section	Minimum average

NOTES:____________________________________

I. SUPPLEMENTARY REQUIREMENTS:

1. **PIPE BODY ABSORBED ENERGY (ft-lb):**________________
2. **PIPE BODY FRACTURE APPEARANCE (% Shear)**________________
3. **WELD ABSORBED ENERGY (Longitudinal Seam) (ft-lb):**________________
4. **HEAT AFFECTED ZONE ABSORBED ENERGY (Longitudinal Seam)(ft-lb):**________
5. **WELD ABSORBED ENERGY (Helical, Skelp End, Circumferential Welds) (ft-lb):**____
6. **HEAT AFFECTED ZONE ABSORBED ENERGY (Helical, Skelp-end, Circumferential Welds) (ft-lb):**________________
7. **REQUIREMENTS FOR END PREPARATION:**________________
8. **REQUIREMENTS FOR EXTERNAL WELD FLUSH-OFF:**________________
9. **MARKING REQUIREMENTS:**________________
10. **COATING:**________________
11. **PLANT INSPECTION BY PURCHASER:**________________
12. **OTHER:**________________

Initiated by:________________	**Date:**________
Reviewed by:________________	**Date:**________
Approved by:________________	**Date:**________

ENBRIDGE

Steel Valve Specification
EES105 - 2006

Version: 0
Issue Date: March 24, 2006
Prepared By: Jack Broyles

Table of Contents

1 Scope

This Specification covers requirements for the manufacture, inspection, testing and shipment of gate, plug, ball and check valves intended for use in crude oil, petroleum product, and natural gas liquid pipeline systems. The pipeline systems are designed and constructed in accordance with:

Canada:

i. National Energy Board, Onshore Pipeline Regulations

ii. CSA Z662 Oil and Gas Pipeline Systems

United States:

i. Code of Federal Regulations, Title 49, Volume 3, Part 195 – Transportation of Hazardous Liquids by Pipeline

ii. ASME B31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

This Specification covers valves in sizes from NPS 2 to NPS 60, inclusive.

Nominal pressure classes covered include:

Class Designation

CSA	ASME
PN 20	150
PN 50	300
PN 68	400
PN 100	600
PN 150	900

2 Intent

This specification embodies the required information of industry standards *API 6D* and *CSA Z245.15* as well as Enbridge requirements.

The Application Datasheet shall be completed by the Owner or the Owner's Engineer.

Any and all deviations from this specification shall be brought to the attention of the Owner in writing for resolution prior to final acceptance. All design documentation shall be submitted for approval in a retrievable and reproducible format.

3 Terms, Definitions

For the purposes of this specification, the following terms and definitions apply:

ANSI Rating Class: Numerical pressure design class defined in *ASME B16.5* and used for reference purposes. *NOTE: The ANSI rating class is designated by the word "Class" followed by a number.*

Bi-Directional Valve: Valve designed for blocking the fluid in both downstream and upstream directions.

Bleed: Drain or vent.

Block Valve: Gate, plug or ball valve that blocks flow into the downstream conduit when in the closed position. NOTE: Valves are single- or double-seated, bi-directional or uni-directional.

Breakaway Thrust and Breakaway Torque: Thrust or torque required for opening a valve with maximum pressure differential.

By Agreement: Agreed between manufacturer and Enbridge purchaser.

Double-Block-and-Bleed (DBB) Valve: Valve with two seating surfaces, which, in the closed position, blocks flow from both valve ends when the cavity between the seating surfaces is vented through a bleed connection provided on the body cavity.

Drive Train: All parts of a valve drive between the operator and the obturator, including the obturator but excluding the operator.

Flow Coefficient: Kv – Volumetric flow rate, in cubic meters per hour, of water at a temperature between 5°C (40°F) and 40°C (104°F) passing through a valve and resulting in a pressure loss of 1 bar (14.7 psi). *NOTE: Kv relates to the flow coefficient Cv in US gallons per minute at 15.6°C (60°F) resulting in a 1-psi pressure drop as follows:*

$$Kv=Cv/1156$$

Full-Opening Valve: Valve that opens to the full diameter of the pipe to which it attached to allow unobstructed flow through the line.

Full Round Port Valve: Valve that opens to the full diameter of the pipe to which it attached to allow unobstructed flow through the line.

Handwheel: Wheel consisting of a rim connected to a hub, for example, by spokes, and used to operate manually a valve requiring multiple turns.

Locking Device: Part or an arrangement of parts for securing a valve in the open and/or closed position.

Manual Actuator:

Manual Operator: Wrench (lever) or handwheel with or without a gearbox.

Maximum Pressure Differential (MPD): Maximum difference between the upstream and downstream pressure across the obturator at which the obturator may be operated.

Nominal Pipe Size (NPS): Numerical inches designation of size, which is common to components in piping systems of any one size. *NOTE: the letters NPS followed by a number designates the nominal pipe size.*

Nominal Pressure (PN) Class: Numerical pressure design class as defined in ISO 7005-1 and used for reference purposes. *NOTE the nominal pressure (PN) class is designated by the abbreviation PN followed by a number.*

Nominal Size (DN): Numerical metric designation of size, which is common to components in piping systems of any one size. *NOTE: Nominal size is designated by the letters DN followed by a number.*

Obturator / Closure Member: Part of a valve, such as a ball, clapper, disc, gate or plug, which is positioned in the flow stream to permit or block flow.

Operator: Device (or assembly) for opening or closing a valve.

Position Indicator: Device to show the position of the valve obturator.

Powered Actuator and Operator: Electric, hydraulic or pneumatic device bolted or otherwise attached to the valve for powered opening and closing of the valve.

Pressure Class: Numerical pressure design class expressed in accordance with either the nominal pressure (PN) class or the ANSI rating class. *NOTE: In this Standard, the pressure class is stated by the PN class followed by the ANSI rating class between brackets.*

Pressure-Containing Parts: Parts, such as bodies, bonnets, glands, stems, gaskets and bolting, designed to contain the pipeline fluid.

Pressure-Controlling Parts: Parts, such as seat and obturator, intended to block or permit the flow of fluids.

Process-Wetted Parts: Parts exposed directly to the pipeline fluid.

Reduced-Opening Valve: Valve with the opening through the obturator smaller than at the end connection(s).

Seating Surfaces: Contact surfaces of the obturator and seat, which ensure valve sealing.

Stem: Part that connects the obturator to the operator and which may consist of one or more components.

Stem Extension Assembly: Assembly consisting of the stem extension and the stem extension housing.

Support Ribs or Legs: Metal structure, which provides a stable footing when the valve is set on a fixed base.

Through-Conduit Valve: Valve with an unobstructed and continuous cylindrical opening.

Twin-Seat, Both Seats Bi-Directional, Valve: Valve with two seats, each sealing in both directions.

Twin-Seat, One Seat Uni-Directional And One Seat Bi-Directional, Valve: Valve with two seats, one sealing in one direction and the other in either direction.

Uni-Directional Valve: Valve designed for blocking the flow in one direction only.

Venturi Plug Valve: Valve with a substantially reduced opening through the plug and a smooth transition from each full-opening end to the reduced opening.

4 Symbols and Abbreviations

4.1 Symbols

C_v Flow coefficient in Imperial units.

K_v Flow coefficient in Metric units.

4.2 Abbreviations

BM	Base Metal
CE	Carbon Equivalent

DBB	Double-Block-and-Bleed
DN	Nominal Size
HAZ	Heat-Affected Zone
HR	Rockwell Hardness
HV	Vickers Hardness
MPD	Maximum Pressure Differential
MT	Magnetic-Particle Testing
NDE	Non-Destructive Examination
NPS	Nominal Pipe Size
PN	Nominal Pressure
PQR	Procedure Qualification Record
PT	Penetrant Testing
PWHT	Post-Weld Heat Treatment
SMYS	Specified Minimum Yield Strength
WM	Weld Metal
WPS	Weld Procedure Specification
WQR	Welder Qualification Record

5 Valve Types

5.1 Valve Types

Valves shall adhere to one of the following types and where applicable it shall also be designated either Full Port (FP) or Reduced Port (RP):

5.2 Gate Valves

Style 1: Single Slab Rising Stem

Style 2: Multi Piece Expanding Gate

Gate valves are to be used for fully opened or fully closed position only.

Multi piece gate valves shall be installed only in the up right position, and shall be used where temperature fluctuations may vary substantially beyond design atmospheric conditions.

Gate valves shall be provided with a back seat or secondary stem-sealing feature in addition to the primary stem seal.

Wedge gate valves shall have an internal wedge guide to prevent chatter and seat damage.

5.3 Plug Valves

Style 1: Non-Lubricated

Style 2: Lubricated

Plug valves shall have a cylindrical or conical obturator, which rotates about an axis perpendicular to the direction of flow.

Plug valves shall be short pattern type.

5.4 Ball Valves

Style 1: Top Entry Floating

Style 2: Three-Piece

Style 3: Welded Body

Ball valves shall have a spherical obturator, which rotates on an axis perpendicular to the direction of flow.

Ball valves 12" and larger shall be trunnion mounted.

5.5 Check Valves

Style 1: Reduced Opening Swing

Style 2: Full Opening Swing

Style 3: Dual Plate Wafer

Style 4: Single Plate Wafer

Check valves shall have an obturator, which responds automatically to block fluid in one direction.

5.6 Full-Opening Valves or Full Port Valves

Full-opening valves shall be unobstructed in the fully opened position and have an internal bore as specified in *Table A1.1, Appendix I*. There is no restriction on the upper limit of valve bore sizes.

Full-opening through-conduit valves shall have a circular bore in the obturator that will allow a sphere to pass. The bore diameter of the valve shall not be less than specified in *Table A1.1, Appendix I.*

Welding-end valves may require a smaller bore at the welding end to mate with the pipe.

5.7 Reduced-Opening Valves or Reduced Port Valves

The internal bore of reduced-opening or reduced port valves shall be less than the internal bore specified in *Table A1.1, Appendix 1*.

6 Design

6.1 Pressure and Temperature Rating

The nominal pressure (PN) class required is identified on the Application Datasheet.

Pressure classes shall be specified in accordance with the applicable rating tables for material groups in *ASME B16.34.*

The pressure and temperature ratings for metal (or equivalent) seats of ball valves, seated check valves shall be the same as for the flanges and shell.

The maximum operating pressure at the minimum and maximum operating temperatures shall be marked on the nameplate.

6.2 Sizes

All valves, except for reduced-opening valves, shall be furnished in the nominal sizes (DN) listed in *Tables A1.2 to A1.6, Appendix I.*

Reduced-opening valves shall be furnished in the nominal sizes in accordance with *Table A1.1, Appendix I.*

Reduced-opening valves with a circular opening through the obturator shall be specified by the nominal size of the end connections and the nominal size of the minimum bore of the obturator in accordance with *Table A.1, Appendix I*, except that for valve sizes DN 50 (NPS 2) or smaller the actual bore of the obturator shall be specified.

Reduced-opening valves with a non-circular opening through the obturator and reduced-opening check valves shall be designated as reduced-bore valves and specified by the nominal size corresponding to the end connections followed by the letter "R".

6.3 Face-to-Face and End-to-End Dimensions

Face-to-face and end-to-end dimensions of valves shall be in accordance with *Tables A1.2 to A1.6, Appendix I.*

The length of valves having one welding end and one flanged end shall be determined by adding half the length of a flanged-end valve to half the length of a welding-end valve.

Tolerances on the face-to-face and end-to-end dimensions shall be ± 2 mm for valve sizes DN 250 and smaller, and ±3 mm for valve sizes DN 300 and larger.

6.4 Minimum-Bore Full-Opening Valves

Minimum bores for full-opening valves shall not be less than those specified in *Table A1.1, Appendix I.*

6.5 Valve Operation

The maximum pressure differential (MPD) at which the valve is required to be opened by the lever, gearbox or actuator is indicated on the Application Datasheet.

The pressure rating as determined in accordance with *Clause 6.1* for material at 38°C (100°F) shall be the MPD, unless otherwise specified.

6.6 Pigging

Valves that will be subjected to pigging shall be identified on the Application Datasheet.

6.7 Valve Ends

6.7.1 Flanged Ends

Standard end flanges shall be furnished with a raised face or ring joint faces (raised face or full face). Dimensions, tolerances and finishes, including drilling templates, flange facing, spot facing and back facing, shall be in accordance with:

a) *ASME B16.5* Steel Pipe Flanges and Flanged Fittings (up to 24 inch).

b) *ASME B16.47* Large Diameter Steel Flanges (formally *MSS SP-44*) (over 24 inch).

6.7.2 Welded Ends

Standard details for welded ends are illustrated in *Appendix V.*

Welding ends shall conform to *Figures A5.1-1 and A5.1-2, Appendix V*. In the case of a heavy-wall valve body, the outside profile may be tapered at 30° and then to 45° as illustrated in *Figure A5.2, Appendix V.*

The outside diameter, wall thickness, material grade, SMYS and special chemistry of the mating pipe, and whether cladding shall be specified in the Application Datasheet.

6.7.3 Special Flanges and Mechanical Joints

Special flanges and mechanical joints are not permitted.

6.8 Pressure Relief

The manufacturer shall determine whether fluid can become trapped in the body cavity in the open- and/or closed-valve position.

If fluid trapping is possible, then the manufacturer shall provide the valve with a means to prevent overpressure or a means to relief pressure such as automatic cavity pressure relief. The pressure relief line shall be connected to the non-isolated portion of the valve body. Relief to atmosphere is not acceptable.

Cavity relief, when required, shall prevent the pressure in the cavity from exceeding 1.33 times the valve pressure rating determined in accordance with *Clause 6.1* for material at 38°C (100°F). External cavity relief valves shall be DN 15 (NPS 1/2) or larger.

6.9 Bypass and Drain Connections

Bypass or drain connections lines shall be identified on the Application Datasheet when required. Unless specified otherwise, bypass lines shall be 1/2" 304 Stainless steel tubing. Swagelok valves, tubing and fittings are preferred.

Valves for below grade service require drain lines to be routed to the top of the valve. For below grade valves, the bottom ½ in. NPT drain shall be piped to 450 mm (18 in.) above grade. The piping is to be capped with a ½ in. ball valve and plug.

Valves for above grade service shall be supplied with a removable drain plug. Drain plug threads shall be either tapered and capable of providing a pressure-tight seal or parallelthreaded. Connections or plugs with parallel threads shall have a head section for trapping and retaining, a sealing member suitable for the specified valve service.

Thread forms shall be in accordance with *ISO 228-1.*

If specified on the Application Datasheet, the Vendor shall supply a double block and bleed port and valve for double seated valves. Bleed valves shall be of bolted or one-piece construction to guard against accidental disassembly.

6.10 Handwheels and Wrenches (Levers)

Wrenches for valves shall be an integral design or consist of a head, which fits on the stem and is designed to take an extended handle. The head design shall allow permanent attachment of the extended section if specified on the Application Datasheet.

The maximum force required at the handwheel or wrench to apply the breakaway torque or thrust shall not exceed 360 N (80 lbf). The manufacture shall provide a gear operator when this value is exceeded.

Wrenches shall not be longer than twice the face-to-face or end-to-end dimension of the valve.

Handwheel diameter shall not exceed the face-to-face or end-to-end length of the valve or 1000 mm, whichever is the smaller. Except for valve sizes DN 40 (NPS 1 1/2) and smaller, spokes shall not extend beyond the perimeter of the handwheel.

The handwheel of the gearbox input shaft shall be provided with a torque-limiting device, such as a shear pin, to prevent damage to the drive train.

The gear and motorized operators shall be designed to operate against the maximum differential pressure.

6.11 Position Indicators

Valves fitted with manual or powered actuators shall be furnished with a visible indicator to show the open and the closed position of the obturator.

For plug and ball valves, the wrench and/or the position indicator shall be in line with the pipeline when the valve is open and transverse when the valve is closed. The design shall be such that the component(s) of the indicator and/or wrench cannot be assembled to falsely indicate the valve position.

Valves without position stops shall have provision for the verification of open and close alignment with the operator/actuator removed.

6.11.1 Operators and Stem Extensions

6.11.2 Stem Extensions

Valves that require stem extensions will be indicated on the Application Datasheet with the length. The reference points for length shall be valve opening centreline to the face of the gear/activator mounting flange. Stems shall be constructed of one piece.

The Application Datasheet will indicate the dimension between centreline of the valve opening and the centreline of the handwheel. For electric motor operated valves, the valve Vendor shall supply the dimensional details for review with the actuator vendor to ensure the desired extension dimensions are met.

Extended stem assemblies shall be strengthened as required to withstand the additional loading. All flanged, bolted, or machined surfaces on stem extensions shall have gaskets or have O-rings on mating surfaces to prevent water ingress into the valve stems.

The dimension of centreline of valve opening to top of grade (or platform) is specified on the Application Datasheet.

Extensions and valve yoke tubes shall be fitted with top and bottom ½ in. NPT drain fittings so that seals can be checked for leakage and water can be drained.

6.11.3 Misalignment

Misalignment or improper assembly of components shall be prevented by suitable means, such as a dowel pin or fitting bolt, which ensure the unique location of manual or powered operators and stem extension assemblies. Intermediate shaft guides shall be installed on extensions greater than 2500 mm (8 ft) in length.

6.11.4 Sealing

External connections shall be sealed, for example with gaskets or O-rings, to prevent external contaminants entering the mechanism.

6.11.5 Overpressure Protection

Operators and stem extension assemblies shall be provided with a means of preventing pressure build-up in the mechanism resulting from stem or bonnet seal leakage.

6.12 Valve Seat Lubrication

All valves shall be non-lubricated for normal valve seating.

Seat and/or stem sealant injection shall be provided when specified on the Application Datasheet. The valves shall be equipped with the provision for external lubricant injection to extend service life and provide emergency sealing, in case of worn seals. All grease fittings shall be "Flo-Wolf" or equal.

6.13 Lifting Lugs

Valves of size DN 200 (NPS 8) and larger shall be provided with lifting lugs.

6.14 Manual Actuator Provisions

The type of operator required is specified on the Application Datasheet.

Handwheel or wrench actuators shall have a maximum rim pull of 35 kg (80 lb). A clockwise rotation of the handwheel shall close the valve. An arrow indicating the direction of rotation to close the valve shall be permanently engraved on the handwheel.

6.15 Powered Actuator Provisions

Valves to be operated by powered actuators are specified on the Application Datasheet.

The interface between actuators and valve bonnet or stem extension assemblies shall be designed to prevent misalignment or improper assembly of the components. Fabrication drawings of the valve–actuator interface plate and stem connection details shall be provided with the valve at time of purchase.

Valves that are to be fitted with actuators by others shall be supplied with stem only and an actuator-mounting bracket installed.

The interface between actuators and valve bonnet or stem extension assemblies shall be sealed with gaskets or O-rings to prevent external contaminants from entering the assembly.

Means shall be provided of preventing pressure build-up in the actuator from stem or bonnet seal leakage.

The output of the actuator shall not exceed the maximum load capacity of the valve drive train.

Unless stated otherwise on the Application Datasheet, for electrically operated valves, the electric motor operator shall be supplied and installed by others.

6.16 Drive Trains

6.16.1 Design Thrust or Torque

The design thrust or torque for all drive train calculations shall be at least two times the breakaway thrust or torque.

Gears and bearings of the gearbox shall be weather, dust proof filled with suitable grease for -45ºC, and fully enclosed.

NOTE: This factor of safety is to allow for thrust or torque increase in service due to infrequent cycling, low-temperature operation and the adverse effect of debris.

6.16.2 Allowable Stresses

Tensile stresses in drive train components, including stem extensions, shall not exceed 67% of SMYS when delivering the design thrust or torque. The maximum design von Mises stress (combined bending, shear, torsion and bearing stresses) shall not exceed the 1/2 of the yield stress of the material for any component under any anticipated load.

A strength efficiency factor of 0.75 shall be used for fillet welds.

6.16.3 Allowable Deflections

For ball valves, the total torsional deflection of the extended drive train when delivering the design torque shall not exceed the overlap contact angle between the seat and obturator.

Deflections of the extended drive train shall not prevent the obturator from reaching the fully closed position.

6.17 Stem Retention

Valves shall be designed with a stem anti-blow-out device to prevent stem ejection by internal pressure when the stem packing and/or retainer has been removed.

7 Materials

The materials of construction shall include but not be limited to the following:

a) Valve body and pressure containment components;

b) Bonnet;

c) Shaft material;

d) Bolts and nuts;

e) Seals.

7.1 Material Specification

Materials of construction shall be as specified in this section. Manufacturers shall submit positive identification certificates in the form of a certified Material Test Report (MTR) for all pressure containing and process wetted components. The minimum information to be provided shall be:

a) Chemical properties;

b) Heat treatment;

c) Mechanical properties;

d) Test results;

e) Manufacturers Certification.

One or a combination of the following material specifications is anticipated for most applications (oil at typical Enbridge pipeline specifications). Alternate material may be proposed provided it is clearly identified by the manufacture and accepted by Enbridge and as required to meet the project specific requirements as indicated on the Application Datasheet. The temperatures shown are the minimum permitted per material specification, impact tested where applicable. For design temperatures below these values, impact testing for notch toughness is required.

Material Specification	Product Form	Minimum Temperature
ASTM A 216 Gr. WCB	Carbon Steel casting	-20 °F
ASTM A 216 Gr. WCC	Carbon Steel casting	-20 °F
ASTM A 217 Gr. WC6	¼ Cr – ½ Mo casting	-20 °F
ASTM A 217 Gr. C5	5 Cr – ½ Mo casting	-20 °F
ASTM A 217 Gr. WC9	2¼ Cr – ½ Mo casting	-20 °F
ASTM A 351 Gr. CF8M	18 Cr-10 Ni-2 Mo (alt. Low temp.)	-425 °F
ASTM A 352 Gr. LCB	C-½ Mo casting	-50 °F
ASTM A 352 Gr. LCC	C-½ Mo casting	-50 °F
ASTM A105	Carbon Steel forging	-20 °F
ASTM A181 Cl. 60	Carbon Steel forging	-20 °F
ASTM A181 Cl. 70	Carbon Steel forging	-20 °F
ASTM A182 F11	¼ Cr. - ½ Mo forging	-20 °F
ASTM A182 F22	2¼ Cr. - 1 Mo forging	-20 °F
ASTM A182 F6	13 Cr. Alloy forging	-20 °F
ASTM A350 LF 2	Carbon steel forging	-50 °F
ASTM A537 Cl 1&2	Carbon steel plate	-20 F
ASTM A333 Gr. 6	Carbon steel pipe	-50 F

Table 7.1 Material Specifications

One or a combination of the following material specifications shall be used for valve trim material.

Trim Number	Stem	Body Seat	Obturator Seat	Back Seat
1	13% Cr.	CS+13% Cr.	CS+13% Cr	13% Cr
5	13% Cr	CS+Stellite 6	CS+13% Cr	13% Cr
8	13% Cr	CS+Stellite 6	CS+Stellite 6	18% Cr
12	SS316	CS+Stellite 6	CS+ SS 316	SS 316

Table 7.2 Trim Material Specifications

7.2 Gate and Globe Valves

Manufacturer may substitute ASTM A217 Gr. CA15 or A 351 Gr. CF8M material for wedge or globe base material.

For additional materials consult ASME B16.34 or Table 2 of CSA Z245.15, depending on location of installation. Alternate approved materials shall be noted on the Valve Datasheet completed by the manufacturer.

7.3 Gaskets and O-Rings

The metallic portion exposed to the service environment shall be of a material that has a corrosion resistance at least equal to that of the body material.

Inside diameter mating gaskets shall not be smaller than the inside diameter of the flanges.

Gasket or O-ring material shall have a duorometer number of 70 to 90. Acceptable materials, depending upon service conditions, are:

a) Kalrez® (-40° to 600° F);

b) Nitrile (Buna-N) (-40° to 275° F);

c) Highly Saturated Nitrile HSN (-40° to 350° F);

d) Viton® (Fluorocarbon) (-20° to 400° F);

e) Braided PTFE graphite.

Manufacturer shall confirm suitability of sealing material for service. Manufacturer shall also confirm suitability of sealing material for field hydrotesting with methanol and or glycol mixes.

7.4 Stem and Stem Nut

The stem shall be designed to accept the maximum torque required to open or close the valve under pressure without excessive deflection.

Stem material shall be selected *per Clause 7.1*. In certain applications, carbon steel stems with 3 mils of electroless nickel plating may be offered as an alternative, subject to the Company's approval.

See also *Clause 6.17.1* for torsion requirements.

Valve stem nuts used to engage gear drive mechanisms shall be of bronze or aluminium-bronze alloy material.

7.5 Valve Ends

Flanged valves shall have raised face flanges with dimensions and tolerances in accordance with the requirements of ASME B16.5 or MSS SP-44-1996.

Welded ends shall be beveled to accommodate a butt weld connection to pipe in accordance with the manufacturing specification. The specifics of the matching pipe are provided on the Application Datasheet.

The Vendor shall indicate whether pipe transition pieces would be required to accommodate the butt weld to the matching pipe. Valves ends made of cast materials shall have transition pieces supplied and installed by the Vendor to accommodate the butt weld to matching pipe.

In some cases, the Company will require transition pieces and will specify this on the Application Datasheet. If transition pieces are required, the Company and Vendor shall agree on the supply of materials and the design of the end connection.

7.6 Service Compatibility

All process-wetted parts, metallic and non-metallic, and lubricants shall be suitable for the commissioning fluids and service specified by on the Application Datasheet.

The description and properties of the fluid handled, including minimum and maximum temperature, specific gravity, viscosity, etc shall be provided to the manufacturer prior to valve fabrication.

The manufacturer shall consider all of the data in the Valve Datasheet when selecting the appropriate materials of manufacture for the valve. Asbestos and asbestos compounds shall not be used.

7.7 Forged Parts

Forged pressure containing parts shall be forged close to the finished shape and size.

7.8 Welding Ends

7.8.1 For Welded End Valves

The chemistry of carbon steel welding ends shall meet the following requirements:

a) The carbon content shall not exceed 0.23% by mass in the ladle (heat) analysis or 0.25% by mass in the product (check) analysis;

b) The maximum content of both sulfur and phosphorus shall not exceed 0.035% by mass;

c) The carbon equivalent (CE) shall not exceed 0.43 in the ladle (heat) analysis or 0.45 in the product (check) analysis. The CE shall be calculated in accordance with the following formula:

$$CE = \%C + (\%\ Mn/6) + (\%\ Cr + \%\ Mo + \%\ V)/5 + (\%\ Ni + \%\ Cu)/15$$

The chemistry of austenitic stainless steels for welding ends shall meet the following requirements:

a) The carbon content shall not exceed 0.03% by mass, except under the conditions outlined in b) and c) below;

b) A carbon content of up to 0.08% by mass is permissible provided the material is stabilized with niobium and the niobium content is at least 10 times the carbon content by mass;

c) For steels stabilized with niobium or tantalum, the combined mass of niobium and tantalum shall be at least eight times the mass of the carbon. Requirements for the chemistry of welding ends made of other materials shall be established by agreement.

7.9 Toughness Test Requirements – Materials

Manufacturer to provide the results of impact testing when the minimum service temperature is below -29°C.

All carbon and low-alloy steels for pressure-containing parts in valves with a specified design temperature below -29°C (-20°F) shall be impact-tested using the Charpy V-notch technique in accordance with *ISO 148 or ASTM A 370.*

Materials shall be procured to documented specifications.

Toughness testing may be performed during the qualification of the valve manufacturing procedure provided that the material for testing is heat-treated using the same equipment as during valve production.

The impact test temperature shall be as defined in the Application Datasheet for minimum temperature.

Except for material for bolting, impact test results for full-size specimens shall meet the requirements of *Table 7.3* Impact test results for bolting material shall meet the requirements of *ASTM A 320.*

Average of Three Specimens (MPa)	**Average of Three Specimens** (J)	**Minimum for Single Specimen** (J)
≤ 586	20	16
587 - 688	27	20
≥ 689	34	25

Table 7.3 Charpy V-Notch Impact Requirements (Full-Size Specimen)

7.10 Bolting

Bolting shall be suitable for the specified valve service and pressure rating.

ASTM Specifications:

a) Bolts A 193 Gr. B7, or A 320 Gr. L7 (low temp)

b) Nuts A 194 Gr. 2H, or A 194 Gr. 4 (low temp)

8 Welding

8.1 Qualifications

Welding, including repair welding, of pressure - containing and pressure-controlling parts shall be performed in accordance with procedures qualified to *ASME Section IX or EN 288-3*, and *Clauses 9.2 and 9.3* of this specification. Welders and welding operators shall be qualified in accordance with *ASME Section IX or EN 287-1*.

The Vendor shall notify the Company when a repair has been made to a valve.

The manufacturer shall provide an adequate quality control of welding and welding repair.

The results of all qualification tests shall be documented in a procedure qualification record (PQR). Post-weld heat treatment (PWHT) shall be performed in accordance with the relevant material specification.

8.2 Impact Testing – Welding

Impact testing shall be carried out for the qualification of procedures for welding on valves with a design temperature below -29°C (-20°F). Where required impact testing temperature shall be -45°C, lower temperatures may be specified on the Application Datasheet.

NOTE: Design code and/or local requirements may require impact testing at minimum design temperatures above -29°C (-20°F).

A set of three weld metal impact specimens shall be taken from the weld metal (WM) at the location shown in *Figure A6.3, Appendix IV*. The specimens shall be oriented with the notch perpendicular to the surface of the material.

A set of three impact specimens shall be taken from the heat-affected zone (HAZ) at the location shown in *Figure A6.4, Appendix IV*. The notch shall be placed perpendicularly to the material surface at a location resulting in a maximum amount of HAZ material located in the resulting fracture.

HAZ tests shall be conducted for each of the materials being joined when the base materials being joined are of a different P-number and/or group number in accordance with *ASME Section IX* or when one or both of the base materials being joined are not listed in the P-number grouping.

Impact testing shall be performed in accordance with *ISO 148 or ASTM A 370* using the Charpy V-notch technique. Specimens shall be etched to determine the location of the notch.

The impact test temperature for welds and heat-affected zones shall be at or below the minimum design temperature specified for the valve.

Impact test results for full-size specimens shall meet the requirements of *Table 7.3*, Hardness testing. Hardness surveys shall be performed on base metal (BM), WM and HAZ as indicated in *Appendix IV* using the Rockwell HRC or Vickers HV10 method.

9 Painting/Coating

9.1 Coating

Valves for below grade service shall be coated. Vendor shall provide the coating procedure with his bid submission for approval by Enbridge. If the procedure is not approved, then the vendor shall coat the valve using Enbridge's "C-110 Coating of Buried Steel with Plural Component Spray Applied Coatings" procedure.

9.2 Painting

Valves for above grade service shall be painted. The Vendor shall provide the painting procedure with his bid submission for Enbridge approval. If the procedure is not approved, then the Vendor shall paint the valve using Enbridge's "P-210 Shop and Field Painting" procedure.

10 Quality Control

10.1 Non-Destructive Testing

Manufacturers that are certified holders of a current API Monogram license, supplying monogrammed product need only submit a copy of the license, and contact name of the responsible shop inspector.

All other Manufacturers shall supply a copy of their Quality Test plan verifying NDE requirements are met and that they are in accordance with the material specification for review and acceptance. Non-Destructive testing shall be conducted to the extent necessary to detect all defects in the manufactured piece or pieces and to determine compliance with dimensional requirements. The Manufacturer shall clearly indicate which procedures (Radiographic, Ultrasonic, Magnetic particle, Liquid Penetrant) are used and to what extent. Acceptable procedures are given in *Table 10.1* below.

One or several of the follow methods shall be utilized for Non Destructive testing of the valve components:

Manufactured Component	Examination	Exam Procedure	Acceptance Criteria
Weldments – all pressure boundary welds require 100% examination	Radiographic	ASME V, Article 22	ASME VIII, Div. 1 Part UW51 for linear indications and Appendix 4 for rounded indications
	Ultrasonic	ASME V, Article 23	ASME VIII, Div. 1, Appendix 12
Castings	Radiographic	ASME V, Article 22	ASME VIII, Div. 1, Appendix 7
Castings	Ultrasonic	ASME V, Article 23	ASTM A 609, Table 2, Quality Level 1
Castings	Magnetic Particle	ASME V, Article 25	ASME VIII, Div. 1, Appendix 6
Castings	Liquid Penetrant	ASME V, Article 24	ASME VIII, Div. 1, Appendix 8
Forgings	Ultrasonic	ASTM A 388	ASTM A 388
Forgings	Magnetic Particle	ASME V, Article 25	ASME VIII, Div. 1, Appendix 6
Plates (as applicable)	Ultrasonic	ASTM A 435 or A 577	ASTM A 435 or A 577

Table 10.1 Non Destructive Testing Requirements

10.2 Non-Destructive Test Records

All radiographs shall be identified and shall be available for the Company representative to view. A written record of all non-destructive examinations required by this Specification and the results shall be submitted to the Company upon completion of the order.

10.3 Measuring and Test Equipment

10.3.1 General

Equipment used to inspect, test or examine material or equipment shall be identified, controlled and calibrated at intervals specified in the manufacturer's instructions.

10.3.2 Dimension-Measuring Equipment

Equipment for measuring dimensions shall be controlled and calibrated in accordance with methods specified in documented procedures.

10.3.3 Pressure-Measuring Devices

10.3.4 Type and Accuracy

Test pressure measuring devices shall be either pressure gauges or pressure transducers, which are accurate to within ± 2.0% of the full-scale reading.

10.3.5 Gauge Range

Pressure measurements shall be made between 25% and 75% of the full pressure range of the measuring device.

10.3.6 Calibration Procedure

Pressure-measuring devices shall be periodically recalibrated with a master pressure-measuring device or a deadweight tester at 25%, 50%, 75% and 100% of the full pressure scale.

10.3.7 Temperature-Measuring Devices

Devices for measuring temperature, if required, shall be capable of indicating and recording temperature fluctuations of 3°C (5°F).

10.4 Qualification of Inspection and Test Personnel

10.4.1 NDE Personnel

NDE personnel shall be qualified in accordance with the requirements specified in ASNT SNT-TC-1A or EN 473 Level II as a minimum.

Personnel performing visual examinations shall have passed an annual eye examination in accordance with ASNT SNT-TC-1A or EN 473 within the previous twelve months.

10.4.2 Welding Inspectors

Personnel performing visual inspection of welding operations and completed welds shall be qualified and certified to the requirements of AWS QC1, or equivalent, or a manufacturer's documented training program.

10.5 NDE of Repair Welding

After defect removal, the excavated area shall be examined by magnetic particle (MT) or liquid penetrant (PT) methods prior to starting repair welding.

Repair welds on pressure-containing parts shall be examined using MT or PT methods. Acceptance criteria shall be specified in documented procedures.

10.6 Shop Inspection

The Company may have a Company Inspector present in the Vendor's manufacturing facility at any time during the manufacture of the valves. The Company Inspector may witness all hydrostatic tests and may be present for other tests and NDE. The Company Inspector may also witness the final inspection of each valve prior to shipment to ensure the valves meet all requirements of this Specification and the purchase order.

The Company shall be notified of any injurious defects found on any pressure containing valve component during non-destructive tests.

11 Pressure Testing

11.1 General

Each valve shall be tested in accordance with this clause prior to shipment. Testing shall be performed in the sequence used in this clause for specifying the test requirements. Shell pressure testing shall be carried out before painting of the valves. Test fluids shall be fresh water, which may contain corrosion inhibitors. The chloride content of test water for austenitic and ferritic-austenitic (duplex) stainless-steel body/bonnet valves shall not exceed 30 ppm.

Valves shall be tested with the seating and sealing surfaces free from sealant except where the sealant is the primary means of sealing.

Tests specified with the valve half-open may also be performed with the valve fully open provided the body cavity is simultaneously filled and pressurized through a cavity connection.

Methods for monitoring pressures and/or leakage shall be adequate also when valve body connections are not available for direct monitoring. The leak test shall be performed at both the minimum and maximum operating temperatures. A sufficient stabilization period shall be allowed for all pressure tests. Test shall be witnessed by Enbridge or designate. Pressure testing shall be performed in accordance with documented procedures.

11.2 Stem Backseat Test

Stem backseat testing shall be performed prior to shell testing. Where a valve has a stem backseat feature, testing of the backseat shall commence with the seat free. Self-energized packing or seals shall be removed unless a test port is provided for this test.

The valves shall be filled with the ends closed off and the obturator in the partially open position until leakage of the test fluid around the stem is observed. The backseat shall then be closed and a minimum pressure of 1.1 times the pressure rating determined in accordance with *Clause 6.1* for material at 38°C (100°F) is applied for the duration specified in *Table 11.1*.

Monitoring for leakage shall be through a test access port or by monitoring leakage around the loosened packing.

No visible leakage is permitted at this test pressure.

Valve Size		**Test Duration (minutes)**
DN (mm)	**NPS (inches)**	
≤ 00	≤ 4	2
≥ 50	≥ 6	5

Table 11.1 Minimum Duration of Stem Backseat Tests

11.3 Hydrostatic Shell Test

Hydrostatic shell testing shall be performed on the fully assembled valve prior to painting or coating.

Valves shall be closed off and the obturator placed in the partially open position during the test. The method of closing the ends shall permit the transmission of the full-pressure force acting on the end blanks to the valve body. Where present, external relief valves shall be removed and their connections plugged.

The test pressure shall be 1.5 or more times the pressure rating determined in accordance with *Clause 6.1* for material at 38°C (100°F). The duration shall not be less than that specified in Table 10.2.

Where the longer test durations are required, these will be indicated on the Application Datasheet.

Valve Size		**Test Duration (minutes)**
DN (mm)	**NPS (inches)**	
15 -100	½ - 4	2
150 -250	6 -10	5
300 -450	12 -18	15
500 - 915	20 - 36	30
Over 915	> 36	120

Table 11.2 Minimum Duration of Hydrostatic Shell Tests

The test shall be documented on a chart recorder.

No visible leakage is permitted during the hydrostatic shell test.

After hydrostatic shell testing, external relief valves shall be (re)fitted to the valve. The connection to the valve body shall be tested at 95% of the set pressure of the relief valve for 2 minutes for valve sizes up to and including DN 100 (NPS 4), and 5 minutes for valve sizes DN 150 (NPS 6) and larger. The relief valve connection shall be free of visible-leakage during this period.

Where provided, the external relief valve shall be set to relieve at the specified pressure and tested. The set pressure of relief valves shall be between 1.1 and 1.33 times the valve pressure rating determined in accordance with *Clause 6.1* for material at 38°C (100°F).

11.4 Hydrostatic Seat Test

11.4.1 Preparation

Lubricants shall be removed from seats and obturator sealing surfaces except, by agreement, for assembly lubricants for metal-to-metal contact surfaces.

11.4.2 Test Pressure and Duration

The test pressure for all seat tests shall not be less than 1.1 times the pressure rating determined in accordance with *Clause 6.1* for material at 38°C (100°F). The test duration shall be in accordance with *Table 11.3*.

When longer test durations are required, these will be indicated on the Application Datasheet.

Valve Size		**Test Duration (minutes)**
DN (mm)	**NPS (inches)**	
15 -100	½ - 4	2
150 - 915	6 - 36	5
Over 915	> 36	10

Table 11.3 Minimum Duration of Seat Tests

The test shall be documented on a chart recorder.

11.4.3 Acceptance Criteria

Leakage for soft-seated valves and lubricated plug valves shall not exceed ISO 5208 Rate A (no visible leakage). For metal-seated valves the leakage rate shall not exceed ISO 5208 Rate D, except that the leakage rate during the seat test in *Clause 11.4.4.5.2* shall not be more than two times ISO 5208 Rate. The test procedures for various types of block valve are given in *Clause 11.4.4.*

11.4.4 Test Procedures for Block Valves

11.4.5 Uni-Directional

With the valve half-open, the valve and its cavity shall be completely filled with test fluid. The valve shall then be closed and the test pressure applied to the appropriate end of the valve.

Leakage from each seat shall be monitored via the valve body cavity vent or drain connection. For valves without a body cavity connection, seat leakage shall be monitored from each seat at the respective downstream end of the valve (the valve end downstream of the pressurized test fluid).

11.4.6 Bi-Directional

With the valve half-open, the valve and its cavity shall be completely filled with test fluid. The valve shall then be closed and the test pressure applied successively to both ends of the valve.

Seat leakage shall be monitored from each seat via the valve body cavity vent or drain connection. For valves without a body cavity vent or drain connection, seat leakage shall be monitored from the respective downstream end of the valve.

11.4.7 Twin-Seat, Both Seats Bi-Directional

Each seat shall be tested in both directions.

Cavity relief valves shall be removed if fitted. The valve and cavity shall be filled with test fluid, with the valve half-open, until the test fluid overflows through the cavity relief connection.

To test for seat leakage in the direction of the cavity, the valve shall be closed. The test pressure shall be applied successively to each valve end to test each seat separately from the upstream side. Leakage shall be monitored via the valve cavity pressure relief connection.

Thereafter, each seat shall be tested as a downstream seat. Both ends of the valve shall be drained and the valve cavity filled with test fluid. Pressure shall then be applied whilst monitoring leakage through each seat at both ends of the valve.

11.4.8 Twin-Seat, One Seat Uni-Directional and One Seat Bi-Directional

11.4.9 Uni-Directional Seat

With the valve half-open, the valve and the test cavity shall be completely filled with test fluid until fluid overflows though the valve cavity vent connection. The valve shall then be closed and the vent valve on the test closure opened to allow fluid to overflow, or the test closure on the downstream end of the valve removed. The test pressure shall then be applied to the upstream end (uni-directional seat end) and leakage monitored from the cavity connection. If leakage is also occurring through the downstream seat, the upstream seat leakage shall be taken as the sum of the leakage measured from the cavity and the downstream connections.

11.4.10 Bi-Directional Seat

The test in *Clause 10.4.4.4.1* shall be repeated to test the bi-directional seat in its upstream-sealing direction.

To test the bi-directional seat in its downstream-sealing direction, both ends of the valve shall be blanked off. With the valve half-open, the valve shall be completely filled with test fluid and pressurized to the test pressure. The valve shall then be closed and test fluid allowed to overflow from a connection on the test closure fitted to the end of the valve at the bi-directional seat end (i.e., downstream of the bi-directional seat). The test pressure shall be maintained on the cavity connection whilst monitoring seat leakage of the bi-directional seat at the overflow connection on the downstream test closure.

11.4.11 Double-Block-and-Bleed Valves

11.4.12 Single-Seat Test

With the valve half-open, the valve and its cavity shall be completely filled with test fluid. The valve shall then be closed and the valve body vent valve opened to allow excess test fluid to overflow from the valve cavity test connection. The test pressure shall then be applied to one end of the valve and the pressure released at the other end. This test shall be repeated for the other valve end.

Seat tightness shall be monitored during each test via overflow from the valve cavity connection.

11.4.13 Double-Block Seat Test

With the valve half-open, the valve and its cavity shall be completely filled with test fluid. The valve shall then be closed and the valve body vent valve opened to allow excess test fluid to overflow from the valve cavity test connection. The test pressure shall be applied simultaneously from both valve ends.

Seat tightness shall be monitored via overflow through the valve cavity connection.

The tests in *Clause 11.4.4.5* may be performed in any order by the manufacturer.

11.4.14 Check-Valves

The pressure shall be applied in the direction of the required flow blockage.

11.4.15 Installation Of Body Connections After Testing

Pressure-containing parts, such as vent/or drain plugs and cavity relief valves, shall be fitted, on completion of testing.

11.5 Draining

Valves and valve cavities shall be drained of test fluids and, where applicable, lubricated before shipment.

12 Marking Requirements

12.1 Marking

Valves shall be marked in accordance with *Table 12.1*.

On valves whose size or shape limits the body markings, they may be omitted in the following order:

1. Size
2. Rating
3. Material
4. Manufacturer's name or trademark.

Valves shall be marked as per MSS-SP-25 plus:

Each valve shall be fitted with a stainless metal tag of 16 BWG minimum thickness, securely attached with stainless steel wire. Tags shall normally be attached to the yoke. When that is not possible, the tag may be attached to the handwheel or other appropriate location. Tags shall not be attached through bolt holes of end flanges.

These additional metal tags shall have the following information:

a) Enbridge Valve Shipping Tag Number;

b) Purchase order number;

c) Supplier number;

d) Any other markings as stipulated on the purchase order.

The minimum letter size shall be 0.2".

The nameplate and serial number may be omitted for valves smaller than DN 50 (NPS 2).

For valves with one seat uni-directional and one seat bi-directional only, the directions of both seats shall be specified on a separate identification plate as illustrated in *Figure 12.1*. In *Figure 12.1*, one symbol indicates the bi-directional seat and the other symbol indicates the uni-directional seat.

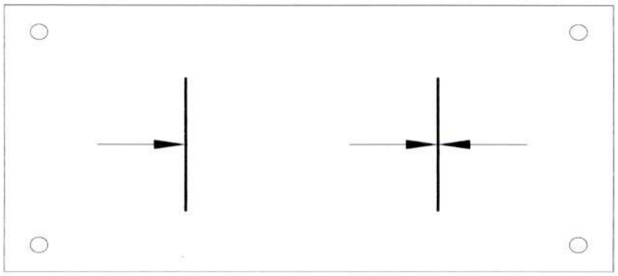


Figure 12.1 Typical Identification Plate for Valve with One Seat Uni-Directional and One Seat Bi-Directional

	Marking	Application
1	Manufacturer's name or trademark	On both body and nameplate
2	Pressure Class	On both body and nameplate
3	Pressure/temperature rating: a) Maximum operating pressure at maximum operating temperature b) Maximum operating pressure at minimum operating temperature	On nameplate
4	Face-to-face/end-to-end dimension (6.3)	On nameplate
5	Body material designation: Material symbol (AISI, ASME, ASTM, ISO) Note: When body is fabricated of more than one type of steel, the end connection material governs marking.	On both body and nameplate. Melt identification (i.e., cast or heat number) on body only
6	Bonnet/cover material designation: Material symbol (AISI, ASME, ASTM, ISO)	On bonnet/cover, including melt identification (i.e., heat number)
7	Trim identification: Symbols indicating material of stem and sealing faces of closure members if different from that of body. Note: MSS-SP-25 gives guidance on marking.	On nameplate
8	Nominal valve size: a) Full-opening valves: nominal valve size b) Reduced-opening valves: shall be marked as specified in *Clause 6.2.*	On body or nameplate or both (where practicable)
9	Ring joint groove number	On valve flange edge
10	SMYS and minimum wall thickness	On body weld bevel ends
11	Flow direction (for check valves only)	On body of uni-directional valves only
12	Seat sealing direction	Separate identification plate on valve body
13	Unique serial number	On both body and nameplate
14	Date of manufacture (month and year)	On nameplate
15	ISO 14313	On nameplate

Table 12.1 Valve Marking

13 Storage and Shipping

13.1 Shipping

Each container shall be identified with its contents as well as the purchase order number.

Valves shall be protected from damage during shipping.

When a manufacturer transports by sea, all valves and their components shall be supplied as below deck cargo in waterproof containers.

All non-corrosion-resistant valves shall be primed and/or painted externally in accordance with the manufacturer's standards.

Stainless-steel valves shall not be painted.

Flange faces, weld bevel ends and exposed stems shall not be painted.

13.2 Corrosion Prevention

Prior to shipment, parts and equipment, which have bare metallic surfaces, shall be protected with a rust preventative, which will provide protection at temperatures up to 50°C (122°F).

13.3 Openings

Valve flanged and welding ends shall be blanked off to protect the surfaces, welding ends and valve internals during shipment and storage. Protective covers shall be made of wood, wood fiber, plastic or metal and shall be securely attached to the valve ends by bolting, steel straps, steel clips or suitable friction-locking devices. The design of the covers shall prevent the valves from being installed unless the covers have been removed.

Plug, ball and reverse-acting through-conduit gate valves shall be shipped in the fully open position, unless fitted with a fail-to-close actuator.

Slab-gate valves shall be shipped with the gate in the fully closed position. Check valves shall be shipped with the disc supported or secured during transit.

Valves provided with stem extensions without an operating mechanism shall have the annular space closed and the stem extension secured against the outer housing.

14 Documentation

14.1 Bid Submission Documents and Information Package

The Vendor is advised that a complete documents and information package is a bid-qualifying requirement.

The elements of this package shall include:

a) Verification of Enbridge valve specification number and revision

b) Verification of conformance to EES105 and the Application Datasheet(s)

A copy of the Application Datasheet shall accompany each valve offering. Note that the Application Datasheet may apply to one valve offering or a group of identical valve offerings.

c) Alternative Features

Where the Vendor is proposing an alternative feature, the Vendor shall also provide an explanation of the benefits of the alternative.

Alternatives include exceptions and substitutions.

d) Manufacturer's Quality Control Plan

The Plan shall be precisely the Plan for use on the referenced valve order. General plans are not acceptable.

Industry certificates of conformance and quality program audit certificates shall be supplied.

e) Coating or Painting Procedures

f) Manufacturing and valve assembly locations, including third party service providers

g) Valve Assembly Drawings

Valve assembly drawings including dimensions, weights, details of sealing design and materials, auxiliaries, stem extensions, drive train elements.

h) Volume of Body Cavity

i) Delivery Dates per Valve

j) Cost per Valve

Basic Valve	
Auxiliary Piping	
Stem Extension	
Gear Operator	
Electric Actuator Adaption	
Coating/Painting	
NDE and Pressure Testing	
Shipping	
Documentation and Other Costs	
TOTAL	

14.2 Post Award

The Vendor shall submit a minimum of the following for Company approval at an agreed upon date after award and prior to manufacture and assembly:

a) Dimensional outline drawings, cross-sectional drawings and detail drawings (see Clause 14.4 Vendor Documentation Schedule for details);

b) Material specifications for all components of the valve at the time of actual valve manufacture;

c) Details of transition pieces supplied by the Vendor;

d) Any proposed weld and heat treatment procedures;

e) Shipping weights, lengths and widths; and

f) Production schedule (every 2 weeks until shipment is complete).

14.3 Final Documentation

The documentation for valves shall include:

a) Operations and Maintenance Manuals;

b) Positive Material Identification (MTR);

c) Weld procedure specification (WPS);

d) Weld procedure qualification record (PQR);

e) Welder qualification record (WQR);

f) Records of test equipment calibration;

g) Mechanical test results as applicable;

h) Non-destructive examination records;

i) Melt identification certificates for body bonnet/cover(s) and end connector(s) traceable to the unique valve serial number;

j) All valve drawings;

k) Detailed parts lists;

l) Any other specific requirements listed in the purchase order;

m) Confirmation that the valve provided has been fabricated and shipped in accordance with the requirements of this specification and the purchase order;

n) Completed Maximo data sheet;

o) Serial number for tracing the valve bill of materials;

p) Charts for hydrostatic tests; and

q) Final QA/QC documentation package.

One copy of each of the above items is to be shipped with the valve. The remaining copies are to be shipped to the location listed in the purchase order as directed by the Company. Documentation shall be provided by the manufacturer in legible, retrievable and reproducible form, and free of damage.

14.4 Vendor Documentation Schedule

DATA AND DRAWINGS REQUIRED	Bid Proposal	Post Award	Shipment
	No. of Copies	No. of Copies	No. of Copies
1. Dimensioned Outline Drawings	1P (1E)	2P, 1E	2P, 1E
2. Cross Sectional Drawings	1P (1E)	2P, 1E	2P, 1E
3. Detail Drawings	1P (1E)	2P, 1E	2P, 1E
4. Assembly - Erect Drawings			
5. Foundation/Anchor Bolt Drawings			
6. Piping Drawings			
7. Wiring/Schematic Diagrams (Hydraulic)			
8. Parts List			2P
9. Priced Recommended Spare Parts List	1P (1E)		2P
10.Installation, Operations and Maintenance Manuals			2P
11.Equipment Data Sheets	1P (1E)	2P	2P
12.Shipping Weight(s)	1P (1E)	2P	2P
13.Manufacturers Test Reports			2P
14.Mill Test Certificates			2P
15.Nameplate Data		2P	2P
16.Surface Preparation QA/QC			
17.Hydrostatic Test Charts			2P
18.Materials Specification and Manufacturing Standard	2P (1E)	2P	2P
19.As-Built Drawings			
20.MAXIMO Information			
21.			
22.			

P – Print E – Electronic

Appendix I
Application Datasheet

Valve Application Datasheet (Page 1 of 2)

Date: (To be completed by Enbridge representative.)

Material Requisition No.					Revision:				
Quantity Required:									
Project Location:						☐ Canada		☐ USA	
Project Name / Number:									
Description of Application:									
Functional Tags:									
Shipping Tags:									
Code: ☐ API 6D ☐ CSA Z245.15					Below Grade	☐ Yes		☐ No	
Fluid: ☐ Oil ☐ NGL ☐ Refined Products					Ambient Temperature	°C min /		°C max	
Fluid Product Description									
Process Conditions	Temp (°C)	Vapor Pressure (kPa)	Viscosity (CP)	Density (kg/m^3)	Flow Rate (m^3/hr)	Pressure (kPa)	Solids %	Corrosives	
Minimum									
Normal									
Maximum									
Valve Size:	mm /	inch			**Port Size:** ☐ Full	☐ Reduced			5.1
Piping Class (PN) ANSI	Type	Valve Style (Clause 5.0)				Inlet	Outlet		
☐ (20) 150	☐ Gate					☐ FLG	☐ FLG		6.7
☐ (50) 300	☐ Globe					☐ WLD	☐ WLD		6.7
☐ (100) 600	☐ Plug					☐ RTJ	☐ RTJ		6.7
☐ (150) 900	☐ Check								
	☐ Ball								
Is pigging required?	☐ Yes	☐ No							6.6
Charpy V-notch test required?	☐ Yes	Test Temperature:______			☐ No				7.1
Supplemental Information for Welded Valves (to be completed when specifying welded valves)									
Pipe Material and Grade									
Pipe OD mm (inch)									
Wall thickness mm (inch)									
Auxiliaries									
Pressure Relief (6.8)	☐ Yes	☐ No			Double Block and Bleed	☐ Yes		☐ No	
Body Drain (6.9)	☐ Yes	☐ No			Position Indicator (6.12)	☐ Yes		☐ No	
If pressure relief devices are required, are there special requirement for these devices?						☐ Yes		☐ No	
Additional valve support members?	☐ Yes	☐ No							
Description:									
Lifting Lugs	☐ Yes	☐ No							

Valve Application Datasheet (Page 2 of 2)

Drive Train Elements:				
Manual	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Electric	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Electric / Hydraulic	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Gear Operation	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Handwheel	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Handle / Lever	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Stem Extension Dimension	____mm/inch			
Valve Opening Centreline to:	☐ Grade ☐ Electric actuator adaptor	☐ Platform	☐ Manual operator handwheel	
Actuator Adaption	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Actuator Mounting	☐ Yes	☐ No	☐ By Manufacturer	☐ By Others
Coating/Painting:				
Coating for below grade valve?	☐ Yes	☐ No	☐ N/A	
Painting for above grade valve?	☐ Yes	☐ No	☐ N/A	
Hydrostatic Testing:				
Hydrostatic Shell Test	Pressure:	Duration:		
Hydrostatic Seat Test	Pressure:	Duration:		
Gasket / O-Ring Material:	☐ Kalrez	☐ Nitrile	☐ Viton	☐ Other — 7.2
Additional Notes:				
Reference Drawings:				
Prepared by: Engineer / Designer Name:				

A					
Revision	Description	By	Reviewed	Approved	Date

Appendix II
Dimension Tables

DIMENSION TABLES

DN (mm)	NPS (inches)	PN 20 to 100 (Class 150 to 600)	PN 150 (Class 900)
15	0.5	13	13
20	0.75	19	19
25	1	25	25
32	1.25	32	32
40	1.5	38	38
50	2	49	49
65	2.5	62	62
80	3	74	74
100	4	100	100
150	6	150	150
200	8	201	201
250	10	252	252
300	12	303	303
350	14	334	322
400	16	385	373
450	18	436	423
500	20	487	471
550	22	538	522
600	24	589	570
650	26	633	617
700	28	684	665
750	30	735	712
800	32	779	760
850	34	830	808
900	36	874	855
950	38	925	-
1000	40	976	-
1050	42	1020	-
1200	48	1166	-
1350	54	1312	-
1400	56	1360	-
1500	60	1458	-

Table A1.1 Minimum Bore for Full-Opening Valves (mm)

DN (mm)	NPS (Inches)	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C
		PN 20	(Class 150)		PN 50	(Class 300)	
50	2	178	216	191	216	216	232
65	2 1/2	191	241	203	241	241	257
80	3	203	283	216	283	283	298
100	4	229	305	241	305	305	321
150	6	267	403	279	403	403	419
200	8	292	419	305	419	419	435
250	10	330	457	343	457	457	473
300	12	356	502	368	502	502	518
350	14	381	572	394	762	762	778
400	16	406	610	419	838	838	854
450	18	432	660	445	914	914	930
500	20	457	711	470	991	991	1010
550	22	-	-	-	1092	1092	1114
600	24	508	813	521	1143	1143	1165
650	26	559	864	-	1245	1245	1270
700	28	610	914	-	1346	1346	1372
750	30	610*	914	-	1397	1397	1422
800	32	711	965	-	1524	1524	1553
850	34	762	1016	-	1626	1626	1654
900	36	711**	1016	-	1727	1727	1756
		PN 100(Class 600)			PN 150(Class 900)		
50	2	292	292	295	368	368	371
65	2 1/ 2	330	330	333	419	419	422
80	3	356	356	359	381	381	384
100	4	432	432	435	457	457	460
150	6	559	559	562	610	610	613
200	8	660	660	664	737	737	740
250	10	787	787	791	838	838	841
300	12	838	838	841	965	965	968
350	14	889	889	892	1029	1029	1038
400	16	991	991	994	1130	1130	1140
450	18	1092	1092	1095	1219	1219	1232
500	20	1194	1194	1200	1321	1321	1334
550	22	1295	1295	1305	-	-	-
600	24	1397	1397	1407	1549	1549	1568
650	26	1448	1448	1461			
700	28	1549	1549	1562			
750	30	1651	1651	1664			
800	32	1778	1778	1794			
850	34	1930	1930	1946			
900	36	2083	2083	2099			

* Through-conduit valves shall be 650 mm.

** Through-conduit valves shall be 800 mm.

Table A1.2 Gate Valves-Face-To-Face (A) and End-To-End (B and C) Dimensions (mm)

		Short-pattern			Reduced			Venturi			Round-port, full-bore		
DN (mm)	NPS (Inches)	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C
		PN 20 (Class 150)											
50	2	178	267	191	-	-	-	-	-	-	267	-	279
65	2 1/2	191	305	203	-	-	-	-	-	-	298	-	311
80	3	203	330	216	-	-	-	-	-	-	343	-	356
140	4	729	356	241	-	-	-	-	-	-	432	-	445
150	6	267	457	279	394	-	406	-	-	-	546	-	559
200	8	292	521	305	457	-	470	-	-	-	622	-	635
250	10	330	559	343	533	-	546	533	559	546	660	-	673
300	12	356	635	368	610	-	622	610	635	622	782	-	775
350	14	-	-	-	-	-	-	686	686	699	-	-	-
400	16	-	-	-	-	-	-	782	762	775	-	-	-
450	18	-	-	-	-	-		864	864	876	-	-	-
500	20	-	-	-	-	-	-	914	914	927	-	-	-
600	24	-	-	-	-	-	-	1067	1067	1080	-	-	-
		PN 50 (Class 300)											
54	2	216	267	232	-	-	-	-	-	-	283	283	298
65	2 1/2	241	304	257	-	-	-	-	-	-	330	330	346
80	3	283	330	298	-	-	-	-	-	-	387	387	403
100	4	305	356	321	-	-	-	-	--	-	457	457	473
150	6	403	457	419	403	-	419	403	457	419	559	559	575
200	8	419	521	435	502	-	518	419	521	435	686	686	702
250	10	457	559	473	568	-	584	457	559	473	826	826	841
300	12	502	635	518	-	-	-	502	635	518	965	965	981
950	14	-	-	-	-	-	-	762	762	778	-	-	-
400	16	-	-	-	-	-	-	838	838	854	-	-	-
450	18	-	-	-	914	-	930	914	914	930	-	-	-
500	20	-	-	-	991	-	1010	991	991	1010	-	-	-
550	22	-	-	-	1092	-	1114	1092	1092	1114	-	-	-
600	24	-	-	-	1143	-	1165	1143	1143	1165	-	-	-
650	26	-	-	-	1245	-	1270	1245	1245	1270	-	-	-
700	28		-	-	1346	-	1372	1346	1346	1372	-	-	-
750	30	-	-	-	1 397	-	1422	1397	1397	1422	-	-	-
800	32	-	-	-	1524	-	1553	1524	1524	1553	-	-	-
850	34	-	-	-	1626	-	1654	1626	1626	1654	-	-	-
900	36	-	-	-	1727	-	1756	1727	1727	1756	-	-	-

Table A1.3 Plug Valves - Face-to-Face (A) and End-to-End (B and C) Dimensions (mm)

DN (mm)	NPS (inches)	Reduced Raised Face A	Reduced Welding End B	Reduced Ring Joint C	Venturi Raised Face A	Venturi Welding End B	Venturi Ring Joint C	Round-port, full-bore Raised Face A	Round-port, full-bore Welding End B	Round-port, full-bore Ring Joint C
		PN 100 (Class 600)								
50	2	292	292	295	-	-	-	330	-	333
65	2 1/2	330	330	333	-	-	-	381	-	384
80	3	356	356	359	-	-	-	445	-	448
100	4	432	432	435	-	-	–	508	559	511
150	6	559	559	562	559	559	562	660	711	664
200	8	660	660	664	660	660	664	794	845	797
250	10	787	787	791	787	787	791	940	1016	943
300	12	-	-	-	838	838	841	1067	1067	1070
350	14	-	-	-	889	889	892	-	-	-
400	16	-	-	-	991	991	994	-	-	-
450	18	-	-	-	1092	1092	1095	-	-	-
500	20	-	-	-	1194	1194	1200	-	-	-
550	22	-	-	-	1295	1295	1305	-	-	-
600	24	-	-	-	1397	1397	1407	-	-	-
650	26	-	-	-	1448	1448	1461	-	-	-
750	30	-	-	-	1651	1651	1664	-	-	-
800	32	-	-	-	1778	1778	1794	-	-	-
850	34	-	-	-	1930	1930	1946	-	-	-
900	36	-	-	-	2083	2083	2099	-	-	-
		PN 150 (Class 900)								
50	2	368	-	371	-	-	-	381	-	384
65	2 1/2	419	-	422	-	-	-	432	-	435
80	3	381	381	384	-	-	-	470	-	473
100	4	457	457	460	-	-	-	559	-	562
150	6	610	610	613	610	610	613	737	-	740
200	8	737	737	740	737	737	740	813	-	816
250	10	838	838	841	838	838	841	965	-	968
300	12	-	-	-	965	965	968	1118	-	1121
400	16	-	-	-	1130	1130	1140	-	-	-

Table A1.3 (continued)

		Full-bore and Reduced-bore			Short-pattern, full-bore and reduced-bore		
DN (mm)	**NPS** (inches)	**Raised Face** A	**Welding End** B	**Ring Joint** C	**Raised Face** A	**Welding End** B	**Ring Joint** C
		PN 20 (Class 150)					
50	2	178	216	191	-	-	-
65	2 ½	191	241	203	-	-	-
80	3	203	283	216	-	-	-
100	4	229	305	241	-	-	-
150	6	394	457	406	267	403	279
200	8	457	521	470	292	419	305
250	10	533	559	546	330	457	343
300	12	610	635	622	356	502	368
350	14	686	762	699	-	-	-
400	16	762	838	775	-	-	-
450	18	864	914	876	-	-	-
500	20	914	991	927	-	-	-
550	22	-	-	-	-	-	-
600	24	1067	1143	1080	-	-	-
650	26	1143	1245	-	-	-	-
700	28	1245	1346	-	-	-	-
750	30	1295	1397	--	-	-	-
800	32	1372	1524	-	-	-	-
850	34	1473	1626	-	-	-	-
900	36	1524	1727	-	-	-	-
950	38	-	-	-	-	-	-
1000	40	-	-	-	-	-	-
1100	42	-	-	-	-	-	-
1200 1400	48 54	-	-	-	-	-	-
1500	60	-	-	-	-	-	-

Table A1.4 Ball Valves-Face-to-Face (A) and End-to-End (B and C) Dimensions (mm)

		Full-bore and reduced-bore			Short-pattern, full-bore And reduced-bore		
DN (mm)	NPS (Inches)	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C
		PN 50 (Class 300)					
50	2	216	216	232	-	-	-
65	2 1/2	241	241	257	-	-	-
80	3	283	283	298	-	-	-
100	4	305	305	321	-	-	-
150	6	403	403	419	-	-	-
200	8	502	521	518	419	419	435
250	10	568	559	584	457	457	473
300	12	648	635	664	502	502	518
350	14	762	762	778	-	-	-
400	16	838	838	854	-	-	-
450	18	914	914	930	-	-	-
500	20	991	991	1010	-	-	-
550	22	1092	1092	1114	-	-	-
600	24	1143	1143	1165	-	-	-
650	26	1245	1245	1270	-	-	-
700	28	1346	1346	1372	-	-	-
750	30	1397	1397	1422	-	-	-
800	32	1524	1524	1553	-	-	-
850	34	1626	1626	1654	-	-	-
900	36	1727	1727	1756	-	-	-
950	38	-	-	-	-	-	-
1000	40	-	-	-	-	-	-
1100	42	-	-	-	-	-	-
1200	48	-	-	-	-	-	-
1400	54	-	-	-	-	-	-
1500	60	-	-	-	-	-	-

Table A1.4 *(continued)*

DN (mm)	NPS (Inches)	Raised Face A	Welding End B	Ring Joint C
		PN 100 (Class 600)		
50	2	292	292	295
65	2 1/ 2	330	330	333
80	3	356	356	359
100	4	432	432	435
150	6	559	559	562
200	8	660	660	664
250	10	787	787	791
300	12	838	838	841
350	14	889	889	892
400	16	991	991	994
450	18	1092	1092	1095
500	20	1194	1194	1200
550	22	1295	1295	1305
600	24	1397	1397	1407
650	26	1448	1448	1461
700	28	1549	1549	1562
750	30	1651	1651	1664
800	32	1778	1778	1794
850	34	1930	1930	1946
900	36	2083	2083	2099
950	38	-	-	-
1000	40	-	-	-
1100	42	-	-	-
1200	48	-	-	-

Table A1.4 *(continued)*

		PN 20 (Class 150)			PN 50 (Class 300)			PN 100 (Class 600)		
DN (mm)	NPS (Inches)	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C	Raised Face A	Welding End B	Ring Joint C
50	2	203	203	216	267	267	283	292	292	295
66	2 1/2	216	216	229	292	292	308	330	330	333
80	3	241	241	254	318	318	333	356	356	359
100	4	292	292	305	356	356	371	432	432	435
150	6	356	356	368	445	445	460	559	559	562
200	8	495	495	508	533	533	549	660	660	664
250	10	622	622	635	622	622	638	787	787	791
300	12	699	699	711	711	711	727	838	838	841
350	14	787	787	800	838	838	854	889	889	892
400	16	864	864	876	864	864	879	991	991	994
450	18	978	978	991	978	978	994	1092	1092	1095
500	20	978	978	991	1016	1016	1035	1194	1194	1200
550	22	1067	1067	1060	1118	1118	1140	1295	1295	1305
600	24	1295	1295	1308	1346	1346	1368	1 397	1397	1407
650	26	1295	1295	-	1346	1346	1372	1448	1448	1461
700	28	1448	1448	-	1499	1499	1524	1600	1600	1613
750	30	1524	1524	-	1594	1594	1619	1651	1651	1664
900	36	1956	1956	-	2083	2083	-	2083	2083	-
950	38	-	-	-	-	-	-	-	-	-
1000	40	-	-	-	-	-	-	-	-	-
1100	42	-	-	-	-	-	-	-	-	-
1200	48	-	-	-	-	-	-	-	-	-
1400	51	-	-	-	-	-	-	-	-	-
1500	60	-	-	-	-	-	-	-	-	-

Table A1.5 Swing Check Valves, Reduced- and Full-Opening Types, Face-to-Face (A) and End-to-End (B and C) Dimensions (mm)

DN (mm)	NPS (inches)	PN 150 (Class 900) Raised Face A	Welding End B	Ring Joint C
50	2	368	368	371
65	2 1/2	419	419	422
80	3	381	381	384
100	4	457	457	460
150	6	610	610	613
200	8	737	737	740
250	10	838	838	841
300	12	965	965	968
350	14	1029	1029	1038
400	16	1130	1130	1140
450	18	1219	1219	1232
500	20	1321	1321	1334
600	24	1549	1549	1568

Table A1.5 *(concluded)*

		PN 20 (Class 150)		PN 50 (Class 300)		PN 100 (Class 600)		PN 150 (Class 900)	
DN (mm)	**NPS** (inches)	**Short-Pattern**	**Long-Pattern**	**Short-Pattern**	**Long-Pattern**	**Short-Pattern**	**Long-Pattern**	**Short-Pattern**	**Long-Pattern**
50	2	19	60	19	60	19	60	19	70
65	2 1/2	19	67	19	67	19	67	19	83
80	3	19	73	19	73	19	73	19	83
100	4	19	73	19	73	22	79	22	102
150	6	19	98	22	98	29	137	35	159
200	8	29	127	29	127	38	165	44	206
250	10	29	146	38	146	57	213	57	241
300	12	38	181	51	181	60	229	NOTE	292
350	14	44	184	51	222	67	273	NOTE	356
400	16	51	191	51	232	73	305	NOTE	384
450	18	60	203	76	264	83	362	NOTE	451
500	20	64	219	83	292	92	368	NOTE	451
600	24	NOTE	222	NOTE	318	NOTE	438	NOTE	495
750	30								-
900	36								-
1100	42								-
1200	48								-
1400	54								-
1500	60								-

Table A1.6 Single- and Dual-Plate, Long- and Short-Pattern, Wafer-Type Check Valves-Face-to-Face Dimensions (mm)

Appendix III
CSA Z245.15 Alternatives (Canadian Installations)

CSA Z245.15 ALTERNATIVES (CANADIAN INSTALLATIONS)

For valves that will be installed In Canada:

Manufacturer shall ensure that the design of all pressure components is registered with a Canadian Registration Number (CRN) in accordance with the Alberta Boiler and Pressure Vessel Act and its regulations, (except when "CRN registration not required" is stated in the purchase order).

The requirements for heat analysis shall be as given in *Table 17.1*.

For grades 290 and higher, at a frequency of one test per heat, a product analysis shall be determined by the manufacturer. The requirements for product analysis shall be as given in *Table 17.1*.

Grades	**Maximum Carbon Equivalent*(%)**	
Grade 290 and Higher	**0.5**	
	Maximum Permitted (%)	
Element	**Lower than Grade 290 Heat Analysis**	**Grade 290 or Higher Product Analysis**
Carbon	0.35	0.30
Manganese	1.35	1.60
Phosphorus	0.05	0.05
Sulfur	0.06	0.06
Silicon	0.35	0.50
Copper	-	1.50
Nickel	-	1.00
Chromium	-	0.25
Molybdenum	-	0.25
Vanadium	-	0.13
Niobium	-	0.10
Boron	-	0.001

Table 17.1 Chemical Composition Limits for Heat and Product Analysis

*The carbon equivalent shall be determined from the product analysis by using the following formula:

C.E. = C + F {Mn/6 + Si/24 + Cu/15 + Ni/20 + (Cr + Mo + V + Nb)/5) + 5B}

Where F is a compliance factor that is dependent on carbon content and is given in Table 17.2.

Notes:

(1) The chemical requirements of this table are not intended to represent the composition of any heat of steel but to record the maximum permissible amounts of individual elements.

(2) Niobium is also known as columbium.

Carbon (%)	Compliance factor (F)	Carbon (%)	Compliance factor (F)	Carbon (%)	Compliance factor (F)
< 0.06	0.53	0.11	0.70	0.17	0.94
0.06	0.54	0.12	0.75	0.18	0.96
0.07	0.56	0.13	0.80	0.19	0.97
0.08	0.58	0.14	0.85	0.20	0.98
0.09	0.62	0.15	0.88	0.21	0.99
0.10	0.66	0.16	0.92	> 0.21	1.00

Table 17.2 Compliance Factor (F) – Carbon Equivalent Formula

The following paragraph numbers refer back to the main body of this specification.

A.6.0 Noise

Where noise levels are a consideration, on request from the purchaser, the manufacturer shall provide estimated noise levels for the flow conditions specified.

A.6.7 Wafer-Type Valve Ends

Wafer-type valves shall be supplied with finished ends compatible with the specified matching flanges.

A.6.7.1 Flanged Ends

End flanges shall be fully machine-finished on die joint side. The bearing surfaces for bolting shall be parallel within 1° to the flange face; back facing or spot facing may be required to accomplish such parallelism. Casket contact surfaces for raised faces shall have a finish in accordance with the requirements of *CSA Z245.12*.

A.6.7.2 Welded Ends

The land shall be machined flat within 0.8 mm.

A.6.12 Position Indicator

Where the valve-closing direction is other than clockwise, the valve-closing direction shall be clearly marked.

A.6.13 Handle Extensions

It shall be permissible for plug- and ball-valve wrenches to be of an integral design or consist of a head that fits on an obturator stem designed to take an extended handle. Such head designs shall provide for permanent attachment of the extended section. Where specified in the purchase order, handle extensions shall be furnished.

A6.13.2 Sealant Fittings

Valves that rely on sealant as a primary seal or a secondary backup seal shall have provision for injection of sealant with fittings that meet the following requirements:

a) The lubricant fitting shall be of the giant button-head type, of a one-piece body design, and shall be of a size consistent with standard North American lubricating devices.
Note: fittings with significant dimensions conforming to those found on Stewart-Warner "Alemite" giant button-head fittings are considered standard.

b) The lubricating part shall be protected by a ball check device independent of the lubricating fitting, in order to provide for safe removal or replacement of the fitting when a valve is under line pressure conditions.

c) The number and locations of the fittings shall be such as to provide proper distribution and sufficient deposition of the sealant.

d) Valves that are intended for buried service or that are intended to be otherwise inaccessible shall have sealant piping extended to a convenient and accessible location. The piping shall be adequately supported and made of a material compatible with the valve and shall be capable of withstanding the maximum line pressure plus the sealant injection pressure.

A.6.17.2 Tension Tests

A.6.17.2.1 General

Except as otherwise required by this Standard, test specimens and testing procedures shall be in accordance with the requirements of *ASTM A370*. Testing shall be conducted with the test specimens at room temperature.

A.6.17.2.2 Requirements

The tensile properties of each pressure-containing part in the valve shall be in accordance with the requirements of the applicable ASTM Material Standard or specification.

A.6.18 Stem Packing

Stem packing shall be replaceable.

Note: Not all valve designs allow the packing to be replaced under line pressure or without removing the top works.

A.7.1 Material Specification

Where sour service is specified in the purchase order, valves shall be in accordance with the requirements of *Clause A.7.1*

Note: Materials, including welding consumables, and manufacturing procedures should be selected in order to avoid microstructures in the weld metal, heat-affected zones, and parent metal that are detrimental for use in sour service.

A.7.1.2

Valves shall be in accordance with the requirements of *NACE MR0175.*

A.7.1.3

Unless otherwise specified in the purchase order, pressure-containing steel bolting shall be in accordance with the requirements of ASTM A193, Grade B7M, or A320, Grade L7M, and nuts shall be in accordance with the requirements of ASTM A 194, Grade 2HM or Grade 7M.

A.7.1.4

Unless otherwise specified in the purchase order, the hardness of each pressure-containing fastener not covered by a Standard listed in *Clause 13.3* shall be determined in accordance with the testing requirements specified for Grade B7M in ASTM A193 and shall not exceed HRC 22.

A.7.1.5

For each welding procedure specification, a separate procedure qualification record shall be developed for wrought material welds, cast material welds, and cast-to-wrought material welds, as applicable.

A.7.1.6

The welding procedure shall be qualified under actual production conditions or under simulated production conditions including weld cooling rates.

A.7.1.7

When the weld procedure does not include post-weld heat treatment, microhardness traverses on a cross-section of the procedure qualification weld required by *Clauses 7.7,* be performed in accordance with the requirements of *ASTM E384*. The location and minimum number of hardness impressions shall be as shown in Appendix VI. The microhardness shall not exceed 248, using a Vickers indenter with a load of 500 g or less. Conversion from other hardness scales shall not be permitted.

A.7.2 Stem Packing

Stem packing shall be replaceable.

Note: Not all valve designs allow the packing to be replaced under line pressure or without removing the top works.

A7.3 Stem Protection

The stem of a rising-stem gate valve shall be protected by a dustproof enclosure.

A7.7 Toughness Test Requirements – Materials

The test temperature shall be as specified in the purchase order, except that it shall be permissible for a lower test temperature to be used provided that the specified absorbed energy requirements are met.

A.7.7 Toughness Test Requirements

The absorbed energy (based upon full-size test specimens) for each Charpy V-notch impact test shall be equal to or greater than

a) 18 J, for parts that are lower than Grade 359;

b) 27 J, for parts that are Grade 359 or higher; or

c) Such higher value as is specified in the purchase order.

A9.1 Quality Control

The manufacturer shall have a documented quality program that is in accordance with the requirements of one or more of the following:

a) One of the CAN/CSA-ISO 9000 Standards;

b) One of the ISO 9000 Standards; or

c) The API Q1 Specification.

Valves shall be free of defects and shall have a competently produced finish.

A.9.2.4 Temperature – Measuring Devices

Where pressure recorders or gauges are used, the pressure range of the instrument shall not exceed twice the shell test pressure. Where temperature charts are used, the temperature range shall be capable of indicating 1 °C fluctuations.

A.9.0.1 Plant Inspection

Finished valves shall be free, both internally and externally, of loose mill scale, foreign matter, oil, and grease, and shall be clean and dry for final inspection. Valves shall be visually inspected to detect defects and to determine compliance with the dimensional and work quality requirements.

A.9.0.2 Inspection Notice

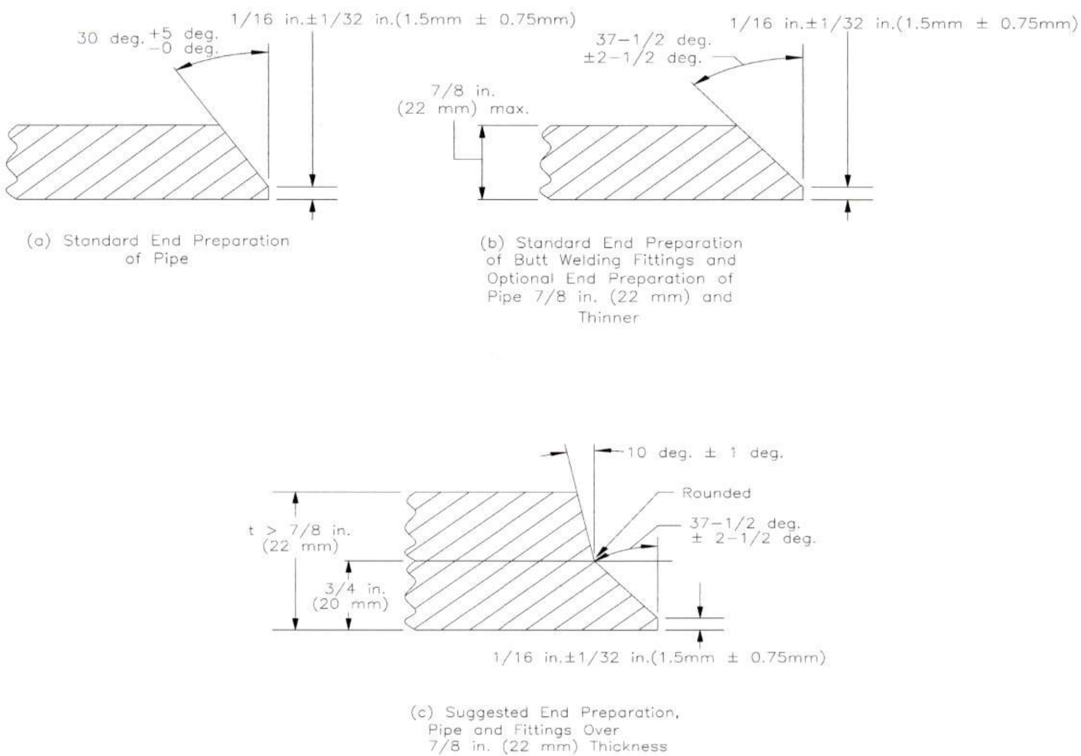
Where it is specified in the purchase order that the inspector representing the purchaser intends to inspect the valves or witness the tests at the manufacturer's plant, the manufacturer shall give the purchaser reasonable notice of the production schedule.

A.9.0.3 Plant Access

The inspector representing the purchaser shall have unrestricted entry at all times, while work on the purchaser's order is being performed, to all parts of the manufacturer's plant concerned with the manufacture of the valves ordered. The manufacturer shall afford the inspector all reasonable facilities to be satisfied that the valves are being manufactured, sampled, tested, and inspected in accordance with the requirements of this Standard and the purchase order. Inspections shall be conducted without interfering unnecessarily with the operation of the plant

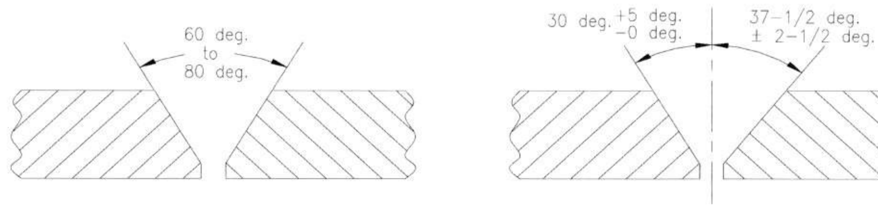
Appendix IV
Welded Ends

WELDED ENDS



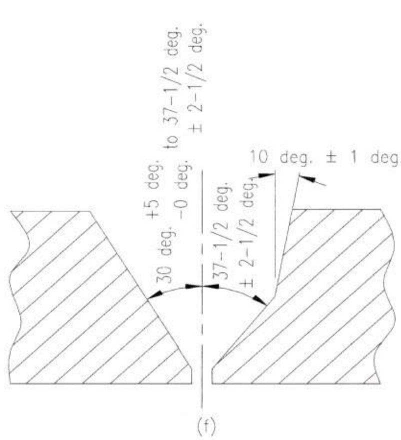
Standard End Preparation (a), (b), and (c)

Figure A5.1-1 Acceptable Butt Welded Joint Design for Equal Wall Thicknesses



(d) (e)

Acceptable Combinations of Pipe and Preparations (d), (e), and (f)



(f)

Figure A5.1-1 Acceptable Butt Welded Joint Design for Equal Wall Thicknesses (continued)

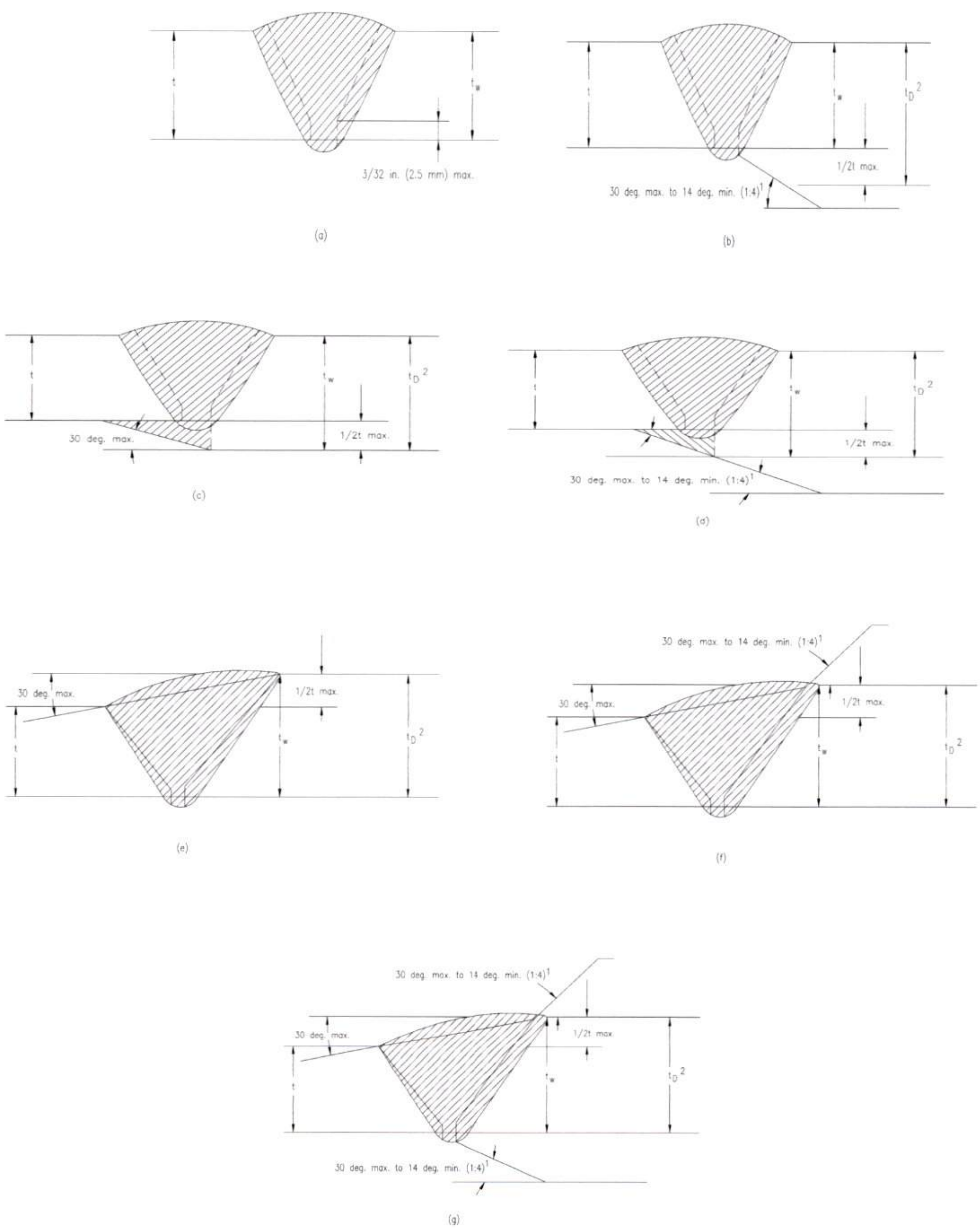
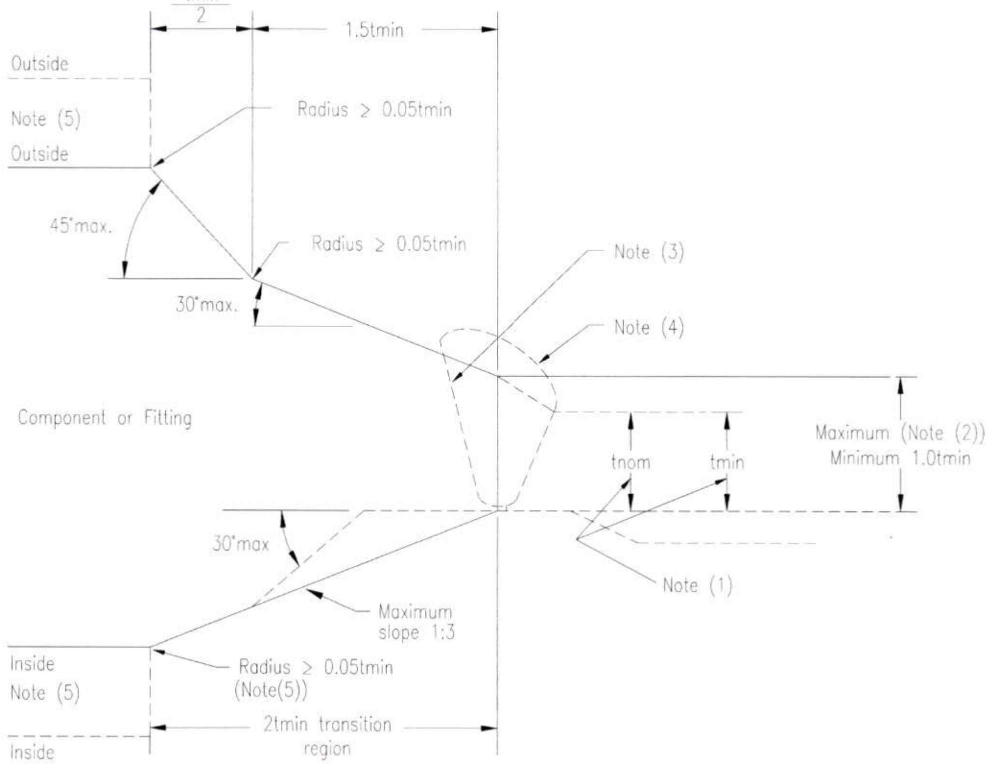


Figure A5.1-2 Acceptable Butt Welded Joint Design for Unequal Wall Thicknesses



NOTES:

(1) The value of t_{min} is whichever of the following is applicable:

- *(a)* The minimum ordered wall thickness of the pipe to include pipe that is purchased to a nominal wall thickness with an under-tolerance other than 12.5%
- *(b)* 0.875 times the nominal wall thickness of pipe ordered to a pipe schedule wall thickness that has an under-tolerance of 12.5%
- *(c)* The minimum ordered wall thickness of the cylindrical welding end of a component or fitting (or the thinner of the two) when the joint is between two components

(2) The maximum thickness at the end of the components is:

- *(a)* The greater of t_{min} + 4 mm (0.16 in.) or $1.15t_{min}$ when ordered on a minimum wall basis
- *(b)* The greater of t_{min}+ 4 mm (0.16 in.) or $1.10t_{nom}$ when ordered on a nominal wall basis

(3) Weld bevel shown is for illustration only.

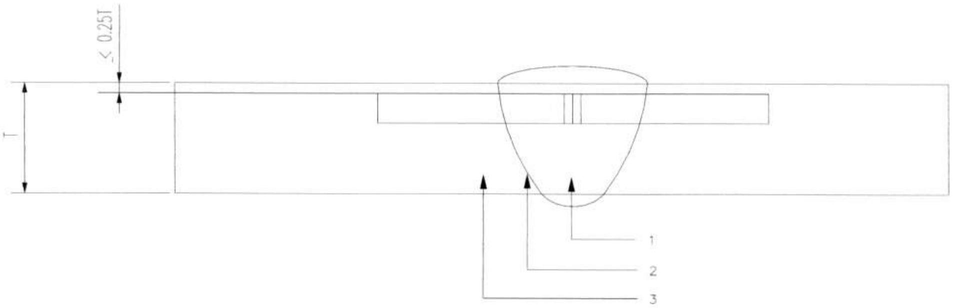
(4) The weld reinforcement permitted by applicable code may lie outside the maximum envelope.

(5) Where transitions using maximum slope do not intersect inside or outside surface, as shown by phantom outlines, maximum slopes shown or alternate radii shall be used.

Figure A5.2 Maximum Envelope for Welding End Transitions

Appendix V
Impact Testing Figures

IMPACT TESTING FIGURES



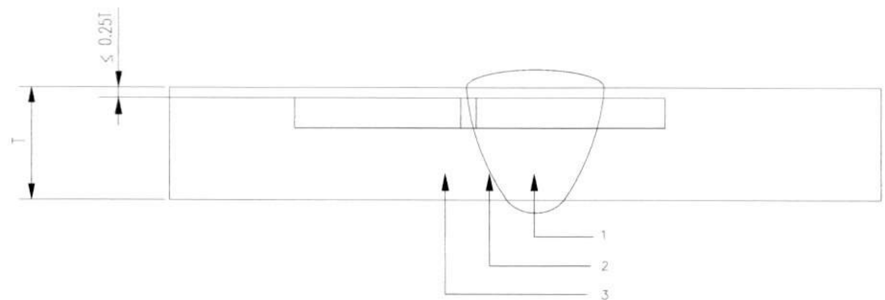
Key:

1 Weld metal

2 Heat-affected zone

3 Base metal

Figure A6.1 Charpy V-notch Weld Metal (WM) Specimen Location



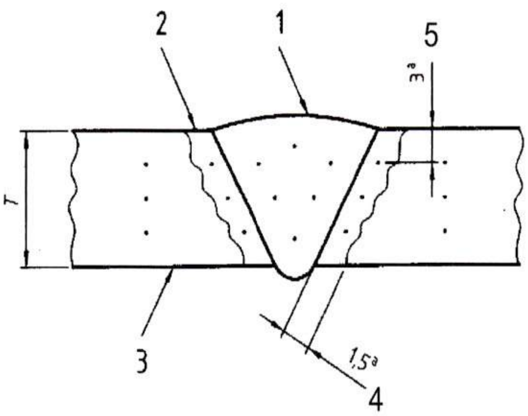
Key:

1 Weld metal

2 Heat-affected zone

3 Base metal

Figure A6.2 Charpy V-notch Heat-affected Zone (HAZ) Specimen Location



Key:

1 Weld metal
2 Heat-affected zone
3 Base metal
4 1.5 mm (typical)
5 3.0 mm (typical)

Figure A6.3 Hardness Survey Specimen Location

D

ENBRIDGE™

NORTH DAKOTA PUBLIC SERVICE COMMISSION APPLICATION FOR A ROUTE PERMIT

ALBERTA CLIPPER PROJECT

Prepared by

NATURAL RESOURCE GROUP, INC.

July 2007

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
Application for a Route Permit
Alberta Clipper Project

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SECTION A

DESCRIPTION OF PROPOSED FACILITY

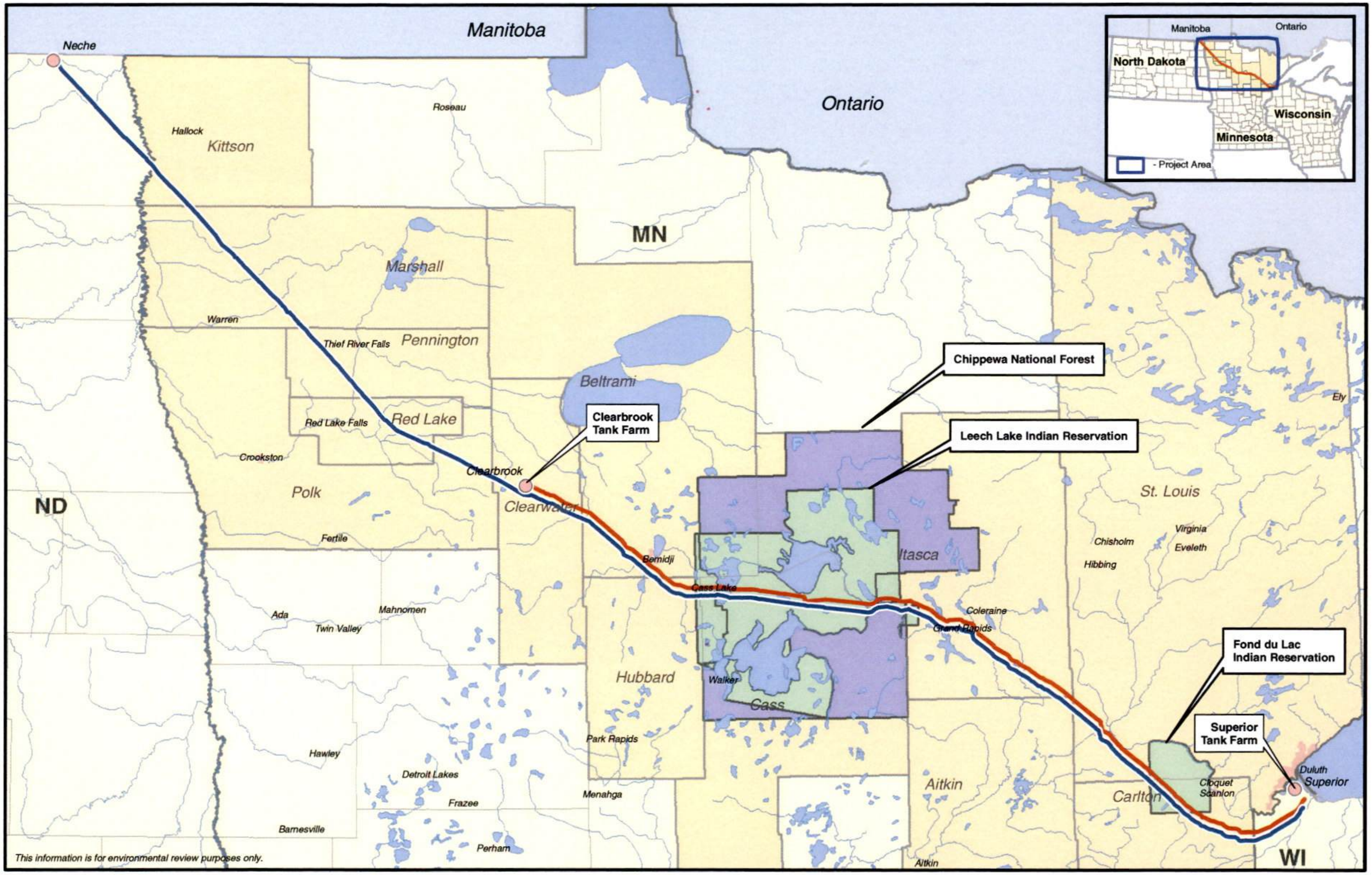
A.1. TYPE OF FACILITY

Enbridge Energy, Limited Partnership ("Enbridge" or "Company" and previously named Lakehead Pipeline, Limited Partnership or "Lakehead") proposes to construct, own, and operate a new 990-mile-long, 36-inch-outside-diameter liquid petroleum pipeline that will interconnect with Enbridge facilities at Clearbrook, Minnesota for subsequent delivery to interconnected facilities operated by Minnesota Pipeline Company, and to Enbridge's Superior, Wisconsin breakout tanks for subsequent delivery to interconnected Enbridge pipeline systems to the south and east of Superior, Wisconsin. The pipeline will originate at affiliated Pipelines, Inc (the affiliated Canadian portion of the Enbridge Liquid's pipeline system) facilities in Hardisty, Alberta, and extend to the southeast, terminating at Enbridge's Superior, Wisconsin terminal facility. The project is referred to as the "Alberta Clipper Project" or the "Project."

The North Dakota portion of the Project consists of approximately 28 miles of 36-inch-outside-diameter pipeline. The pipeline will be buried underground on or adjacent to Enbridge's right-of-way in Pembina County. The pipeline will enter the State of North Dakota at the Canadian border near Neche, North Dakota and exit North Dakota at the Minnesota border approximately 2 miles northeast of Bowesmont, North Dakota. The new pipeline will continue through Minnesota and terminate at Enbridge's Superior, Wisconsin terminal facility. Figure 1 shows the general location of the facilities.

The new pipeline will be operationally integrated with and form part of the Enbridge Mainline System (consisting of Enbridge Pipelines, Inc. in Canada and Enbridge Energy, Limited Partnership in the U.S.) and will provide needed capacity to transport increased supplies of petroleum produced in western Canada into the United States. The capacity provided by this new pipeline segment provides independent utility to Enbridge and its customers, who will use the pipeline for the transportation of petroleum to the Clearbrook and Superior terminals for subsequent delivery to interconnected pipeline systems.

The estimated cost of the North Dakota portion of the Project is approximately $90.7 million. The facilities will add approximately 450,000 barrels per day (bpd) of capacity to the Enbridge system.



Alberta Clipper
Southern Lights Diluent

0 10 20 40 Miles

N

Figure 1
Alberta Clipper Project
General Project Location Map

ENBRIDGE

NATURAL RESOURCE GROUP

M:\Clients\D-F\EEL\SLP_ArcGIS\2007\05\MN_PUC\Fig111.mxd

A.2. PRODUCT

As defined by Enbridge Energy, Limited Partnership's Federal Energy Regulatory Commission (FERC) Tariff on Rules and Regulations, the following commodities are transported by the Company:

- natural gas liquids;
- condensate;
- light crude oil;
- medium crude oil; and
- heavy crude oil.

This 36-inch-diameter pipeline is expected to transport light crude petroleum and heavy crude petroleum.

A.3. SIZE AND DESIGN

The pipe to be installed for the Project will have an outside diameter of 36 inches, a predominant wall thickness of 0.469-inch (road and railroad crossings will use 0.562-inch wall pipe; the horizontal directional drill section of the Pembina R. crossing will be 0.650- to 0.750-inch wall pipe), API Grade 5L X70, and will be double submerged – arc welded (DSAW) steel pipe.

A.4. TIME SCHEDULE

Enbridge is planning to start construction of the Alberta Clipper Project in October 2008, with a planned completion and in-service date of December 2009. The Project is on an aggressive schedule to meet the immediate and increasing U.S. refinery demand for incremental pipeline capacity from western Canadian production. Due to such demand, Enbridge has periodically experienced apportionment of pipeline capacity on the Enbridge System and forecasts of production and shipping demands indicate demand on the system will exceed availability capacity consistently starting in 2010.

Enbridge is prepared to work diligently to facilitate review of the Alberta Clipper Project to strive to meet the December 2009 in-service date.

APPLICATION FOR ROUTE PERMIT

SECTION B

LOCATION

B.1. APPLICANT'S POLICIES AND COMMITMENTS TO LIMIT ENVIRONMENTAL IMPACT

Enbridge's Environmental Policy states that protection of the environment is an integral element in the conduct of Company business. Environmental protection efforts will span the entire Project, from planning through construction, restoration, and into full operation.

B.1.a Construction

The Project involves installing a new pipeline on or adjacent to Enbridge's right-of-way, which includes the LSr Project pipeline route (Docket No. PU07-75). Construction of the new 36-inch-diameter pipeline will result in temporary short-term impacts, but is not expected to result in significant long-term change to the environment.

Planning, design, construction, and restoration will incorporate the equipment and measures discussed in section B.6. Environmental monitoring, in the form of ongoing environmental inspection, will be conducted during and following construction. Environmental inspectors will monitor compliance with required environmental protection measures, permit conditions, and specifications, and provide ongoing oversight for day-to-day issues that may arise during construction. The environmental inspectors will be trained and well-versed in the implementation of environmental best management practices during construction. Contract specifications will incorporate environmental protection and mitigation measures, and contractors will be expected to implement these measures in the field. Contractor training and project orientation will also be provided by Enbridge.

Most of the pipeline route in North Dakota (more than 98 percent) is located on private land, and landowner concerns will be addressed during all phases of construction including final restoration. Land agents assigned to the Project will work closely with landowners to negotiate agreements and will, to the extent practicable, be responsive to issues that may arise during the course of the Project.

Environmental data collected to date includes information on soils, land use, wetland and waterbody crossings, protected species, and cultural resources. Enbridge will continue to work with appropriate regulatory agencies and will continue to gather comprehensive information during the permitting process.

B.1.b Ongoing Pipeline Operation

The pipeline is a permanent, ongoing system; as such, Enbridge has a continuing commitment to conduct its operations in an environmentally responsible manner. Substantial, continual effort is placed on pipeline integrity, operational safeguards, emergency response, and landowner relationships, all of which reduce the impact of the pipeline to the environment. The Company also has an internal environmental staff responsible for monitoring compliance with environmental regulations, Company policy, and a review program is in place to ensure policies and procedures are effective and compliant. Additional discussion on operations and safety is provided in section B.9.c.

B.1.c Energy Conservation Considerations

The completion of the Alberta Clipper Project will add an additional pipeline on the Enbridge system. The total crude petroleum throughput increase is expected to be proportionately higher than the energy usage (actual kilowatts per hour) increase.

Energy conservation is a major concern at Enbridge since energy/power costs represent the largest single recurring expense in pipeline operation. Attention is continually being directed toward energy conservation.

Enbridge has an Energy Management Department, which is responsible for negotiating contracts and allocating power to assure economical and efficient use of power for Enbridge. This department is continuously reviewing and tracking firm and non-firm power requirements, and works closely with electrical utilities in planning for transmission and generation needs.

Enbridge's energy conservation goal is to minimize power/energy unit costs, through the implementation of internal programs directed at continuous improvement of energy utilization efficiency.

Enbridge has considered several energy efficiency and conservation programs. The following provides a brief explanation of the programs reviewed during the project development phase:

Pipeline Diameter

Utilization of larger pipeline diameters reduces fluid velocities, resulting in reduced hydraulic line loss due to friction. Enbridge prefers to minimize the line losses ultimately reducing the overall operating cost. This, however, must be balanced with the Project capital cost (funded by the shippers through rates) and batch quality degradation associated with lower fluid velocities.

Variable Frequency Drives (VFDs)

The installation of variable frequency induction motor drives is a program that has been in place for approximately 16 years. VFDs allow the pipeline operator to vary the pump rotation speed thereby controlling the pressure produced to match the desired flow rate. This eliminates the need to dissipate or waste pressure (energy) with pressure control valves (PCVs). VFDs, however, do introduce energy losses and therefore are considered only when there is a range of operating conditions (primarily flow rate, density and viscosity) that would often require dissipation of pressures produced by the pumps. Ideally, if operating conditions were constant, the pump would deliver constant pressures eliminating the need for pressure dissipation. Therefore, operating conditions play a key role in designing the pumping stations for optimum efficiency.

Pipeline Control Center

Enbridge pipeline control operators are trained in applied hydraulics and pipeline control through the use of a computerized pipeline control simulation system. They are trained to operate the pipeline at a natural flow rate using efficient combinations of pumps, thereby minimizing energy consumption. Operators have the capability to start and stop pumps and monitor pipeline operating conditions to assist in achieving an energy efficient operation.

Energy Efficient Pumps and Motors

For new installations, Enbridge purchases high efficiency pumps and motors at a premium initial cost in an effort to conserve long range energy requirements. Specifically, a high polish is used on the pump impeller, and motors are custom designed for high efficiency. For example, a fully loaded 2,500 horsepower pump and motor unit, operating 300 days per year at 80% efficiency will consume 17 million kilowatt hours (kWh) of energy annually and sets a demand of 2,331 kW. Increasing the efficiency by only 1% translates into 170,000 kWh of energy savings. With this substantial potential for energy savings, it is desirable to optimize efficiency. Pumps are hydraulically designed and selected to obtain a high best efficiency point (BEP) at the desired flow rates. The forecasts are continually being evaluated and if the flow rate is outside the BEP range, impeller changes are typically implemented for improved efficiency.

Electric Service Agreements

A unique electric service agreement was negotiated with Otter Tail Power. The contract structure motivates Enbridge to apply its unique load to maximize its use of non-firm energy. This minimizes the amount of firm capacity required to serve Enbridge's needs which reduces the amount of generation Otter Tail Power must build. The contract energy structure aligns with tariff "Time of Use" energy rates and motivates pipeline operators to consume more off-peak energy to further maximize the use of existing utility generation.

Drag Reducing Agents (DRA)

Injections of DRA have been considered for use within the Enbridge system for over 11 years. Injection of DRA reduces flow turbulence of liquid hydrocarbons which results in reduced pressure loss between stations. This allows a high flow rate (increased throughput) at the same operating pressure, or a decrease in operating pressure while maintaining flow rate. These two scenarios allow increased throughput or decreased power use. The flexibility furthers opportunities to shift power use to improve economics or accommodate the utilities. In these cases, the economic benefits realized with the implementation of the DRA program have outweighed the material cost of the DRA. As a result, lower unit energy costs and greater efficiency have occurred.

In addition, during high throughput periods, 23% of our power is supplied on a non-firm basis which has reduced utility needs to add generation and transmission. Overall utility load factors and utilization of assets have improved, benefiting all regional electric customers.

Enbridge has received Conservation Improvement Program (CIP) funds from both Minnesota Power and Otter Tail Power. The funds were associated with Enbridge's Terrace III pipeline expansion project and were used for increasing system efficiency through the addition of large pipeline segments.

Other energy efficiency programs being investigated for future implementation include:

- Enhancements to the pipeline control system to allow further energy use optimization;
- Coordination of our energy use between utilities for mutual benefit; and
- Replace selected pump wear rings with new geometrically optimized pump wear rings to improve pump efficiency.

B.2. DISCUSS THE FACTORS LISTED IN SECTION 49-22-09 NDCC TO AID THE COMMISSION'S EVALUATION OF THE PROPOSED PIPELINE ROUTE

Factors which the North Dakota Public Service Commission (NDPSC or Commission) considers in evaluating the designation of corridors and routes include the following:

<u>B.2.a Available Research and Investigations Relating to the Effects of the Location, Construction, and Operation of the Proposed Facility on Public Health and Welfare, Natural Resources, and the Environment</u>

A discussion of the effects of the location, construction, and operation of the pipeline on public health and welfare, natural resources, and the environment is included in section B.4. Research and investigation relating to these effects have included thorough cultural resource reviews, protected species and sensitive area reviews, and a field wetland delineation study conducted during the 1998 Terrace I Project under the previous name of Lakehead.

<u>B.2.b The Effects of New Energy Conversion and Transmission Technologies and Systems Designed to Minimize Adverse Environmental Effects</u>

The Project does not include new energy conversion or transmission technologies that are expressly designed to minimize adverse environmental effects. As described in Enbridge's Environmental Mitigation Plan (EMP), current construction techniques and mitigation measures will be employed to minimize the effect of construction on environmental resources. Enbridge's EMP is provided as Appendix A. These measures are also discussed in sections B.6 and B.9.

B.2.c The Potential for Beneficial Uses of Waste Energy from a Proposed Energy Conversion Facility

The Project does not involve new energy conversion facilities; no usable waste energy will result from the Project.

B.2.d Adverse Direct and Indirect Environmental Effects, Which Cannot be Avoided Should the Proposed Site or Route be Designated

Unavoidable adverse direct and indirect environmental effects may include short-term or temporary effects on vegetation, wildlife, agricultural operations, transportation, and noise levels as described in section B.4. Additionally, Enbridge will implement thorough mitigation measures to minimize these impacts as described in section B.6 and in Enbridge's EMP (see Appendix A).

B.2.e Alternatives to the Proposed Site, Corridor or Route, Which are Developed During the Hearing Process and Which Minimize Adverse Effects

Enbridge has operated a pipeline system in North Dakota since the 1950s. This pipeline corridor provides an established, direct route between Hardisty, Alberta and Superior, Wisconsin, and was originally selected to avoid or minimize environmental and socioeconomic impact. Use of this corridor takes advantage of Enbridge's right-of-way, and mostly or in large part precluding the establishment of new permanent right-of-way and new severance on properties. No other corridor will offer these advantages over the pipeline route. Enbridge has evaluated and developed a pipeline alignment to further minimize environmental impact. That route is described in section B.3.

B.2.f Irreversible and Irretrievable Commitments of Natural Resources Should the Proposed Site, Corridor or Route be Designated

Enbridge is installing the pipeline within a previously disturbed corridor and, therefore, minimal irreversible or irretrievable commitments of natural resources will result from the Project.

B.2.g The Direct and Indirect Economic Impacts of the Proposed Facility

B.2.g.(1) The Alberta Clipper Project presents an optimization of new and existing pipeline capacity to meet the needs for additional liquid petroleum transportation to this region.

As presented in section C.2 of Enbridge's Application for Corridor Certificate, which provides a description of feasible alternatives, projects considered for meeting these transportation needs can be classified as follows:

1. Optimize existing pipelines without addition of new pipelines.

2. Construct new pipe in connection with existing pipelines through existing routes (Enbridge's route).

3. Construct an entirely new pipeline.

4. Utilize alternative modes of transportation other than pipelines.

During the initial design of the Alberta Clipper Project, all but two of these options were rejected as not feasible and/or uneconomical. Enbridge's proposal represents an optimal use of new and existing pipelines on an existing route. Enbridge's shippers support Enbridge's proposal to be an appropriate economical response to the need for additional capacity.

B.2.g.(2) The Alberta Clipper Project has significant economic benefits.

Currently, the Enbridge System supplies approximately 71 percent of Minnesota refinery capacity, 100 percent of Wisconsin refinery petroleum supply, and 62 percent of Greater Chicago refinery supply. As demand for transportation services has steadily increased, average daily deliveries on the Enbridge System of crude petroleum have risen, from 1.34 million bpd in 2005 to 1.52 million bpd in 2006, and it is expected that the Enbridge System will transport approximately 1.64 million bpd in 2007. The Alberta Clipper Project will meet the increased demands of these and other markets with a reliable North American crude supply. The stable supply of petroleum to the region supports a healthy economic environment throughout the entire Upper Midwest.

Enbridge's current property taxes in North Dakota are approximately $500,000 per year. The total assessed value resulting from the Project will increase the estimated property taxes in Pembina County by about $800,000. An indirect economic benefit to North Dakota is that through the expansion of the Enbridge System, growing supplies of Canadian crude oil will have increased access to pipeline transport east of Alberta into the Midwest. This, in turn, lessens the pressure to transport petroleum south of Alberta and worsen the over-supply at the Guernsey, Wyoming hub, a market condition that has resulted in discounts to northern Rockies crude oil producers.

The cost of the Alberta Clipper Project in North Dakota, Minnesota, and Wisconsin will be approximately $922.5 million ($90.7 million in North Dakota alone). For the entire Project, over 1,500 construction workers will be hired from pipeline contractors, equipment contractors, suppliers, and regional testing firms. Forty to fifty percent of the labor force is expected to be hired from the regional labor pool. In addition, environmental consultants and safety, environmental, and construction inspectors will also be employed during the Project. During the months of preparation, construction, and testing, these workers will have a significant positive economic impact (e.g., payroll tax, local expenditures, sales tax) on Pembina County.

Pipe and other materials for the expansion are all expected to be from U.S. and North American suppliers. Much of the materials and equipment needed for construction, including welding supplies, heavy equipment, electrical components, and building materials will be supplied from this region. Operation of the Project will likely require Enbridge to hire at least four new full-time permanent employees.

B.2.g.(3) Enbridge is solely a transportation company.

Enbridge owns and operates a non-shipper-owned liquid hydrocarbon pipeline facility. Enbridge does not own any of the crude petroleum or natural gas liquids transported in its pipeline system. Enbridge does not determine markets or destinations for petroleum commodities. Enbridge's business activity is to provide a service which is available to anyone tendering commodities for transportation pursuant to tariffs published and on file with the FERC and in accordance with their rules and regulations and the Interstate Commerce Act. Enbridge attempts to anticipate the need for additional pipeline capacity by relying upon forecasts for throughput generated by shippers on the system.

B.2.h Existing Plans of the State, Local Government, and Private Entities for Other Developments at or in the Vicinity of the Proposed Site, Corridor, or Route

Enbridge is not aware of other development by state, local or governmental entities at or in the vicinity of the Project corridor. Enbridge is planning the LSr Project, which will result in the construction of a new 20-inch-diameter, buried petroleum pipeline within or adjacent to the Enbridge corridor. Enbridge applied to the NDPSC under separate cover for authorization for this facility on April 12, 2007.

Enbridge is aware of another proposed petroleum transmission system, the Keystone Pipeline, which is planned to be located west of the Enbridge pipeline corridor in western Pembina County, North Dakota. The Keystone Pipeline does not relate to or otherwise affect the routing, construction or operation of the Alberta Clipper Project. The Keystone project does not serve many of the Upper Midwest refinery markets served by the Enbridge Mainline System, such as Minnesota, Wisconsin and northern Illinois/Indiana refineries.

B.2.i The Effect of the Proposed Site or Route on Existing Scenic Areas, Historic Sites and Structures, and Paleontological or Archaeological Sites

Enbridge has reviewed existing site file data maintained by the State Historical Society of North Dakota, North Dakota State Historic Preservation Office (SHPO) to determine if any portion of the pipeline route was surveyed previously for cultural resources. A total of six previous archaeological studies have been completed that directly relate to the pipeline route. The entire Enbridge pipeline corridor between Neche, North Dakota and Clearbrook, Minnesota was surveyed as part of the 1994 Capacity Expansion Project (North Dakota SHPO No. 94-200). In 1998, portions of the previous survey corridor were included in a project named Terrace I or Terrace Expansion. The Terrace I project did not extend beyond the survey corridor for the 1994 Capacity Expansion and, therefore, no additional archaeological investigations were required for Terrace I.

Enbridge also reviewed the North Dakota SHPO's site files to identify previously recorded cultural resources within the construction right-of-way. This review identified one archaeological site (32PB132) in North Dakota, a historic ox-cart trail referred to as Angle Road, which has been determined eligible for nomination to the National Register of Historic Places. The pipeline route will cross this feature. Enbridge has previously avoided impacts to this site by using conventional boring construction methods and plans to bore beneath the Angle Road for the Alberta Clipper Project as well; therefore the Project is not anticipated to impact this site. Enbridge will be coordinating this crossing with the North Dakota SHPO.

B.2.j The Effect of the Proposed Route on Areas Which Are Unique Because of Biological Wealth or Because They are Habitats for Rare and Endangered Species

Enbridge has initiated consultations with the North Dakota Game and Fish Department (NDGFD) and the U.S. Fish and Wildlife Service (FWS) to identify known occurrences of federally listed threatened or endangered species, state-listed protected species, or critical habitat (unique biological areas or habitat) located on or near the pipeline route. Copies of correspondence from these consultations are included in Appendix C.

The NDGFD did not identify any state-listed protected species or unique biological areas within the Project area. The NDGFD identified the Pembina and Tongue Rivers as Class III fisheries and the Red River of the North as a Class I fishery. The NDGFD recommended that Enbridge consider boring techniques for crossing these rivers to minimize impacts on the waterbodies. Enbridge is currently evaluating waterbody crossing methods for these waterbodies and will coordinate with the NDGFD regarding feasible waterbody crossing techniques at these locations.

The FWS identified two federally listed species, the bald eagle and the gray wolf, as potentially occurring within the vicinity of the pipeline route. No recommendations to avoid or minimize impacts to these species were identified. Additionally, the FWS provided recommendations to minimize environmental effects of waterbody and wetland crossings.

The FWS also identified one parcel owned in fee by the FWS that will be crossed by the pipeline route. That fee-owned parcel is located approximately at milepost (MP) 791.4 and is referred to as the Juhl National Wildlife Management Area (Juhl WMA), and is crossed by the Enbridge pipelines in the corridor. Enbridge has reviewed this crossing and determined that it is possible to avoid the Juhl WMA by making a slight route deviation within Enbridge's corridor. Therefore, Enbridge is proposing a route that avoids this parcel.

B.2.k Problems Raised by Federal Agencies, Other State Agencies, and Local Entities

No problems or concerns other than those identified in section B.2.j have been raised by commenters or identified by Enbridge.

B.3. IDENTIFY AND MAP CRITERIA LEADING TO PROPOSED PIPELINE ROUTE LOCATION WITHIN CORRIDOR

The following criteria, which include but are not limited to the criteria required by North Dakota Administrative Code (North Dakota Rules) Chapter 69-06-08-02, were considered in evaluating the location of the pipeline route: Exclusion and Avoidance Areas, Selection and Policy Criteria, Design and Construction Limitation, Economic Considerations, Human Environment, Soils, Vegetation/Wildlife, Land Use, Water Resources, and Cultural Resources. Detailed discussions of these criteria, including descriptions, potential impacts, and mitigation measures where appropriate are provided in sections B.4, B.5, and B.6. The pipeline route will cross or is in close proximity to three types of Avoidance Areas, the Juhl WMA at about MP 791.4, three rural residences within 500 feet of the pipeline route, and Angle Road near MP 786.3, an Area of Historic, Archaeological, or Paleontological Significance. As described in section B.2.i, Enbridge intends to avoid impacts to the Angle Road historic site by using conventional boring construction methods. As described in B.2.j, Enbridge is proposing a route that avoids crossing the Juhl National Wildlife Management Area.

B.4. RELATIVE VALUE AND EFFECTS UPON EACH CRITERION INCLUDING LOCATION, CONSTRUCTION, AND OPERATION OF THE FACILITY

In accordance with North Dakota Rules Chapter 69-06-08-02, the pipeline route has been situated after consideration of its impact on humans and the environment. Adverse effects of construction of the pipeline are substantially minimized by using the existing Enbridge right-of-way. Alternative routes or options, which are discussed in section C.2 of the Application for Corridor Certificate, are not preferable and will typically result in more significant human and environmental impacts.

Underground pipeline installation minimizes potential impacts on human or animal welfare and aesthetics. Construction of the new pipeline will cause temporary disruption to the environment, but will not result in long-term changes to the environment. The following is a general analysis of the existing human and natural environment along the pipeline route and the potential impacts of pipeline right-of-way preparation, construction practices, and operation and maintenance procedures.

<u>B.4.a Exclusion and Avoidance Areas (North Dakota Rules Chapter 69-06-08-02.1 and 69-06-08-02.2)</u>

The NDPSC has identified certain sensitive or otherwise important environmental features that must be considered during the selection of a route for transmission facilities. These features have been classified as either "Exclusion Areas" or "Avoidance Areas." As defined in North Dakota Rules Chapter 69-06-08-02.1 and 69-06-08-02.2, Exclusion Areas are areas that are to be excluded from consideration for energy conversion sites and transmission facility routes. Avoidance Areas are areas not to be considered in the routing of a transmission facility unless it is shown that, under the circumstances, there are no reasonable alternatives. In 1978, the NDPSC published the Inventory of Exclusion and Avoidance areas for the Siting of Energy Conversion and Transmission Facilities, which lists these areas for each county in North Dakota (see table 1). Enbridge has confirmed with NDPSC staff that no new types of Exclusion or Avoidance Areas have been added to the inventory to date.

Appendix D contains maps depicting Exclusion and Avoidance Areas within a one mile study corridor centered on the pipeline route.

TABLE 1

North Dakota Public Service Commission Exclusion and Avoidance Areas – Transmission Facility Siting

Avoidance and Exclusion Area	Category	Crossed By Route	Administering Agency
National Memorial Parks	Exclusion	No	National Park Service (NPS)
National Historic Sites and Landmarks	Exclusion	No	NPS
National Natural Landmarks	Exclusion	No	NPS
National Wilderness Areas	Exclusion	No	NPS and U.S. Forest Service (FS)
National Parks	Exclusion	No	NPS
National Monuments	Exclusion	No	NPS and State Historical Society
State Parks	Exclusion	No	State Park Service
State Historic Sites	Exclusion	No	State Historical Board
State Historical Markers	Exclusion	No	State Historical Board
State Archaeological Sites	Exclusion	No	State Historical Board
State Monuments	Exclusion	No	State Historical Society
State Nature Preserves	Exclusion	No	State Park Service
Areas Critical to the Life Stages of Threatened or Endangered Animal or Plant Species	Exclusion	No	U.S. Fish and Wildlife Service (FWS)
Areas Where Animal or Plant Species Unique or Rare in the State Would be Irreversibly Damaged	Exclusion	No	Various
County Parks and Recreation Areas, Municipal Parks, and Parks under other Governmental Jurisdiction	Exclusion	No	Various
National Wildlife Areas	Avoidance	No	FWS
National Wildlife Refuges	Avoidance	No	FWS
National Grasslands	Avoidance	No	FS
National Historic Districts	Avoidance	No	State Historic Society
National Wild, Scenic or Recreational Rivers	Avoidance	No	Heritage Conservation Recreation Service, State Outdoor Recreation Agency
State Wild, Scenic or Recreational Rivers	Avoidance	No	State of North Dakota Legislative Assembly
State Game Refuges	Avoidance	No	North Dakota Game and Fish Department
State Game Management and Management Areas	Avoidance	No	North Dakota Game and Fish Department
State Forests	Avoidance	No	State Forest Service
State Forest Management Lands	Avoidance	No	State Forest Service
State Grasslands	Avoidance	No	State Park Service
Irrigated Land	Avoidance	No	State Water Commission
Areas of Historic, Archaeological or Paleontological Significance	Avoidance	Yes	State and County Historical Society
Areas of Recreational Significance	Avoidance	No	Various
Reservoirs	Avoidance	No	U.S. Army Corps of Engineers and State Water Resource Commission
Municipal Water Supplies	Avoidance	No	State Water Resource Commission
Water Sources for Organized Rural Water Districts	Avoidance	No	State Water Commission
Areas which are Geologically Unstable	Avoidance	No	State Geologist Geological Survey
Within 500 Feet of a Residence, School, or Place of Business	Avoidance	Yes (see table 2)	Landowner

B.4.a.(1) Juhl National Wildlife Management Area.

The Juhl WMA was identified during Enbridge's environmental analysis of the pipeline route. National WMAs are Avoidance Areas as identified in the NDPSC's 1978 inventory. The Enbridge pipeline route crosses the extreme southwest corner of the Juhl WMA in the Northwest ¼ of Section 32, Township 162 North, Range 51 West. If Enbridge were to construct the Alberta Clipper Project within its right-of-way, a Special Use permit or amendment to an existing permit would be required from the FWS prior to construction.

Enbridge has reviewed its system route and is proposing a modified route that avoids the Juhl WMA but remains within the Enbridge corridor. Because the potential crossing of the Juhl WMA using the pipeline route is minimal, a minor route modification enables Enbridge to construct the Alberta Clipper Project in close proximity to the other pipelines currently operated by Enbridge through this area while avoiding this Avoidance Area. Finally, the cover type associated with this area is predominantly coarse grass interspersed with wetland. Project-related impacts on this type of vegetative cover will be temporary and short-term.

B.4.a.(2) Areas of Historic, Archaeological, or Paleontological Significance.

The pipeline route will cross one area of Historic, Archaeological, or Paleontological Significance, an historic ox-cart trail referred to as Angle Road. This feature is located on Enbridge's right-of-way and Enbridge has previously avoided this feature by using conventional boring crossing methods at this location. Enbridge again plans to bore Angle Road; therefore the Project is not anticipated to impact this site.

B.4.a.(3) Areas within 500 feet of Farmhouse, Rural Residence, or Place of Business.

The pipeline route will pass near three farmhouses or rural residences. Table 2 provides the milepost and distance from the pipeline route for each residence. No places of business or schools were identified within 500 feet of the pipeline route.

TABLE 2

Rural Residences Within 500 Feet of the Alberta Clipper Project Pipeline Route

Feature	Nearest Milepost	Approximate Distance from Pipeline (feet)
Residence	781.1	>100
Residence and Structures	788.5	>100
Residence and Structures	795.3	250

No residences or other occupied structures will be razed due to construction, nor will future residential development be precluded following completion of the pipeline, except as required by state and/or local setback ordinances and easement restrictions. Construction could temporarily restrict access to residences along the pipeline route. Where this potential exists, Enbridge will either limit the time such restrictions are in place or will make arrangements to accommodate the landowner's needs.

During construction, residences in close proximity to construction activities will be exposed to short-term increases in construction-related noise and dust. Some minor dust emissions are inevitable in any construction project; however, if excessive, the construction right-of-way and access roads near residential areas will be watered down to control dust during construction. After construction is completed, measures to stabilize and revegetate the right-of-way promptly will prevent further dust emissions.

The heavy construction equipment needed to install the pipeline will generate unavoidable short-term increases in ambient noise levels. Increases in ambient noise levels due to equipment operation will be limited to the period of construction and will generally be limited to daylight hours. No noise will be generated along the right-of-way during normal operation of the pipeline.

Although rural residences within 500 feet of the pipeline route are considered Avoidance Areas, Enbridge believes there is no reasonable alternative to avoid them. Disturbance of these areas will be temporary and short-term; long-term incremental impacts will be minimal. As previously noted, the pipeline route is preferable to establishing a new route. A new route could possibly avoid these areas, but will likely result in greater environmental impacts and increase the number of affected landowners.

B.4.b Selection Criteria (North Dakota Rules Chapter 69-06-08-02.3)

State of North Dakota Rules specify several selection criteria to be considered in designating a pipeline corridor or route. Specifically, the NDPSC considers whether adverse effects from the location, construction, and maintenance of the facility as they relate to these criteria, will be at an acceptable minimum, and whether these effects will be managed and maintained at an acceptable minimum. Potential impacts, as they relate to each of the selection criteria, are discussed below. Measures Enbridge will implement to minimize these impacts are noted below and discussed in greater detail in section B.6.

B.4.b.(1) Impact on Agriculture.

The Project will be installed within or adjacent to Enbridge's pipeline right-of-way in Pembina County in northeastern North Dakota. The vast majority of the pipeline route will cross agricultural lands where crop production is the predominant economic activity. Principal crops include wheat, sugar beets, grain, corn, canola, and alfalfa.

Agricultural Production

The Project will have only a temporary effect on agricultural land use. Current construction practices and the measures described in Enbridge's EMP (see Appendix A) have significantly reduced or avoided long-term impacts on crop production previously associated with underground utility installations. The effectiveness of these practices was observed by NDPSC staff during previous Enbridge construction projects.

The pipeline will be buried deeper than typical tillage depth and at a depth comparable with other pipelines within the easement. Therefore, the pipeline will not interfere with normal agricultural operations on cropland after construction is complete. Above-ground facilities that may be located on cropland are limited to pipeline appurtenances such as valves, line markers, and cathodic protection rectifiers. Therefore, minimal long-term loss of farmland use is expected.

Approximately 69 percent (326.6 acres) of the pipeline route will cross prime farmlands in North Dakota as classified by the Natural Resources Conservation Service (NRCS) (see table 7). This total includes prime farmland and land that would be considered prime farmland if drained. Prime farmland is defined as land with the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, and oilseed crops. Prime farmland has the soil quality, growing season, and moisture supply needed to economically produce sustained high yield crops when treated and managed according to acceptable farming methods. Construction activities will not significantly affect the factors such as soil quality, growing season, or moisture supply that are considered in determining whether land is prime farmland.

Following construction, agricultural lands will be returned to preconstruction uses to the maximum extent practicable.

Family Farms and Ranches

The construction of the Project will not cause changes in patterns of land ownership or long-term disruptions of family farming operations. The Project will be constructed in large part or mostly on existing right-of-way and adjacent to other Enbridge pipelines. Payments made in connection with easements will directly benefit landowners along the route. Enbridge's crop loss compensation program will offset the temporary financial losses resulting from pipeline construction. Enbridge will also compensate landowners if future pipeline maintenance and repair activities result in crop damage. Wherever practicable, maintenance equipment will be confined to access routes agreed upon with the landowner to minimize soil compaction, drainage alteration, and damage to crops.

Pipeline construction can result in short-term disruption to livestock operations, and general inconvenience to farm activities. Potential impacts include the possible removal of or damage to fences and gates and possible disruption of private road use. Enbridge will minimize these inconveniences by limiting the length of time that the trench is open and generally working to confine construction activities such that attendant disruptions are kept to a minimum. Where appropriate, Enbridge will maintain temporary access ways across the trench as necessary to allow the passage livestock, farm equipment, or people, and will erect temporary fences (including gates) as necessary to contain and protect livestock from construction-related hazards. Construction activities are conducted sequentially, with the least possible amount of time between each task. After completing construction, fences and gates will be repaired or replaced to each landowner's reasonable satisfaction.

Lands Suitable for Irrigation

Construction of the Project will not impact irrigated lands. Land that is best suited for irrigation is relatively level and has soils that are well drained and highly permeable. The route crosses silt and clay soils which are poorly drained and have low permeability, making them unsuitable for irrigated agriculture. No aboveground irrigation systems have been identified along the route.

Surface Drainage Patterns

Construction of the Project will not alter surface drainage patterns. Streams, swales, ditches, and other natural drains will be restored to preconstruction contours after construction. The pipe will be installed beneath drainage ditches in a manner that will not interfere with flow or future maintenance efforts by landowners or the drainage authority. Mitigation measures will include installation of the pipe at a sufficient depth to avoid being encountered by drain cleaning equipment, or installing concrete slabs above the pipe but below the grade of the ditch.

Groundwater Flow Patterns

Groundwater flow could potentially be altered by pipeline construction through blasting and trenching activities. As described in section B.4.g, no exposed bedrock or areas of shallow bedrock will be encountered. Therefore, blasting is not anticipated. Other construction-related disturbance and excavation (trenching) could temporarily disturb the level of groundwater and increase the sediment in the groundwater. Because no surficial aquifers are crossed by the pipeline route, the effect of trenching on groundwater flow or quality is anticipated to be minimal. Given the low permeability of the soils crossed by the route, dewatering activities, if necessary, are not expected to have a significant effect on regional groundwater flow patterns.

The use of regulated materials, such as fuel, lubricants, and coolants during construction could present a potential for accidental discharges, which could affect groundwater. Enbridge's EMP (Appendix A) and Spill Prevention, Containment, and Control Plan (SPCC Plan) (Appendix B) describe preventative measures Enbridge will implement to prevent accidental discharges of fuels or other hazardous substances. The SPCC Plan also describes spill response, containment and clean-up procedures in the event a spill occurs. With the implementation of these protective measures, contamination of groundwater due to construction activities is not anticipated. A description of Enbridge's pipeline protection and emergency response procedures for pipeline operations and maintenance is provided in section B.9.c.

B.4.b.(2) Impact of Noise Sensitive Land Uses.

Three farmsteads with houses and structures are located within 500 feet of the right-of-way (see table 2). No other sensitive noise receptors such as schools or hospitals are located in the vicinity of the Project. During construction, residences in close proximity to the construction spread will experience short-term increases in construction-related noise. The heavy construction equipment needed to construct the pipeline will generate short-term increases in ambient noise levels. Typical bulldozers, backhoes, and side booms used to install large-diameter pipelines generate between 80 to 90 decibels within 50 feet of the equipment. Increases in ambient noise levels due to heavy equipment operation will be limited to the period of construction, typically during daylight hours.

No noise is generated along the right-of-way during normal operation of the pipeline. The pumping station at Joliette, North Dakota generates noise in the immediate vicinity of the facility. Noise levels at the fenced boundary of the station site average approximately 40 to 60 decibels. No additional pump stations or noise increases at the pump station are proposed as part of the Project in North Dakota.

B.4.b.(3) Impact on Visual Effect on the Adjacent Area.

The only aboveground facilities that will be constructed in North Dakota as part of the Project are pipeline appurtenances such as mainline valves, line markers, and cathodic protection equipment. Mainline valves will be sited at existing aboveground facility sites. Other than these permanent above ground facilities, the Project will result in only short-term visual effects related to construction activities.

B.4.b.(4) Impact on Extractive and Storage Resources.

No extractive or storage resources will be affected by the Project.

B.4.b.(5) Impact on Wetlands.

The route crosses 27 wetlands totaling approximately 1.30 miles in length. Wetland crossings by milepost are described in table 3 below.

TABLE 3
National Wetland Inventory Wetland Types Crossed by the Alberta Clipper Pipeline Route [a]

Milepost In	Milepost Out	Crossing Length (Feet)	Wetland Type [b]
774.99	775.01	117	PEM
775.25	775.29	217	PEM
775.37	775.41	215	PEM
775.48	775.50	107	PFO
775.55	775.57	98	R2U
790.74	790.75	63	PEM
790.76	790.80	219	PEM
790.80	790.92	620	PAB
790.92	790.99	403	PEM
790.99	791.04	277	PEM
791.04	791.08	186	PEM
791.08	791.09	78	PEM
791.09	791.16	333	PEM
791.16	791.21	277	PEM
791.21	791.46	1315	PEM
791.46	791.50	221	PEM
792.35	792.38	156	PEM
792.56	792.67	569	PEM
795.13	795.16	146	PEM
795.13	795.16	146	PEM
797.65	797.69	226	PEM
798.13	798.15	84	PEM
799.52	799.55	167	PEM
799.95	799.97	84	PEM
800.36	800.38	95	PEM
801.67	801.72	234	PEM
801.72	801.76	206	R2U
	Total	6,861	

TABLE 3
National Wetland Inventory Wetland Types Crossed by the Alberta Clipper Pipeline Route [a]

Milepost In	Milepost Out	Crossing Length (Feet)	Wetland Type [b]

[a] Data Source: National Wetlands Inventory, http://www.fws.gov/nwi/.
[b] Wetland Types based on Cowardin et al. wetland classification system, 1979.

Pipeline construction in wetlands will be conducted in accordance with applicable regulatory requirements and the measures specified in Enbridge's EMP. No wetlands will be permanently drained or filled as part of the Project, and effects on wetlands are expected to be short-term and minor.

In unsaturated wetlands, topsoil will be segregated from the trench line during construction to preserve natural sources of seed and rootstock. During trenching, water quality of inundated wetlands adjacent to the construction area could be temporarily affected due to the suspension of sediments and organic matter. Silt fence or straw bales will be installed as needed to minimize this effect. Although wetland vegetation will be cleared for pipeline construction, these areas will be allowed to revegetate to their preconstruction structure and function. After the trench is backfilled, the topsoil will be replaced to facilitate the natural revegetation process in unsaturated wetlands.

Unsaturated wetlands may be revegetated with a temporary cover crop if specified by permitting agencies. No fertilizer, lime, or mulch would be applied in wetlands. The long-term operation and maintenance of the pipeline will not have adverse effects on wetland function or value.

B.4.b(6) Impact on Woodlands and Wooded Areas.

The route crosses scattered windrows and approximately 0.1 mile of wooded areas, primarily gallery forests associated with the crossings of the Pembina and Tongue Rivers.

Enbridge's permanent right-of-way is maintained in an herbaceous state to facilitate aerial patrol and access to the pipeline for maintenance. The Project will cross the Pembina River on the north side of the existing right-of-way to minimize environmental impacts during construction and operation of the pipeline. Incremental clearing will be necessary at the Pembina River crossing to accommodate this route. At the Tongue River, the Project route deviates approximately 500 feet south and west of the existing maintained right-of-way. This route deviation minimizes environmental impacts to the Tongue River at the crossing location but will result in new clearing at the crossing location. The NDGFD has requested that Enbridge minimize loss of woody vegetation, therefore woody vegetation greater than 3 inches diameter at breast height will be replaced on a 2:1 basis (see Appendix C).

Where additional temporary construction right-of-way or extra workspace beyond the permanent right-of-way is required, it may be necessary to clear some additional mature trees. These additional workspaces will be allowed to revert to woodlands following construction. Consequently, impacts on woodlands and wooded areas due to additional temporary workspace will not result in long-term changes in existing cover types.

Enbridge will work with appropriate state agencies to identify appropriate revegetation measures.

B.4.b.(7) Impact on Radio and Television Reception, and Other Communication of Electronic Control Facilities.

No impacts on television or radio reception or communication or electronic control facilities are anticipated as a result of the Project.

B.4.b.(8) Impact on Human Health and Human Safety.

Enbridge has operated in the United States since 1950, when the first pipeline (then named Lakehead Pipe Line Company, Inc.) from Alberta to Superior, Wisconsin was completed. Since that time, pipelines have been extended to eastern Canada and in 1968 and 1998 Enbridge extended its system to Chicago where the pipeline system now extends further east and south. By building and operating this extensive network, Enbridge is one of the largest pipeline companies in North America and experienced in managing construction and operating pipeline systems that protect the public's health and safety.

Causes of and Prevention of Accidents on Pipelines

The major causes of pipeline leaks in the United States are corrosion (both internal and external), excavation damage, pipe or weld failure, incorrect operations, or natural causes (e.g. floods or outside force). To prevent these categories of failures, Enbridge will construct and maintain the Alberta Clipper Project to meet or exceed industry and governmental requirements and standards. Specifically the steel pipe will meet U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) federal codes under 49 CFR Part 195 (referred to hereafter as PHMSA regulations), follow standards issued by the American Society of Mechanical Engineers, National Association for Corrosion Engineers and American Petroleum Institute (API). As a safety factor, the Alberta Clipper Project is designed to withstand pressures over and above its normal operating pressures and will operate according to codes and regulations. All pipe is inspected and integrity-tested at the factory and transported per the highest technical standards. All of the pipe will be manufactured with fusion-bonded epoxy coating to protect against corrosion. The actual installation of the pipeline and all construction and testing records will be subject to regulatory inspection, including by PHMSA inspectors. PHMSA also conducts regularly scheduled field inspections of the pipeline facilities to ensure compliance with federal regulatory requirements, including the integrity testing of the pipeline through the use of internal inspection devices.

Once installed, the pipeline will be subjected to careful testing to verify its integrity and compliance with specifications. Such testing will include checking coating integrity, examining by X-ray 100% of field welds (over and above the 10% required by regulations), internally inspecting the entire length of each line by using an in-line inspection tool known as a caliper pig, and hydrostatically testing the line to qualify the maximum allowable operating pressure. The pipeline will be placed into service only after inspection to verify compliance with all construction standards and requirements are met.

This new pipeline, as well as the existing pipelines in this same right-of-way, are maintained and inspected according to PHMSA regulations, industry codes and prudent pipeline operating techniques. All of Enbridge's mainline liquids pipelines are externally coated to resist corrosion, internally inspected at regular intervals using in-line inspection technology, and equipped with a cathodic-protection system to prevent external corrosion. Enbridge's cathodic protection system and internal inspection program were implemented prior to these techniques becoming a regulatory standard.

The Enbridge System rights-of-way are patrolled and inspected by air at least every three weeks but not less than 26 times per year to watch for abnormal conditions or dangerous activities, e.g., unauthorized excavation, along the routes of the lines. Enbridge also conducts extensive public education and outreach programs that exceed industry (API Recommended Practice 1162) and PHMSA (49 CFR 195.440) requirements concerning public awareness of pipelines and pipeline-safety matters. All Enbridge lines are marked with signage and warnings, per federal regulations, at road and highway crossings, railroad crossings, navigable rivers, and other locations to alert the public to the presence of underground lines and to provide information, contact numbers, and emergency data.

Pipeline workers and contractors performing critical tasks are qualified under OSHA safety standards and PHMSA "operator qualification" rules and are subjected to federal drug and alcohol testing requirements. Enbridge meets, and often exceeds, these requirements so that human error in construction and operation is avoided.

Baseline Transportation Accident Rates

Releases from interstate liquid petroleum pipelines are reportable to PHMSA as required by 49 CFR Part 195 Subpart B. Currently, the federal regulations require reporting of all releases greater than 5 gallons (and/or if other threshold reporting criteria are met), which becomes public record. In addition, Enbridge is required by North Dakota to report releases to the North Dakota Department of Health.

There is no alternative mode of transportation or route to transport the equivalent daily volumes proposed by the Alberta Clipper Project. However, it is illustrative to compare pipeline safety to other modes of transportation. Pipelines operate more safely than any other mode of oil transportation. In table 4, the numbers show how much more likely a transportation mode is to have an accident of a particular type compared to an oil pipeline. For example, truck accidents result in deaths at least 87 times more often than pipeline accidents. Likewise, truck accidents result in fires and/or explosions about 35 times more frequently per barrel of oil transported per mile. These figures include only accidents involving petroleum shipments, not all accidents for a given transportation mode.

Table 4
Accident Rates of Petroleum Transportation Methods [a]

Method	Death	Fire/Explosion	Injury
Truck	87.3	34.7	2.3
Rail	2.7	8.6	0.1
Barge	0.2	4.0	3.6
Tank Ship	4.0	1.2	3.1

[a] Values less/more than 1.0 indicate risk of accident is lower/greater than pipeline transportation. Comparisons based on calculated rates per ton-mile.
Source: Allegro Energy Group as posted on the Association of Oil Pipelines website: http://www.aopl.org

Crude Oil Pipeline Accident Rates

An analysis of the historical record shows that the liquid petroleum pipeline industry's safety performance has improved significantly over the last 30 years. These improvements correlate with advancements in technology as well as increased environmental awareness. The annual number of spills has decreased by nearly 40%. Over the last 30 years, the number of spills has also dropped from an average of 318 in the first six years (1969 to 1974) to the most recent six year running average of 197 spills nationwide. The median size of a spill has greatly decreased. The annual volume of oil spilled from pipeline systems has fallen by about 60%, based on six year running averages (PHMSA website and Association of Oil Pipelines website).

Enbridge Pipeline Incidents and Public Safety

According to available records or knowledge of staff, there have been no deaths or major injuries of landowners or members of the public as a direct result of a pipeline leak on the Enbridge System since the system began operations in the U.S. in 1950.

Enbridge Ten Year Pipeline Accident Record

Enbridge's ten year pipeline accident record on the mainline pipe system is presented in table 5 below. Data excludes pipeline or facility leaks within Enbridge station or terminal properties.

Table 5

Mainline Pipeline Incidents – Enbridge System a/

Date	City	County	State	Milepost	Product Spilled b/	Volume Spilled (barrels)	Volume Recovered (barrels) c/	Primary Cause	Additional Detail/Notes
9/16/98			MN	878.10	Crude	5,700	5,415	Outside Force Damage	Damage by Others
10/19/98			MN	878.10	NGL	950	0	Outside Force Damage	Damage by Others
1/16/99	Superior	Douglas	WI	1097.60	NGL	130	30	Corrosion	External
2/22/99			MN	834.50	Crude	400	385	Other	Loose Flange Bolts
11/2/99			MI	1286.00	NGL	5,300	2,750	Outside Force Damage	Natural Forces
11/15/99		Taylor	WI	116.03	Crude	15	14	Other	Original Construction
2/7/00		Clearwater	MN	920.60	Crude	25	10	Failed Weld	
2/23/00		Cass	MN	957.10	Crude	10	5	Other	Pinhole Leak
5/9/00			MN	913.05	Crude	25	20	Other	Failed Repair Sleeve Side Seam Weld
7/22/00		Clearwater	MN	914.10	Crude	50	10	Other	Failed Repair Sleeve Side Seam Weld
1/25/01		Clearwater	MN	918.70	Crude	25	10	Other	Failed Sleeve
3/4/01		Cass	MN	955.05	Crude	25	15	Failed Weld	
7/4/02	Cohasset	Itasca	MN	1002.70	Crude	6,000	2,574	Material / Weld Failure	Pipe Seam Weld
1/24/03	Superior	Douglas	WI	1096.95	Crude	4,500	4,450	Material / Weld Failure	Terminal Leak d/
4/14/03	Trail	Polk	MN	892.95	Crude	125	75	Girth Weld	Pinhole Leak
2/19/04	Grand Rapids	Itasca	MN	1007.33	Crude	1,003	9	Natural Forces	Earth Movement
12/29/04	Juniata	Tuscola	MI	1677.50	HVL	1	1	Natural Forces	
1/14/05	Rio	Columbia	WI	268.82	Crude	3	3		
4/1/05	Carpentersville	McHenry	IL	379.16	Crude	5	5	Material / Weld Failure	Body of Pipe
10/20/06	Wilton	Beltrami	MN	927.5	Crude	5	0	Material/Weld Failure	Crack in Side Seam Weld
1/1/07	Owen	Clark	WI	149.17	Crude	1,500	1,450	Material / Weld Failure	Pipe Seam Weld
2/2/07	Exeland	Rusk	WI	84.9	Crude	3,000	2,534	Operator Excavation Damage	(not 3rd party)

a/ Pipeline system leaks reportable to U.S. DOT, PHMSA 1996-2007. Reporting criteria for leaks changed in 2002 from 50 barrels to 5 gallons.
b/ NGL = Natural gas liquids.
c/ Initial volume recovered is the free oil and drain-up from pipe with special vacuum equipment and typically returned to the pipeline system. Remaining product in soil recovered by removing soils or other approved methods.
d/ Occurred within station/terminal but recorded as off-site release. All other such releases not included (but reported).

B.4.b.(9) Impact on Animal Health and Safety.

General construction-related effects on domestic animals and wildlife will result primarily from activity in the Project area during construction. The clearing of herbaceous and woody vegetation will temporarily reduce cover, nesting, and foraging habitat for some species. Clearing may also result in the loss of some members of small, slower moving species. However, most will move into adjacent undisturbed habitats until construction and restoration are complete. Overall habitat availability is not expected to change in the long term.

Pipeline trenching activities and associated spoil piles may result in a short-term barrier to movement of some wildlife species (typically two to four weeks at any one area). Except for short-term interruptions during construction, existing public roads, farm lanes, and livestock crossings will be kept open, providing crossing access. Shelter belts and trees will be protected to the extent practicable in a manner compatible with the safe operation, maintenance, and inspection of the pipeline.

B.4.b.(10) Impact on Plant Life.

During construction, vegetation will be removed from the construction right-of-way. Where extra workspace is required, additional vegetation will be removed. In non-agricultural areas, trees and shrubs cleared from extra workspace will be allowed to re-establish after construction, and revegetation measures will take into account recommendations from applicable regulatory agencies and arrangements with landowners. Overall, significant change in plant life is not anticipated.

B.4.c Policy Criteria (North Dakota Rules Chapter 69-06-08-02.4)

The NDPSC may give preference to an applicant that will maximize benefits resulting from the adoption of policies and practices of the NDPSC. These policies, and the extent to which the Project aligns with or reinforces these policies, are described below.

B.4.c.(1) Location and Design.

Enbridge believes that the Project has been placed in the optimal alignment. No designated Exclusion Areas are crossed by the route. Mitigation measures will be implemented to avoid or minimize potential adverse impacts on Avoidance Areas crossed. Further, the alignment is generally on or adjacent to Enbridge's pipeline right-of-way, minimizing the need for new right-of-way and the environmental and human impacts associated with a new route.

The Project is designed and will be operated in a manner that meets or exceeds state and federal engineering, safety and operational design standards.

B.4.c.(2) Training and Utilization of Available Labor in this State for the General and Specialized Skills Required.

No training of local labor is anticipated as a direct result of this pipeline expansion. During construction of the facility, skilled and unskilled labor, both local and non-local workers will be employed by Enbridge or by the General Contractor selected to construct this pipeline.

B.4.c.(3) Economies of Construction and Operation.

The Project is believed to be the most cost-effective and operationally sound means of meeting Enbridge's delivery obligations. Refer to section B.2.g of this Application and section C.2 of the Application for Corridor Certificate.

B.4.c(4) Use of Citizen Coordinating Committees.

No Citizen Coordinating Committee is anticipated as a result of the Project.

B.4.c.(5) Commitment of a Portion of the Transmitted Product for Use in this State.

No portion of the transported commodity will be delivered to terminals or refineries in North Dakota. On average, Enbridge delivered 1.52 million bpd in 2005 of crude petroleum on its U.S. mainline system. The source of the liquid hydrocarbons is predominantly from western Canadian oil fields. These stable sources of North American petroleum supply well over 50 percent of the Upper Midwest refinery supply. Refined product pipelines operated by other companies originating from these refineries, in turn, are routed into North Dakota to supplement the refined product supplies for North Dakota residents.

B.4.c.(6) Labor Relations.

The Project will have no anticipated effect on labor relations within North Dakota.

B.4.c.(7) Coordination of Facilities.

The Project has been designed to optimally utilize Enbridge's existing transportation system.

B.4.c.(8) Monitoring of Impacts.

Enbridge believes that construction-related impacts will be adequately mitigated throughout the Project route by the use of best management practices, good construction techniques, and environmental inspection. Therefore, long-term monitoring of impacts directly related to the Project is not anticipated. Following the installation of the pipeline, a thorough inspection will be performed to ensure restoration efforts have been successful.

B.4.c.(9) Utilization of Existing and Proposed Rights-of-way and Corridors.

The Alberta Clipper Project will generally be constructed and installed adjacent to Enbridge System right-of-way. However, Enbridge also has proposed to install the LSr Project generally within or immediately adjacent to the southern boundary of the right-of-way corridor of the Enbridge System. The LSr Project will be constructed prior to commencement of the Alberta Clipper Project construction. The LSr Project right-of-way requirements typically include up to 50 feet of permanent easement and 50 feet of temporary workspace. The additional permanent easement is required in order to provide a 25-foot offset from the southernmost pipeline in the right-of-way to the LSr Project and a 25-foot offset to the newly located southern boundary of the right-of-way.

In order to maintain a 25-foot of offset between the southern-most pipeline (which at the time of construction of the Alberta Clipper Project will be the LSr Project) and a buffer zone to the newly located southern boundary of the right-of-way, up to 25 feet of additional permanent easement and 65 feet of temporary workspace typically will be required to accommodate construction and installation. A depiction of the typical configuration of the existing right-of-way corridor and the configuration of the Alberta Clipper and LSr Projects and their construction footprint is provided in figure 2. Enbridge's design configuration and anticipated construction execution methods are intended to take advantage of the proximity of the Alberta Clipper Project to the LSr Project in North Dakota to minimize right-of-way requirements.

The Alberta Clipper Project will be constructed using a 140-foot-wide construction right-of-way consisting of existing or new easements and generally 65 feet of temporary work space. Additional temporary extra workspace of up to 75 feet in width and 300 feet in length will be required at feature crossings (e.g., roads, waterbodies). No pipe storage yards or private or new access roads have been identified at this time. This information will be filed when available, approximately July 2008. Enbridge will acquire additional workspace from the landowners where necessary; use of unauthorized workspace is prohibited without the landowner and Enbridge's approval. In all cases, the size of additional temporary workspace will be kept to the minimum necessary to safely conduct work. Temporary working areas will not be restricted by or subject to permanent easement restrictions upon completion of construction.

B.4.c.(10) Other Existing and Proposed Transmission Facilities.

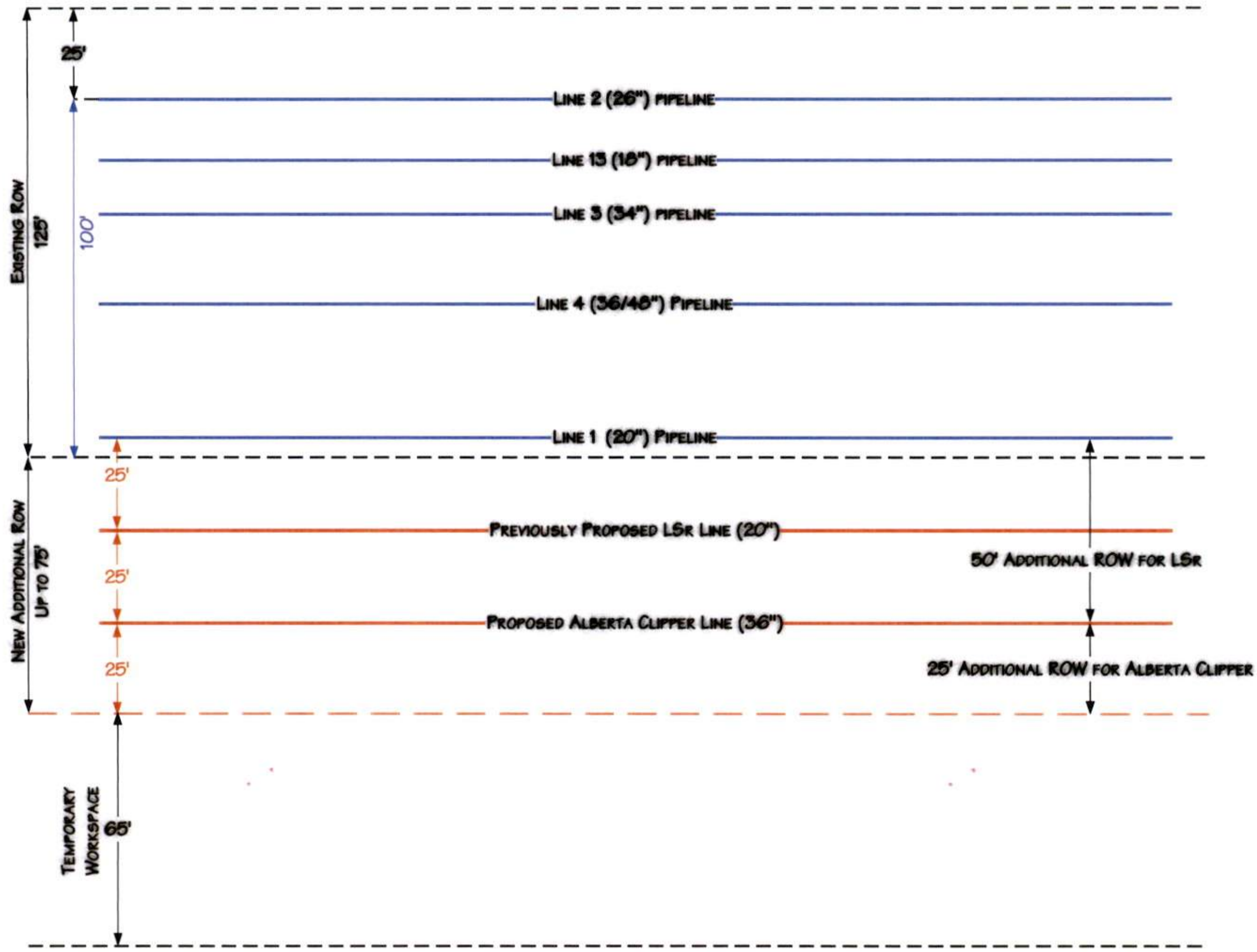
This Project will be an addition to the five existing pipelines currently operated by Enbridge within its right-of-way. Construction practices will be implemented to protect the existing pipelines. No other existing or proposed transmission facilities will be involved in the Project within North Dakota.

B.4.d Design and Construction Limitations

See section A.3 of the Application for Corridor Certificate.

B.4.e Economic Considerations

See section B.2.g of this application and section C of the Application for Corridor Certificate.



- Existing row boundary defined by location of northern most pipeline: 25 feet to the north and 100 feet to the south.
- Because pipeline spacing varies due to construction requirements at the time of installation, the distance between the southern most line (Line 1 (20")) and southern existing row boundary varies between 0 and 35 feet.
- New additional ROW requirements will vary along the proposed route from the Minnesota/North Dakota Border to the Canadian Border. These ROW requirements will depend on the location of Enbridge's southern most existing line and the existing ROW boundary. Enbridge will need up to 50 feet of additional permanent ROW for the LSr Project, and will need another 25 feet of additional permanent ROW for the Alberta Clipper Project. This additional 25 feet of the permanent ROW for the Alberta Clipper Project is necessary to allow for approximately 25-foot spacing between the proposed LSr and Alberta Clipper Projects, while also allowing for a buffer to the southernmost permanent ROW boundary.
- Temporary workspace adjacent to new additional ROW will be required to install the pipeline(s). Typically 65' in width and the length of the ROW will be rented from landowners. Additional temporary workspace at civil and environmental crossings of up to 75' in width and up to 300' in length on each side of the crossing will be rented.

For environmental review purposes only.

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Figure 2
Alberta Clipper Project
Typical Right-of-Way Configuration
In North Dakota

DATE:	8/9/2006
REVISED:	7/10/2007
SCALE:	NTS
DRAWN BY:	MHN6795
K:\335\ROW_CONFIG_TYPICALS\AC_ROW.VSD	

B.4.f Human Environment

The Project area is sparsely populated and farming is the predominant economic activity. Within Pembina County, the route crosses approximately 170 separate tracts of land owned by approximately 64 different landowners. Except for highway crossings, the remaining land crossed by the route is privately owned. Three rural residences (some with associated aboveground structures) are located within 500 feet of the right-of-way (see table 2 in section B.4.a(3)). The route does not pass through parks, recreation areas, or the incorporated limits of cities.

The pipeline route crosses 1 state highway (North Dakota State Highway 5/U.S. Highway 81), 1 federal highway (Interstate 29), and 35 public roads. Additionally, one active Burlington Northern Santa Fe Railroad single track is crossed at MP 795.28. Paved roads and the railroad will be bored. Interstate 29 will be directionally drilled and, therefore, use of these facilities will not be disrupted as a result of the Project. Gravel roads will be open cut. Open cutting a road will temporarily close it to traffic; however, the road network throughout the Project area is sufficient that suitable alternative routes are readily available. Road and railroad crossings for the route are summarized in table 6.

TABLE 6

Roads Crossed by the Alberta Clipper Project Pipeline Route

Milepost	Roadway Name
774.55	109th Street NE
775.77	108th Street NE
776.75	147th Street NE
777.11	107th Street NE (County Road 55)
778.23	148th Street NE
778.50	106th Street NE
779.66	149th Street NE
779.87	105th Street NE
781.12	150th Street NE
781.28	104th Street NE
782.60	151st Street NE
782.65	103rd Street NE
783.97	152nd Street NE
784.04	102nd Street NE
785.39	County Road 1
785.51	153rd Street NE
786.76	100th Street NE
787.05	154th Street NE
788.46	155th Street NE
789.47	98th Street NE
790.82	97th Street NE
792.30	North Dakota State Highway 5/U.S. Highway 81
793.04	158th Street NE
793.57	95th Street NE
794.49	159th Street NE
795.05	94th Street NE

TABLE 6

Roads Crossed by the Alberta Clipper Project Pipeline Route

Milepost	Roadway Name
795.20	Interstate 29
795.24	Old Highway 44
795.28	Burlington Northern Santa Fe Railroad
795.84	160th Street NE
796.50	93rd Street NE
797.27	161st Street NE
797.91	92nd Street NE
799.00	162nd Street NE
799.29	91st Street NE
800.05	163rd Street NE
800.72	90th Street NE
801.12	163rd Street NE (2nd crossing)

B.4.g Terrain and Geology

The Project will cross the bed of glacial Lake Agassiz, which is a nearly level lacustrine plain. Surface elevations along the route range from 825 feet near the Manitoba border to approximately 770 feet near the Red River of the North. Glacial Lake Agassiz was formed 10,000 to 12,000 years ago as glacial ice melted and retreated northward, blocking the natural drainage to the north. The resulting lacustrine deposits in the Project area consist of thick, horizontal beds of predominantly silts and clays which stratigraphically are part of the Coleharbor Group. More recent alluvial deposits of the Walsh Group are found along the Pembina, Tongue, and Red Rivers. The soils along the rivers tend to have higher sand content than the soils formed in the older lacustrine deposits.

The lacustrine sediments in the Project area are approximately 50 feet thick and underlain by approximately 150 feet of glacial till, which in turn is underlain by igneous and sedimentary bedrock. The Project area is seismically stable and there are no active mining operations, oil or gas wells, or gravel pits in the vicinity of the route.

B.4.h Soils

The route crosses the Red River Valley of the North Major Land Resource Area (MLRA). This area consists of a nearly level glacial lake plain that is bordered on the east by outwash deposits, gravelly beaches, and dunes. The dominant soils in this MLRA are Aquolls. These deep, somewhat poorly to poorly drained soils have a sandy to clayey texture and a frigid temperature regime. In general, the pipeline route crosses soils that formed in glaciolacustrine deposits.

Detailed soil characteristics along the pipeline route were identified and assessed using the Soil Survey Geographic database (SSURGO; U.S. Department of Agriculture (USDA), Natural Resources Conservation Service (NRCS), 2003). The SSURGO database is a digital version of the original county soil surveys developed by the NRCS for use with geographic information systems (GIS). It provides the most detailed level of soils information for natural resource planning and management. The mapping scale in the Project area is 1:20,000, with a minimum delineation size of 4.0 acres. SSURGO is linked to an attribute database that gives the proportionate extent of the component soils and their properties for each map unit (USDA, NRCS 1995). The SSURGO database was used to define soil characteristics along the pipeline route in Pembina County. SSURGO attribute data consist of physical properties, chemical properties, and interpretive groupings. Attribute data apply to the whole soil (e.g., listed hydric, prime farmland soils, slope class) as well as to layer data for soil horizons (e.g., texture, permeability). The soil attribute data can be used in conjunction with spatial data to describe the soils in a particular area.

Tables 7, 8, and 9 list the soil associations, the approximate crossing length of each soil association, STATSGO map unit identification numbers (MUIDs) crossed by the pipeline route, and provides a summary of soil limitations for the pipeline route. STATSGO MUIDs are geologically and geographically related soils which correspond to soil associations. Approximately 69 percent of the soils crossed by the pipeline route (19.3 miles) in North Dakota are NRCS-classified prime farmland, provided there is sufficient artificial drainage to remove excess surface water. Approximately 5.8 miles of the pipeline route cross soils classified as saline, which in severe cases precludes their use for agricultural production. This saline area is predominantly wetland or grassland and near the portion of the pipeline route by the Juhl WMA.

TABLE 7

Soil Characteristics in the Alberta Clipper Project Area [a]

County	Total Acres in County	Prime Farmland	Hydric Soils	Compact. Prone	Highly Erodible: Water	Highly Erodible: Wind	Reveg. Concerns	Stony/ Rocky	Shallow to Bedrock
		Acres (percent)							
Pembina	474.0	326.6 (69)	302.7 (63)	427.4 (90)	0.6 (<1)	-- (-)	-- (-)	-- (-)	-- (-)

[a] Acreage is based on a 140-foot-wide construction right-of-way and does not include access roads, temporary extra workspace, or areas of open water, and does not account for reduced right-of-way widths in wetlands and forested areas.

TABLE 8

Topsoil Depths and Slope Class in the Alberta Clipper Project Area [a]

		Topsoil Depth (inches)				Slope Class (percent)				
County	Total Acres in County	0-6	>6-12	>12-18	>18	0-5	>5-8	>8-15	>15-30	>30
		Acres (percent)								
Pembina	474.0	77.9 (16)	15.0 (3)	-- (-)	381.1 (80)	470.3 (99)	1.3 (<1)	0.6 (<1)	1.7 (<1)	-- (-)

[a] Acreage is based on a 140-foot-wide construction right-of-way and does not include access roads, temporary extra workspace, or areas of open water, and does not account for reduced right-of-way widths in wetlands and forested areas.

TABLE 9

Topsoil Depths on Prime Agricultural Land in the Project Area [a]

County	Total Acres in County	Topsoil Depth (inches) 0-6	>6-12	>12-18	>18
		Acres (percent)			
Pembina	326.6	9.3 (3)	9.1 (3)	-- (-)	308.2 (94)

[a] Acreage is based on a 140-foot-wide construction right-of-way and does not include access roads, temporary extra workspace, or areas of open water, and does not account for reduced right-of-way widths in wetlands and forested areas.

Potential temporary effects on soil resources include the loss of soil productivity due to erosion, soil mixing, or soil compaction. Soil disturbances associated with clearing, grading and trenching will expose soils to water and wind and increase the potential for erosion. Analysis of STATSGO data indicates that soils in the Project area are not susceptible to erosion by wind. Soil erosion by water is not common along the pipeline route because the land is nearly level. Less than 0.1 mile of the Project area contains highly erodible soils. During construction, the effects of erosion by water on steep slopes will be mitigated by use of silt fence and other erosion control measures as described in Enbridge's EMP (see Appendix A).

Soil productivity could potentially be affected if topsoil were to become mixed with subsoil during construction. To minimize this potential in agricultural land and other areas where soil productivity is an important concern, Enbridge will segregate topsoil during trench excavation. In cropland, topsoil will be removed to a maximum depth of 12 inches from the trench and spoil storage area unless otherwise requested by the landowner. Topsoil will be stored separately from the trench spoil and will be returned to its approximate original location after the trench is backfilled.

Heavy equipment used to construct the pipeline may cause soil compaction along the right-of-way. Soils will be tilled with a chisel plow or other deep-tillage equipment to loosen the soil to the reasonable satisfaction of the landowner. Because the soils of the Project area generally have a high shrink-swell potential, compaction will correct itself over time as the soil goes through wet-dry and freeze-thaw cycles.

B.4.i Vegetation and Wildlife

Vegetation

The route crosses predominantly agricultural land. Agricultural areas are discussed in detail in sections B.4.b(1) and B.4.j. Non-agricultural areas include wetlands, woodlands at river crossings, windrows, and approximately 0.8 mile of grassland located in an area of wetlands and saline soils around the Juhl WMA.

The primary impact on vegetation will result from construction-related removal or disturbance of vegetation on the right-of-way. Vegetation will also be removed from areas where extra workspace is required (e.g., road and waterbody crossings).

Enbridge will clear the right-of-way only to the extent necessary to assure suitable access for construction, safe operation, and maintenance of the pipeline. At waterbody crossings, Enbridge will maintain a 10-foot-wide vegetative cover until the actual crossing of the waterbody takes place.

In areas that require permanent revegetation, Enbridge will specify appropriate seed mixes, application rates, and seeding dates, taking into account recommendations of appropriate state and federal agencies and landowner requests.

During construction in unsaturated wetlands, topsoil will be segregated from the trench line to preserve natural sources of seed and rootstock. After the trench is backfilled, the topsoil will be replaced to facilitate the natural revegetation process. Consequently, significant changes in cover types are not anticipated.

Wildlife

Enbridge contacted the NDGFD and the FWS to identify known occurrences of state and federally listed threatened or endangered species and critical habitat located along the route. In response to this consultation, the FWS identified the bald eagle and gray wolf as potentially occurring in the Project area. No recommendations to protect or minimize effects to these species were provided and FWS stated that providing a list of these species fulfills the FWS' requirements under Section 7 of the Endangered Species Act (see Appendix C).

The NDGFD reviewed the route and has advised Enbridge that the State of North Dakota does not maintain an endangered species list, and that they defer to the FWS-maintained federal list. The NDGFD has previously identified common terrestrial wildlife in the Project area. These species include moose, white-tailed deer, beaver, badger, raccoon, mink, weasel, muskrat, sharp-tailed grouse, Hungarian partridge, songbirds, migratory waterfowl, and raptors.

Although some loss of members of smaller, slower moving species may occur during construction, most species will move away from the right-of-way into adjacent undisturbed habitats until construction and restoration are complete. Long-term habitat availability is not expected to change as a result of the Project, as the right-of-way will be restored to pre-construction conditions to the extent feasible.

Typical fish species within the Project area include catfish, walleye, perch, white bass, and white sucker. Additional species occurring in the Red River of the North include muskellunge, sauger, northern pike, bullhead, and lake sturgeon. Less commonly occurring fish species in the Project area include the common and large stone rollers, blacknose shiner, and rosy-faced shiner. Construction-related impacts on aquatic species will be temporary and limited mainly to areas immediately at or downstream from the pipeline crossings.

The NDGFD and FWS recommended that construction at major waterbody crossings be scheduled to avoid fish spawning periods. The FWS also recommended that construction in wetlands be scheduled to avoid disruption of waterfowl and other wildlife during nesting season. Enbridge will continue to work with these agencies to address concerns about wildlife and aquatic resources.

B.4.j Land Use

Agricultural production is the predominant land use in the Project area. Principal crops include wheat, barley, potatoes, dry beans, sunflowers, soybeans, sugar beets, grain corn, canola, and alfalfa. The Project will have only a temporary effect on agricultural land use. Crop production will be temporarily disrupted in cases where the construction period overlaps with the growing season. Landowners will be compensated for crop loss or reduced yields caused by construction of the pipeline. Deep tillage or other measures will be implemented as necessary to mitigate effects of soil compaction.

The only industrial area crossed by the pipeline route is the Enbridge Joliette pumping station, which is owned and operated by the Company. Construction and operation of the pipelines will preclude future unrelated industrial development on lands occupied by the permanent maintained right-of-way; however, as previously noted, the Project will be located on or adjacent to existing right-of-way; therefore, impacts to land use are anticipated to be minimal. Furthermore, after installation of the pipeline, disturbed areas will be restored to preconstruction conditions to the extent practicable, and will generally revert to preconstruction uses. Therefore, no long-term change in land use is anticipated.

B.4.k Water Resources-Ground Water

Groundwater in the Project area is strongly influenced by the Dakota Group sandstone, which contains saline water under artesian pressure. Groundwater along the route is low in quality and most domestic water is obtained from surface water sources and piped to residences by a rural water authority.

No wells will be installed or abandoned as part of this Project, nor will require connection to a municipal water supply. Groundwater can be adversely affected by pipeline construction that involves blasting. For the Project, no blasting of bedrock is anticipated, and other construction-related disturbance of soils is not expected to adversely affect groundwater.

Another potential source of adverse impacts on groundwater is the introduction of contaminants resulting from accidental spills of construction-related chemicals, fuels, or hydraulic fluid. This potential effect is greatest near water wells. Enbridge's EMP and SPCC Plan describe preventative measures that the Company will implement to prevent accidental discharges of fuels or other hazardous substances, including specific storage and handling requirements. The SPCC Plan also describes response, containment, and reporting and clean-up procedures. With the implementation of these protected measures, contamination of groundwater due to construction activities is not anticipated.

Water Resources-Surface Waters

Topographic maps and current aerial photos were reviewed to identify streams, rivers, and lakes crossed by the pipeline route. The three major waterbodies crossed by the pipeline route are the Pembina River, Tongue River, and Red River of the North. The pipeline route also crosses several drainage ditches and intermittent waterbodies; however, the pipeline route does not cross any lakes or ponds. No state or federally designated wild or scenic rivers are crossed by the pipeline route. Waterbodies crossed by the Project are listed in table 10.

TABLE 10

Waterbodies Crossed by the Alberta Clipper Project Pipeline Route

Milepost	Waterbody Name	Type	Hydrology	County
775.59	Pembina River	River	Perennial	Pembina
777.65	East Branch, County Ditch #42	Stream	Intermittent	Pembina
778.82	County Ditch #42	Canal/Ditch	Canal/Ditch	Pembina
781.25	Ditch to Louden Coulee	Stream	Intermittent	Pembina
781.48	Louden Coulee	Stream	Intermittent	Pembina
782.68	County Drain #33	Stream drain	Intermittent	Pembina
783.34	Tongue River Cutoff	Canal/Ditch	Canal/Ditch	Pembina
785.71	Tongue River	Stream	Intermittent	Pembina
785.72	Tongue River	Stream	Intermittent	Pembina
786.21	Tongue River	River	Perennial	Pembina
787.80	Trib. to Tongue River	Stream	Intermittent	Pembina
789.96	Ditch to Loughton WMA	Stream	Intermittent	Pembina
790.62	Ditch to Loughton WMA	Stream	Intermittent	Pembina
795.78	County Ditch #39	Stream	Intermittent	Pembina
797.21	County Ditch #7	Stream	Intermittent	Pembina
798.58	County Ditch #6	Stream	Intermittent	Pembina
799.99	County Ditch #5	Stream	Intermittent	Pembina
800.92	Trib. to the Red River	Stream	Intermittent	Pembina
801.82	Red River of the North	River	Perennial	Pembina

The Pembina River has been designated on the Nationwide Rivers Inventory (NRI). The NRI is a listing of more than 3,400 free-flowing river segments in the United States that are believed to possess one or more "outstandingly remarkable" natural or cultural values judged to be of more than local or regional significance. Under a 1979 Presidential directive, and related Council on Environmental Quality procedures, federal agencies must seek to avoid or mitigate actions that will adversely affect designated NRI river segments. Enbridge will consult with appropriate regulatory agencies regarding measures to be implemented during the crossing of the Pembina River to protect its status on the NRI.

The FWS has recommended that Enbridge avoid construction in river channels during fish migration and spawning periods from April 15 – June 1 and that appropriate erosion control measures be installed to reduce sediment transport into waterbodies and wetlands. Implementation of the measures described in Enbridge's EMP will provide adequate protection to water resources during construction.

Waterbody crossings are planned to be constructed using either horizontal directional drill (HDD) or open-cut construction techniques, with most waterbodies crossed by the open-cut method. The HDD method is an expensive and complex technique used for wide waterbodies where there is a need to avoid disturbance of the streambed and banks. HDD is typically used for large river crossings because of the magnitude of the crossing length, disruption of navigation, long duration of trenching, and potential sedimentation. Subject to engineering evaluations, Enbridge plans to use the HDD method to cross the Red River of the North.

For the HDD crossing at the Red River of the North, temporary extra workspace will be established on each side of the river as staging areas for drilling equipment and to assemble the pipe. A slant drill until will be placed on one bank and a small-diameter pilot hole will be drilled under the river along a prescribed profile. Electromagnetic sensors will be used to monitor and guide the path of the drill bit. After the pilot hole has been completed, it will be enlarged with the use of a barrel reamer to accept the pipeline. Drilling mud will be circulated to remove cuttings and to maintain the integrity of the hole.

HDD essentially eliminates increases in sediment that will result from trenching; however, potential impacts include the inadvertent flow of stored drilling mud into the waterbody and the possibility that pressurized drilling mud will seep to the surface through natural fractures or voids in the soil. The feasibility and ultimate success of a directional drill is dependent on site-specific soil conditions. Enbridge's successful completion of a directionally drilled crossing of the Red River of the North during previous construction projects increases the likelihood that this method will be feasible for the Project.

The other waterbodies crossed by the route are much smaller than the Red River of the North and these waterbodies will be crossed by means of the "wet trench" (open-cut) construction technique. In a wet trench crossing, backhoes excavate a trench in the waterbody channel, leaving "hard plugs" of soil in place on each bank of the crossing. When the trench has been excavated and the crossing section fabricated, the hard plugs are removed and the pipe segment is moved into place. The newly installed pipeline is welded in place and the trench is backfilled with native materials or as required by applicable permits.

Temporary, incremental increases in sediment load can be expected downstream of open-cut waterbody crossings during the excavation and backfilling phases of construction. Additionally, some incremental increase in surface run-off sedimentation may be expected to occur at each of the crossings due to the close proximity of exposed soils. No significant or long-term increase in sedimentation is expected from construction of the waterbody crossings.

Enbridge will obtain applicable permits for waterbody crossings, including authorization from the North Dakota State Water Commission to cross the Red River of the North. One or more environmental inspector(s) will be retained to monitor compliance with applicable permit requirements and specifications required by Enbridge's EMP.

Wetlands

In planning its 1994 Capacity Expansion project, Enbridge conducted field wetland delineations to identify wetlands crossed by the pipeline route. This wetland delineation, in conjunction with aerial photo-based alignment sheets and USGS topographic maps, were used to identify wetlands along the pipeline route.

Section B.4.b.(5), Impact on Wetlands

Construction of the Project will not result in the permanent drainage or filling of wetlands. Enbridge will implement the measures identified in its EMP to minimize adverse effects on wetlands during construction and restore wetlands following construction. Effects on wetlands are therefore expected to be short-term and minor. During trenching, water quality of inundated wetlands will be temporarily affected due to the suspension of sediments and organic matter. Construction of the Project will result in temporary disturbance to some of the existing vegetation along the pipeline route and within the right-of-way.

During construction in unsaturated wetlands, topsoil will be segregated from the trench line to preserve natural sources of seed and rootstock. After the trench is backfilled, the topsoil will be replaced to facilitate the natural revegetation process. The long-term operation and maintenance of the pipeline will not have adverse effects on wetland function or value.

Construction in wetlands will require authorization by the U.S. Army Corps of Engineers (COE). Enbridge will be obtaining necessary authorization for wetland crossings and work in wetlands will be conducted in accordance with applicable permit conditions.

Water Use

The Project will not significantly affect water use patterns. Following construction, drains, swales, and flowages will be restored to preconstruction conditions to the extent practicable to minimize disruption of water resources.

The Project will require temporary appropriations of water (likely surface water) for use in the hydrostatic testing of the newly installed pipeline. Additionally, some temporary trench dewatering will be required, particularly during road bores. No significant effect on existing and future water uses is anticipated.

Discharge of water used to hydrostatically test the new pipeline is not expected to have an impact on the environment or receiving waters. The discharge is regulated by the North Dakota Department of Health under a North Dakota Pollutant Discharge Elimination System (NDPDES) general permit issued specifically for temporary dewatering activities including hydrostatic testing and trench dewatering (Permit No. NDG-070000). Water appropriated for hydrostatic testing will be subject to permit conditions from the North Dakota State Water Commission and is not expected to have an environmental impact.

Surface Water Runoff

Potential construction-related effects on surface waters are primarily related to sedimentation from uncontrolled erosion of disturbed areas. Much of the pipeline route is level or only gently sloping, which limits the potential for runoff effects. Because the right-of-way will be restored to preconstruction conditions, area runoff following construction will generally reflect surrounding land use.

Enbridge will obtain authorization under a general permit for Storm Water Discharges Associated with Construction Activity from the North Dakota Department of Health, which implements a federal program under the Clean Water Act. Enbridge's EMP, which was developed in part to meet requirements of this permit, describes best management practices Enbridge will implement to minimize off-site erosion from site stormwater runoff. These practices will protect surface water and soil resources within the Project area. Enbridge's EMP will be included in the construction specifications for the Project and enforced by one or more environmental inspectors during construction.

Discharges to Surface Waters

During construction, point source wastewater discharge will be generated from hydrostatically testing the new pipeline prior to placing it in service. Discharges will also occur as needed for trench dewatering during construction. The North Dakota Department of Public Health has developed a General Permit (Permit No. NDG-070000) which authorizes the discharge of waters related to temporary dewatering and hydrostatic testing. Enbridge will obtain authorization for construction-related discharges and will conduct trench dewatering and hydrotest water discharges in a manner consistent with the NDPDES General Permit.

Testing and discharge is anticipated to be consistent with past practices and experience. Discharges of hydrostatic test water typically are controlled discharges directly to the ground surface or occasionally into Waters of the State. Specific discharge point(s) for hydrostatic test water for the pipeline have not been determined at this time. In most cases, it is anticipated that this water will be acquired from several of the rivers crossed by the pipeline route and discharged back to the original source. The NDPDES permit specifies that discharge water must be free from process and other wastewater discharge.

Protection from Fuel Spills

Enbridge has developed a SPCC Plan to minimize the potential for accidental releases of petroleum or other substances during construction. Water resources will be protected from fuel spills by prohibiting the storage of fuel within 100 feet of a wetland or surface water body. Refueling and overnight parking of equipment will not be allowed within this zone unless, due to site-specific conditions, there is no practical alternative. Enbridge's EMP and SPCC Plan describe protective measures that must be implemented. Contractors will be required to provide adequately trained personnel, and proper equipment and materials to contain and clean up spills of fuel, lubricating oil or hydraulic fluid that result from equipment failure.

B.4.I Cultural Resources

Enbridge reviewed existing site file data maintained by the North Dakota SHPO to determine if any portion of the route was surveyed previously for cultural resources. A total of six previous archaeological studies have been identified that directly relate to the pipeline route. The entire Neche, North Dakota to Clearbrook, Minnesota portion of the corridor was first surveyed as part of the 1994 Capacity Expansion project. In 1998, portions of the previous survey corridor were included in a project named Terrace I or Terrace Expansion. The Terrace I project did not extend beyond the survey corridor for the 1994 Capacity Expansion and, therefore, no additional archaeological investigations were required for Terrace I. The reports of these previous surveys are as follows:

- Breakey, Kim C., and Clark Dobbs

  1993 *Files Search and Literature Review of Lakehead Pipeline Between Clearbrook, Minnesota and Neche, North Dakota.*

- Dobbs, Clark A., Kim Breakey and Howard Mooers

1994 *A Model of Archaeological Sensitivity for Landforms Along the Lakehead Pipe Line Company Corridor from Neche, North Dakota to Clearbrook, Minnesota.*

- Breakey, Kim, Clark Dobbs and Matthew Murray

  1994a *Phase I Archaeological Investigations of Selected Areas of the Lakehead Pipe Line Company Corridor between Neche, North Dakota and Clearbrook, Minnesota.*

  1994b *Evaluation of the Archaeological Sites on the Lakehead Pipe Line Company Corridor between Neche, North Dakota and Clearbrook, Minnesota.*

  1994c *Evaluation of the archaeological Sites on the Lakehead Pipe Line Company Corridor between Neche, North Dakota and Clearbrook, Minnesota: 32PB153 and the Angle Road, Tongue River, Pembina County, North Dakota.*

- Foth & Van Dyke and Associates Inc.

  1998 *Archaeological Monitoring at the Pembina River Crossing, North Dakota, Lakehead Pipe Line Company Terrace Expansion Project.*

Enbridge reviewed the North Dakota SHPO's site files to identify previously recorded cultural resources within the construction right-of-way. This review identified one archaeological site (32PB132) in North Dakota, which has been determined eligible for nomination to the National Register of Historic Places. The route will cross a historic ox-cart trail known as the Angle Road. Enbridge has previously avoided effects to this site by using conventional boring construction methods to cross this feature. Enbridge plans to bore the Angle Road again and, therefore, the Project is not anticipated to affect this site. Enbridge will consult with the North Dakota SHPO regarding treatment and protection of this historic resource.

B.5. THE CRITERIA TO BE EVALUATED SHALL INCLUDE AT A MINIMUM ALL OF THE FOLLOWING, WHICH ARE WITHIN THE DESIGNATED CORRIDOR:

- Exclusion Areas;
- Avoidance Areas;
- selection criteria;
- policy criteria;
- design and construction limitations; and
- economic considerations

Complete descriptions, potential impacts, and mitigation measures relevant to the six criteria cited above are provided in section B.4 in conjunction with the descriptions of potential impacts. Below is a discussion of additional measures Enbridge will employ.

B.6. MITIGATION MEASURES

B.6.a Measures to Preserve the Human Environment

The Company will require its construction contractor to clean up on a daily basis personal litter, bottles and paper deposited by right-of-way preparation and construction crews. Waste and scrap that is the product of pipeline construction will be removed and properly disposed of in accordance with applicable regulations before construction is completed.

To the maximum extent practicable, the Company will minimize noise and dust resulting from construction near residential areas.

The Company will obtain applicable permits prior to conducting road crossings. Temporary signs will be posted at each crossing as appropriate to alert motorists of construction activity. Paved roads and railroads will be bored which will minimize interference with traffic flow caused by construction activities.

B.6.b Measures to Protect Terrain and Geological Resources

The Company will, to the maximum extent practicable, restore the area affected by pipeline construction to the natural conditions that existed immediately before construction of the pipeline. Restoration will be compatible with the safe operation, maintenance, and inspection of the pipeline.

To the maximum extent practicable, the Company will restore the construction area to pre-construction contours. Measures such as slope breakers, erosion control blankets and revegetation will be employed to maintain the stability of slopes along the right-of-way. No crown of backfill material will be left over the trench in wetlands.

Fuel and all other hazardous materials will be stored in accordance with the requirements of Enbridge's SPCC Plan (Appendix B). The SPCC Plan also describes response, containment, and cleanup measures.

B.6.c Measures to Protect Soils

Enbridge will implement temporary and permanent erosion control measures as specified in the EMP (Appendix A). The EMP will be included in contract documents and enforced as such throughout the Project.

Temporary erosion and sedimentation control measures may include installation of silt fence, straw bales, slope breakers, trench breakers, erosion control fabric and mulch.

To minimize potential impacts on soil productivity, topsoil will be segregated during trench excavation in agricultural land, unsaturated wetlands, and if applicable, other areas where soil productivity is an important consideration. Unless otherwise requested by the landowner, topsoil in cropland will be removed to a maximum depth of 12 inches from the trench and spoil storage area and stored separately from the trench spoil. After the trench is backfilled, topsoil will be returned to its approximate original location.

Compaction of agricultural soils will be minimized by restricting construction activities during periods of prolonged rainfall. Where unacceptable levels of compaction occur in agricultural lands, deep tillage, a chisel plow or other deep tillage equipment will be utilized to loosen the soil to the reasonable satisfaction of the landowner.

The Company will retain environmental inspectors to monitor the contractor's compliance with applicable requirements to protect soil resources during construction of the Project.

B.6.d Measures to Protect Vegetation and Wildlife

The Company will clear the right-of-way to the extent necessary to assure suitable access for construction, safe operation, and maintenance of the pipeline.

In areas that require permanent revegetation, Enbridge will specify appropriate seed mixes, application rates, and seeding dates, taking into account recommendations of appropriate state and federal agencies and landowner requests. In non-agricultural areas, vegetation cleared from extra workspace will be allowed to revegetate after construction depending on arrangements with the landowner. Consequently, significant changes in cover types are not anticipated.

After completion of waterbody crossings, the Company will revegetate disturbed stream banks in accordance with the EMP and requirements of applicable state or federal permits. During construction in unsaturated wetlands, topsoil will be segregated from the trench line to preserve natural sources of seed and rootstock. After the trench is backfilled, the topsoil will be replaced to facilitate the natural revegetation process.

The Company will take appropriate precautions to protect livestock and crops affected by construction. Operation of the pipeline is not anticipated to significantly affect terrestrial wildlife, fisheries resources, or other aquatic species. Shelter belts and trees will be protected and restored by the Company to the extent practicable in a manner compatible with the safe operation, maintenance, and inspection of the pipeline.

B.6.e Measures to Protect Land Use Permits

The Company will obtain and comply with applicable county permits regulating zoning and land use. These permits may include, but are not limited to grade and fill permits, ditch crossing permits, road and utility permits and conditional use permits. The Company will retain one or more environmental inspectors to monitor compliance with environmental conditions of county permits.

The Company will repair surface drains disturbed during right-of-way preparation, construction and maintenance activities. The Company will repair private roads and farm lanes damaged when moving equipment or when obtaining access to the right-of-way. The Company will repair or replace fences and gates removed or damaged as a result of right-of-way preparation, construction or maintenance activities.

The Project will be installed at a minimum depth of 36 inches from the surface contour to minimize the potential for environmental damage resulting from deep tillage activities unless modified to accommodate special construction issues at the site.

Shelter belts and trees will be protected by the Company to the extent possible in a manner compatible with the safe operation, maintenance, and inspection of the pipeline.

B.6.f Measures to Protect Water Resources

Enbridge will obtain applicable permits for crossing wetlands and waterbodies and for water appropriations related to hydrostatic testing and trench dewatering. Environmental inspectors will monitor compliance with applicable waterbody and wetland protection requirements during construction of the facilities.

Measures to protect water resources have been discussed to some extent in section B.4.k and in previous mitigation sections on soils (see section B.6.c) and vegetation and wildlife (see section B.6.d). Enbridge's EMP describes these measures in detail, and contains illustrations of how sediment control devices are typically installed at waterbody crossings. Additionally, Enbridge will maintain a 10-foot-wide vegetative buffer until the actual crossing of the waterbody takes place. Temporary sediment control measures such as silt fence installed at each crossing will minimize the introduction of sediment into waterbodies during construction and minimize the movement of spoil and sediment from surface runoff during and after construction. Permanent erosion control measures, such as vegetation and installation of slope breakers, will effectively stabilize riparian zones. The Company will stabilize streambanks disturbed during construction using methods as directed by applicable state and/or federal permits.

For open-cut crossings, "hard plugs" of soil prevent the flow of water from the waterbody into the adjacent trench and the migration of sediment from the adjacent trench into the waterbody. After the pipe is installed, the trench will be backfilled in such a manner to restore the natural contours of the waterbody to the extent practicable. Directional drilling of the Red River of the North will minimize construction-related disturbance of this river because in-stream trenching and backfilling will not be necessary. Enbridge is currently evaluating crossing methods for the Pembina and Tongue Rivers and will coordinate with the NDGFD and the FWS regarding crossing methods for these two rivers.

Wetland crossings will be conducted in accordance with applicable regulatory requirements. If construction mats or timbers are placed in wetlands to support equipment, they will be removed after construction is completed. In order to maintain surface water hydrology within wetlands, preconstruction contours will be restored and no crown will be left over the trench. If there is a potential for a wetland to be drained by trenching, trench plugs will be installed as needed at the edge of a wetland. In unsaturated wetlands, topsoil will be replaced to facilitate the natural revegetation process.

Enbridge's EMP and SPCC Plan specify several measures to protect wetlands and waterbodies from pollution during construction by fuels or other hazardous materials. These plans prohibit the storage of fuel or other hazardous materials within 100 feet of a wetland or waterbody. The EMP also specifies that equipment must be refueled at least 100 feet from waterbodies unless, due to site-specific conditions, there is no practical alternative. In that case, the contractor must implement site-specific protective measures and containment procedures described in the SPCC Plan. Contractors will be required to provide trained personnel, appropriate equipment and materials to contain and clean up spills of fuel, lubricating oil or hydraulic fluid that result from equipment failure when working in or near wetlands or surface water bodies.

Water appropriations for hydrostatic testing will be conducted in accordance with applicable permits. The Company will conduct trench dewatering and hydrostatic test discharges in a manner consistent with the NDPDES General Permit. Enbridge's EMP describes best management practices that will be implemented to minimize off-site erosion from surface water runoff, and protect water and soil resources within the Project area.

Much of the concerns associated with the quality of the water being discharged are addressed by the fact that no additives to the water are permitted unless written approval is received from Enbridge and applicable permits authorize such additives. Environmental Inspectors will monitor compliance with permits. Where appropriate, water will be discharged into an energy dissipation and/or filtering device to remove sediment and to reduce the erosive energy of the discharge.

B.6.g Measures to Protect Cultural Resources

Enbridge has initiated consultation with the North Dakota SHPO through the COE. Enbridge will comply with the recommendations of the North Dakota SHPO and take appropriate measures to avoid Project-related effects to sites eligible for listing on the National Register of Historic Places. If additional cultural resource surveys are recommended by North Dakota SHPO in order to assess Project effects, Enbridge will complete those surveys in accordance with state-approved protocols and provide the results of those surveys to the North Dakota SHPO and appropriate lead federal agency.

B.7. QUALIFICATIONS OF PERSONS CONTRIBUTING TO THE STUDY

See section D.6 of the Application for Corridor Certificate.

B.8. MAPS

See section D.7 of the Application for Corridor Certificate.

B.9. OTHER MATTERS

The information provided below is in accordance with North Dakota Century Code 49-22-08.1 Sections 1.e, 1.f, and 1.g.

B.9.a Right-of-Way Preparation, Construction and Reclamation Procedures

This section provides a general overview of the typical construction sequence for a pipeline. Figure 2 shows the typical steps of cross-country pipeline construction. Standard pipeline construction proceeds in the manner of an outdoor assembly line composed of specific activities that make up the linear construction sequence.

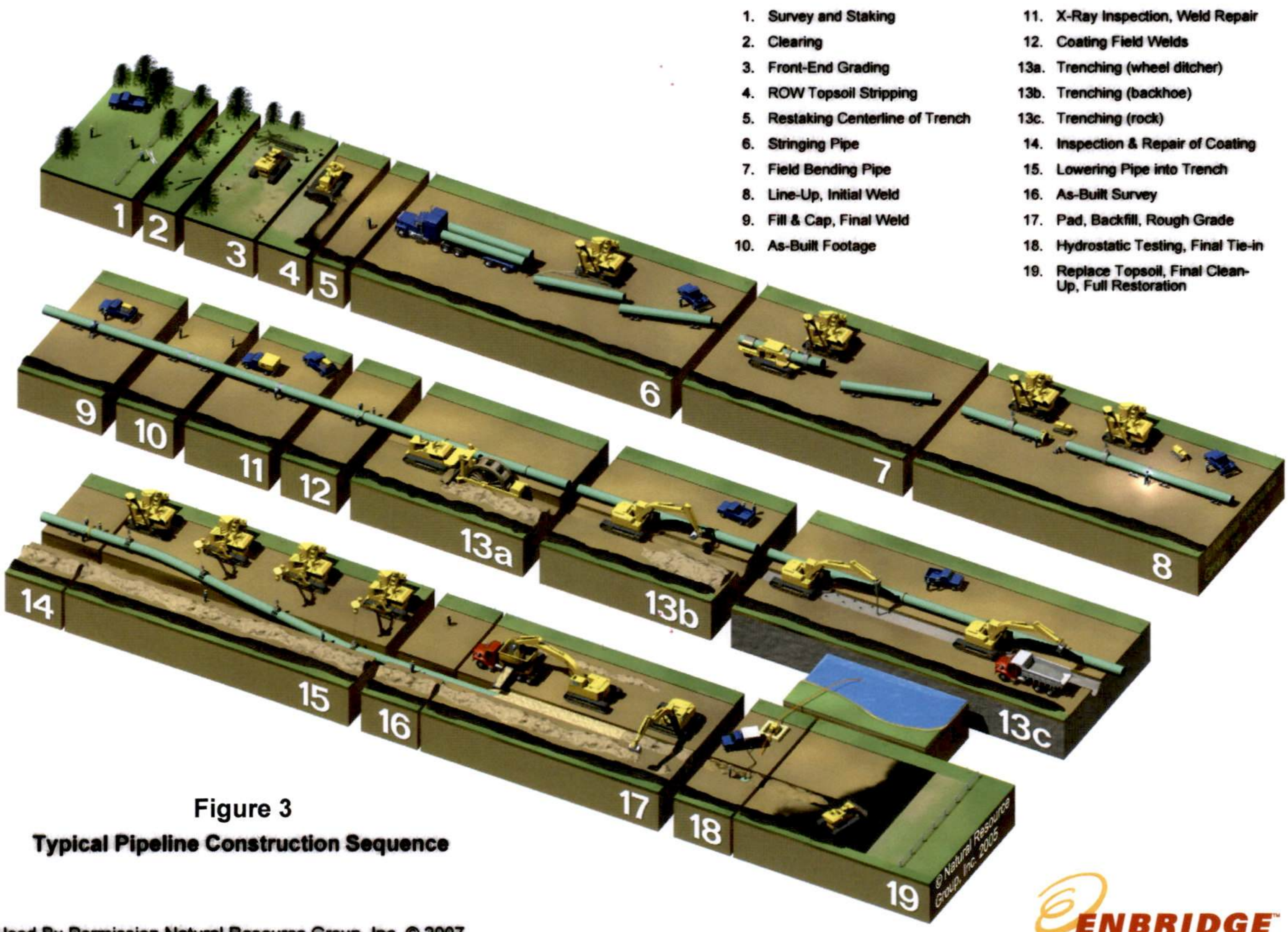

Figure 3

Typical Pipeline Construction Sequence

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These operations collectively include survey and staking of the right-of-way, clearing and grading, topsoil stripping, pipe stringing and bending, welding and coating, trenching, lowering-in and backfilling, hydrostatic testing, cleanup, and restoration and revegetation.

B.9.a.(1) Survey and Staking.

Before construction, Enbridge crews will survey and stake the centerline and exterior boundaries of the construction right-of-way. The exterior boundary stakes will mark the limit of approved disturbance areas, which will be maintained throughout the construction period. The North Dakota One Call system will be contacted to identify and mark the locations of underground utilities. During this period, equipment involved in pipeline construction will be moved onto the right-of-way using existing roads for access wherever practicable.

B.9.a.(2) Clearing and Grading.

Enbridge will clear the 140-foot-wide construction right-of-way and additional temporary extra workspaces of shrubs and trees. The clearing crew will typically mow, chip, mulch and/or haul off all non-merchantable timber. Burning of non-merchantable wood may be allowed when the contractor has obtained the necessary permits and approvals. All merchantable timber will be property of the Company unless other arrangements are made with the landowner.

Following clearing, grading of the ground surface may be done to provide a relatively smooth working surface and a safe working area. Typically, a 10-footwide buffer will be left relatively undisturbed, except where grading is needed for bridge installation, at waterbody crossings until immediately before the pipelines are installed across the waterbody.

Following clearing and grading, temporary bridges will be installed at waterbodies, except for drainage ditches, intermittent waterbodies, and other non-fisheries water, along the pipeline route to provide temporary access for equipment traveling along the construction right-of-way. In addition, temporary erosion control measures will be installed in accordance with Enbridge's EMP (see Appendix A).

B.9.a.(3) Topsoil Stripping.

Topsoil will be stripped and segregated in agricultural areas, cropland, hayfields, pasture, residential areas, and other areas as requested by the landowner along the pipeline route in accordance with Enbridge's EMP. In unsaturated wetlands, a maximum of 12 inches of surficial soils will also be stripped from the trench areas. Topsoil will be stripped to a maximum depth of 12 inches in cultivated lands.

B.9.a.(4) Stringing and Bending.

Before excavating pipeline trenches, individual joints of pipe will be strung along the construction right-of-way and arranged to be accessible to construction personnel. This operation typically involves specially designed stringing trucks to deliver pipe from pipe yards to the right-of-way. Small portable cranes and/or side-boom tractors are used to unload the stringing trucks and place pipe along the right-of-way. A mechanical pipe-bending machine will bend individual joints of pipe to the desired angle to accommodate natural ground contours or pipeline alignment. In certain areas, prefabricated fittings will be used where field bending is not practicable.

B.9.a.(5) Welding and Coating.

After stringing and bending are complete, pipe sections will be aligned, welded together, and placed on temporary supports along the edge of the trench. Enbridge will inspect the welds, both visually and radiographically. The pipe is typically delivered with a factory coating of fusion-bonded epoxy or similar material to prevent corrosion. Enbridge will apply coating at welded joints and will electronically inspect the pipeline coating before the pipe is lowered into the trench.

B.9.a.(8) Trenching.

Backhoes and/or ditching machines will be used to excavate trenches in accordance with PHMSA regulations, which require a minimum thirty inches of cover for normal excavations and 18 to 30 inches of cover in rocky areas. The trench walls will generally be kept vertical to the extent practicable and the trenches will typically be 4 to 8 feet wide, but may be wider in less stable or saturated soils.

Where trench dewatering is needed, water will be discharged directly to the ground if there is adequate vegetation along the right-of-way to filter the water effectively. Where vegetation is sparse or absent, or in environmentally sensitive areas (e.g., adjacent to waterbodies or wetlands), straw bale dewatering structures or suitable filtering alternatives will be used to minimize siltation in adjacent waterbodies.

B.9.a.(9) Lowering In, Padding, and Backfilling.

After welding and coating are completed and the trench is excavated, the pipe will be lowered into the trench by side-boom tractors. Bladed equipment or a specially designed backfilling machine will be used to backfill the trench to the approximate ground surface elevation. This generally consists of replacing the material excavated from the trench. In areas where topsoil has been segregated, subsoil will be replaced first, and topsoil will be spread uniformly on top. Directly above the pipeline, an excess of soil or "crown" will be placed to allow for future settling, excluding wetlands. Construction debris, including wooden supports, welding rods, containers, brush, trees, or refuse of any kind, will not be permitted in the backfill. If an excessive amount of rocks are present in the backfill, the pipeline will be protected with rock shield or similar protective coating and/or backfilled with clean padding prior to backfilling with the rocky material.

B.9.a.(10) Hydrostatic Testing.

After backfilling, Enbridge will hydrostatically test the pipelines in accordance with the PHMSA regulations to ensure that the system is capable of operating at the design pressure. The testing process will involve filling a segment of the pipeline with water and maintaining a prescribed pressure for a specified amount of time.

The length of individual test segments will be determined by topography and water availability. Water withdrawals used to fill and test the pipelines will be consistent with state regulations and Enbridge's EMP. Enbridge will obtain hydrostatic test water from major waterbodies crossed by the pipeline and/or municipal sources along the pipeline route. Adequate flow will be maintained to protect aquatic life and allow for downstream uses. The test water will be discharged through energy dissipation devices to the ground surface or to a nearby waterbody. These discharges will be done in accordance with Enbridge's EMP and permits issued by the state agencies.

B.9.a.(11) Cleanup.

After the backfilling is completed, Enbridge will regrade and restore work areas as nearly as practicable to the original contour of the land. Topsoil will be redistributed over areas from which it was originally removed. Permanent soil stabilization efforts will primarily include revegetation of the right-of-way. Fences that are removed to install the pipelines will be reconstructed across the right-of-way.

B.9.a.(12) Restoration and Revegetation.

Following installation and final cleanup of the pipelines, original grade and contours will be restored to the extent practicable and temporary and permanent erosion controls will be installed. Disturbed areas will be revegetated in accordance with Enbridge's Revegetation Plan, other permit requirements, and site-specific landowner requests.

B.9.b Landowner Issues

B.9.b.(1) Procedures for Landowner Relations.

Landowners have already been contacted by mail to advise them that survey crews will be working along the pipeline route. In addition, a brief description of the Project has been mailed to landowners. Enbridge is committed to giving landowners complete information about the Project and keeping them informed throughout construction. Enbridge has begun to personally contact landowners to discuss methods of damage settlements, tenant's rights, and to address any unique property concerns they may have.

B.9.b.(2) List of Landowners.

By use of county records, a current list of landowners was generated and used for required mailings and will also be used for future personal contacts. In addition to landowners, all known tenant farmers in the construction area have been notified on the Project. A list of landowners and tenants who have been supplied information regarding the Project is attached as Appendix E.

B.9.c Operations and Safety

B.9.c.(1) Pipeline Operation and Control.

The Enbridge pipeline control center for its Liquid Pipelines Systems in North America is located in Edmonton, Alberta.

The Control Center is manned by pipeline operators 24 hours a day. A computerized pipeline control system allows these operators to remotely monitor and control the pipeline and related facilities. The Control Center also serves as an emergency center to receive calls from employees, the public or public officials reporting unusual conditions or pipeline failures.

The computerized pipeline control system has been designed to control the pipeline within pre-established minimum and maximum operating pressures. Both the computer system and operating practices include procedures for abnormal operating conditions, including emergency shutdown and isolation of the pipeline and notification procedures in the event of suspected emergencies.

B.9.c.(2) Communications Capabilities.

Land-lines and satellite communications are used to exchange the necessary computerized data for pipeline monitoring and control. Enbridge maintains a UHF radio system, supplemented by cellular phones as needed, to facilitate personnel communications during operation, maintenance, or emergency activities.

B.9.c.(3) Protection of the Pipe from Damage.

Enbridge has an aggressive program in educating excavators and the public about the presence of the pipeline and preventing damage to the pipeline from excavating equipment. Enbridge has joined and supports the North Dakota One-Call system and other one-call systems in the states where they exist.

The pipeline is protected from corrosion in a number of ways. Pipelines are covered with a protective coating. In addition, all buried or submerged metallic structures (pipeline systems) are under a cathodic protection system, as required by PHMSA regulations.

B.9.c.(4) Inspections.

The Company conducts routine inspections of the pipeline and facilities to determine that the system is operating properly, in compliance with PHMSA regulations.

Each calendar year (not to exceed a 15-month interval), the cathodic protection system is monitored by taking pipe/structure-to-soil and line current (where possible) readings. Additionally, each rectifier and anode groundbed used to impose cathodic protection on the pipeline is inspected to ensure proper operation. Repairs and adjustments to the cathodic protection system are either made during the annual survey or during later maintenance activities. At least six times per year, each rectifier and critical cathodic protection interference bond to foreign structures is inspected and corrective measures taken, if needed.

In addition, Enbridge periodically evaluates the effectiveness of its cathodic protection system by conducting supplemental close interval surveys (*e.g.*, close interval pipe to soil, etc.) of the system.

In addition, Enbridge regularly evaluates the effectiveness of its cathodic protection system by conducting close internal surveys of the system. Although not required by regulation, this method allows Enbridge to assess overall effectiveness of the system.

The pipeline route is patrolled by air at least 26 times per year to inspect the surface conditions of land on or adjacent to the pipeline right-of-way. If weather and other conditions permit, this aerial inspection is conducted weekly. Linewalking inspection of the right-of-way is sometimes used to supplement aerial inspections in congested areas. This inspection also assists in identifying unknown construction or other unsafe activity on the pipeline right-of-way.

Isolating valves are checked at least twice per year to ensure proper operation. In the event of a leak, it is important for valves to close properly to isolate the section of pipeline and minimize the amount of petroleum that may escape. Other components of the pipeline, such as tanks and pump stations are also routinely inspected.

The Company began a program in the 1970s of periodically inspecting the pipeline internally with an electronic inspection tool – called "instrument pigs." These devices travel through the inside of the pipeline and either mechanically, ultrasonically, or magnetically examine the condition (dents, gouges, corrosion, or cracks) of the pipe by on-board computers. Results of the inspection are then analyzed, and the pipe inspected to verify preliminary findings and then repaired as required.

All overpressure safety devices capable of limiting, regulating, controlling, and/or relieving operating pressures are inspected and tested to ensure the device is in good mechanical condition and functioning properly.

Periodically, government officials inspect the Company's compliance with applicable government regulations. Inspections of the Company's written procedures, records, and facilities are routinely conducted by the PHMSA.

B.9.c.(5) Maintenance.

Many other maintenance activities are performed on the pipeline and related facilities. Enbridge has a comprehensive preventative maintenance program that meets and, in many cases exceeds, minimum federal safety standards set forth PHMSA regulations, including 49 CFR Part 195. When facilities are added or replaced, there are comprehensive standards for their design and installation in both Enbridge procedure manuals and contract specifications. Repair pipe is pre-tested and other components used to repair the pipeline meet national standards and regulatory requirements. Other procedures, such as welding procedures, movement of the pipe, coating repair, corrosion control, and tank maintenance are all guided by written procedures which have been reviewed by the PHMSA inspectors.

B.9.c.(6) Training of Personnel.

The Company has established a comprehensive orientation, technical, safety, emergency, and on-the-job training program that is in compliance with the Operator Qualification rules issued by the PHMSA under 49 CFR Part 195. As personnel progress in pipeline operation and maintenance positions, they receive hundreds of hours of formal and on-the-job training. Demonstrations of competence are shown through review of job performance, periodic pipeline control system simulators, emergency exercises, welding certification tests, and other functions required to continue safe pipeline operation and maintenance.

B.9.c.(7) Public Awareness Program.

Enbridge conducts a comprehensive public education program to ensure that the affected public (those who work and live along the pipeline), excavators, local public officials, and emergency units of government are aware of how to recognize and avoid or respond to a pipeline emergency. Enbridge has also been active at the local, county, and state level in emergency response planning and joint training/exercises to prepare all potential responders to deal with emergencies.

The pipeline route is marked at all public road and railway crossings (at a minimum) to increase the public's awareness of the underground pipeline. Additional markings are posted at valves, other pipeline facilities, and stations along the pipeline route.

B.9.c.(8) Emergency Preparedness.

Enbridge's operating and maintenance practices are aimed at preventing emergencies on the pipeline. However, it is imperative that Enbridge be prepared to respond to an emergency should one occur. In addition to preventative activities described above, Enbridge's emergency response program includes pre-planning, equipment staging, notifications, and emergency and leak containment procedures. The emergency response plan has been submitted and approved by PHMSA as required by 49 CFR Part 194.

E

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INTRODUCTION

This Environmental Mitigation Plan (EMP) outlines construction-related environmental policies, procedures, and mitigation measures developed by Enbridge Energy, Limited Partnership (referred to as Enbridge or Companies) for its pipeline construction projects. The EMP was developed based on Enbridge's experience implementing best management practices during construction. It is intended to mesh with applicable federal, state and local environmental protection and erosion control specifications and practices. The EMP is designed to address typical circumstances and may be amended by Enbridge as necessary to address site-specific conditions. The measures described in the EMP are consistent with relevant portions of the State of Minnesota *Construction Site Erosion and Sediment Control Planning Handbook* and the Minnesota *Protecting Water Quality in Urban Areas Manual.* In addition, the EMP complies with the intent of the *Wisconsin Construction Site Best Management Practice Handbook* and Wisconsin technical standards, and North Dakota's *Guide to Temporary Erosion-Control Measures for Contractors, Designers, and Inspectors.*

This document includes the following sections:

- Section 1.0 of the EMP describes general mitigation measures, including soil erosion and sedimentation control procedures, to be implemented during construction;
- Section 2.0 discusses stream and river construction and crossing procedures;
- Section 3.0 describes practices for wetland construction and crossings;
- Section 4.0 discusses highway, road, and trail crossings;
- Section 5.0 discusses construction dewatering;
- Section 6.0 outlines water appropriation practices;
- Section 7.0 addresses restoration; and
- Section 8.0 addresses winter construction issues.

Alternative construction procedures implemented in lieu of EMP guidelines will provide an equal or greater level of protection to the environment, and must be approved in writing by Enbridge.

Unless otherwise specified, the construction contractor (Contractor) will be responsible for implementing the requirements of this EMP. Enbridge will make the requirements of the EMP and applicable environmental permits known to the contractor. If the contractor has questions concerning these environmental requirements, the contractor will contact an Enbridge representative.

Enbridge will provide appropriate construction oversight to confirm Enbridge's and Contractor's compliance with the measures of this EMP and requirements of applicable federal, state, and local permits. Environmental Inspectors will assist the contractor in interpreting and implementing the requirements of the EMP, and verify compliance with these procedures for the company. The Environmental Inspector will be expected to use judgment in the field to interpret environmental conditions and requirements, but will not have the authority to authorize major modifications or changes without the prior written approval of Enbridge. The Environmental Inspector will have the authority to stop activities and order corrective mitigation for actions that are not in compliance with the measures in this EMP, landowner agreements, or environmental permit requirements. The Environmental Inspector will maintain appropriate records to document compliance with these and other applicable environmental permit conditions.

1.0 GENERAL MITIGATION MEASURES

1.1 TEMPORARY EROSION AND SEDIMENT CONTROL

Temporary erosion and sediment control measures include slope breakers, sediment barriers, trench breakers, and mulch. The goal of temporary erosion and sedimentation control measures is to prevent construction-related sediment from entering streams, wetlands, lakes, drainage ditches (dry or flowing), other waterbodies, or migrating offsite. The contractor will, at all times, maintain erosion and sedimentation control structures as effectively as possible. All non-functional erosion control features will be repaired, replaced, or supplemented with functional materials as soon as field conditions allow access, but no later than 24 hours after discovery. Additional information of the project erosion control measures are provided in the applicable sections below.

1.2 RIGHT-OF-WAY ACCESS

Access to the right-of-way will be from public roadways and Enbridge-approved access roads only. The contractor will be responsible for creating signs or other methods to identify approved access roads in the field and to ensure that access is confined to only the approved roads.

1.3 RIGHT-OF-WAY REQUIREMENTS

All construction equipment and vehicles will be confined to the approved right-of-way and extra workspace. Right-of-way requirements may vary between projects. For these projects, construction activities will generally use a right-of-way as shown in Figures 1.1 and 1.1-1. These typicals illustrate Typical Right-of-Way Cross Sections for the project north and south of Clearbrook, MN.

Additional extra workspace adjacent to the temporary construction right-of-way may be necessary during construction in areas such as steep slopes and staging areas for stream, wetland, and road crossings, for safety reasons, to provide an area for prefabrication of sections of pipeline, or for storage of spoil material. Enbridge will acquire additional extra workspace from the landowner where necessary; use of unauthorized workspace is prohibited without Enbridge's approval. In all cases, the size of extra workspace will be kept to the minimum necessary to safely conduct work. Enbridge will conduct a preconstruction review of the entire project area to determine specific extra workspace locations.

Construction staging will not occur in wetlands unless necessary for safe work conditions.

1.4 LINE LIST AND PERMITS

Enbridge will provide the contractor with a construction line list that describes special requirements (e.g., timber salvage, topsoil segregation, restoration measures, fencing requirements, etc.) as agreed upon with landowners. The contractor must comply with these special requirements, as well as take all appropriate precautions to protect livestock and crops affected by construction.

The line list reflects requirements and comments provided by landowners; however it is not a comprehensive list of construction requirements. The line list must be considered in conjunction with other project documents. Any third party agreements between the contractor and the landowner must be pre-approved by Enbridge.

Enbridge will obtain the necessary permits (federal, state, local, county, watershed district, stream crossing, wetland crossing, and road crossing permits) for the installation of the pipeline. Permit requirements may be more stringent than the requirements of this EMP. <u>In all cases the more restrictive requirements will apply.</u>

1.5 CLEARING AND GRADING

The initial stage of construction involves the clearing of brush, trees, and vegetation from the right-of-way. Clearing may be accomplished with chain saws, brush hogs, and hydraulic tree-cutting equipment. The clearing crew will typically mow, chip, mulch and/or haul off all wood. Burning of wood may be allowed only where the contractor has acquired all applicable permits and approvals (e.g. agency and landowner) and in accordance with all state and local regulations. No burning will be allowed in wetlands.

Grading generally follows clearing and involves leveling and smoothing the construction right-of-way to create an even working surface for equipment and vehicles. Tree stumps outside the ditchline shall be ground no less than four-inches below normal ground surface or removed and hauled off to an approved disposal facility. Stumps in the ditch line shall be completely removed, ground, and/or hauled off to an approved disposal facility. Topsoil and subsoil disturbed during grading operations will not be mixed with foreign material (e.g., stumps and brush).

1.5.1 Disposal of Non-Merchantable Timber

Non-merchantable timber and slash will be disposed of by mowing, chipping, grinding, and/or hauling off site to an approved disposal facility. In no case will non-merchantable timber be disposed of by placing it off the right-of-way. Woody debris that is chipped or mulched on the right-of-way that will not be hauled off site for proper disposal may be wind-rowed if approved by Enbridge over the ditchline and raked along the ditchline for incorporation into the ditch spoil during excavation. No woody debris disposal will be allowed in agricultural areas or wetlands. Burning of non-merchantable wood may be allowed only where the contractor has acquired all applicable permits and approvals (e.g. agency and landowner) and in accordance with all federal, state and local regulations. No burning will be allowed in wetlands.

1.5.2 Disposal of Merchantable Timber

All merchantable timber will be the property of the company and the contractor will be responsible for merchandising all merchantable timber, unless other arrangements have been made with the landowner or land-managing agency. If a commercial buyer cannot be found, the timber may be considered non-merchantable and disposed of as referenced in Section 1.5.1.

1.5.3 Fencing

Before or during clearing of the right-of-way, existing fences and livestock barriers will be cut as necessary to access the right-of-way. Existing fencing will be braced and secured prior to cutting to prevent the slacking of wires. Temporary gates and/or fencing will be installed where necessary to maintain existing access restrictions and contain livestock. These temporary measures will remain in place until construction is complete and permanent repairs or new fencing can be installed.

1.5.4 Trees and Shelterbelts

Care will be taken to minimize tree removal. To the extent possible, wind breaks and shelterbelts will be crossed by minimizing the width of the right-of-way to that necessary for the trench line and vehicle traffic. When clearing, trees will be felled onto the right-of-way to minimize damage to off-right-of-way vegetation.

1.5.5 Irrigation Systems

If pipeline construction activities interfere with the operation of spray irrigation systems, Enbridge will establish with the landowner or Tenant, an acceptable amount of time the irrigation system may be out of service. If feasible, temporary measures will be implemented to allow an irrigation system to continue to operate across the right-of-way during pipeline construction. Any damage to irrigation systems caused by construction-related activities will be repaired following backfilling.

1.5.6 Topsoil Segregation

Topsoil generally has physical and chemical properties that are conducive to good plant growth. Because subsoil properties are usually less favorable, mixing of topsoil and subsoil can result in lowering the overall productivity of soils. To prevent soil mixing during construction, topsoil will be segregated in selected areas where soil productivity is an important consideration. These areas include cropland, hay fields, pasture, golf courses, residential areas and other areas as requested by the landowner. Topsoil will not be used to construct trench breakers (see Section 1.8) or to pad the pipe.

Topsoil Segregation Methods

The following topsoil segregation methods may be employed during construction:

- Ditch Plus Spoil Side (see Figures 1.2 and 1.2-1)
- Full Right-of-Way (see Figures 1.3 and 1.3-1)
- Trench Line Only (see Figures 1.4 and 1.4-1)

Topsoil will be segregated from ditch plus spoil areas in active cropland unless full construction right-of-way width topsoil segregation is requested by the landowner. The trench-line-only method will be used in unsaturated wetlands or where the width of the construction right-of-way is insufficient for other methods to be used. In upland areas with a fairly thick sod layer such as hay fields, pasture, golf courses, and residential areas, the trench-line-only method will be used unless otherwise requested by the landowner.

Topsoil is not typically segregated in forested areas, saturated wetlands, and nonagricultural open areas. Segregated topsoil is usually stored on the spoil side, separate from subsoil, or on the working side of the right-of-way.

Depth of Topsoil Stripping

Topsoil will be stripped to a maximum depth of 12 inches in cultivated lands, unless otherwise requested by the landowner. Additional space may be needed for spoil storage if more than 12 inches of topsoil are segregated. If less than 12 inches of topsoil are present, every effort will be made to segregate to the depth that is present.

1.5.7 Temporary Slope Breakers

Temporary slope breakers are to be installed to minimize concentrated or sheet flow runoff in disturbed areas in accordance with the following maximum allowable spacing.

Slope (%)	Approximate Spacing (ft)
1	300
2	200
3-5	150
>5	<100

If the length of the slope is less than the distance of the required spacing, slope breakers are not required. Temporary slope breakers will be constructed according to the following specifications:

- slope breakers may be constructed using earthen material, silt fence, or hay bales;
- earthen berms will be installed with a two to eight percent outslope, with a four foot base and a height of 1.5 feet (see Figures 1.5 and 1.6);
- earthen berms will be constructed of compacted subsoil where practicable;
- the outfall of temporary slope breakers will be directed to a well-vegetated area or an appropriate energy-dissipating device (e.g., silt fence, straw bales, rock aprons) and directed off the construction right-of-way if possible;
- slope breakers will be inspected daily and repaired as necessary within 24 hours after discovery to maintain operational integrity and prevent erosion in active construction areas;
- a hard plug will be left in place where a slope breaker crosses the open trench; and
- temporary slope breakers will not be installed on agricultural land unless specifically requested by the landowner.

1.5.8 Temporary Sediment Barriers

Temporary sediment barriers may be constructed with silt fence (36 inches high or greater) and/or staked straw bales (see Figures 1.7 and 1.8). If temporary sediment barriers are removed to allow equipment access, the barriers will be reinstalled at the end of the day.

Temporary sediment barriers will be installed after clearing and prior to grubbing and grading activities and maintained at the base of sloped approaches to streams, wetlands, and roads, and at the edge of the right-of-way as needed to prevent siltation of waterbodies and wetlands downslope or outside of the construction right-of-way (e.g., swales and side slopes).

When the depth of sediment reaches about one-third of the height of a sediment barrier, the barrier will be replaced and/or the sediment removed. Nonfunctional sediment-control measures will be repaired, replaced, or supplemented with functional structures as soon as possible, but no later than 24 hours after discovery.

1.5.9 Noise and Dust Control

The contractor will take all reasonable steps to control construction-related noise and dust near residential areas and other areas as directed by Enbridge. Control practices may include wetting the right-of-way, limiting working hours in residential areas, and/or additional measures as appropriate based on site-specific conditions.

1.6 PIPE DELIVERY, BENDING & WELDING

Before excavating the pipeline trench, individual joints of pipe will be strung along the construction right-of-way and arranged to be accessible to construction personnel. This operation typically involves specially designed stringing trucks to deliver pipe from pipe yards to the right-of-way

After pipe stringing is complete, the pipe will be bent, as necessary, to conform to changes in ground contour and pipeline alignment. Individual pipe joints will be welded together and the welds will be radiographically inspected. The welds will then be coated with a material to protect them from corrosion.

1.7 TRENCHING

Trenching in uplands consists of excavating the trench for the pipeline, and is typically accomplished with a backhoe excavator or a rotary wheel ditching machine. Excavated material will be sidecast within the approved construction right-of-way separate from topsoil (see Section 1.4.6), and stored such that the area subject to erosion is minimized. Enbridge will coordinate with landowners to minimize disruption of access caused by the trench during construction. Where appropriate, Enbridge will leave plugs of soil in the ditch or will construct bridges across the trench for the landowner to move livestock or equipment across the trench. Trenches will be sloped where started and ended to allow ramps for wildlife to escape.

1.7.1 Timing

The length of time a trench is left open will be minimized to ensure that installation of the pipe and restoration of the right-of-way occurs in a timely fashion. Typically, trenching will be conducted after pipe has been delivered and welded so that no trench location stays open more than two days, weather permitting.

1.7.2 Pipeline Depth

The pipeline(s) will be buried in accordance with U.S. Department of Transportation regulations, which stipulate a minimum of three feet of topcover for normal excavations, and 18 to 30 inches of cover for rock excavations (depending on the location), to prevent damage to the pipeline from normal use of the land.

If a state-level agency specifies a more stringent requirement for pipeline depth, the Companies may request a waiver of that requirement. Increased pipeline depth will result in greater amounts of ditch spoil and, consequently, will require additional temporary workspace for storage of the spoil.

1.8 PIPE INSTALLATION

Once the trench has been inspected for proper depth, rocks, or other obstructions, the welded pipe is lowered into the trench. The pipe may be wrapped with a protective shielding if necessary to protect the pipe coating while backfilling.

1.9 TRENCH BREAKERS

After pipe has been lowered into the trench, trench breakers (soft plugs) will be installed as needed in sloped areas. Trench breakers protect against subsurface water flow erosion along the pipe after the trench is backfilled. Trench breakers will be constructed with burlap sandbags filled with rock-free subsoil or sand. They will be placed from the bottom of the trench to near the top of the trench, completely surrounding the pipe (see Figures 1.9 and 1.10). The following conditions apply to the placement and installation of trench breakers unless otherwise directed by the Environmental Inspector:

- Trench breakers will be spaced as described for permanent berms (see Section 7.3) or as otherwise specified by Enbridge.
- Trench breakers will be installed on slopes greater than five percent adjacent to streams, wetlands, or other waterbodies.
- Topsoil will not be used to construct trench breakers.

1.10 DRAIN TILE REPAIR

Where drain tiles are cut during trenching, the locations will be flagged by the contractor. Prior to backfilling, drain tiles crossed by the trench will be probed with a sewer rod or pipe snake to determine if tiles were damaged during construction. Drain tiles damaged during construction will be repaired to their preconstruction condition or better.

1.11 BACKFILLING

Backfilling follows pipe installation and generally consists of replacing the material excavated from the trench. In areas where topsoil has been segregated, the subsoil will be replaced first, and the topsoil will be spread uniformly over the area from which it was removed. Prior to backfilling, the trench shall be dewatered in accordance with the methods discussed in Section 5.1. An earth crown will be left over the trench line to allow for future settling of the backfill material. No crown will be left in swales, drains, or wetlands crossed by the right-of-way.

1.12 WET WEATHER SHUTDOWN

During construction, certain activities may be suspended in wet soil conditions, based on consideration of the following factors:

- plasticity of the surface soil to a depth of approximately four to eight inches;
- extent of surface ponding;

- extent and depth of rutting and mixing of soil horizons;
- aerial extent and location of potential rutting and compaction (i.e., can traffic be rerouted around wet area); and
- type of equipment and nature of the construction operations proposed for that day.

If the above factors cannot be achieved to the satisfaction of the Environmental Inspector, the contractor shall cease work in the applicable area until conditions allow work to continue. The contractor is responsible for appropriately planning for work and considering for the potential for wet conditions, and being prepared to implement mitigative measures in the event of wet weather conditions. This is particularly important when conducting work in unsaturated wetlands. If the contractor attempts to construct through the "dry" wetland without matting or an approved equivalent, the contractor is responsible for implementing any and all such corrective measures should conditions subsequently worsen where the above described criteria cannot be met.

1.13 CONTROLLING SPREAD OF UNDESIRABLE SPECIES

Enbridge will require that construction equipment be cleaned before arriving on site to prevent the introduction of undesirable species to the project area. If undesirable species such as purple loosestrife and/or others are determined to be present within the construction right-of-way, Enbridge will implement the following plans:

- Enbridge will make an effort to prevent the spread of noxious weed seeds during clearing and grading activities, and to use straw mulch and seed mix that are free of noxious weed seed to revegetate the right-of-way. Contractors and inspectors will receive information aiding in the identification of noxious weeds. Enbridge will also provide training to its Environmental Inspectors to identify and prevent the spread of undesirable species.
- During preconstruction walkovers, the Environmental Inspectors will flag and document areas containing noxious weeds. The construction crews will be informed of these areas. Enbridge will instruct the contractors to minimize the numbers of construction equipment and to limit the number of passes by this equipment through infested areas. Construction mats may be required to minimize the transport of weed seed or plant material via construction equipment.
- Equipment and construction mats will be cleaned immediately after passing through infested areas. Cleaning will consist of removing large soil clods and/or plant parts from the equipment and construction mats using shovels and brooms, and if necessary, washing the equipment with water or cleaning using compressed air. Soil and water from cleaning activities will not be allowed to flow to non-infested areas.
- Final seeding will be initiated within 24 hours of final grading, pending appropriate weather and soil conditions, to prevent the establishment of noxious weed seeds that may be present in the existing seed bed.

2.0 STREAM AND RIVER CROSSING GENERAL REQUIREMENTS

Pre-construction planning is an essential part of stream crossings. Stream crossing requirements, including construction methods, timing, erosion control, and restoration are described in this section and in the stream crossing permits issued by state and federal agencies. If the contractor considers certain parts of these procedures to be technically impractical due to site-specific engineering constraints, the contractor may seek modifications. Prior to construction, the contractor must identify alternative provisions that would provide an equal or greater level of protection to stream and river ecosystems. Enbridge will review the contractor's alternatives and consult with appropriate regulatory agencies. Crossings of perennial streams will generally be installed by a special tie-in crew.

The procedures in this section apply to streams, rivers, and other permanent waterbodies such as ponds and lakes. These procedures require that judgment be applied in the field and will be implemented under the supervision of the Environmental Inspector. The intent of the mitigation procedures is to minimize construction-related disturbance to streams and waterbodies by limiting the duration of construction in these areas and by minimizing erosion and sedimentation.

2.1 TIME WINDOW FOR CONSTRUCTION

In-stream trenching will be conducted during periods permitted by the appropriate regulatory agencies and applicable permits.

2.2 PRE-CONSTRUCTION CONSIDERATIONS

2.2.1 Hazardous Materials

Enbridge or its Contractors will not store hazardous materials, chemicals, fuels, lubricating oils, or perform concrete coating activities within 100 feet of streams and waterbodies. Refer to Enbridge's Spill Prevention, Containment and Control Plan (Spill Plan) for additional requirements pertaining to hazardous materials.

2.2.2 Refueling/Equipment Care

Construction equipment will be refueled at least 100 feet from streams and waterbodies. Where conditions require construction equipment (e.g., barge-mounted backhoes, trench dewatering pumps) to be refueled within 100 feet of streams, the contractor must follow the procedures described in Enbridge's Spill Plan. No equipment will be washed, lubricated, or parked overnight within 100 feet of streams or waterbodies.

2.2.3 Alignment of Crossing

Stream crossings will be designed as close to perpendicular to the axis of the stream channel as engineering and routing constraints allow, creating the shortest crossing length.

2.3 CLEARING AND GRADING

The contractor will leave a 10-foot buffer (from the waterbody bank) of undisturbed vegetation on all stream banks during initial clearing, except where grading is needed for bridge installation. Woody vegetation within this buffer, less than four inches diameter-at-breast height, may be manually cut and removed during clearing. Non-woody vegetation and the soil profile will be left intact until the contractor is ready to begin trenching the stream crossing. The contractor will properly install and maintain sediment control measures adjacent to streams immediately after clearing and prior to initial ground disturbance (see Figures 2.1 through 2.3-1). This buffer should not be confused with the 50-foot setback required for extra workspace (see Section 2.4).

2.4 EXTRA WORKSPACE

Extra workspaces as defined in Section 1.2 include work areas outside the boundary of the typical construction right-of-way. These spaces are used to assemble pipe segments and for temporary spoil storage. Extra workspaces will be constructed as follows:

- Extra workspaces will be located at least 50 feet away from waters edge if topographic or other physical conditions such as stream channel meanders permit (see Figures 2.1 through 2.2-1).
- If conditions do not allow for a 50-foot setback, extra workspaces should be located no closer than 10 feet from the waters edge, subject to site-specific approval by Enbridge.
- Extra workspaces will be limited to the minimum size needed to construct the stream crossing.

2.5 BRIDGES

Temporary bridges will be used where necessary to transport equipment across streams, except for drainage ditches, intermittent streams, and other non-fisheries waters (unless required by permit). Bridges will be constructed as described below. Bridges will not typically be installed at directionally drilled streams.

2.5.1 Types of Bridges

Equipment bridges will be constructed using one of the following techniques:

- Timber mats (see Figure 2.5)
- Clean rock and flume (see Figure 2.6)
- Railroad flat cars
- Flexi-floats
- Other methods as approved by Enbridge and appropriate agencies

2.5.2 Bridge Design and Maintenance

Equipment bridges will be designed to withstand the maximum foreseeable flow of the stream, and will be securely anchored with cables or cable-like material. Bridges will not restrict flow or pool water while the bridge is in place, and will be constructed with clean materials and maintained to minimize soil from equipment from falling into the water.

2.6 STREAM AND RIVER CROSSING CONSTRUCTION METHODS

The following stream and river crossing methods are typically used, subject to further restrictions by Enbridge and applicable permits. Clearing equipment will be allowed one opportunity to ford waters crossed by the project, unless otherwise stated in applicable permits.

2.6.1 Wet Trench Method

Installation

The wet trench method will be used to cross streams and rivers not scheduled to be flumed, dammed and pumped, or directionally drilled (see Figures 2.1 and 2.1-1). The following procedures will be used during wet trench crossings:

- Sediment control measures will be in place before grading from the 10-foot vegetative buffer left on each stream bank. Spoil containment structures made of silt fence and/or straw bales will be installed back from the stream bank so that spoil does not migrate into the stream. Grading will be directed away from the waterbody to reduce the risk of material entering the stream. Grading of stream banks will be restricted to the trench line and areas necessary for safe bridge installation, if required.

- After grading, backhoes or draglines will be used to excavate the trench. Excavating equipment will operate from one or both banks, without entering the stream. If equipment must encroach into the stream, it will operate on clean construction mats. Existing material will be segregated and placed within a spoil containment structure in approved construction work area limits.

- In-stream trenching and backfilling will typically be completed within 24 hours or less on minor waterbodies and forty eight hours or less on intermediate or major waterbodies (not including HDD crossings) or as directed by applicable permits.

- Earthen trench plugs (hard plugs) between the stream and the upland trench will be left undisturbed during excavation of the in-stream trench to prevent diversion of the stream flow into the open trench and to prevent water that may have accumulated in the adjacent upland trench from entering the waterbody. Trench plugs will be removed immediately prior to pipe placement, and then replaced when the pipe is in place.

- If trench dewatering is necessary, the pump intake will be suspended off the trench bottom and dewatering will take place into a sediment filter bag or a straw bale dewatering structure (see Figures 2.7 and 2.8). The trench will be dewatered in such a manner that no heavily silt-laden water flows into streams or wetlands (see Section 5.1.3). Only non-woven fabric will be used for filter bags. It is the contractor's responsibility to meet applicable water quality standards.

- Backfilling will begin immediately after the pipe is positioned in the trench at the desired depth. Backfill material will consist of the spoil material excavated from the trench unless otherwise specified in state or federal permits. The in-stream trench will be backfilled so that the stream bottom is similar to its pre-construction contour, with no impediments to normal water flow.

Temporary Erosion Control

After pipe installation and backfilling, the stream banks will be shaped to their original contours or to a 3:1 slope, whichever is less steep. Approaches to streams will be restored to pre-construction contours. Temporary erosion control measures (e.g., straw bales, silt fence, etc.) will be installed within 24 hours of backfilling the crossing. Temporary slope breakers will be installed on all sloped approaches to streams in accordance with the spacing requirements outlined in Section 1.5.7.

2.6.2 Dam and Pump Method

Installation

The dam and pump method is a dry crossing method that is suitable for low flow streams and is a preferred alternative to fluming for crossing meandering channels. The dam and pump method involves damming of the stream with sandbags, inflatable dams, and/or steel plates upstream and downstream of the proposed trench before excavation (see Figures 2.2 and 2.2-1) and pumping water around the construction area. The following procedures will be used for dam and pump crossings:

- Pumping of the stream across the right-of-way will commence simultaneously with dam construction to prevent interruption of downstream flow. Stream flow will be pumped across the construction area through a hose and will be discharged onto an energy-dissipation device such as plywood boards to prevent scouring of the stream bed.

- The pumps will be located on the upstream side of the crossing and will be placed in impermeable, sided structures which will act as containment units for the pumps and fuel containers. Spill kits will be stored adjacent to pumps and fuel. Pumps will have a capacity greater than the anticipated stream flow. The pumping operation will be staffed at all times and pumping will be monitored and adjusted as necessary to maintain an even flow of water across the work area and near-normal water levels upstream and downstream from the crossing. A backup pump of equal or greater capacity will be on-site at all times in the event that the primary pump fails.

- Dams will be constructed of sandbags, inflatable dams, and/or steel plates. The dams will prevent the stream from flowing into the construction area. The dams will be continuously monitored for a proper seal. Adjustments to the dams will be made where necessary to prevent large volumes of water from seeping around the dams and into the construction work area.

- Backhoes located on one or both stream banks will excavate a trench across the stream bed. Spoil generated during trenching will be stored in a straw bale/silt fence containment area set back from the stream banks. Existing streambed material will be segregated and placed within approved construction work area limits.

- Trench (earth) plugs between the stream and the upland trench will be used if necessary during excavation of the in-stream trench to prevent diversion of the seeped groundwater into the open trench. Trench plugs will be removed immediately before pipe placement, and then replaced when the pipe is in place.

- Standing water that is isolated in the construction area by the dams or any stream water that leaks around the dams or seeps from the ground into the trench during construction will be pumped into a sediment filter bag or a straw bale dewatering structure located in an upland area in such a manner that no heavily silt-laden water flows into streams or wetlands (see section 5.0). Only non-woven, felt fabric bags will be used for filter bags.

- Backfilling will begin immediately after the pipe is positioned in the trench to the desired depth. Backfill material will consist of the spoil material excavated from the trench unless otherwise specified in state or federal permits. The in-stream trench will be backfilled so that the stream bottom is similar to its pre-construction contour, with no impediments to normal water flow.

Temporary Erosion Control

Restoration of the right-of-way and the installation of temporary erosion controls will be similar to that described for the wet trench method above. Once the stream banks have been stabilized, the dams and pump will be removed.

2.6.3 Flume Method

Installation

The flume method is a dry crossing method that is suitable for crossing sensitive, relatively narrow streams that have straight channels and are relatively free of large rocks and bedrock at the point of crossing. This method involves placement of flume pipe(s) in the stream bed to convey stream flow across the construction area without introducing sediment to the water (see Figures 2.3 and 2.3-1). The procedures for using the flume method are described below.

- The flume(s) will be of sufficient diameter to transport the maximum flows anticipated to be generated from the watershed. The flume(s), typically 40 to 60 feet in length, will be installed before trenching and will be aligned so as not to impound water upstream of the flume(s) or cause downstream bank erosion. The flumes will not be removed until after the pipeline has been installed, trench has been backfilled, and the stream banks have been restored.

- The upstream and downstream ends of the flume(s) will be incorporated into dams made of sand bags and plastic sheeting (or equivalent). The upstream dam will be constructed first and will funnel stream flow into the flume(s). The downstream dam will prevent backwash of water into the trench and construction work area. The dams will be continuously monitored for a proper seal. Adjustments to the dams will be made where necessary to prevent large volumes of water from seeping around the dams and into the trench and construction work area.

- After the stream bed is dewatered, backhoes located on one or both stream banks will excavate the trench across the stream bed. Spoil generated during trenching will be stored in a straw bale/silt fence containment area located away from the stream banks within approved construction work areas. Existing streambed material will be segregated and placed within approved construction work area limits.

- Trench (earth) plugs between the stream and the upland trench will be used if necessary during excavation of the in-stream trench to prevent diversion of the stream flow into the open trench. Trench plugs will be removed immediately before pipe placement, and then replaced when the pipe is in place.

- If trench dewatering is necessary to complete the installation of the pipe, the discharge will be pumped into a sediment filter bag or a straw bale dewatering structure located in an upland area in such a manner that no heavily silt-laden water flows into streams or wetlands (see section 5.0). Only non-woven fabric will be used for filter bags.

- Backfilling will begin immediately after the pipe is positioned in the trench to the desired depth. Backfill material will consist of the spoil material excavated from the trench unless otherwise specified in state or federal permits. The in-stream trench will be backfilled so that the stream bottom is similar to its pre-construction contour, with no impediments to normal water flow.

Temporary Erosion Control

Restoration of the right-of-way and the installation of temporary erosion controls will be similar to that described for the wet trench method above. After the stream banks have been stabilized, the dams will be removed from the stream bed allowing water to resume its flow in the channel. The flume pipe(s) and dams will then be removed.

2.6.4 Directional Drill Method

Installation

Directionally drilling the pipe underneath a stream will involve placing a drill unit on one side of the stream (see Figure 2.4). A small-diameter pilot hole will be drilled under the stream along a prescribed profile. After the pilot hole has been completed, barrel reams will be used to enlarge the pilot hole to accommodate the desired pipeline diameter. Drilling mud (bentonite clay) will be necessary to remove cuttings and maintain the integrity of the hole. Water from an approved source (typically the river to be crossed) will be used to prepare the slurry of drilling mud, and will be appropriated according to applicable permits. The pipe section will be pulled through the hole by the drilling rig and welded to the adjoining sections of pipe on each side of the river.

Temporary Erosion Control

Directional drilling normally does not result in the disturbance of the stream banks or riparian vegetation, which reduces the potential for erosion and sedimentation at the stream crossing. Consequently, temporary erosion control measures that are installed at open-cut crossings typically are not necessary for drilled crossings.

During drilling operations, drilling mud and slurry will be stored back from the river bank in an earthen berm sediment control structure, in tanks, or by other methods so that it does not flow into the stream, adjacent wetlands or off the workspace.

Enbridge has developed a directional drill contingency plan to address measures to be performed in the event of a release of drilling fluid onto the ground surface or waterbody. See the Enbridge *Drilling Mud Containment, Response, and Notification Plan* for additional details.

After the pipe is in place, excess drilling mud and slurry will be spread over an upland area approved by Enbridge and the landowner, or hauled off site to an approved disposal location.

2.7 DRAINAGE DITCHES AND INTERMITTENT STREAMS

Intermittent streams and agricultural ditches will be crossed using the wet trench method (see Section 2.6.1) if water is present and flowing. For dry intermittent streams and agricultural drainage ditches, standard upland construction procedures will be used, which involve stringing, welding, excavating the trench with backhoes, installing the pipe in the trench, and backfilling the trench with native material. As soon as practical, the banks of each crossing will be reshaped, mulched, and, if required, seeded with annual ryegrass to stabilize the crossing until permanent erosion control is implemented. No refueling or fuel storage will be allowed within 100 feet of a drainage ditch or intermittent stream. Where dry swales cross the right-of-way, silt fence or straw bales will be installed at the edge of the right-of-way to prevent the flow of sediment from the right-of-way.

3.0 WETLAND CROSSING GENERAL REQUIREMENTS

Typical pipeline construction in wetlands will consist of clearing, trenching, dewatering, installation, backfilling, final grading, cleanup, and revegetation. However, due to the unstable nature of some wetland soils, construction activities may differ somewhat from those described for upland areas. Construction activities will be minimized in wetlands and/or special construction techniques will be used to minimize the disturbance to plants and soils and to protect wetland hydrology.

Pre-construction planning is an essential part of wetland crossings. Wetland crossing requirements, including construction methods, timing, erosion control, and restoration, are described in this section and in the wetland crossing permits issued by state and federal agencies. If the contractor considers certain parts of these procedures to be technically impractical due to site-specific engineering constraints, the contractor may seek modifications. Prior to construction, the contractor must identify alternative provisions that would provide an equal or greater level of protection to wetland ecosystems. Enbridge will review the contractor's alternatives and consult with appropriate regulatory agencies. The contractor must receive approval from Enbridge prior to implementing the alternatives.

The procedures in this section apply to all jurisdictional wetlands that will be affected by the project. These procedures require that judgment be applied in the field and will be implemented under the supervision of the Environmental Inspector. The intent of these procedures is to minimize construction-related disturbance and sedimentation of wetlands and to restore wetlands as nearly as possible to pre-existing conditions.

3.1 WETLAND ACCESS

Unless otherwise approved by Enbridge, only the construction right-of-way and existing public roads can be used to access wetland areas.

3.2 SPILL PREVENTION

3.2.1 Storage of Fuels and Other Materials

No storage of hazardous materials, chemicals, fuels, and lubricating oils, and no concrete coating activities will be permitted in, or within 100 feet of, any wetland. All vehicles will be parked overnight 100 feet or more from delineated wetlands.

3.2.2 Refueling and Fuel Handling

Attempts will be made to refuel all construction equipment in an upland area at least 100 feet from a wetland boundary. Where conditions require that construction equipment (e.g., pontoon-mounted backhoes, trench dewatering pumps) be refueled in a wetland or within 100 feet of any wetland boundary, these activities will be in accordance with Enbridge's Spill Plan, and in consultation with the Environmental Inspector.

3.3 CLEARING

Clearing the construction right-of-way in wetlands will be similar to clearing in uplands. For construction to proceed, obstructions (e.g., trees, brush, and logs) need to be removed. Typically, low ground pressure equipment will be used, limiting disturbance to the wetland. When clearing in wetlands, the following restrictions apply:

- The construction right-of-way width will typically be limited to 100 feet or less.

- Staging areas, additional spoil storage areas, and other additional work areas will be located in upland areas at least 50 feet away from wetland boundaries (see Figures 3.1 and 3.1-1) where topographic conditions permit. If topographic conditions do not permit a 50-foot setback, then these areas will be located as far away from the wetland as is practicable. Vegetation will not be cleared between these areas and the wetland in any event. This requirement will not apply where a wetland occurs within the extra workspace for a stream crossing.

- The size of the additional workspace areas will be limited to the minimum needed to construct the wetland crossing.

- Vegetation and trees within wetlands will be cut off at ground level, leaving existing root systems intact; clearing debris will generally be removed from the wetland for disposal. Chips, hydro-axe debris, or similar can be left in the wetland if spread evenly in the right-of-way, in a manner which will allow for normal revegetation.

3.4 GRADING

Grading activities will be confined to the area of the trench. Grading outside the trench is only permitted where required to ensure safety and restore contours after backfilling the trench.

Sedimentation control practices (e.g., silt fence) will be installed and maintained in proper working order to prevent the flow of sediment into wetlands from spoil piles or sloped approaches that are adjacent to the wetlands.

When the depth of sediment reaches one-third of the height of a sediment barrier, the barrier will be replaced and/or the sediment removed. Non-functional sediment-control measures will be repaired, replaced, or supplemented with functional features as soon as possible but in all cases within 24 hours of discovery.

3.5 RIGHT-OF-WAY STABILIZATION

Tree stumps, brush riprap, imported soil, and rock fill will not be brought in to stabilize the right-of-way in wetlands. Where a wetland cannot support construction equipment, and low-ground-weight equipment is not used, construction activities will be accomplished from timber construction mats (see Figures 3.1 and 3.1-1). The contractor is responsible for having a sufficient number of construction mats to perform the work. Timber riprap (also known as corduroy road) cannot be used without prior written approval from the company. Subsoil from the pipeline trench within the immediate wetland may be placed on top of equipment mats for additional stabilization. Timber mats are the only materials that can be brought into a wetland and placed on the working side. Timber mats may be placed over the ditch line to facilitate trench excavation. All timber mats will be removed during cleanup of wetlands.

3.6 TRENCHING

Excavation of the pipeline trench in wetlands typically will be accomplished using backhoe excavators. The duration of open trench will be minimized to the extent possible, but typically not longer than 24 hours.

3.6.1 Topsoil Segregation

Where feasible (normally in wetland areas without standing water or saturated soils), up to 12 inches of topsoil will be stripped from the trench line and stockpiled separate from trench spoil (see Figures 3.1 and 3.1-1).

3.6.2 Trench Breakers

Where the pipeline trench has the potential to partially drain a wetland, trench breakers will be installed as necessary to maintain the original wetland hydrology.

3.7 PIPELINE INSTALLATION

The following procedures are intended to minimize siltation and disturbance to wetlands during installation.

3.7.1 Construction Matting

If the wetland right-of-way is stable (dry work area or construction mats), the pipe may be strung, welded, and lowered into the trench as in upland areas. Supplemental equipment supports, such as timber mats, will be used in wetlands to provide temporary portable support for heavy construction equipment to reduce ground pressure and minimize soil compaction and/or soil mixing.

3.7.2 Push/Pull Method

Large wetlands with standing water and saturated soils cannot be crossed with typical crossing methods. In these areas, the pipeline will be assembled in an upland area and positioned in the trench using the "push-pull" and/or "float" techniques.

Usually this fabrication requires use of extra temporary workspace adjacent to the right-of-way. The trench will be dug by a backhoe supported on timber mats. The prefabricated section of pipeline will then be pushed-pulled into position or floated across the wetland. When the pipeline is in position, floats, if used, will be removed and the pipeline will sink into position. The trench will then be backfilled and the original contours will be restored by a backhoe working from construction mats.

3.7.3 Sediment Controls

Sediment control practices will be installed as described in Section 1.5.8, according to the specifications presented on Figures 1.7 and 1.8.

3.7.4 Concrete Coating

Mixing concrete and washing equipment used for mixing, pouring, casting, or coating will not be conducted within 100 feet of any wetland. Concrete coating on the pipe will be cured for a minimum of three days prior to installation in a wetland to prevent potential toxic effects on wetland and aquatic biota.

3.8 BACKFILLING

During backfilling of wetland areas, subsoil material removed from the trench during construction will be replaced so that no crown remains. Any excess backfill material will be removed to an upland area approved by Enbridge. Segregated topsoil will not be used as padding and will be returned to its original horizon over the backfilled trench.

3.9 ROUGH GRADING, CLEANUP, AND TEMPORARY RESTORATION

Cleanup and rough grading activities may take place simultaneously. Cleanup typically will involve removing construction debris and replacing fences removed during construction. Rough grading will include restoring original contours and installing or repairing temporary erosion control measures. Temporary slope breakers will be installed near the boundary between the wetland and adjacent sloped approaches, to prevent sediment flow into the wetland.

3.9.1 Timing

Every effort will be made to begin cleanup and rough grading (including installation of temporary erosion control measures) as soon as practical after the trench is backfilled, weather permitting.

3.9.2 Temporary Revegetation

Unsaturated wetlands will be revegetated with annual rye unless standing water is prevalent or unless permanent planting or seeding with native wetland vegetation is required. No fertilizer, lime, or mulch will be applied in wetlands.

4.0 HIGHWAY, ROAD AND RAIL CROSSINGS

4.1 ADDITIONAL WORKSPACE

Additional workspaces for bored road and railroad crossings and open-cut road crossings will be determined on a site-specific basis. These workspaces will be adjacent to the road or railroad and limited to the size needed to contain spoil from the crossing.

4.2 MAINTENANCE

Roadway crossings will be maintained in a condition that will prevent tracking of mud onto the roadway. If mud is tracked onto a roadway, it will be shoveled or swept off the road and placed within a sediment barrier as soon as possible, but in no circumstances more than 24 hours after discovery.

In the case of mud incorporation into the aggregate road surface, the fouled surface aggregate will be removed or covered with an equal layer of new aggregate (not less than six inches compacted depth). The new aggregate will be consistent with the existing road surface and must be approved by the landowner.

4.3 SEDIMENT BARRIERS

Temporary sediment barriers (e.g., silt fence and/or double-staked straw bales) will be installed on sloped approaches to road crossings where vegetation has been disturbed (see Figures 4.1 and 4.1-1).

5.0 CONSTRUCTION DEWATERING

5.1 TRENCH DEWATERING

Before the pipe is lowered into the trench, dewatering may be necessary to visually inspect the trench bottom for the presence of rocks. Trench dewatering may also occur where tie-in welds are necessary, at road-boring sites adjacent to wetlands or waterbodies where groundwater has seeped into the trench, locations where set-on weights are placed over the pipe, and in other areas where increased visibility or physical access to the trench is needed. Dewatering pumps and equipment placement are discussed in Figures 2.7 and 2.8. Dewatering will be performed in accordance with applicable appropriation and discharge permits, but at a minimum, will comply with the following procedures:

- The trench will be dewatered into a well-vegetated upland area with an appropriate energy-dissipation device (see Figure 2.7). Whenever possible, the slope at the point of discharge will be away from any streams or wetlands.
- If the flow of a discharge cannot be kept out of streams, wetlands, drainage ditches, etc, the discharge shall be filtered by one of the methods described below. Dewatering discharge will be directed into a sediment filter bag or a straw bale/silt fence dewatering structure which discharges into a vegetated area to prevent heavily silt-laden water from flowing into wetlands and waterbodies (see Figures 2.7 and 2.8).
- Only non-woven, felt fabric filter bags will be used for dewatering.
- Filter bags and dewatering structures must be maintained in a functional condition throughout dewatering activity (e.g., clogged or ripped bags must be replaced) and will be attended at all times during active pumping. Accumulated sediment from the filter bags shall be spread in an approved upland location.
- The contractor will assist Enbridge in complying with applicable permit requirements, including tracking volumes of water pumped, obtaining water samples (if needed) for testing, and taking necessary measures to meet effluent limitations.

5.1.1 Flow Measurement

At no time will the discharge rate exceed the applicable discharge rates specified in state-issued or other discharge permits. Discharge rate must be monitored and adjusted as necessary to prevent failure of the filtration structure.

The discharge rate and total volume of water discharged will be determined with a flow meter (or equivalent), or as required by the National Pollutant Discharge Elimination System (NPDES) permit. The total volume of water discharged will not exceed the volume specified in the NPDES permit.

5.1.2 Erosion Control

Dewatering of the trench will be conducted in a manner which will prevent soil erosion. Discharge rates will be monitored and regulated to prevent erosion. Energy-dissipation devices (i.e., filter bags or straw bale structures) will be used to prevent sediment discharge into a wetland or waterbody.

5.1.3 Regulatory Notification and Reporting

Enbridge will notify appropriate state agencies prior to each discharge in accordance with its NPDES permit.

Reports regarding the volume and quality of the water withdrawn will be submitted by Enbridge, as required by the state NPDES permit. The contractor will assist Enbridge in collecting appropriate data and any water samples required or in determining volumes of water appropriated.

5.1.4 Water Sampling

Water discharged from trench dewatering locations may need to be sampled as required by the state-issued NPDES discharge permit. The construction contractor will assist Enbridge in obtaining these samples and will be responsible for complying with the permit limitations.

5.2 HYDROSTATIC TEST DISCHARGES

Hydrostatic testing involves filling the new pipeline segments with water acquired in accordance with applicable permits (see section 6.0), raising the internal pressure level, and holding that pressure for a specific period of time per federal Department of Transportation specifications. Hydrostatic testing will be done to verify that there are no flaws in the pipe or welds. Pre-built sections may be hydrostatically tested prior to installation at significant streams and wetland crossings. Water used for hydrostatic testing typically will be taken from, and returned to, local streams and rivers. After the hydrostatic test is completed, the line will be depressurized and the water expelled. During withdrawal and discharge, the water will be sampled as required by permits to determine if contaminants are present.

If site conditions or engineering constraints make adhering to these hydrostatic testing procedures and documentation impractical, Enbridge will propose alternative provisions to the regulatory agency issuing the NPDES permit. Any such alternative will provide an equal or greater level of protection to the environment than the condition from which Enbridge or its Contractor seeks relief.

5.2.1 Refueling

The operation and refueling of hydrostatic test equipment will be in accordance with the conditions outlined in Enbridge's Spill Plan.

5.2.2 Permit Requirements

Hydrostatic testing will be conducted in accordance with applicable appropriation and discharge permits obtained by Enbridge.

5.2.3 Siting of Test Manifolds

Where practicable, hydrostatic test manifolds will be located outside of wetlands and riparian areas.

5.2.4 Water Sampling

Water discharged from hydrostatic tests will be sampled as required by state-issued appropriation or discharge permits. The contractor will assist Enbridge in obtaining these samples and will be responsible for complying with the permit limitations.

6.0 WATER APPROPRIATION

6.1 GENERAL

After the pipeline has been installed and the trench backfilled, the entire pipeline system will be hydrostatically tested to ensure its integrity. Water used to conduct hydrostatic testing may need to be appropriated from nearby waterbodies. The following outlines the procedures that will be performed for water appropriation. Intake hoses will be suspended off of the stream or lake bottom and will be screened to prevent entrainment of fish. During withdrawal, adequate flow rates will be maintained to protect aquatic life and allow for downstream uses.

6.2 WATER SOURCES

Water will only be withdrawn from sources approved by Enbridge and in accordance with applicable permits. No additives to the water are permitted unless written approval is received from Enbridge and applicable permits authorize such additives.

If appropriation is scheduled to occur during possible periods of low flow, including frozen conditions, a backup source will be identified.

6.3 FLOW MEASUREMENT

At no time will the withdrawal rate for the water source exceed the rate specified in the applicable permits.

The withdrawal rate and total volume of water appropriated for hydrostatic testing will be determined with a flow meter (or equivalent) as required by the state-issued permit.

6.4 WATER SAMPLING

Water withdrawn for hydrostatic testing may be sampled by Enbridge during appropriation. The contractor will assist Enbridge in obtaining these samples.

6.5 REGULATORY NOTIFICATION AND REPORTING

Enbridge will notify appropriate state agencies of the time of appropriations if required by the state appropriations permits. Reports regarding the volume and quality of the water withdrawn will be submitted by Enbridge if required by the state permit.

7.0 RESTORATION

Permanent soil erosion and sediment control will begin as soon as soil conditions permit seed bed preparation and seed germination. Agricultural lands will be restored but will not be reseeded unless requested by the landowner.

7.1 ROUGH GRADING AND CLEANUP

Cleanup and rough grading activities may take place simultaneously. Cleanup involves removing construction debris (including litter generated by construction crews and excess rock) and replacing fences removed during construction. Rough grading includes restoring the original contours, and installing or repairing temporary erosion control measures.

7.1.1 Timing

Every effort will be made to begin cleanup and rough grading (including installation of temporary erosion control measures) within 24 hours after backfilling.

7.2 FINAL CLEANUP AND FINAL GRADING

Permanent erosion and sediment control will begin with general cleanup of the construction area. Extraneous material that would impede seed bed preparation will be removed from the right-of-way. Final grading will restore the disturbed areas as near as practicable to the contours of the land that existed before construction.

If not previously removed during rough grading, all construction-related debris and material that are not an integral part of the pipeline (including litter generated by pipeline crews) will be removed from the landowner's property.

7.3 PERMANENT EROSION CONTROL MEASURES

After final grading, slopes in areas other than cropland will be stabilized with erosion control structures (see Figure 7.1). Erosion control treatments of specific physical land features are described below.

7.3.1 Slopes

Permanent berms (diversion dikes or slope breakers) will be installed on all slopes, according to the following maximum spacing requirements:

Slope (%)	Approximate Spacing (ft)
<5	125
5-10	100
10-20	75
20-30	50
>35	25

Permanent berms will be constructed according to the following specifications:

- Permanent berms will be installed with a two to eight percent outslope.
- Permanent berms will be constructed of compacted earth.

- The outfall of berms will be directed toward appropriate energy-dissipating devices, and off the construction right-of-way if possible

- Permanent berms will be inspected and repaired as necessary to maintain function and prevent erosion. Figures 1.5 and 1.6 illustrate berm specifications.

- Erosion control blankets (wood excelsior, jute, or equivalent) will be placed on slopes over 30 percent (see Figure 7.2).

7.3.2 Stream Banks

Stream banks will be permanently restored with erosion control fabric and permanent seeding or with rock riprap as specified by Enbridge and/or state and federal permits.

Berms or other sediment filter devices will be installed at the base of sloped approaches to streams greater than five percent, and the outlet of the berm will be directed away from the stream into a well vegetated area (see Figures 1.5 and 1.6).

Rock Riprap Bank Restoration

When backfilling is complete, a backhoe or other suitable equipment will be used to shape the stream banks to their original contours, or to a 3:1 slope, whichever is less steep. Geotextile fabric and rock riprap will be placed immediately thereafter according to site and permit conditions (see Figure 7.3). Soil upslope from the riprap will be prepared for seeding.

Vegetative Bank Restoration

Stream banks that are not lined with rock riprap will be shaped with a backhoe or other appropriate equipment after backfilling is complete, then seeded with the specified seed mix and, finally, covered with an erosion control blanket.

Bridge Removal

Equipment bridges will be removed before final cleanup or, if necessary, after final cleanup and initial permanent seeding. Upon bridge removal, any final restoration and seeding will be completed. Bridges must be removed prior to freezing conditions. Bridges installed for winter construction will be removed before spring break up.

7.3.3 Swales

Swales across the right-of-way will be restored during cleanup to original contours as near as practicable. Swales will be seeded and mulched with straw for the width of the right-of-way.

7.3.4 Drainage Ditches and Intermittent Streams

Drainage ditches and intermittent streams will be permanently restored and stabilized with erosion control blanket, permanent seeding, or other appropriate measures.

7.4 SOIL COMPACTION TREATMENT

Cultivated fields and any other severely compacted or rutted areas will be tilled with a deep tillage device or chisel plowed to loosen compacted soils. If subsequent construction and cleanup activities result in further compaction, additional measures will be undertaken to reduce soil compaction.

7.5 STONE REMOVAL

A diligent effort will be made to remove excess stones larger than four inches in diameter from the upper 12 inches of soil. Stone removal efforts will cease when the size and density of stones on the right-of-way are similar to undisturbed areas adjacent to the right-of-way.

7.6 OFF-ROAD VEHICLE BARRIERS AND FENCES

Off-road vehicle control measures will be installed as requested by landowners or as directed by land management agencies. All fences and gates removed or damaged will be repaired or replaced.

7.7 REVEGETATION

General guidance regarding revegetation efforts is provided in this section.

Permanent revegetation will involve preparing the seedbed and seeding disturbed, non-agricultural areas. The right-of-way will be seeded as soon as possible after backfilling, weather and soil conditions permitting. With the exception of wetland areas, fertilizer and pH modifying agents (e.g., lime) will be applied as specified by Enbridge, in consultation with appropriate state and federal agencies and landowners.

The following steps will be taken to establish permanent vegetation in those portions of the site where the landowner does not plan to plant a crop during the next growing season.

- Seed will be purchased in accordance with Pure Live Seed (PLS) specifications for the seed mix.
- Seed will be used within 12 months of testing.

Legume seed will be treated with an inoculant specific to the species. When hydroseeding, four times the manufacturer's recommended rate of inoculant will be used. Inoculated seed will not be held in a slurry with fertilizer for more than one hour.

A seed drill equipped with a cultipacker is preferred for applying seed, but broadcast or hydroseeding methods may be used at double the recommended seeding rate. When broadcast seeding, the seedbed will be firmed with a cultipacker or roller after seeding.

Specific seed mixes, application rates, and seeding dates will be specified by Enbridge, and will take into account recommendations of appropriate state and federal agencies and landowner requests as appropriate.

Mulch will not be applied to cropland unless specifically requested by the landowner. In other areas, mulch will be applied according to the following specifications:

- After seeding, slopes greater than five percent or dry, sandy areas will be mulched with two tons per acre of straw or hay or as specified by Enbridge.
- All areas of dormant seeding must be mulched with two tons per acre of hay or straw or as specified by Enbridge.

Mulch will be anchored after placement to minimize loss by wind and water. If soil conditions allow, a mulch anchoring tool or farm disc set in the straight position will be used to crimp the mulch to a depth of two to three inches. Liquid tackifiers may be used with advance written approval from Enbridge.

Where conditions allow (e.g., unsaturated and unponded areas), wetlands will be revegetated after final grading with annual ryegrass and then allowed to revegetate naturally. The natural revegetation process will be encouraged by the seeds and rhizomes in the topsoil spread back over the right-of-way after pipe installation.

Permanent revegetation at stream crossings will be as specified by Enbridge, and will take into account recommendations of appropriate state and federal agencies and landowner requests.

7.8 ROAD REPAIR

The contractor will repair private roads and lanes damaged when moving equipment or obtaining access to the right-of-way.

7.9 REPAIR OF DAMAGED CONSERVATION PRACTICES

All soil conservation practices (such as terraces, grassed waterways, etc.) that are damaged by the pipeline construction will be restored to preconstruction conditions to the extent practicable.

7.10 LAND LEVELING FOLLOWING CONSTRUCTION

Following the completion of the installation of the pipeline, the right-of-way will be restored to its preconstruction elevation and contour as practical. Should uneven settling or documented surface drainage problems occur following the completion of pipeline construction, Enbridge will take appropriate steps to remedy the issue.

8.0 WINTER CONSTRUCTION

8.1 EROSION CONTROL

During frozen conditions, the following procedures will apply to construction in uplands, unless otherwise directed by Enbridge:

- Temporary slope breakers will not be installed unless snow melt and runoff are likely during construction.
- Installation of temporary sediment barriers (silt fence and staked straw bales) will be delayed until final grading and cleanup, unless snow melt and runoff are likely during construction.
- If final grading and/or cleanup is not completed until the following spring, temporary slope breakers and sediment barriers will be installed during rough grading and subject to the same inspection and repair requirements.
- Mulch will be applied and anchored to all slopes greater than eight percent. The mulch will be applied as soon as practical after the last grading operation of winter construction. Mulch can be applied to snow covered ground. Mulch will not be applied by hand, nor will the application rate exceed two tons per acre, as it may have to be removed the following spring during preparation of a seed bed.
- Steel reinforcing rods will be used to stake straw bales if frozen conditions make wooden stakes impractical.
- Topsoil will be segregated from the trench line only.

8.2 STREAM CROSSING CONSTRUCTION

During frozen conditions, the following procedures will apply to construction at stream crossings, unless otherwise directed by Enbridge:

- Erosion control measures at stream crossings during frozen conditions will be the same as for summer construction.
- All temporary construction bridges will be removed before spring breakup. They can be replaced after breakup if needed for access during final seeding.
- Except with prior written approval from Enbridge, additives will not be used to prevent drilling mud from freezing.

8.3 CONSTRUCTION IN WETLANDS

During frozen conditions, the following procedures will apply to construction in wetlands, unless otherwise directed by Enbridge:

- As soon as wetlands are sufficiently frozen to support light construction equipment, snow will be removed from the entire construction right-of-way. This will result in a greater depth of freezing than would normally occur. Progressively heavier equipment will then be driven over the working side to further encourage the depth of freezing.

- If sufficient frost depth is obtained, construction mats may not be needed to support construction equipment.

- Snow berms will be used at the edge of the right-of-way to contain spoil during construction. Silt fence or hay bales will be installed if snow berms are infeasible or ineffective.

- The original contours of the wetlands will be restored after backfilling. If a crown is left over the trench in wetlands to account for settling of frozen backfill, the contractor will be required to restore the original contours during the following spring or summer.

- If feasible (i.e., no snow cover) annual oats will be applied as a dormant seeding. If dormant seeding is not feasible, annual oats will be seeded during the next growing season in those wetlands that are sufficiently dry to support appropriate equipment.

8.4 RESTORATION

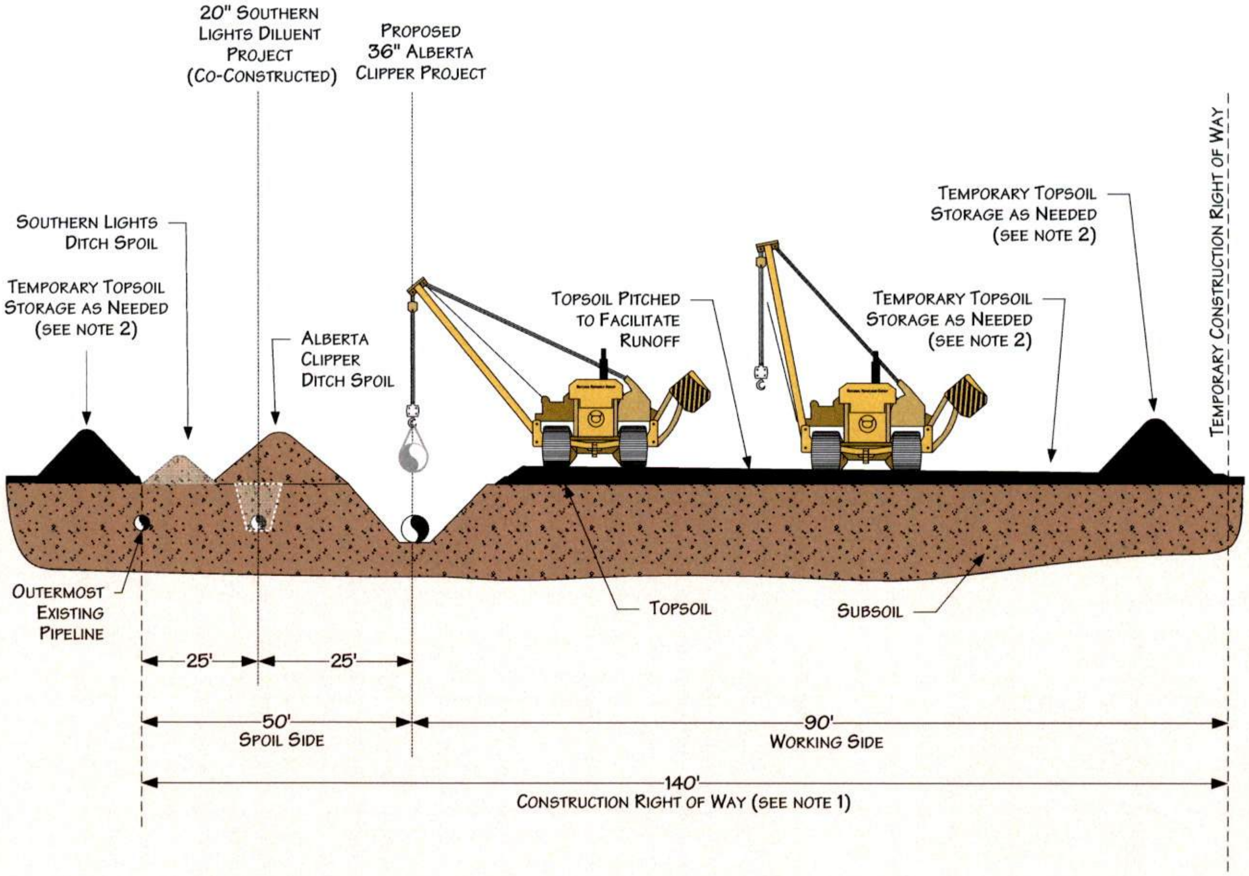
During frozen conditions, the following procedures will apply, unless otherwise directed by Enbridge:

- Permanent revegetation of the right-of-way after winter construction will be accomplished by dormant seeding or seeding during the next growing season.

- Temporary bridges will be removed before spring break up.

Environmental Mitigation Plan

Figures



PROFILE

Notes:

1. Construction Right of Way will typically be 140' wide. The spoil side will be approximately 50' wide and generally within the existing maintained right-of-way. The working side will be 90' wide.
2. This drawing reflects "Ditch Plus Spoil Side" topsoil stripping procedure. Stockpile topsoil separately from ditch spoil as shown or in other configurations approved by the company.
3. The offset from northernmost or southernmost existing pipeline, where applicable, will be 25' for most locations but may be increased or decreased depending on the site specific construction requirements.

ENBRIDGE

Figure 1.1
Environmental Mitigation Plan
Typical Construction Layout
(Clearbrook, MN to Superior, WI)

DATE: 7/9/2001	
REVISED: 5/9/2007	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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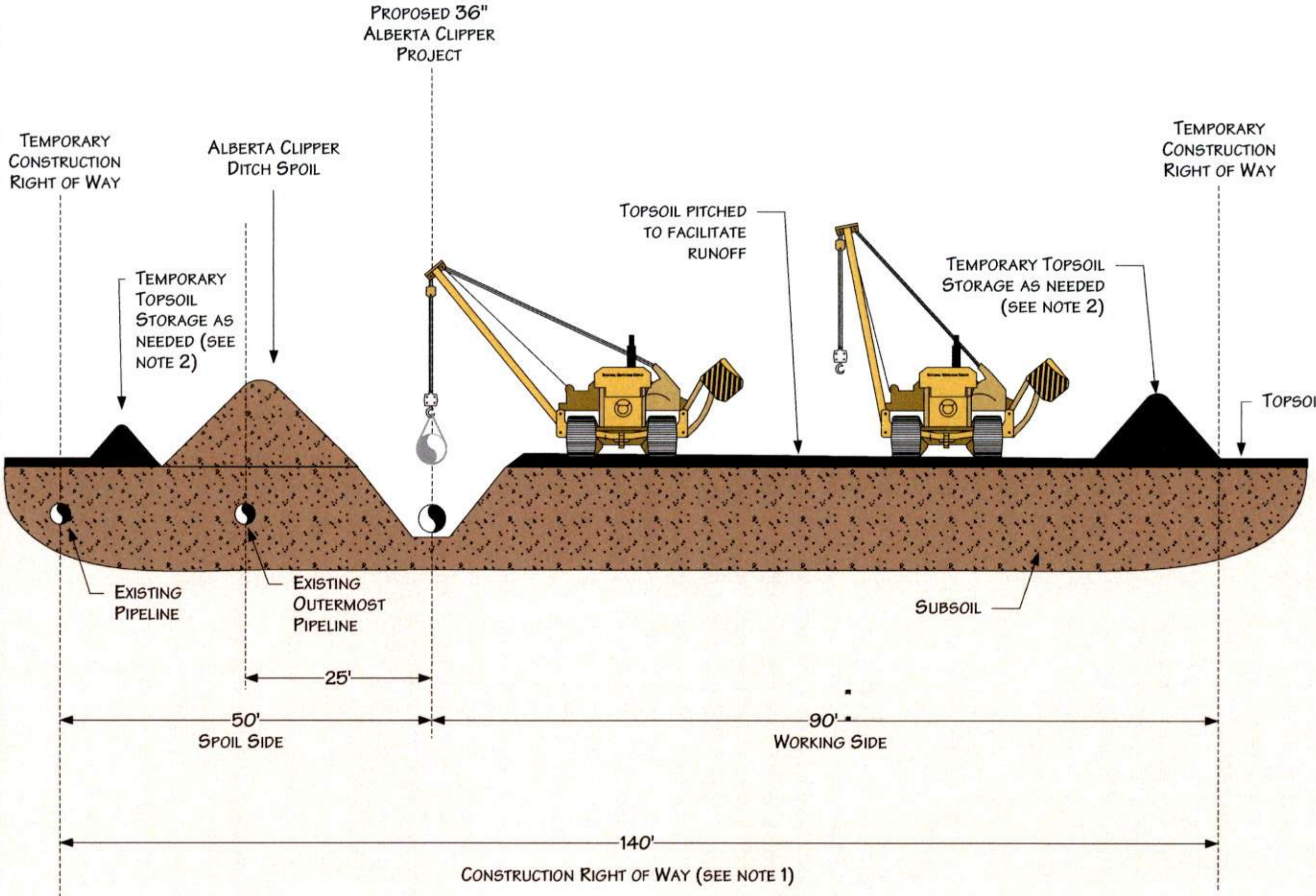

PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 140' WIDE. SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE.
2. THIS DRAWING REFLECTS "DITCH PLUS SPOIL" SIDE TOPSOIL STRIPPING PROCEDURE. STOCKPILE TOPSOIL SEPARATELY FROM DITCH SPOIL SHOWN OR IN OTHER CONFIGURATION APPROVED BY COMPANY.
3. THE OFFSET FROM OUTERMOST EXISTING PIPELINE WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

For environmental review purposes only.

ENBRIDGE

Figure 1.1-1
Environmental Mitigation Plan
Typical Construction Layout
(Neche, ND to Clearbrook, MN)

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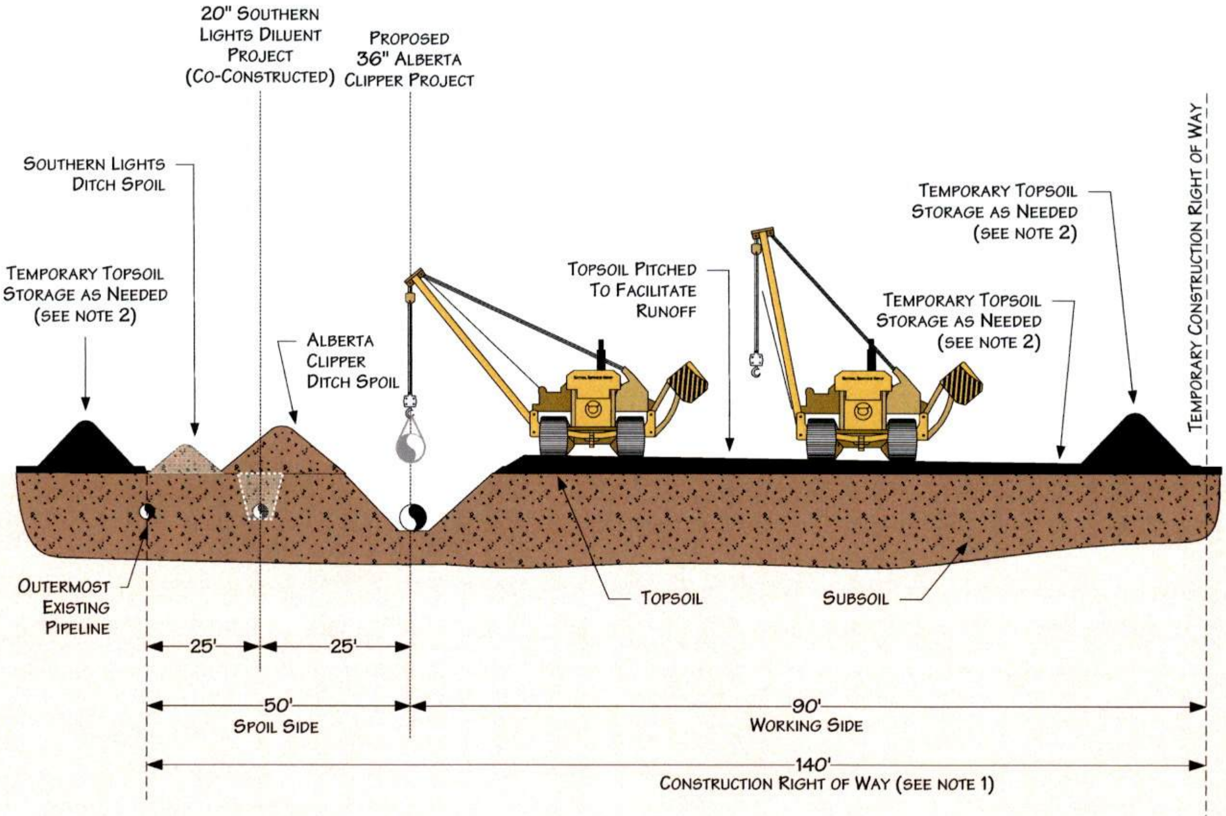

PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 140' WIDE. THE SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE AND GENERALLY WITHIN THE EXISTING MAINTAINED RIGHT-OF-WAY. THE WORKING SIDE WILL BE 90' WIDE.
2. THIS DRAWING REFLECTS "DITCH PLUS SPOIL SIDE" TOPSOIL STRIPPING PROCEDURE. STOCKPILE TOPSOIL SEPARATELY FROM DITCH SPOIL AS SHOWN OR IN OTHER CONFIGURATIONS APPROVED BY THE COMPANY.
3. THE OFFSET FROM NORTHERNMOST OR SOUTHERNMOST EXISTING PIPELINE, WHERE APPLICABLE, WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

ENBRIDGE™

Figure 1.2
Environmental Mitigation Plan
Typical Topsoil Segregation
Ditch Plus Spoil Side
(Clearbrook, MN to Superior, WI)

DATE:	7/9/2001
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SCALE:	NTS
DRAWN BY:	KMKENDALL
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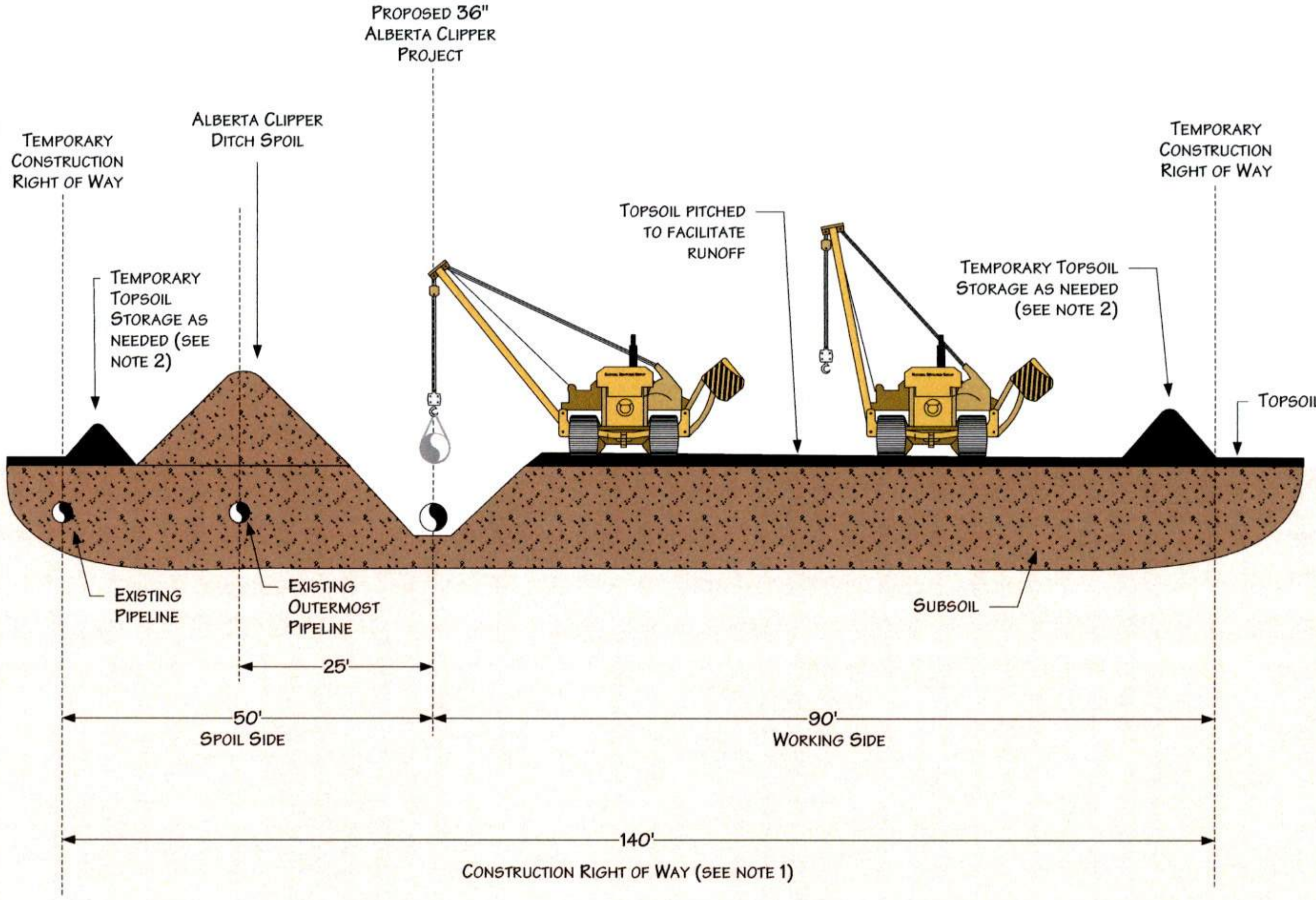

PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 140' WIDE. SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE.
2. THIS DRAWING REFLECTS "DITCH PLUS SPOIL" SIDE TOPSOIL STRIPPING PROCEDURE. STOCKPILE TOPSOIL SEPARATELY FROM DITCH SPOIL SHOWN OR IN OTHER CONFIGURATION APPROVED BY COMPANY.
3. THE OFFSET FROM OUTERMOST EXISTING PIPELINE WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

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Figure 1.2-1
Environmental Mitigation Plan
Typical Topsoil Segregation
Ditch Plus Spoil Side
(Neche, ND to Clearbrook, MN)

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SCALE: NTS	
DRAWN BY: KMKENDALL	
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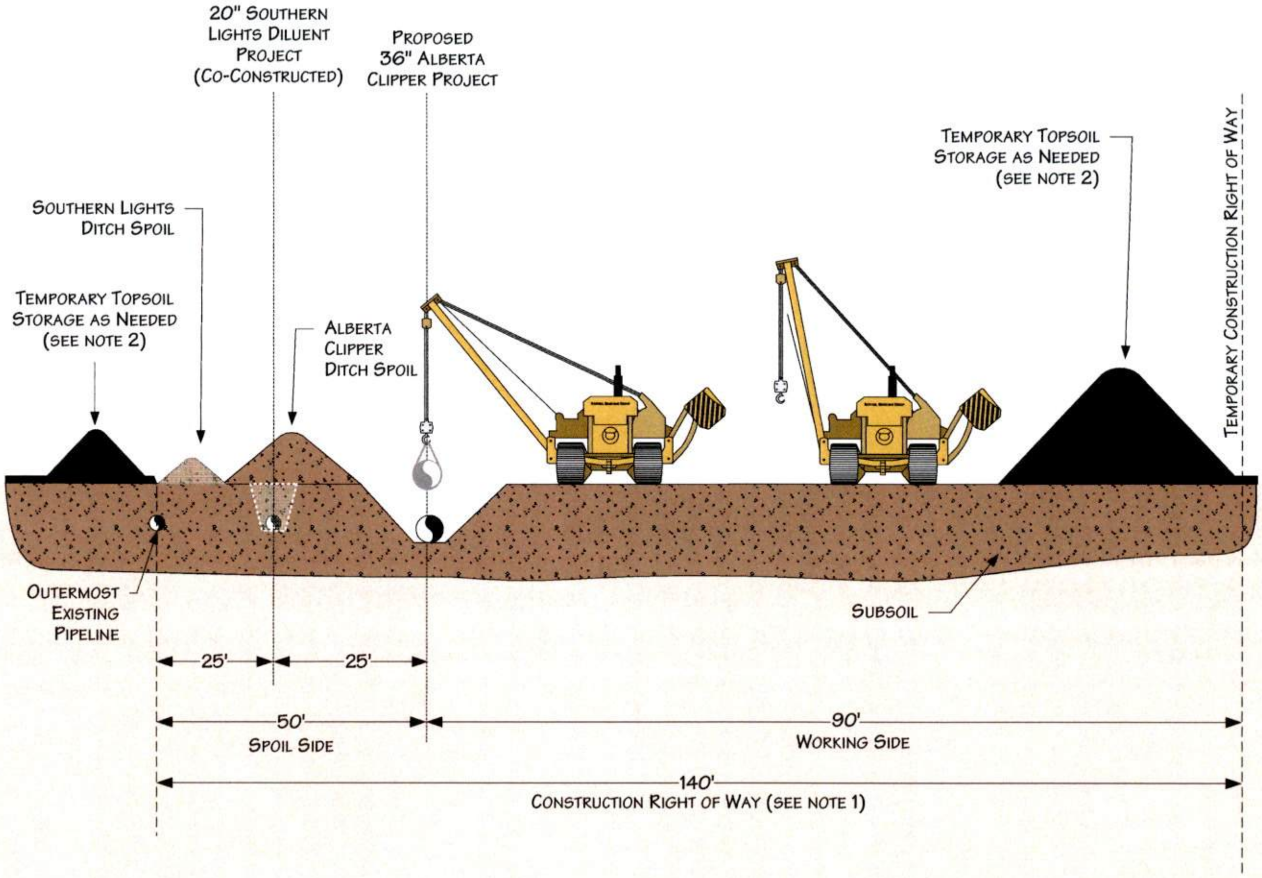

PROFILE

NOTES:

1. Construction Right of Way will typically be 140' wide. The spoil side will be approximately 50' wide and generally within the existing maintained right-of-way. The working side will be 90' wide.
2. This drawing reflects "Full Right-of-Way" topsoil stripping procedure. Stockpile topsoil separately from ditch spoil as shown or in other configurations approved by the company.
3. The offset from northernmost or southernmost existing pipeline, where applicable, will be 25' for most locations but may be increased or decreased depending on the site specific construction requirements.

ENBRIDGE

Figure 1.3
Environmental Mitigation Plan
Typical Topsoil Segregation
Full Right-of-Way
(Clearbrook, MN to Superior, WI)

DATE: 7/9/2001	
REVISED: 5/9/2007	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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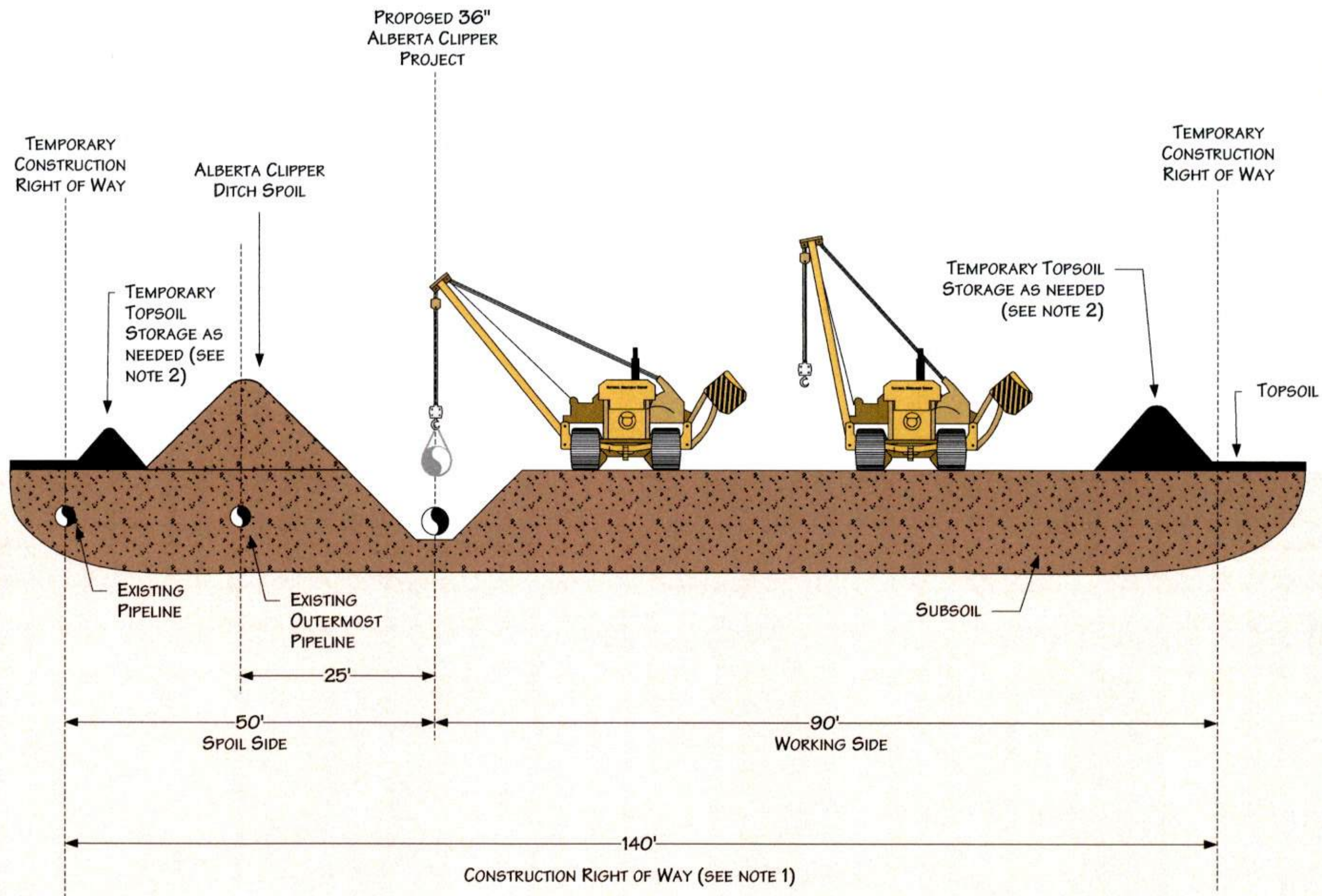

PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 140' WIDE. SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE.
2. THIS DRAWING REFLECTS "FULL RIGHT OF WAY" TOPSOIL STRIPPING PROCEDURE. STOCKPILE TOPSOIL SEPARATELY FROM DITCH SPOIL SHOWN OR IN OTHER CONFIGURATION APPROVED BY COMPANY.
3. THE OFFSET FROM OUTERMOST EXISTING PIPELINE WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

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Figure 1.3-1
Environmental Mitigation Plan
Typical Topsoil Segregation
Full Right-of-Way
(Neche, ND to Clearbrook, MN)

DATE: 7/9/2001
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SCALE: NTS
DRAWN BY: KMKENDALL
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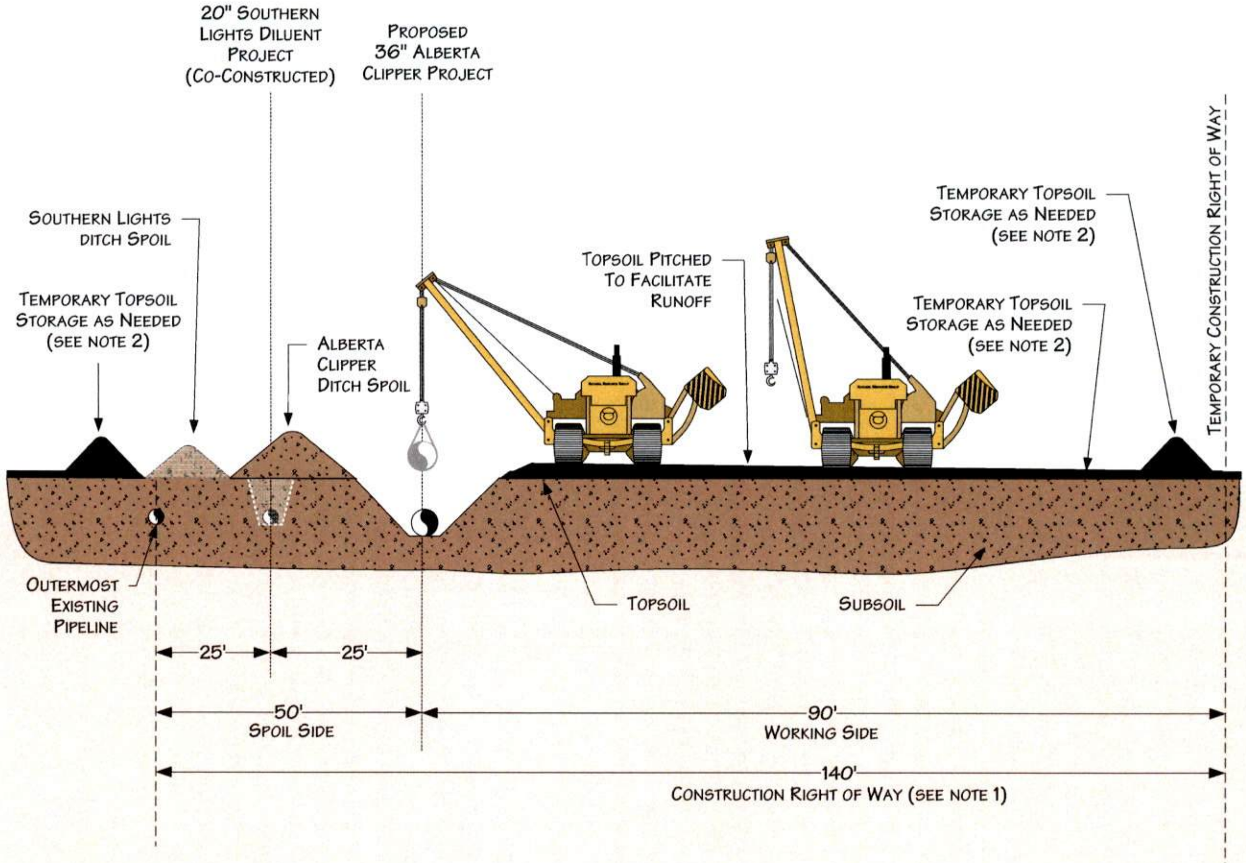

PROFILE

Notes:

1. Construction Right of Way will typically be 140' wide. The spoil side will be approximately 50' wide and generally within the existing maintained right-of-way. The working side will be 90' wide.
2. This drawing reflects "Trench Line Only" topsoil stripping procedure. Stockpile topsoil separately from ditch spoil as shown or in other configurations approved by the company.
3. The offset from northernmost or southernmost existing pipeline, where applicable, will be 25' for most locations but may be increased or decreased depending on the site specific construction requirements.

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Figure 1.4
Environmental Mitigation Plan
Typical Topsoil Segregation
Trench Line Only
(Clearbrook, MN to Superior, WI)

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SCALE: NTS	
DRAWN BY: KMKENDALL	
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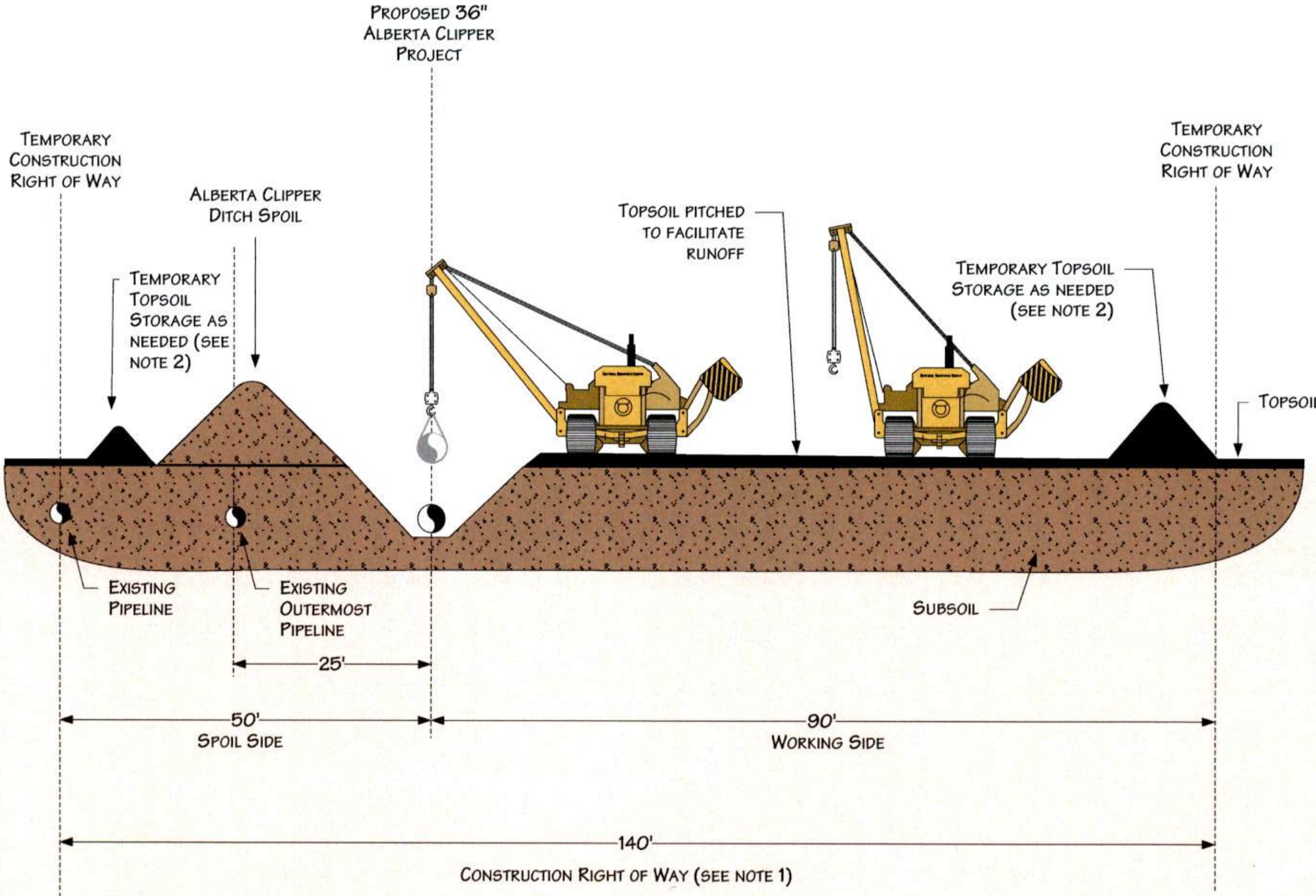

PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 140' WIDE. SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE.
2. THIS DRAWING REFLECTS "TRENCH LINE ONLY" TOPSOIL STRIPPING PROCEDURE. STOCKPILE TOPSOIL SEPARATELY FROM DITCH SPOIL SHOWN OR IN OTHER CONFIGURATION APPROVED BY COMPANY.
3. THE OFFSET FROM OUTERMOST EXISTING PIPELINE WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

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Figure 1.4-1
Environmental Mitigation Plan
Typical Topsoil Segregation
Trench Line Only
(Neche, ND to Clearbrook, MN)

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SCALE: NTS	
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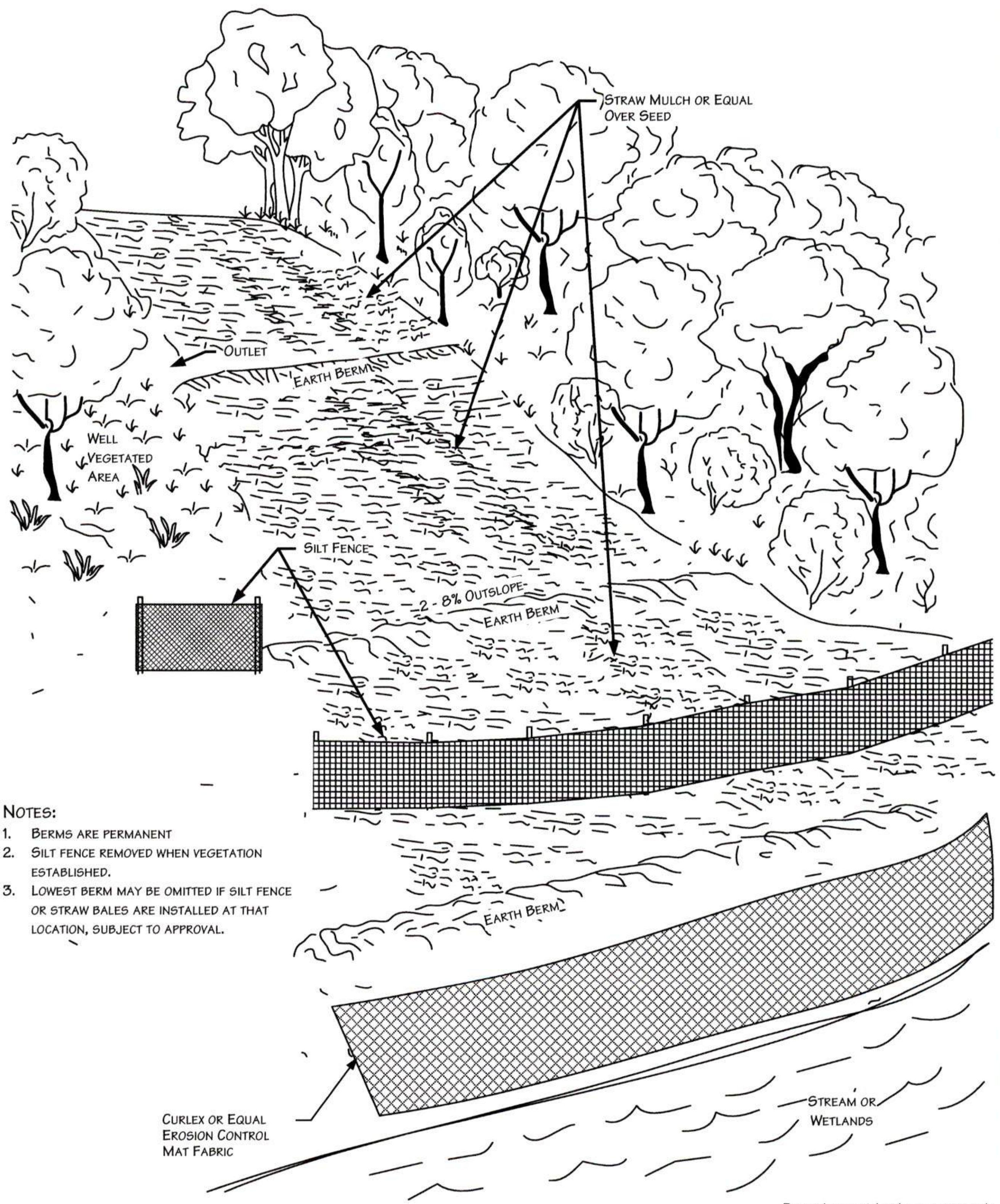

NOTES:

1. BERMS ARE PERMANENT
2. SILT FENCE REMOVED WHEN VEGETATION ESTABLISHED.
3. LOWEST BERM MAY BE OMITTED IF SILT FENCE OR STRAW BALES ARE INSTALLED AT THAT LOCATION, SUBJECT TO APPROVAL.

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Figure 1.5
Environmental Mitigation Plan
Typical Temporary or Permanent Berms
Perspective View

DATE: 11/14/2000	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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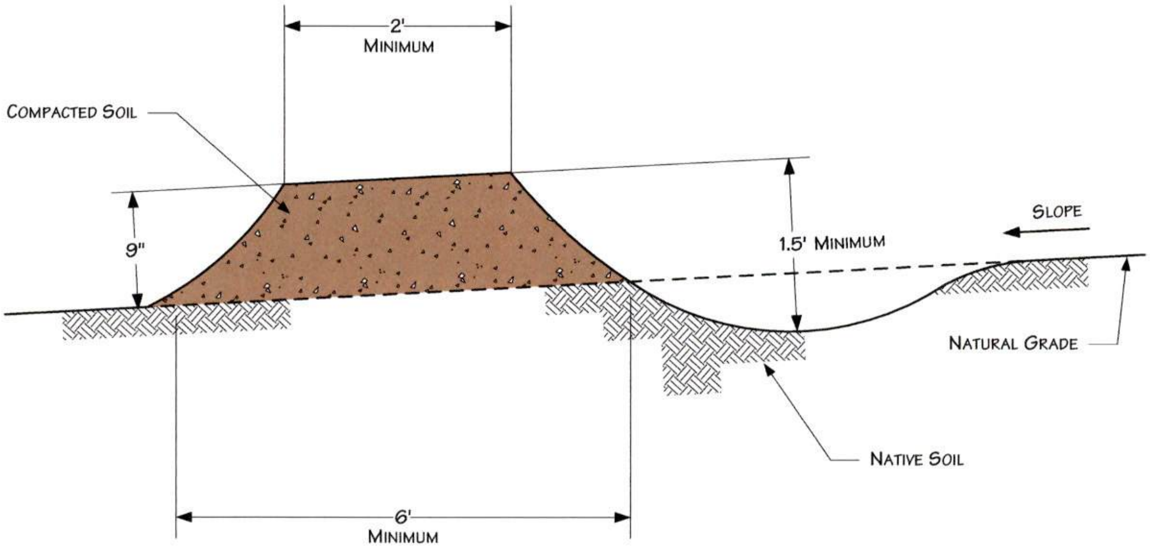

NOTES
1. BERMS SHALL BE CONSTRUCTED WITH 2 TO 8 PERCENT OUTSLOPE.
2. BERMS SHALL BE OUTLETED TO WELL VEGETATED STABLE AREAS, SILT FENCES, STRAW/HAY BALES OR ROCK APRONS.
3. BERMS SHALL BE SPACED AS DESCRIBED IN CONSTRUCTION SPECIFICATIONS.
4. ADDITIONAL INFORMATION INCLUDED ON OTHER DRAWINGS.

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Figure 1.6
Environmental Mitigation Plan
Typical Temporary or Permanent Berms
Elevation View

DATE: 5/25/2001	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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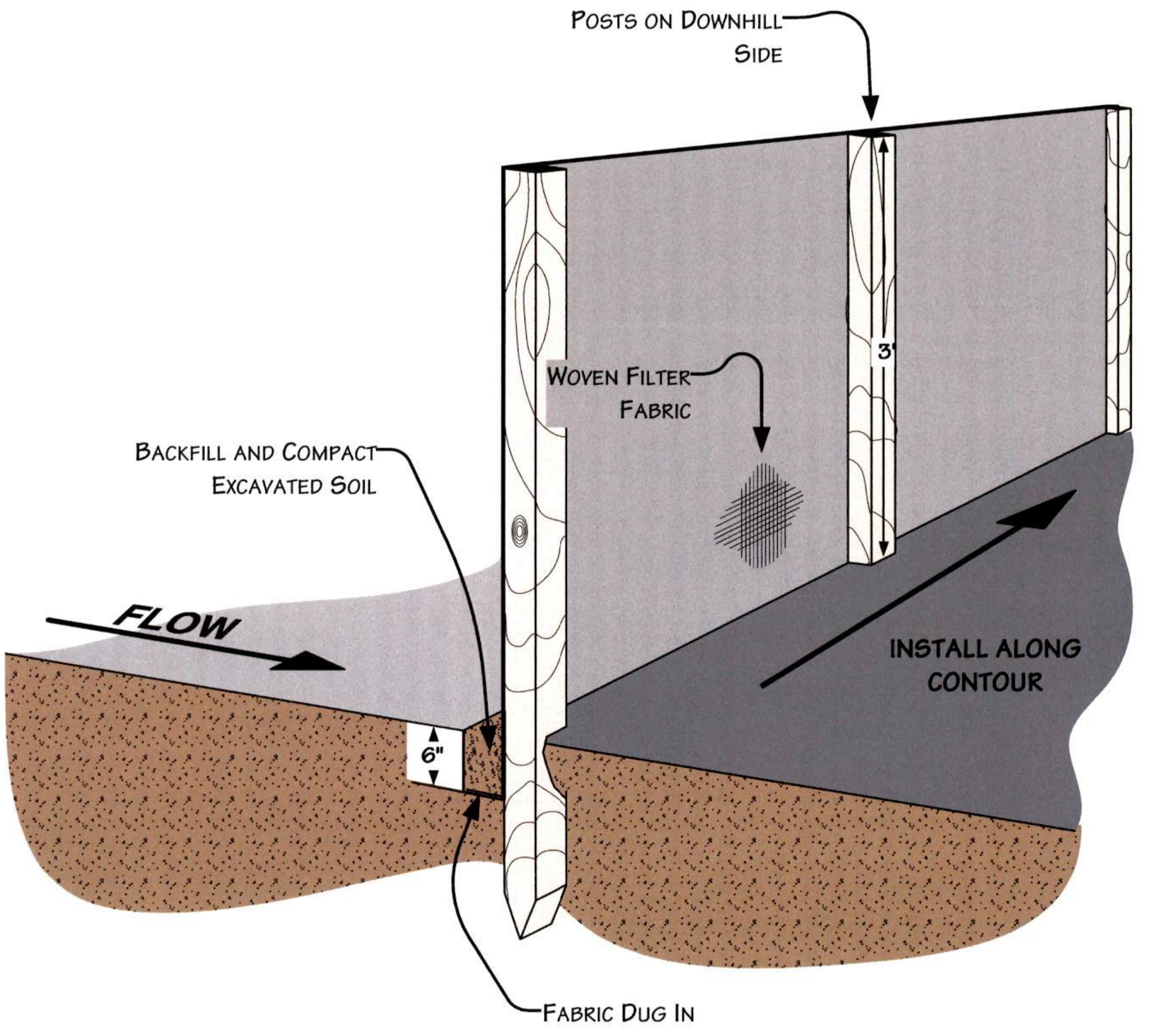

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Figure 1.7
Environmental Mitigation Plan
Typical Silt Fence Installation

DATE: 5/25/2001	
REVISED: 08/02/06	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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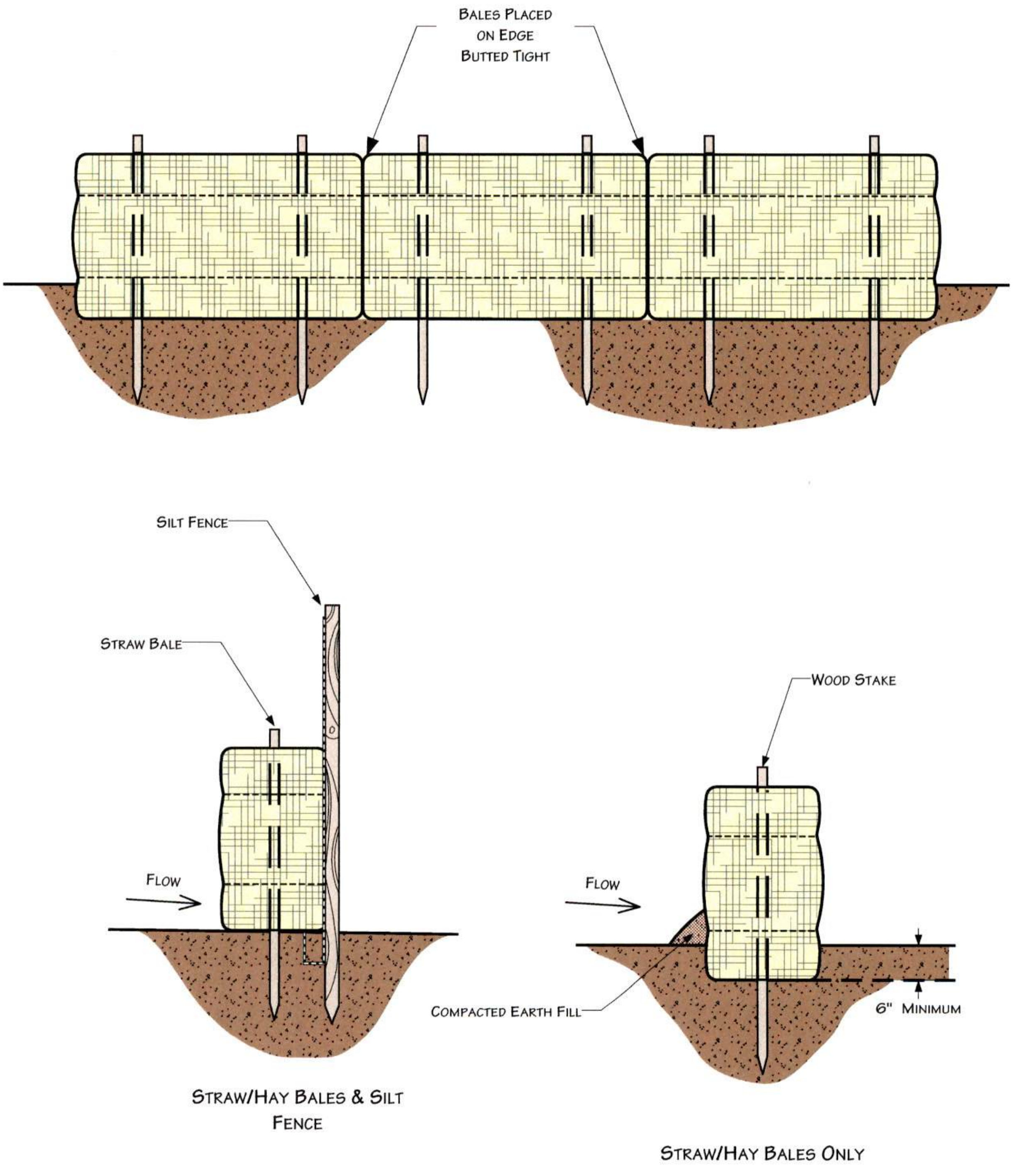

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Figure 1.8
Environmental Mitigation Plan
Typical Straw Bale Installation

DATE: 5/25/01	
REVISED: 3/14/07	
SCALE: Not to Scale	
DRAWN BY: KMKENDALL	
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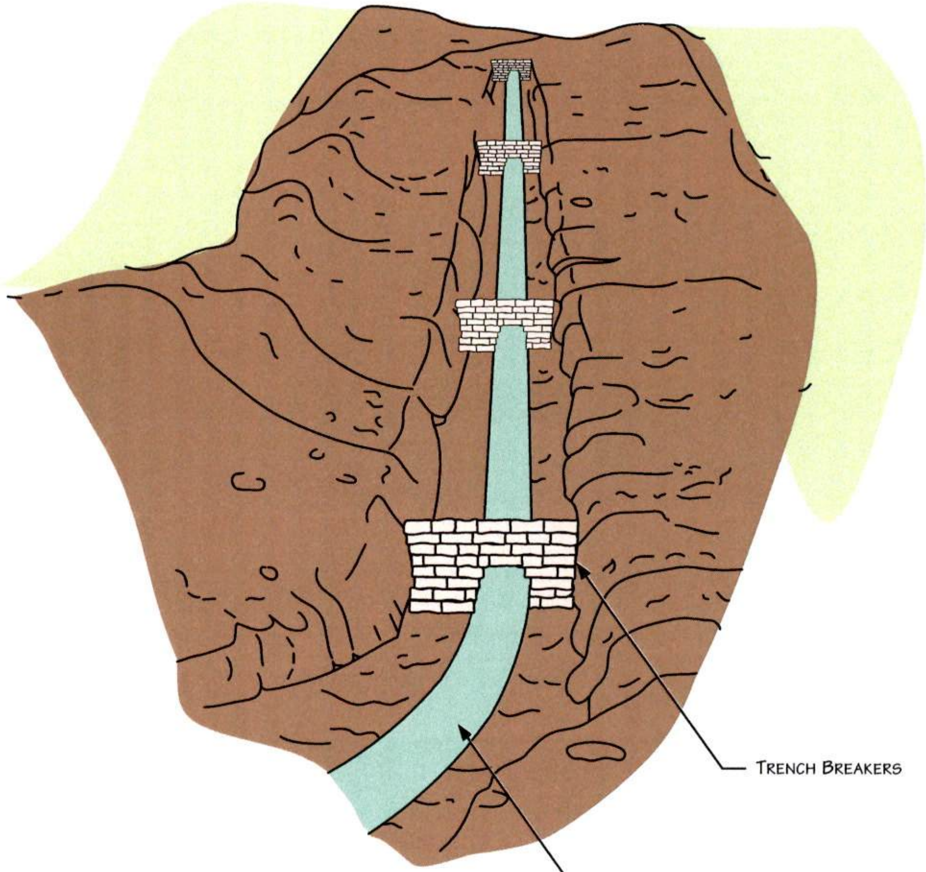
NATURAL RESOURCE GROUP, INC.



NOTES

1. BAGS WILL NOT BE FILLED WITH TOPSOIL.
2. ADDITIONAL INFORMATION INCLUDED ON OTHER DRAWINGS.

ENBRIDGE™

Figure 1.9
Environmental Mitigation Plan
Typical Trench Breakers - Perspective View

DATE: 5/25/2001	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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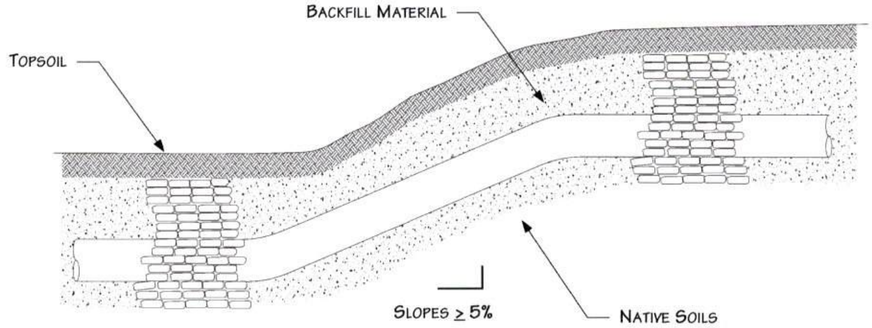
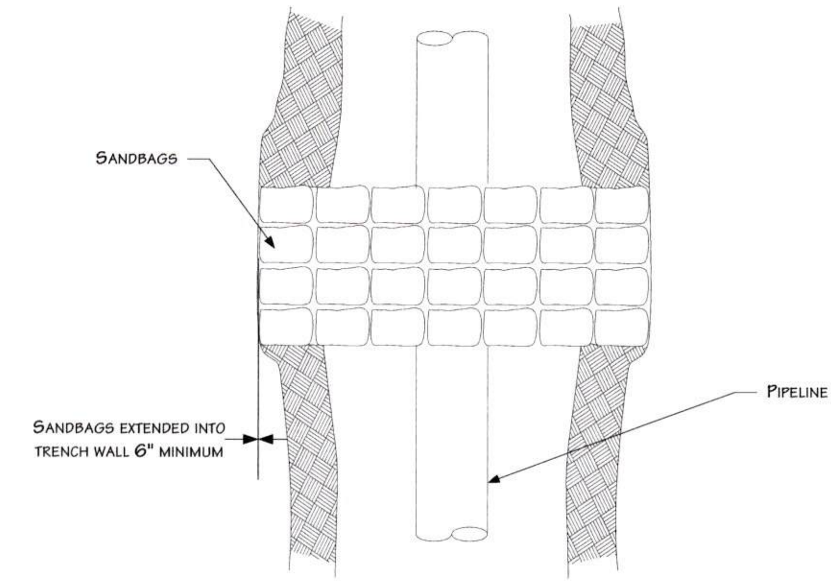
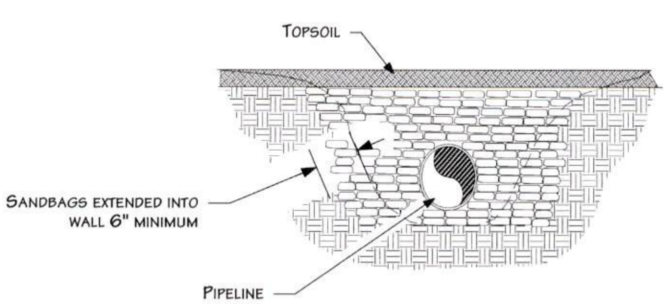


PROFILE VIEW
(NOT TO SCALE)



PLAN VIEW
(NOT TO SCALE)



FACE VIEW
(NOT TO SCALE)

NOTES

1. BAGS WILL NOT BE FILLED WITH TOPSOIL
2. ADDITIONAL INFORMATION INCLUDED ON OTHER DRAWINGS

For environmental review purposes only.

Figure 1.10
Environmental Mitigation Plan
Typical Trench Breakers – Plan & Profile View

DATE:	11/15/2000
REVISED:	5/19/05
SCALE:	NTS
DRAWN BY:	KMKENDALL
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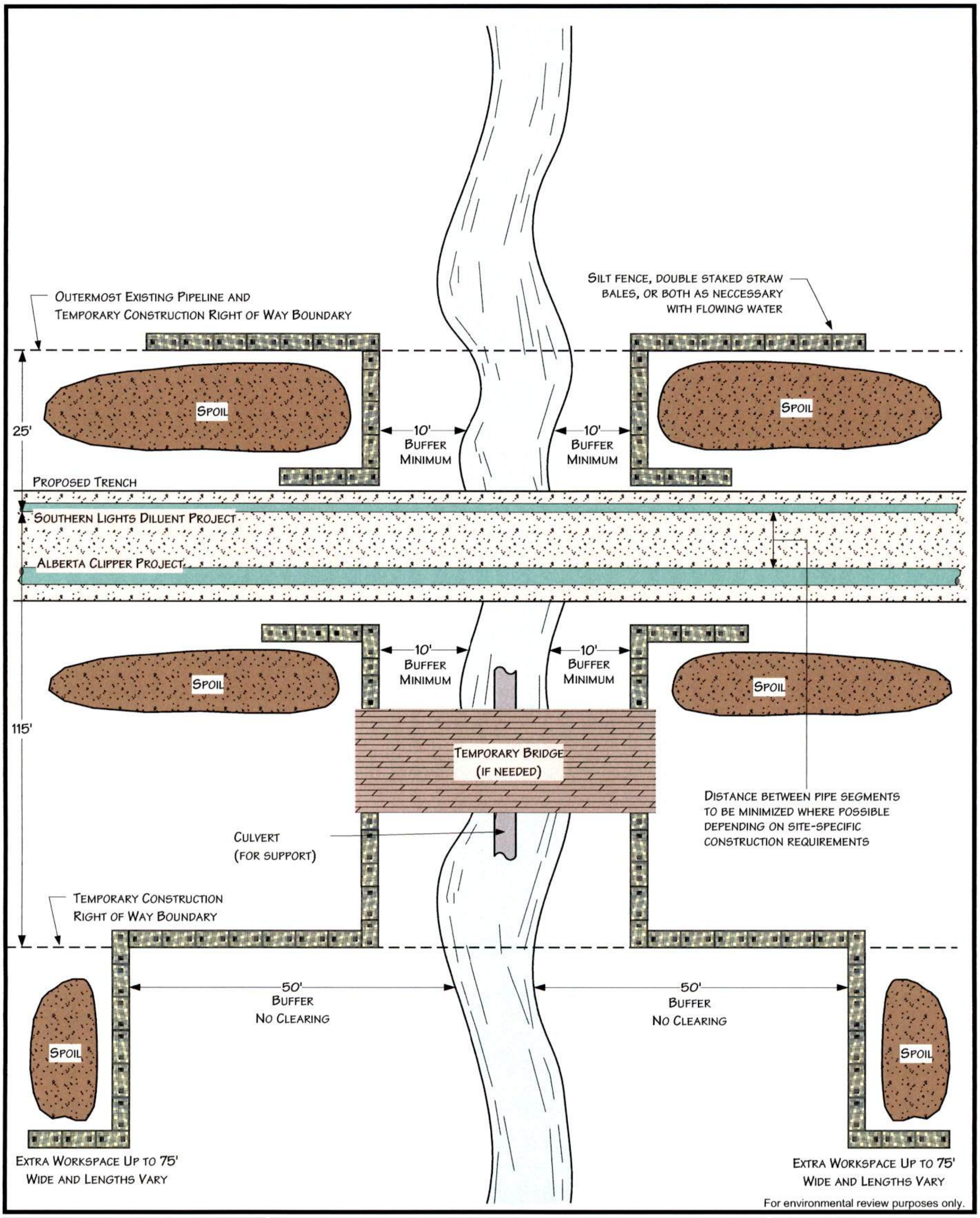

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Figure 2.1
Environmental Mitigation Plan
Typical Waterbody Crossing
Wet Trench Method
(Clearbrook, MN to Superior, WI)

DATE: 11/29/2005	
REVISED: 04/25/07	
SCALE: NTS	
DRAWN BY: KJA	
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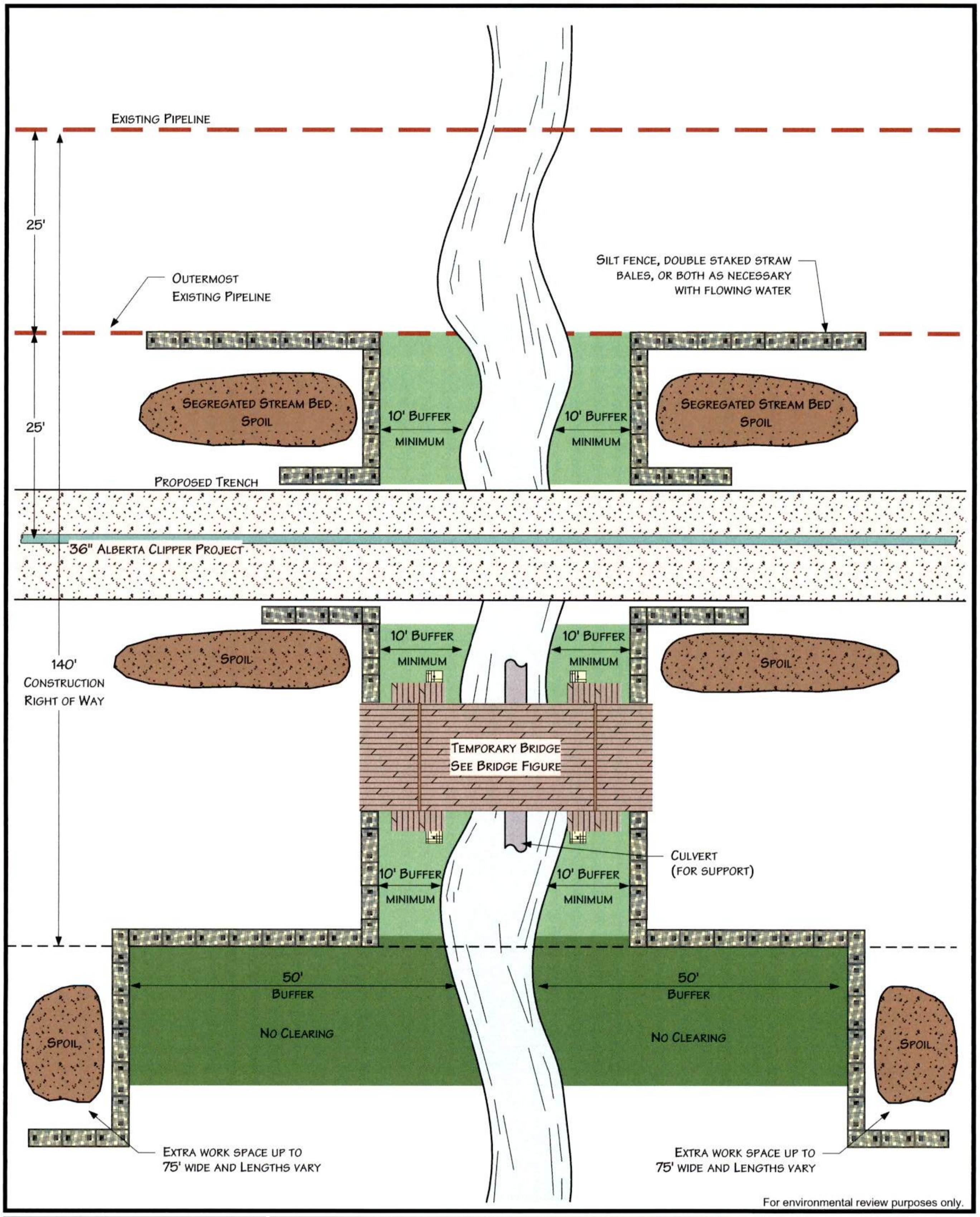

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Figure 2.1-1
Environmental Mitigation Plan
Typical Waterbody Crossing
Wet Trench Method
(Neche, ND to Clearbrook, MN)

DATE: 11/29/2005	NATURAL RESOURCE GROUP, INC.
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SCALE: NTS	
DRAWN BY: KJA	
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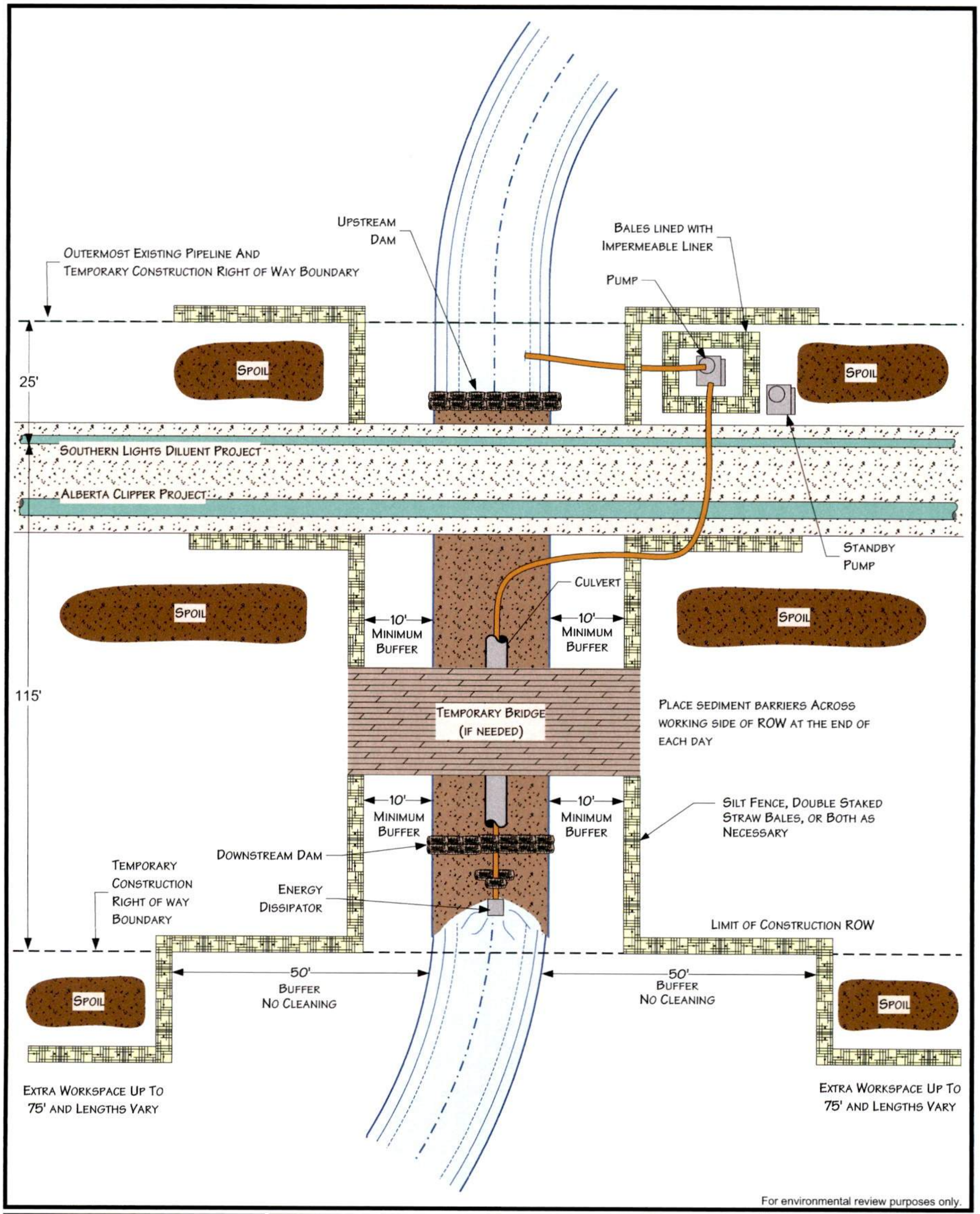

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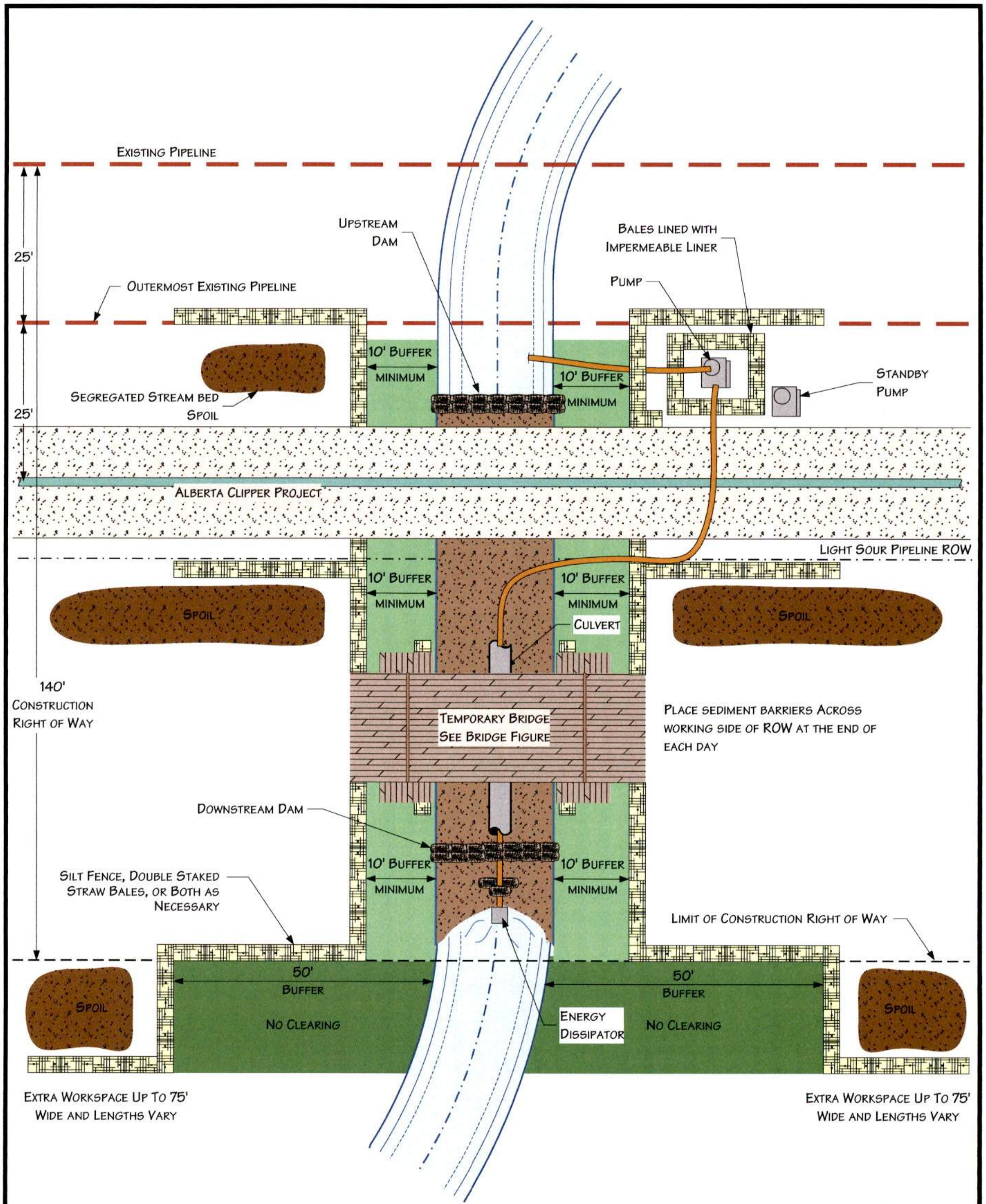
Figure 2.2
Environmental Mitigation Plan
Typical Waterbody Crossing
Dam and Pump Method
(Clearbrook, MN to Superior, WI)

DATE: 11/29/2005	NATURAL RESOURCE GROUP, INC.
REVISED: 04/25/07	
SCALE: NTS	
DRAWN BY: KJA	
K:\335\ALBERTA\2006-135\400\DAM_PUMP.VSD	



For environmental review purposes only.

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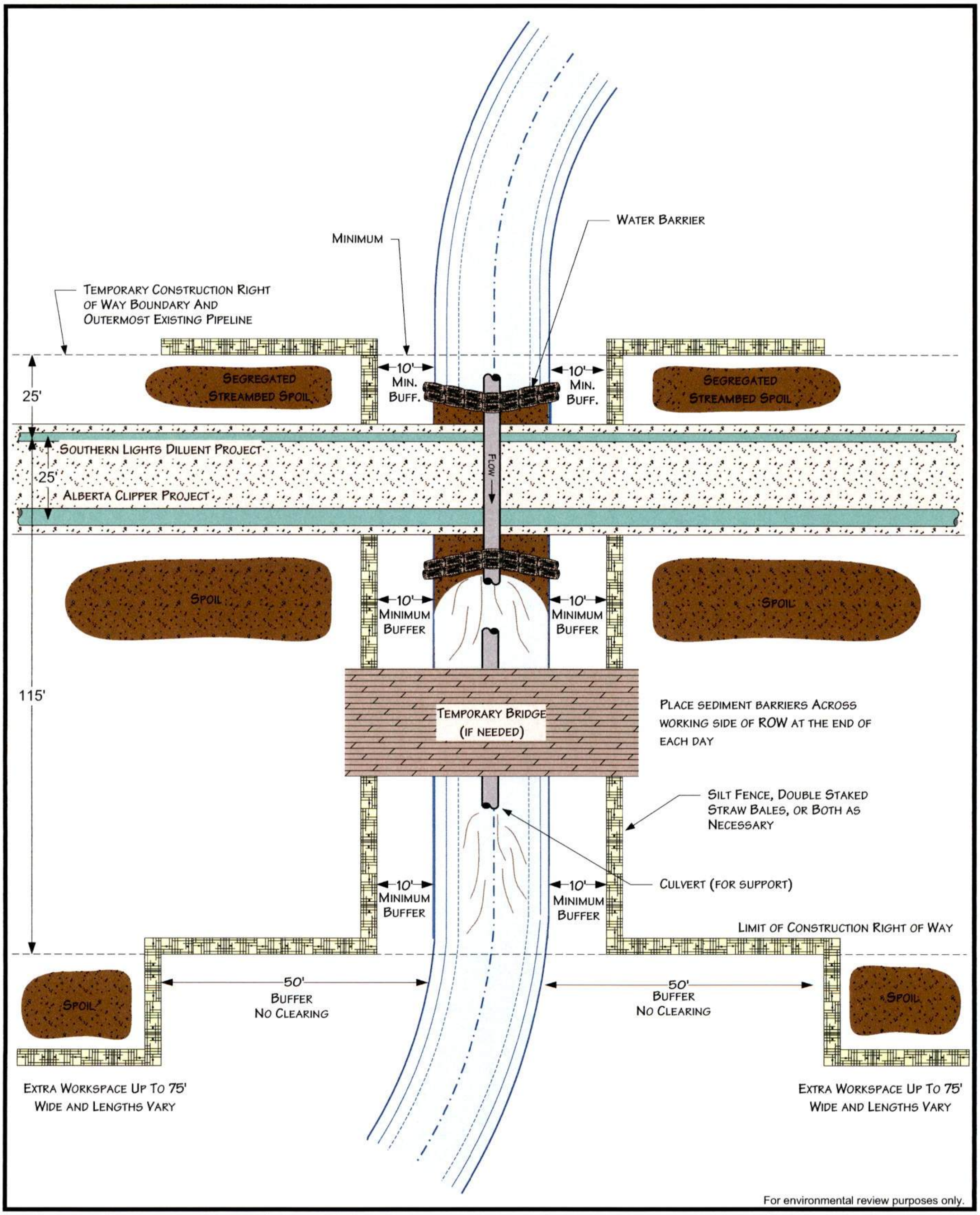
Figure 2.2-1
Environmental Mitigation Plan
Typical Waterbody Crossing
Dam and Pump Method
(Neche, ND to Clearbrook, MN)

DATE: 11/29/2005	NATURAL RESOURCE GROUP, INC.
REVISED: 04/03/07	
SCALE: NTS	
DRAWN BY: KJA	
K:\335\ALBERTA\2006-135\400\2.2.VSD	



For environmental review purposes only.

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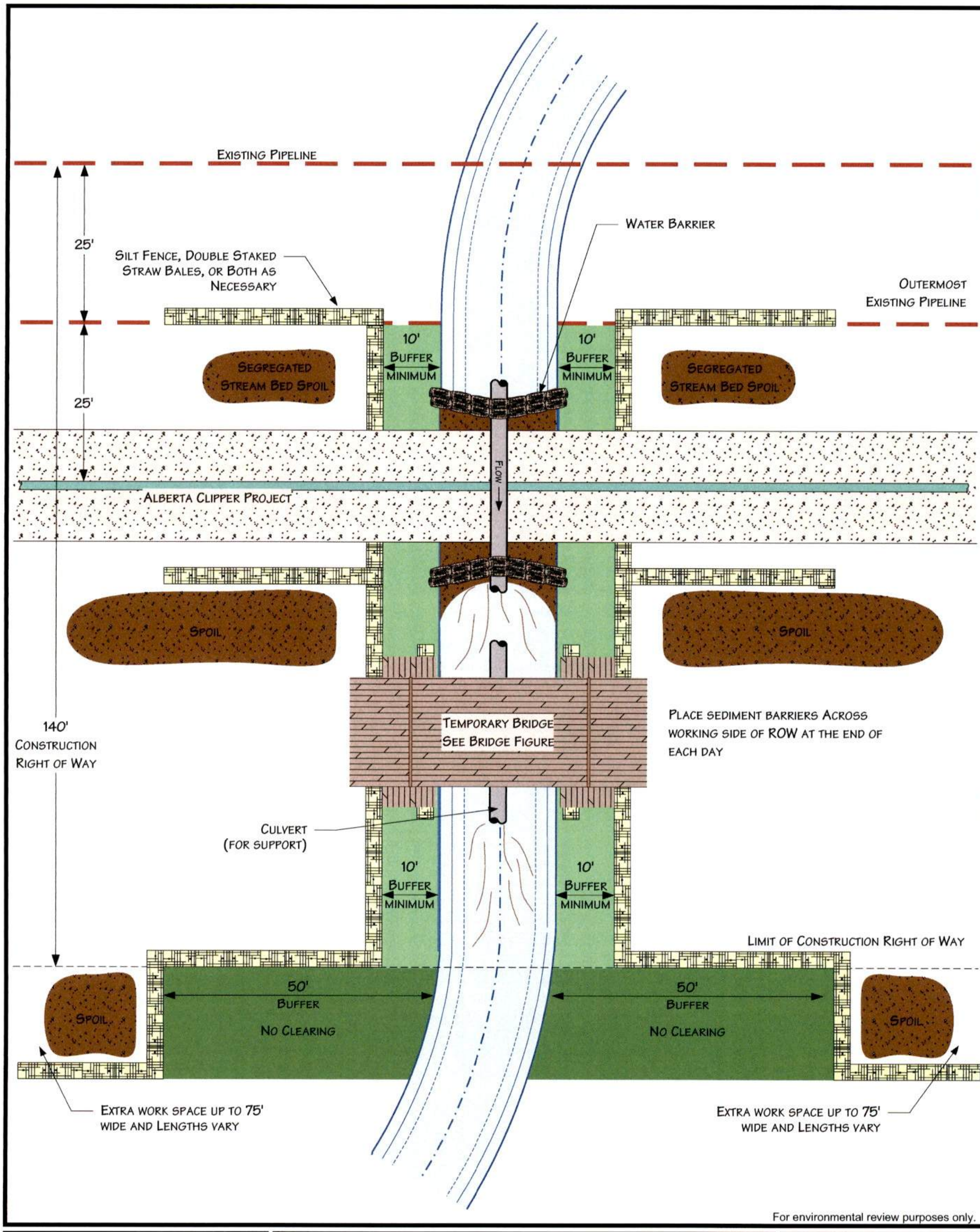
Figure 2.3
Environmental Mitigation Plan
Typical Waterbody Crossing
Flume Method
(Clearbrook, MN to Superior, WI)

DATE: 11/29/2005
REVISED: 05/09/07
SCALE: NTS
DRAWN BY: KJA
K:\335\ALBERTA\2006-135\400\FLUME.VSD

NATURAL RESOURCE GROUP, INC.



For environmental review purposes only.

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Figure 2.3-1
Environmental Mitigation Plan
Typical Waterbody Crossing
Flume Method
(Neche, ND to Clearbrook, MN)

DATE: 11/29/2005
REVISED: 04/25/07
SCALE: NTS
DRAWN BY: KJA
K:\335\ALBERTA\2006-135\400\2.3.VSD

NATURAL RESOURCE GROUP, INC.

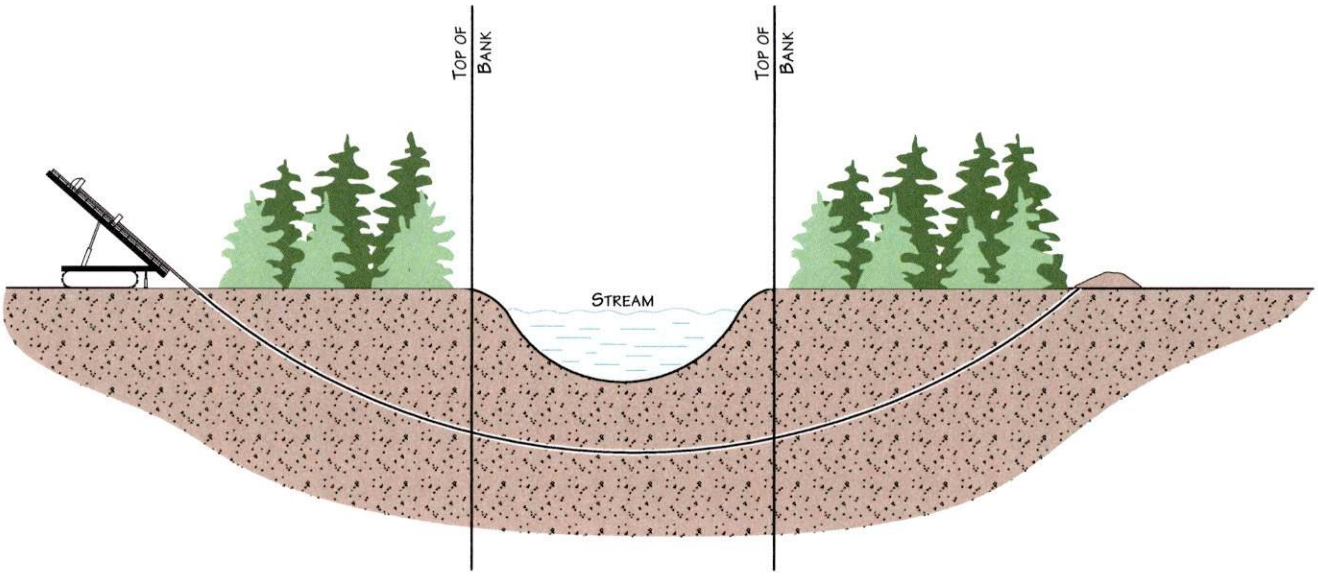

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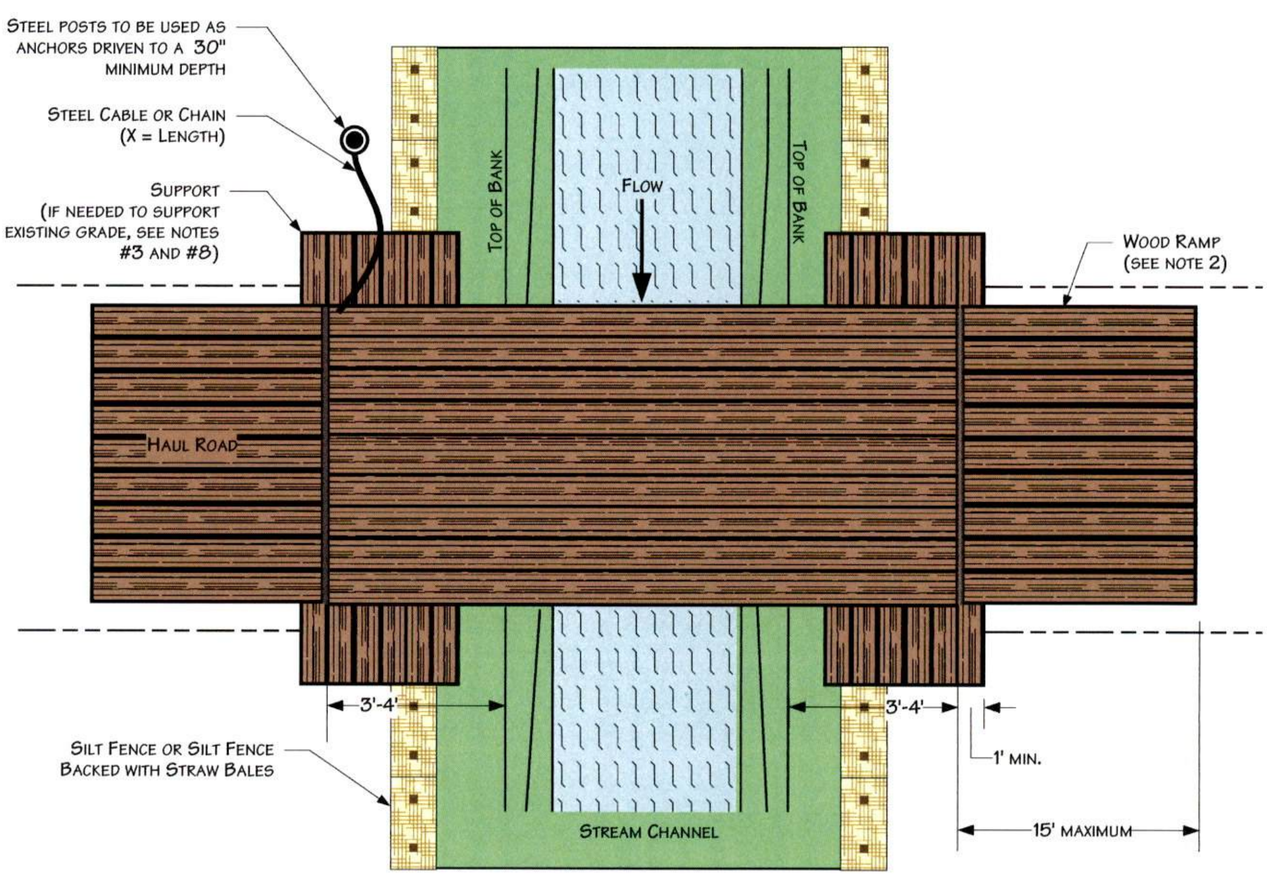
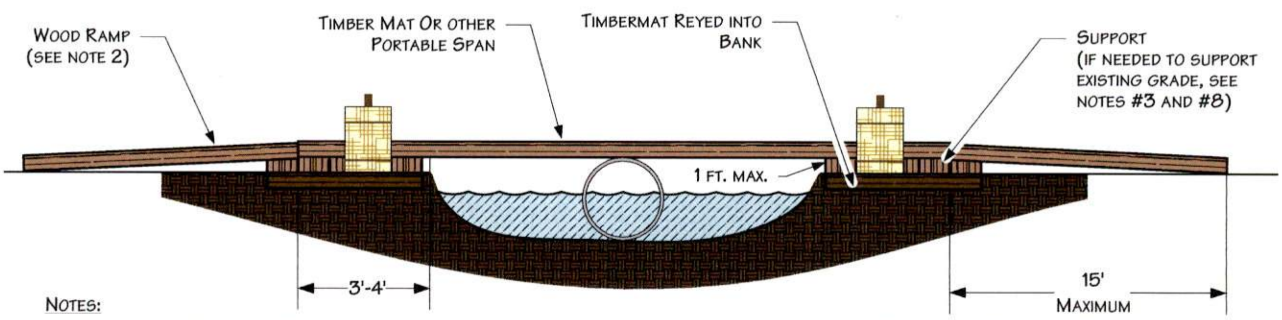
Figure 2.4
Environmental Mitigation Plan
Typical Waterbody Crossing
Directional Drill Method

DATE: 7/14/2000	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
K:\335\ALBERTA\2006-135\400\2.4.VSD	

Plan View



Profile View



Notes:

1. Inspect bridge opening periodically and following rainfalls of over ½". Remove any debris restricting flow and deposit it at an upland site outside of floodplain.
2. If physical circumstances prohibit wood or metal ramps, earthen ramps may be used as approved.
3. Inspect bridge elevation so bridge remains supported above high bank and does not sink into bank.
4. The culvert support must be anchored to the stream bottom and may not be supported with fill.
5. Earthen ramp cannot be taller than 1' and cannot extend for more than 15' on either side of the crossing.
6. The bridge must span from top of bank to top of bank.
7. The bridge must be firmly anchored to prevent it from being transported downstream during high flow.
8. Additional support must be added on top of bank and under span if initial support starts to settle.
9. Erosion and sedimentation control measures shall be inspected and maintained in accordance with the company's Environmental Mitigation Plan

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Figure 2.5

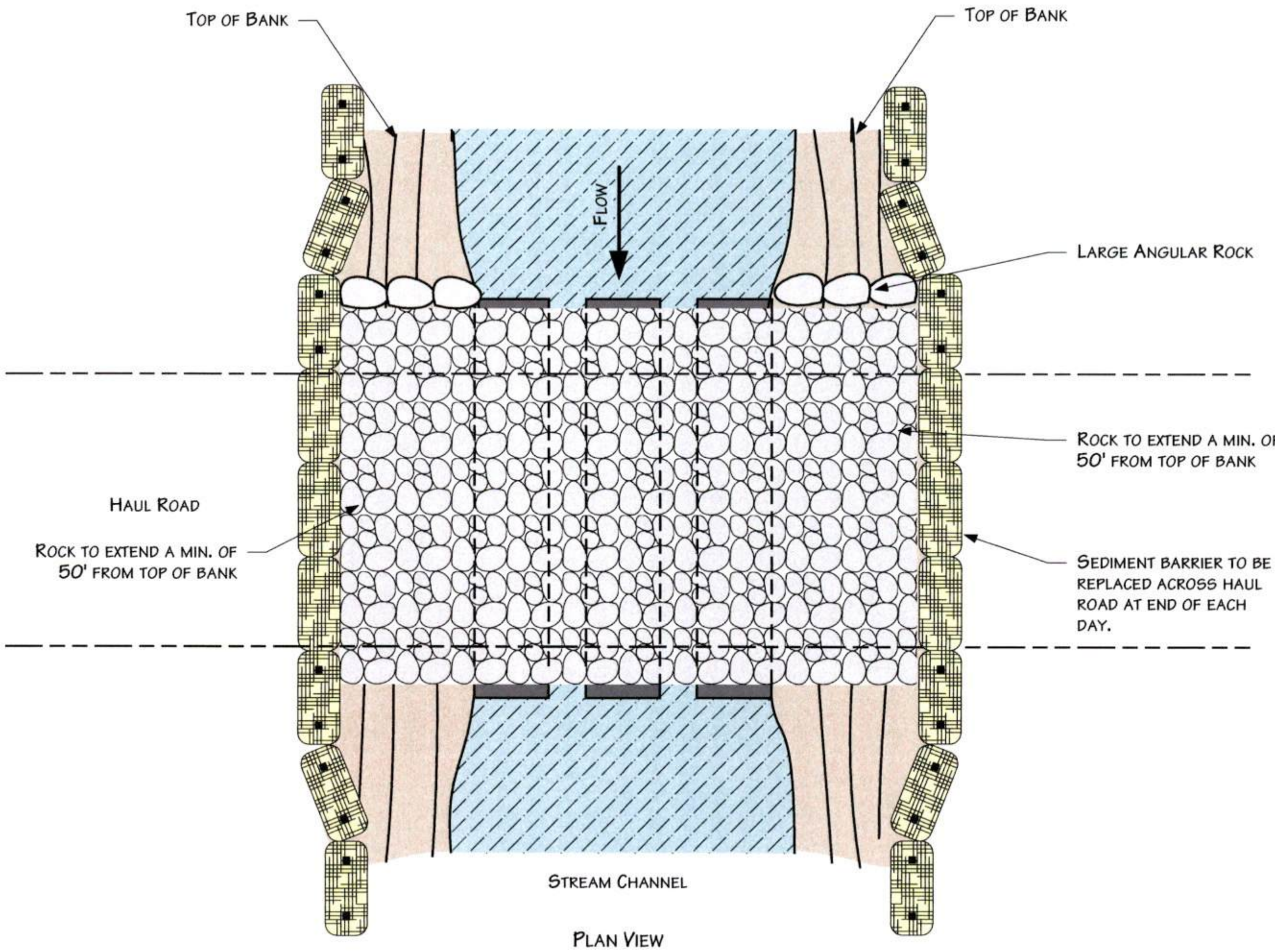
Environmental Mitigation Plan

Typical Span Type Bridge

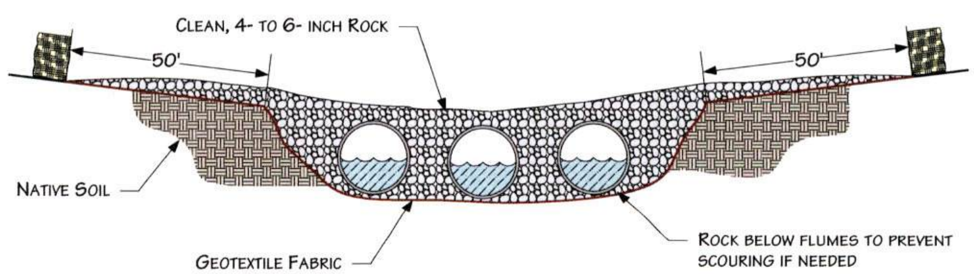
With or Without Instream Support

DATE: 3/11/2003	
REVISED: 3/14/2007	
SCALE: NTS	
DRAWN BY: KMK6792	
K:\335\ALBERTA\2006-135\400\2.5.VSD	

Natural Resource Group, Inc.



PLAN VIEW
(NOT TO SCALE)



NOTES:

1. STEEL FLUME PIPE(S) SIZED TO ALLOW FOR STREAM FLOW AND EQUIPMENT LOAD.
2. STRAW BALES SHALL BE PLACED ACROSS BRIDGE ENTRANCE EVERY NIGHT.
3. ADDITIONAL INFORMATION INCLUDED ON OTHER DRAWINGS.

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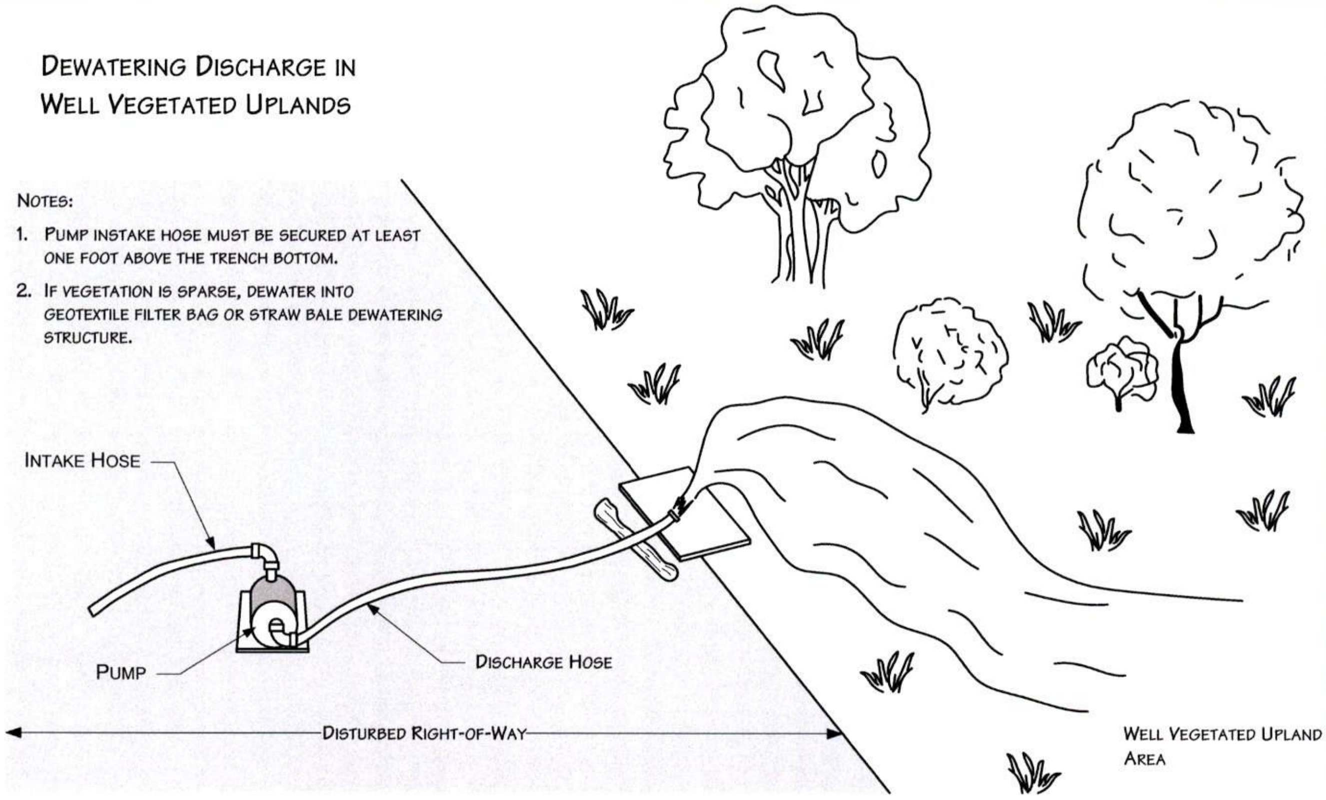
Figure 2.6
Environmental Mitigation Plan
Typical Rock Flume Bridge

DATE: 5/25/2001	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
K:\335\ALBERTA\2006-135\400\2.6.VSD	

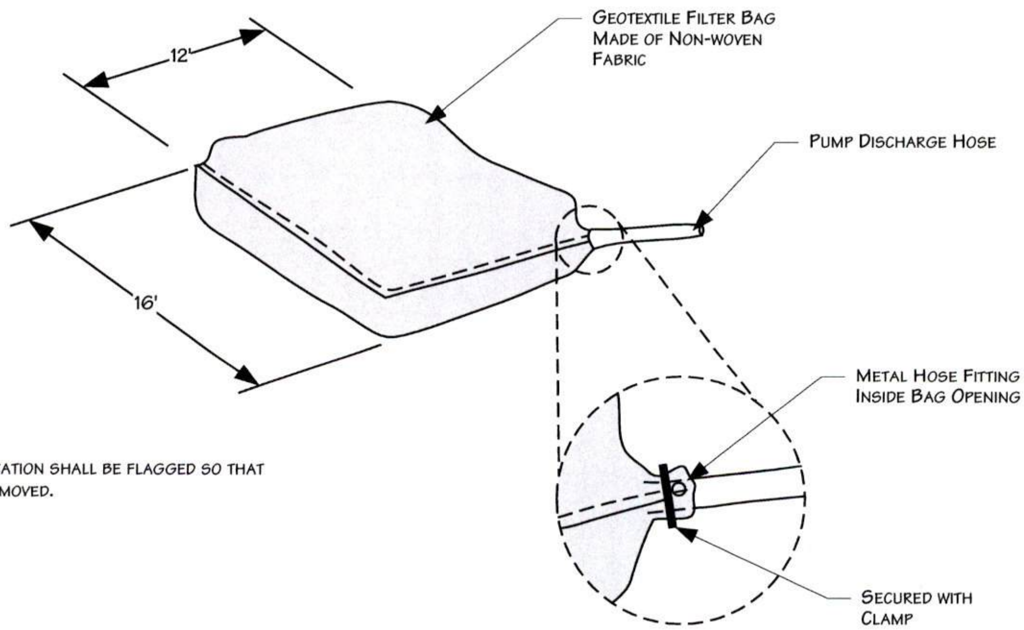
Dewatering Discharge in Well Vegetated Uplands

Notes:

1. Pump instake hose must be secured at least one foot above the trench bottom.
2. If vegetation is sparse, dewater into geotextile filter bag or straw bale dewatering structure.



Geotextile Filter Bag



Note:

1. Filter bag location shall be flagged so that bag can be removed.

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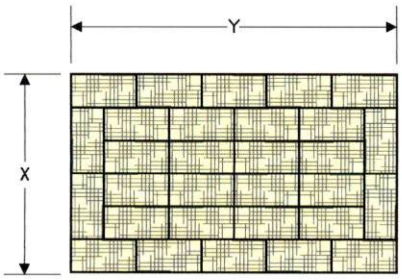
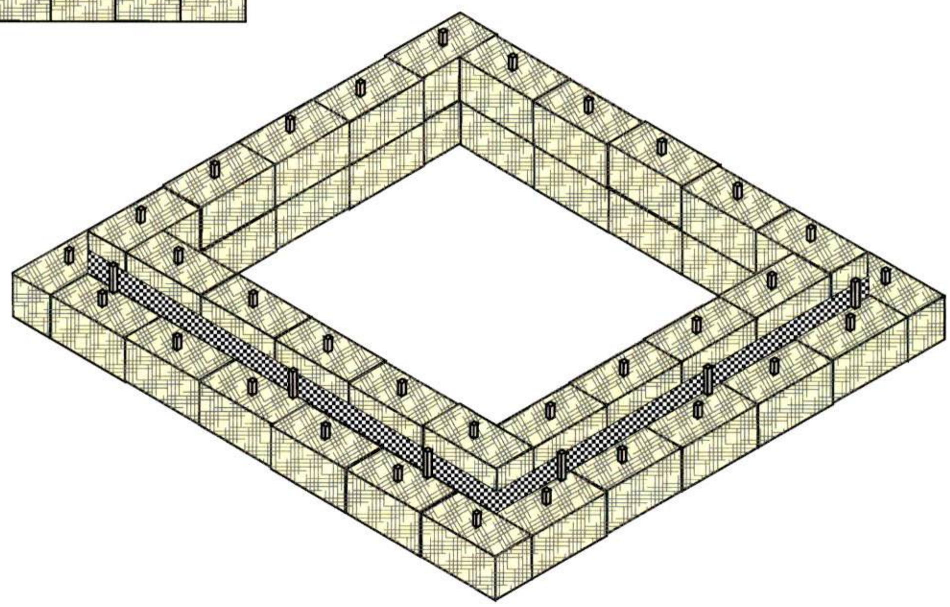
Figure 2.7
Environmental Mitigation Plan
Typical Dewatering Measures

DATE: 5/25/2001	Natural Resource Group, Inc.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
K:\335\ALBERTA\2006-135\400\2.7.VSD	

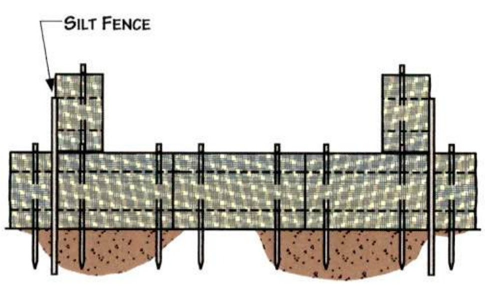


NOTES

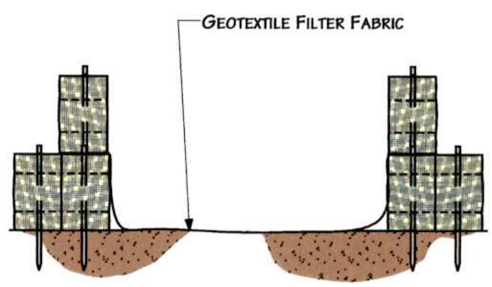
1. ARRANGE THE STRAW BALES TO THE X AND Y DIMENSIONS AS SPECIFICIED BELOW.
2. IF BOTTOM OF STRUCTURE IS NOT LINED WITH STRAW BALES (OPTION 1), LINE ENTIRE STRUCTURE WITH GEOTEXTILE FILTER FABRIC.



PERSPECTIVE VIEW



OPTION 1



OPTION 2

MINIMUM SUMP DIMENSIONS (FEET)		MAXIMUM PUMPING RATE
X	Y	GALLONS PER MINUTE
10	20	300
15	20	350
20	20	400
20	25	450
25	25	500
25	30	550
30	30	660

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Figure 2.8
Environmental Mitigation Plan
Typical Straw-Bale Dewatering Structure

DATE: 5/25/2001
REVISED: 05/29/02
SCALE: NTS
DRAWN BY: KMKENDALL
K:\335\ALBERTA\2006-135\400\2.8.VSD

NATURAL RESOURCE GROUP, INC.

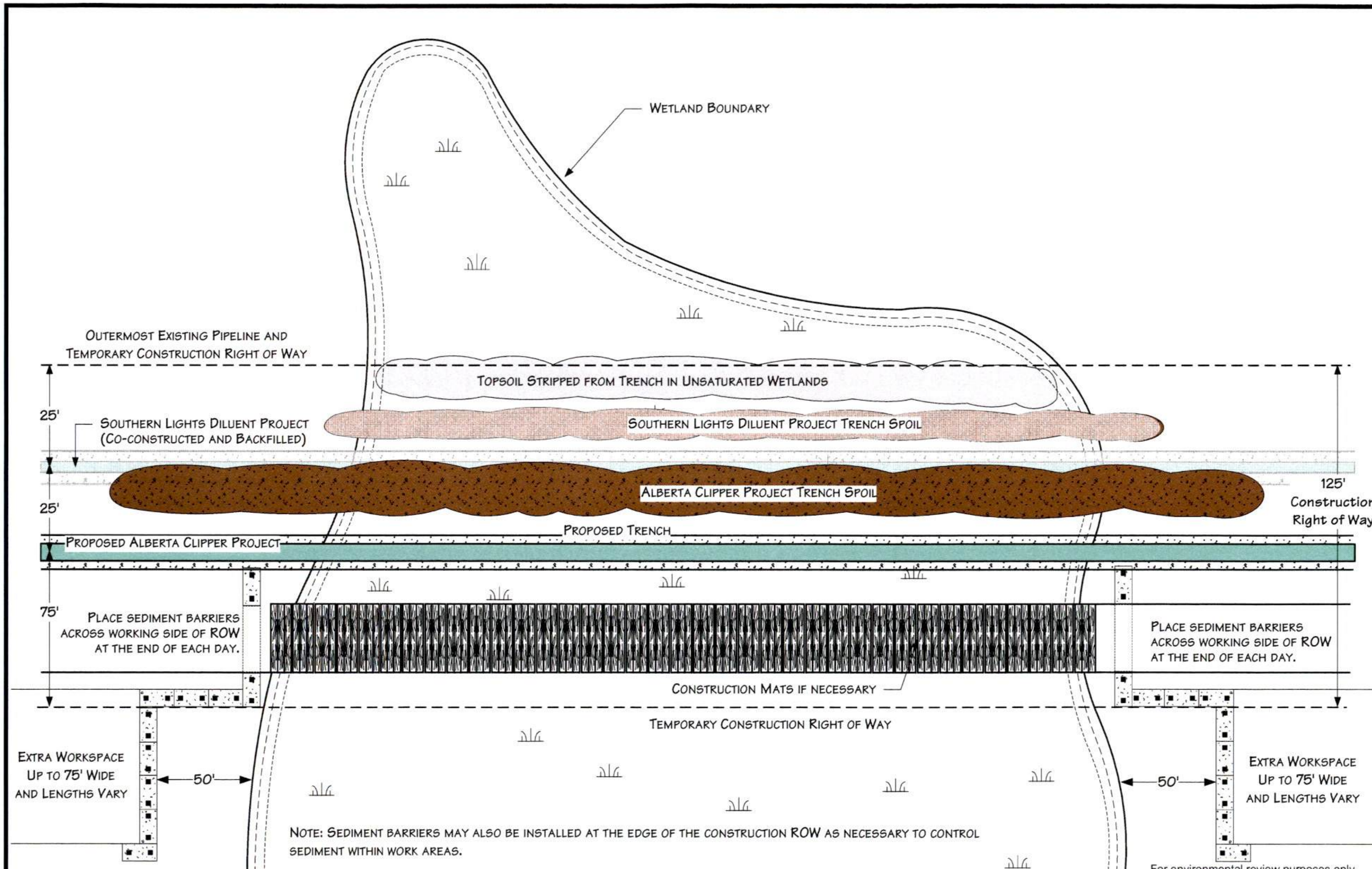

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Figure 3.1
Environmental Mitigation Plan
Typical Wetland Crossing Method
(Clearbrook, MN to Superior, WI)

DATE: 5/25/2001
REVISED: 05/03/07
SCALE: NTS
DRAWN BY: KMKENDALL
K:\335\ALBERTA\2006-135\400\WETX2.VSD

NATURAL RESOURCE GROUP, INC.

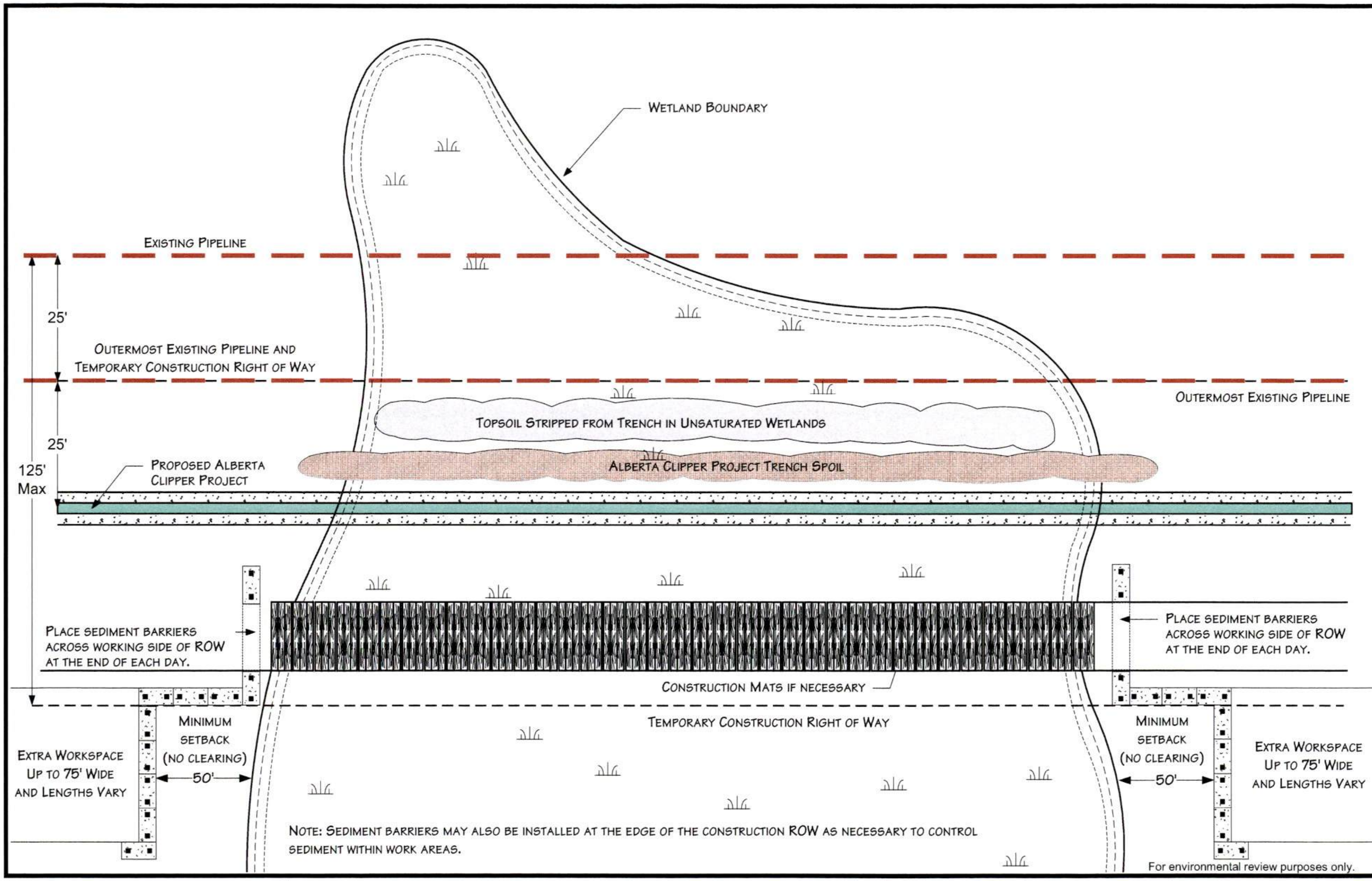

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Figure 3.1-1

Environmental Mitigation Plan

Typical Wetland Crossing Method

(Neche, ND to Clearbrook, MN)

DATE: 5/25/2001

REVISED: 05/10/07

NATURAL RESOURCE GROUP, INC.

SCALE: NTS

DRAWN BY: KMKENDALL

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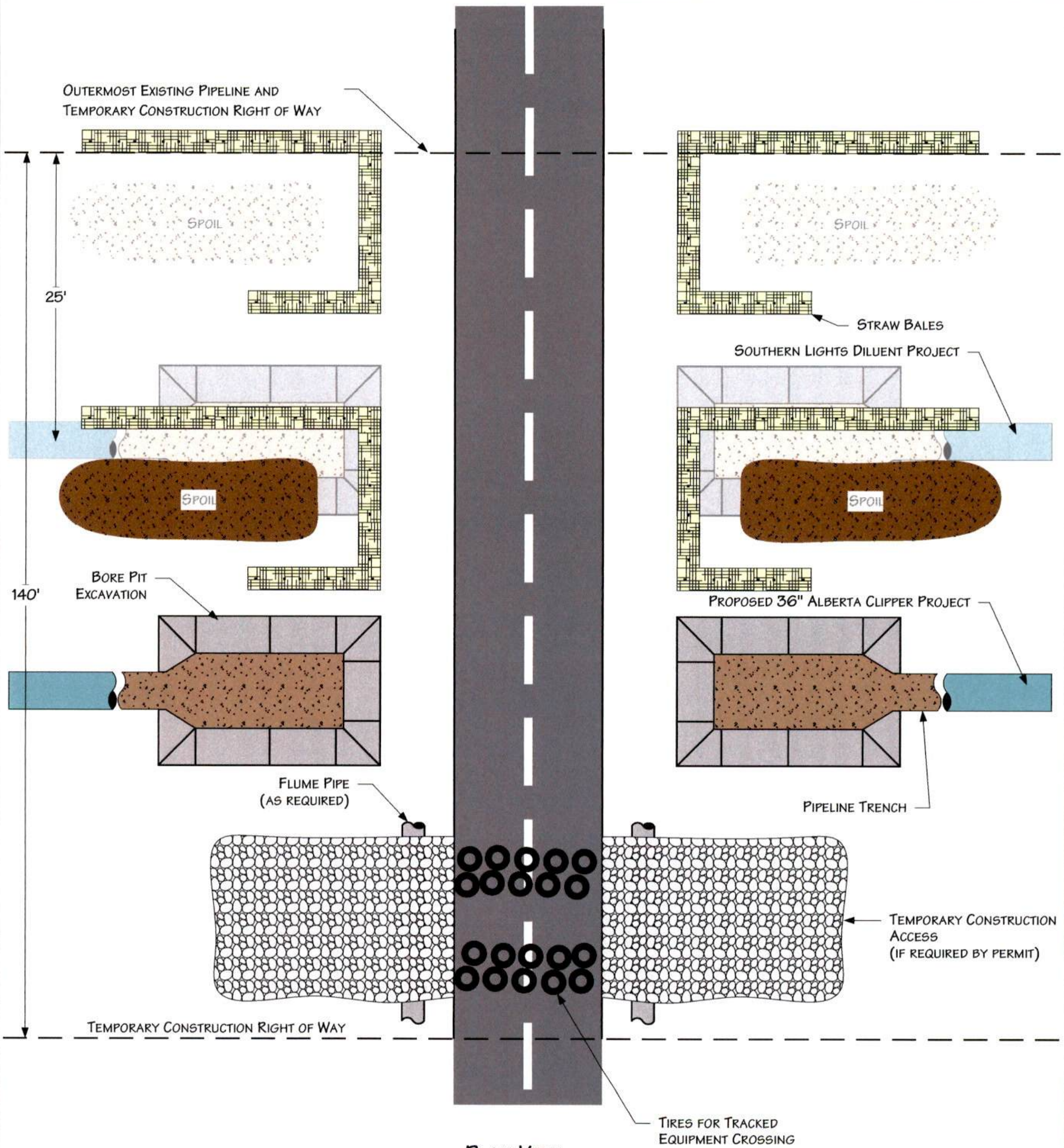

PLAN VIEW

NOTES

1. PROCEDURES SHOWN IN THIS DRAWING APPLY TO IMPROVED ROADS.
2. ROADS MUST BE CLEANED AFTER EQUIPMENT CROSSES AND DIRT PLACED IN SPOIL CONTAINMENT AREAS.
3. TEMPORARY ACCESS MATERIALS MUST BE REMOVED UPON PROJECT COMPLETION.
4. ADDITIONAL INFORMATION INCLUDED ON OTHER DRAWINGS OR PERMITS.
5. CONSTRUCTION AREAS LOCATED OUTSIDE ROAD ROW.

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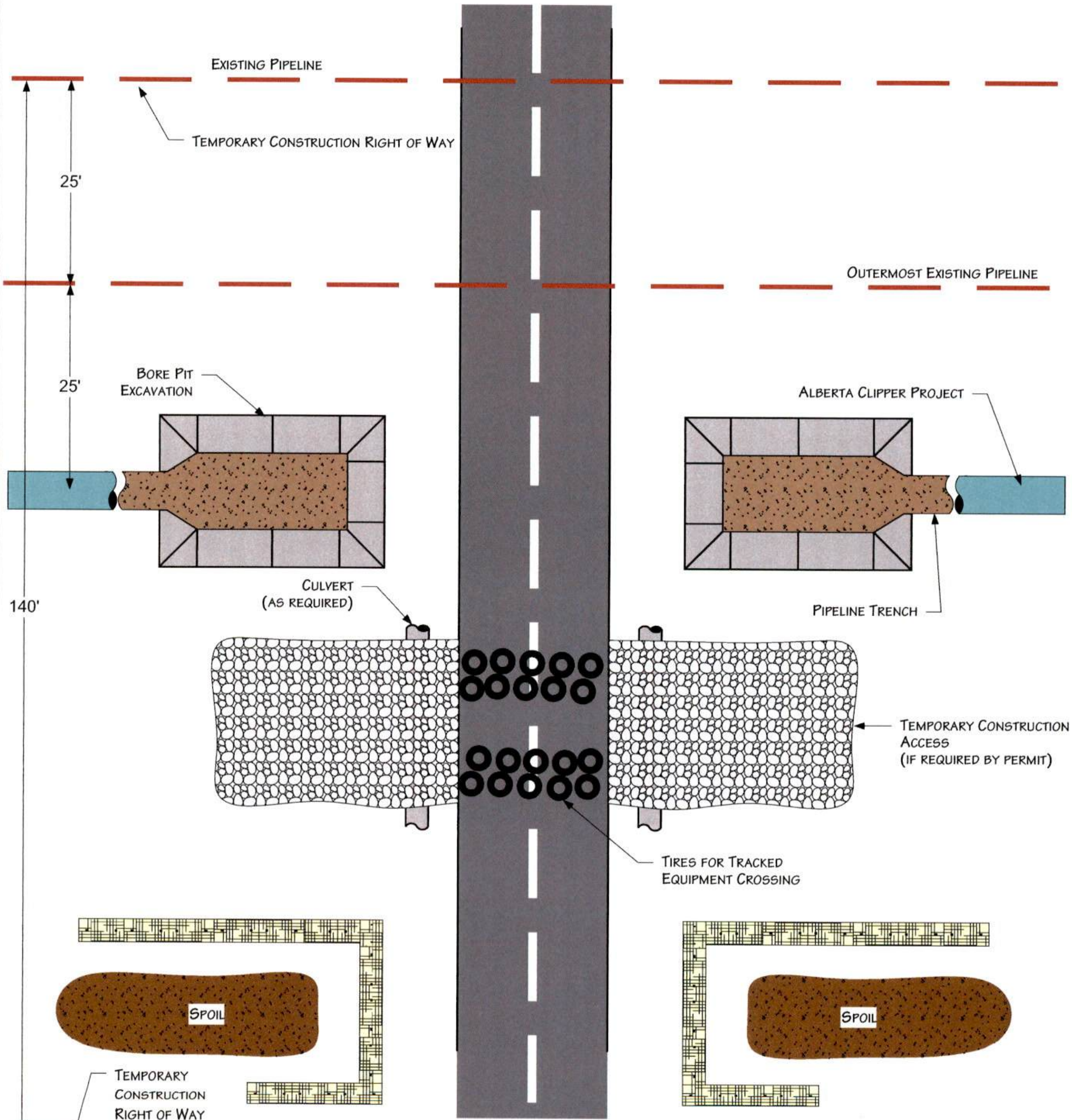
NATURAL RESOURCE GROUP, INC.

Figure 4.1
Environmental Mitigation Plan
Typical Improved Road Crossing
Directional Bore Method
(Clearbrook, MN to Superior, WI)

DATE:	7/13/1999
REVISED:	5/3/2007
SCALE:	NTS
DRAWN BY:	KMKENDALL
K:\335\ALBERTA\2006-135\400\IMPROVED ROAD CROSSINGREV.VSD	



Plan View

Notes

1. Procedures shown in this drawing apply to improved roads.
2. Roads must be cleaned after equipment crosses and dirt placed in spoil containment areas.
3. Temporary access materials must be removed upon project completion.
4. Additional information included on other drawings or permits.
5. Construction areas located outside road ROW.

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ENBRIDGE

Figure 4.1-1
Environmental Mitigation Plan
Typical Improved Road Crossing
Directional Bore Method
(Neche, ND to Clearbrook, MN)

DATE: 7/13/1999
REVISED: 5/3/2007
SCALE: NTS
DRAWN BY: KMKENDALL
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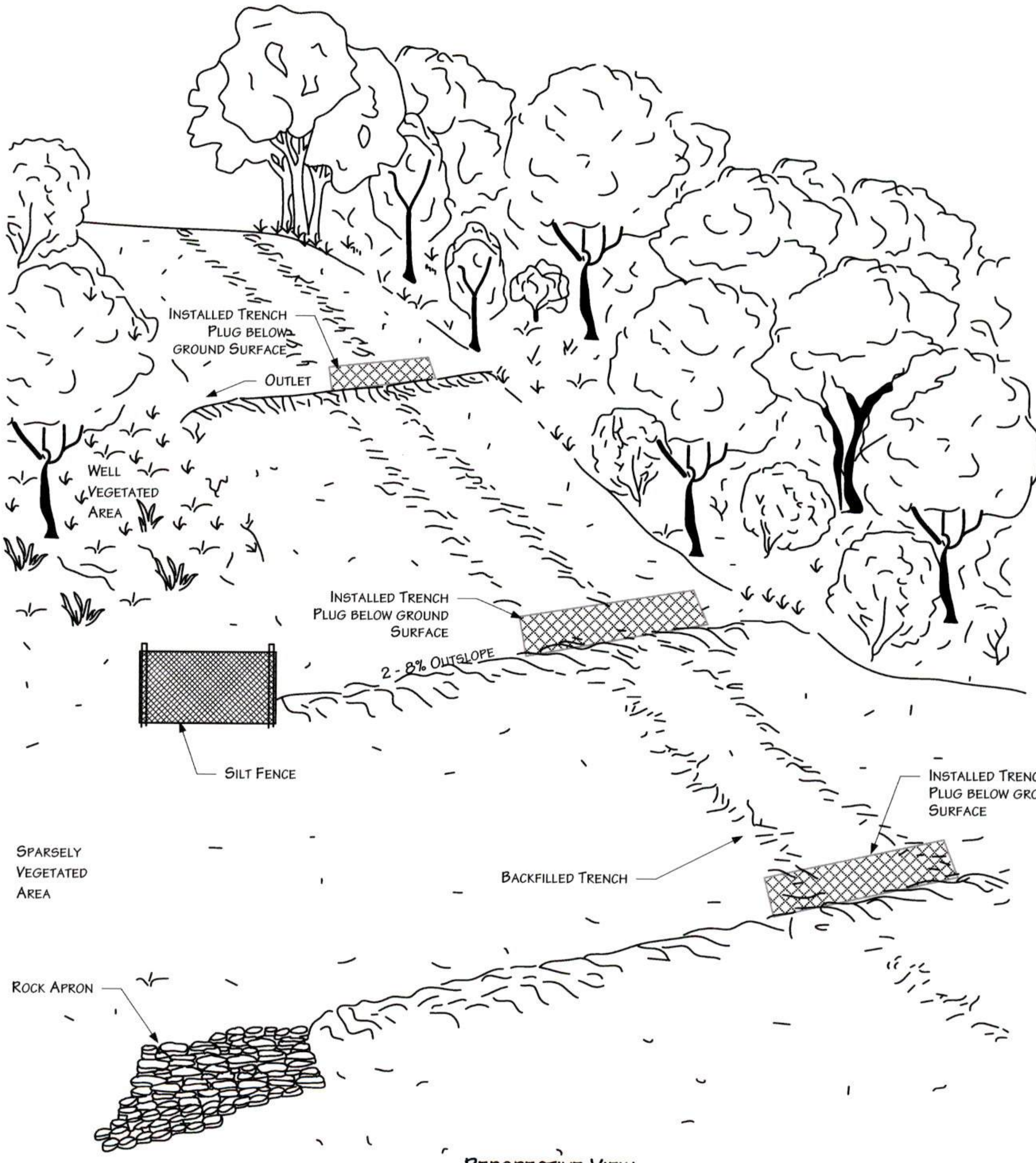
NATURAL RESOURCE GROUP, INC.



Perspective View
(NOT TO SCALE)

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Figure 7.1
Environmental Mitigation Plan
Permanent Slope Breakers - Perspective View

DATE: 5/25/2001	
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
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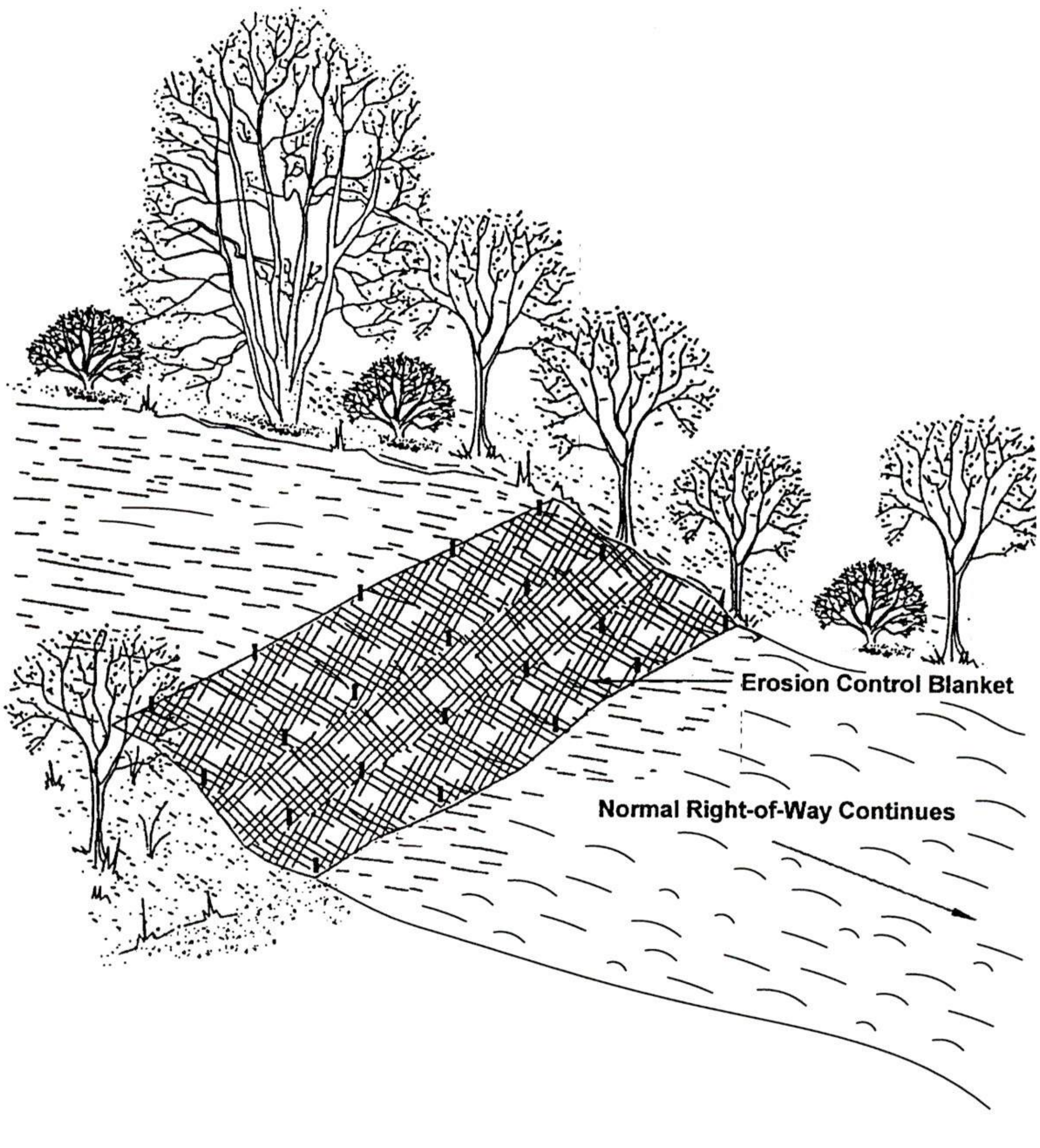
NATURAL RESOURCE GROUP, INC.



NOTES

1. Install erosion control blanket as per manufacturer's specifications.
2. Additional information included on other drawings.

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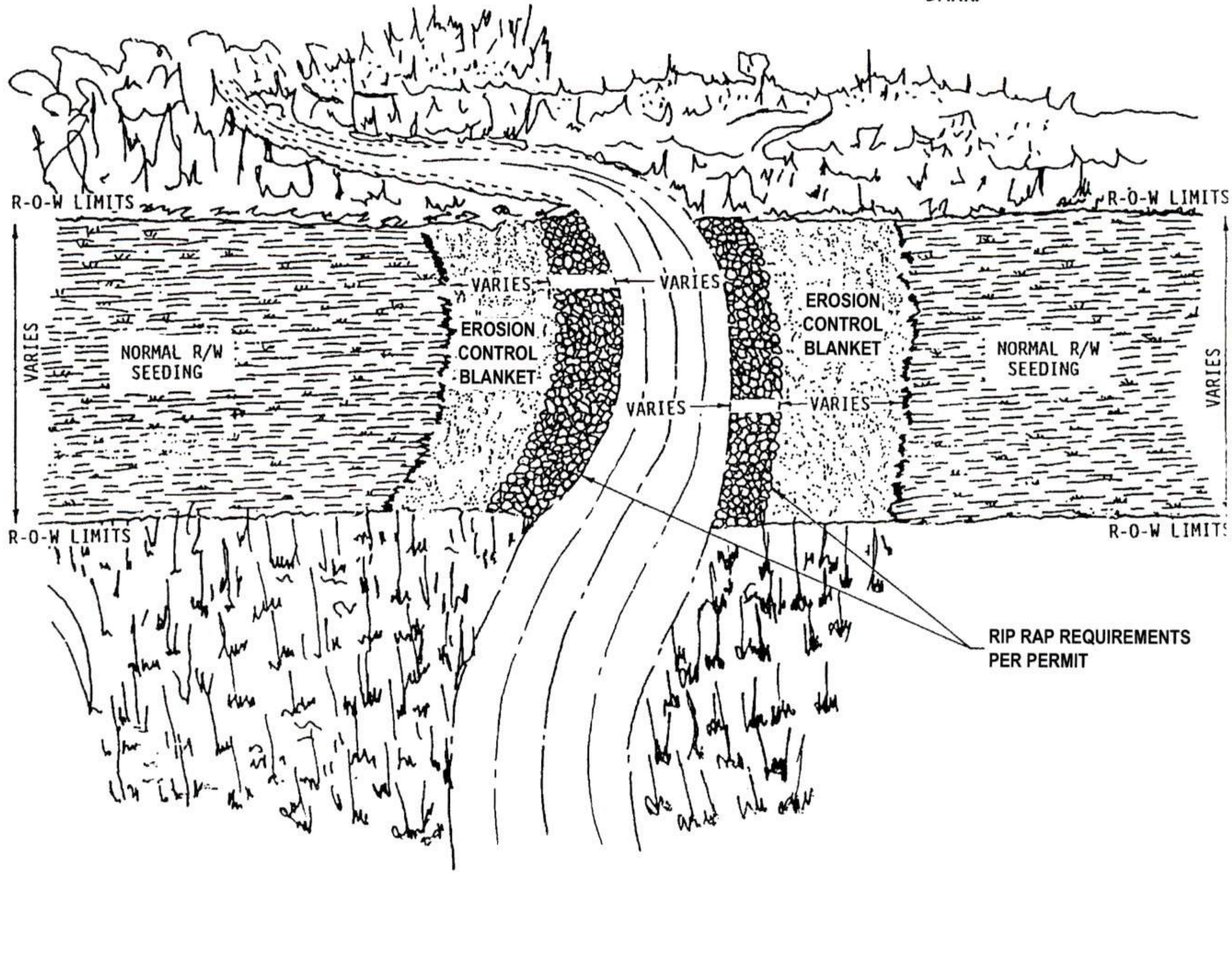
Figure 7.2
Environmental Mitigation Plan
Erosion Control Blanket - Steep Slopes (≥30%)

DATE: 11/15/2000	NATURAL RESOURCE GROUP, INC.
REVISED: 12/21/05	
SCALE: NTS	
DRAWN BY: KMKENDALL	
K:\335\ALBERTA\2006-135\400\7.2.VSD	

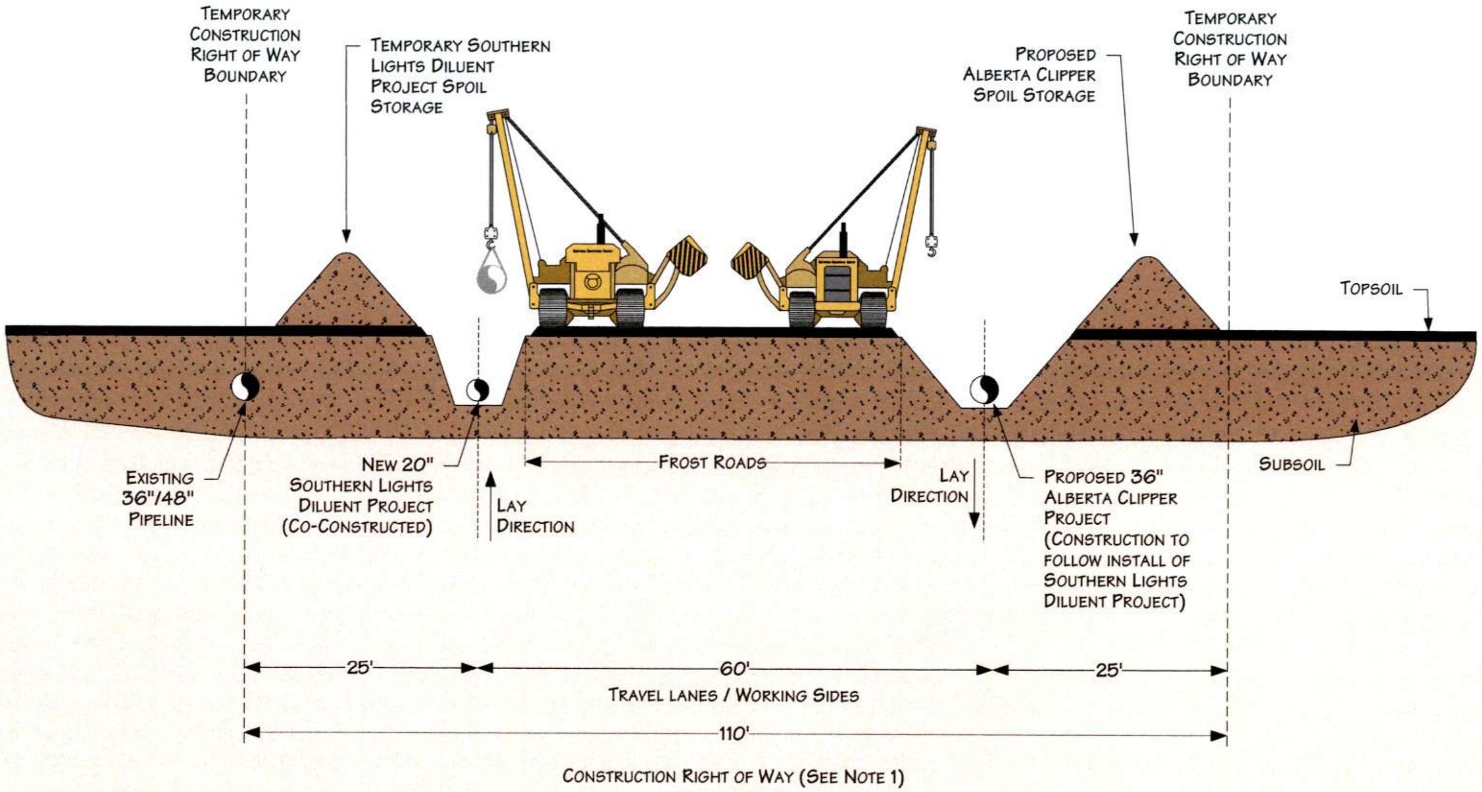
NOTE: PLACE JUTE BLANKET A MINIMUM OF ONE (1) FOOT UNDER RIP RAP. EXTEND JUTE BLANKET FROM MEAN HIGH WATER LEVEL TO SEVERAL FEET BEHIND HIGH BANK.



For environmental review purposes only.

ENBRIDGE™	**Figure 7.3** **Environmental Mitigation Plan** Typical Final Stream Bank Stabilization Rip Rap & Erosion Control	DATE: 7/19/2000 REVISED: 12/21/05 SCALE: NTS DRAWN BY: KMKENDALL K:\335\ALBERTA\2006-135\400\7.3.VSD

NATURAL RESOURCE GROUP, INC.



PROFILE

NOTE:

CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 110' WIDE. EACH SPOIL SIDE WILL BE APPROXIMATELY 25 FEET WIDE. THE WORKING SIDE WILL BE 60 FEET WIDE.

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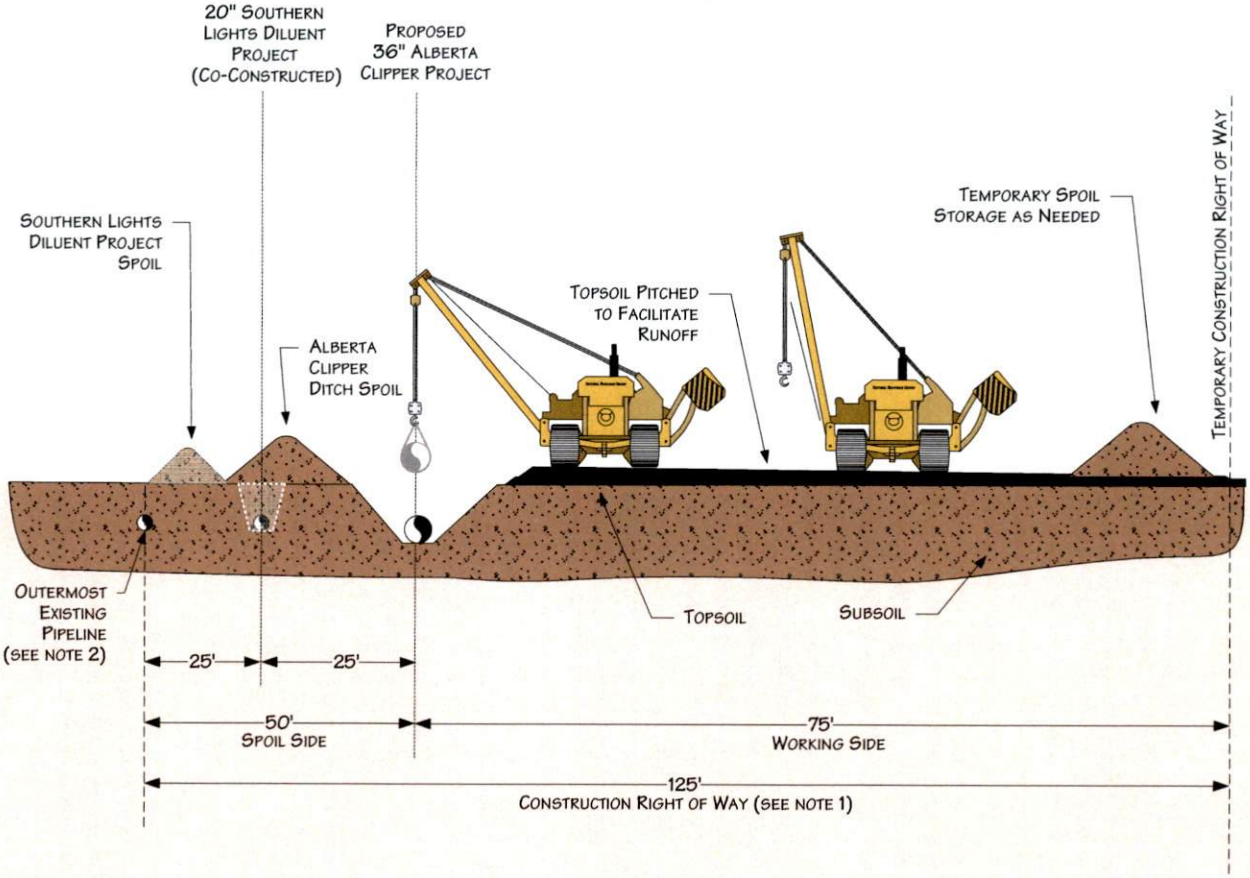
Figure 8.1
Environmental Mitigation Plan
Typical Winter Construction-Method 1

DATE: 3/3/2005
REVISED: 5/9/2007
SCALE: NTS
DRAWN BY: MHN6795
K:\335\ALBERTA\2006-135\400\8.1.VSD



PROFILE

NOTES:

1. CONSTRUCTION RIGHT OF WAY WILL TYPICALLY BE 125' WIDE. THE SPOIL SIDE WILL BE APPROXIMATELY 50' WIDE AND GENERALLY WITHIN THE EXISTING MAINTAINED RIGHT-OF-WAY. THE WORKING SIDE WILL BE 75' WIDE.
2. THE OFFSET FROM NORTHERNMOST OR SOUTHERNMOST EXISTING PIPELINE, WHERE APPLICABLE, WILL BE 25' FOR MOST LOCATIONS BUT MAY BE INCREASED OR DECREASED DEPENDING ON THE SITE SPECIFIC CONSTRUCTION REQUIREMENTS.

ENBRIDGE™

Figure 8.2
Environmental Mitigation Plan
Typical Winter Construction-Method 2

DATE: 5/5/2007	NATURAL RESOURCE GROUP, INC.
REVISED: 5/9/2007	
SCALE: NTS	
DRAWN BY: KMKENDALL	
K:\335\ALBERTA\2006-135\400\8.2.VSD	

Enbridge Energy, Limited Partnership

ENBRIDGE EXPANSION PROJECTS

Spill Prevention, Containment, and Control Plan

July 2007

Enbridge Energy, Limited Partnership

Spill Prevention, Containment, and Control Plan

TABLE OF CONTENTS

Enbridge Energy, Limited Partnership

Spill Prevention, Containment, and Control Plan

1.0 INTRODUCTION

This Spill Prevention, Containment and Control Plan (Spill Plan) describes planning, prevention and control measures to minimize impacts resulting from spills of fuels, petroleum products, or other regulated substances as a result of construction. These measures will be implemented by the Contractor working on Enbridge expansion projects, unless otherwise indicated by Enbridge.

2.0 PLANNING AND PREVENTION

Enbridge requires its Contractors to implement proper planning and preventative measures to minimize the likelihood of spills, and to quickly and successfully clean up a spill should one occur. Enbridge has developed this Spill Plan to set forth minimum standards for handling and storing regulated substances and cleaning up spills. Potential sources of construction-related spills include machinery and equipment failure, fuel handling, transfer accidents and storage tank leaks. The Contractor will be responsible for implementing, at a minimum, the following planning and prevention measures.

2.1 ROLES AND RESPONSIBILITIES

Spill Coordinator

A Spill Coordinator shall be designated by the Contractor, subject to approval by Enbridge. For pipeline spills, the Spill Coordinator shall ensure that the Enbridge Representative is notified immediately, and may assist in response action as dictated by Enbridge. For all construction related spills, the following shall apply:

- The Spill Coordinator shall report all spills to the Enbridge Representative immediately.
- The Spill Coordinator (under Enbridge oversight), shall report spills to appropriate federal, state and local agencies as soon as possible.
- The Spill Coordinator shall mobilize on-site personnel, equipment, and materials for containment and/or cleanup commensurate with the extent of the spill.
- The Spill Coordinator shall assist the Emergency Response Contractor (Appendix A) and monitor containment procedures to ensure that the actions are consistent with the requirements of this Spill Plan.
- The Spill Coordinator and/or Enbridge Representative, in consultation with appropriate agencies, shall determine when it is necessary to evacuate spill sites to safeguard human health.
- The Spill Coordinator (under Enbridge oversight), shall coordinate with appropriate agencies the need to contact additional parties or agencies.

- The Spill Coordinator is responsible for completing a Spill Report Form (Appendix B) within 24-hours of the occurrence of a spill, regardless of the size of the spill.

Environmental Inspector

- The Environmental Inspector will monitor the Contractor's compliance with the provisions of this Spill Plan.

Authorized Personnel

- Authorized Personnel are representatives of the Contractor who are designated to handle fuel, lubricants or other regulated substances.

- Authorized Personnel must be familiar with the requirements of the Spill Plan and the consequences of non-compliance.

Construction Superintendent

- The Contractor's Construction Superintendent or representative must notify the Enbridge Representative and the Environmental Inspector immediately of any spill of a petroleum product or hazardous liquid, regardless of volume.

Construction Personnel

- Construction Personnel are representatives of the Contractor involved with the installation of the pipeline.

- Construction Personnel shall notify the crew foreman or Spill Coordinator immediately of any spill of a petroleum product or hazardous liquid, regardless of volume.

Enbridge Representative

- The Enbridge Representative shall oversee the Spill Coordinator to ensure that appropriate agency notifications are made, spill resources are allocated, and clean-up is accomplished in accordance with applicable agency requirements.

2.2 TRAINING

- The Contractor shall train all employees who handle fuels and other regulated substances to prevent spills and to quickly and effectively contain and clean up spills that may occur in accordance with applicable regulations.

- The Contractor and employees will be briefed on procedures to respond to a pipeline spill (e.g. third party damage to the adjacent in-service pipeline) during mandatory safety and environmental training to be provided by the Enbridge.

2.3 EQUIPMENT

- Each construction crew must have adequate absorbent materials and containment booms on hand, to enable the rapid cleanup of any spill which may occur.

- The Contractor must maintain spill kits containing a sufficient quantity of absorbent and barrier materials to adequately contain and recover foreseeable spills. These kits may include, but are not limited to absorbent pads, straw bales, absorbent clay, sawdust, floor-drying agents, spill containment barriers, plastic sheeting, skimmer pumps, and holding tanks. This equipment shall be located near fuel storage areas and other locations as necessary to be readily available to control foreseeable spills.

- Suitable plastic lining materials shall be available for placement below and on top of temporarily-stored contaminated soils and materials.

- All fuel, and where necessary, service vehicles, shall carry spill containment materials adequate to control foreseeable spills. Such material may include but not be limited to absorbent pads, commercial absorbent material, plastic bags with ties, and a shovel.

- The Spill Coordinator shall make known to Authorized Personnel, Construction Personnel, the Environmental Inspector, and the Enbridge Representative the locations of spill control equipment and materials, and have them readily accessible during construction activity.

- Construction equipment shall be removed from wetlands and parked a minimum of 100 feet away from streams, wetlands, ditches, and other waterbodies at the end of each work day.

- In large wetlands where no upland site is available for refueling, auxiliary fuel tanks on construction equipment are recommended.

- All fuel nozzles shall be equipped with functional automatic shut-offs and over-flow alarms.

- Fuel trucks transporting fuel to on-site construction equipment shall travel only on approved access roads.

2.4 SUPERVISION AND INSPECTION

- The Contractor shall perform a pre-construction inspection and test of all equipment to ensure that it is in good repair.

- During construction, the Contractor shall regularly inspect hoses, pipes, valves, and tanks to ensure equipment is free of leaks. Any equipment that is leaking or in need of repair will be immediately removed from service by Contractor and repaired, prior to resuming work.

3.0 STORAGE AND HANDLING OF FUELS/HAZARDOUS LIQUIDS

3.1 FUEL STORAGE - GENERAL

The Contractor shall follow proper fuel storage practices, including, but not limited to the following:

- Fuel storage shall be at Contractor yards only or as approved by Enbridge.

- Proper signage at and adjacent to fuel storage areas to include "Fuel Storage Area – No smoking within 50 feet.

- A minimum of two 30-pound or four 20-pound fire extinguishers must be located and readily available at all fuel storage locations. The extinguishers shall be located not less than 25 feet and not more than 75 feet from these locations.

- Tools and materials to stop the flow of leaking tanks and pipes shall be kept on-site. Such equipment may include, but not be limited to, plugs of various sizes, 3M tank patches, a hammer, assorted sizes of metal screws with rubber washers, a screwdriver, and plastic tape. Spill kits (see Section 2.3 of this Spill Plan) must be located at fuel storage areas.

- Fuels, lubricants, waste oil, and any other regulated substances shall be stored in aboveground tanks only.

- Storage tanks and containers must conform to all applicable industry codes (NFPA, UFC, etc.).

- A suitable secondary containment structure must be utilized at each fuel storage site. These structures must be lined with suitable plastic sheeting; provide a minimum containment volume equal to 150 percent of the volume of the largest storage vessel; and provide at least 1 foot of freeboard.

- If earthen containment dikes are used, they shall be constructed with slopes no steeper than 3:1 (horizontal to vertical) to limit erosion and provide structural stability.

- Secondary containment areas must not have drains. Precipitation may be drawn off as necessary. If visual inspection indicates that no spillage has occurred in the secondary containment structure, accumulated water may be drawn off and sprayed on the surrounding upland areas. If spillage has occurred in the structure, accumulated waste shall be drawn off and pumped into drum storage for proper disposal.

- Vehicle maintenance wastes, including used oils and other fluids, shall be handled and managed by personnel trained in the procedures outlined in this plan. Vehicle maintenance wastes will be stored and disposed of in accordance with Section 7.0 of this Spill Plan.

3.2 REFUELING

- Fuels shall be dispensed by Authorized Personnel during daylight hours only.

- Fuel dispensing operations shall be attended by Authorized Personnel at all times. Personnel must be stationed at both ends of the hose during fueling unless both ends are visible and are readily accessible by one person.

- Fuel dispensing equipment (i.e., portable gas cans, nozzles, hoses, etc.) shall be of the appropriate type. Consult with the Contractor Safety Program (CSP) for details.

3.3 REFUELING AND FUEL STORAGE NEAR WETLANDS AND WATERBODIES

Enbridge requires that the storage of petroleum products, refueling and lubricating operations take place in upland areas that are more than 100 feet from wetlands, streams, and waterbodies (including drainage ditches), and water supply wells. In addition, the Contractor must store hazardous materials, chemicals, fuel and lubricating oils, and perform concrete coating activities outside these areas. Auxiliary fuel tanks solidly attached to construction equipment or pumps are not considered storage and are acceptable.

In certain instances, refueling or fuel storage may be unavoidable due to site-specific conditions or unique construction requirements (*e.g.* continuously operating pumps or equipment on barges). These locations must be approved in advance by the Environmental Inspector. In addition to those practices described above, the following precautions will be taken when refueling within 100 feet of streams, wetlands or other waterbodies:

- Adequate amounts of absorbent materials and containment booms must be kept on hand by each construction crew to enable the rapid cleanup of any spill which may occur.
- If fuel must be stored within wetlands or near streams for refueling of continuously operating pumps, secondary containment must be provided.
- Secondary containment structures must be lined with suitable plastic sheeting, provide a containment volume of at least 150 percent of the storage vessel, and allow for at least one foot of freeboard.
- Provide for adequate lighting of these locations and activities.

4.0 INITIAL SPILL MANAGEMENT

4.1 IMMEDIATE RESPONSE

Immediately upon learning of any fuel, oil, hazardous material or other regulated substance spill, or upon learning of conditions that will lead to an imminent spill, the person discovering the situation shall:

- Initiate actions to contain the fluid that has spilled or is about to spill, and initiate action to eliminate the source of the spill to the maximum extent that is safely possible.
- Notify the crew foreman and/or the Spill Coordinator and provide them with the following information:
- Location and cause of the spill
- The type of material that has spilled
- Whether the spill has reached or is likely to reach any surface water

Upon learning of a spill or a potential spill the Spill Coordinator shall:

- Assess the situation and determine the need for further action.

- Direct subsequent activities and/or further assign responsibilities to other personnel.

- Procedures regarding excavation and disposal of contaminated soil material from wetlands or near waterbodies are described in Section 6.2 of this Plan.

- Notify the Enbridge Representative and Environmental Inspector.

4.2 MOBILIZATION

- The Spill Coordinator shall mobilize on-site personnel, equipment, and materials for containment and/or cleanup commensurate with the extent of the spill.

- If the Spill Coordinator determines that a spill is beyond the scope of on-site equipment and personnel, the Spill Coordinator shall immediately notify the Construction Superintendent that an Emergency Response Contractor is needed to contain and/or clean up the spill. Appendix A contains a list of potential Emergency Response Contractors.

- The Spill Coordinator shall assist the Emergency Response Contractor and monitor containment procedures to ensure that the actions are consistent with the requirements of this Spill Plan.

- In the event of a pipeline spill (to an adjacent pipeline), Enbridge's Emergency Pipeline Control Center must be notified at 1-800-858-5253 (24-hours/day), as well as the Company Representative. Actions requiring emergency response employees and contractors will be coordinated by the Company Representative.

5.0 SPILL NOTIFICATION RESPONSIBILITIES

5.1 NOTIFICATION VOLUMES

The Contractor's Construction Superintendent or representative must notify the Enbridge Representative and the Environmental Inspector immediately of any spill of a petroleum product or hazardous liquid, regardless of volume.

5.2 SPILL REPORT FORM (APPENDIX B)

The Spill Coordinator shall complete a Spill Report Form for each release of a regulated substance, regardless of volume. The Spill Report Form must be submitted to the Enbridge Representative within 24 hours of the occurrence of a spill. To complete the Spill Report Form, the Spill Coordinator shall compile the following information:

- A legal description of the spill location, and specific directions from the nearest community.

- The time and date of the spill, and the time and date the spill was discovered.

- The type and estimated volume of spilled material, and the manufacturer's name.

- The media in which the spill exists (e.g., soil, water, etc.).
- The topography and surface conditions of the spill site.
- Proximity of surface waters.
- Weather conditions.
- Name, company, address, and telephone number of the Construction Superintendent, Spill Coordinator, Enbridge representative, and the person who reported the spill.
- The cause of the spill.
- Immediate containment and/or cleanup actions taken.
- Current status of cleanup actions.

Follow-up written reports, associated laboratory analyses, confirmatory field sampling and other documentation may also be required separately on a site-specific basis as directed by the Company Representative or Environmental Inspector. Documentation is the responsibility of the Contractor.

5.3 AGENCY NOTIFICATION

The Contractor will notify Enbridge and report spills to appropriate federal, state and local agencies as soon as possible. These include, but may not be limited to the following:

National Response Center, in Washington, D.C.
Phone: (800) 424-8802 (24 hours)

The Contractor, in coordination with Enbridge and the appropriate federal, state and local agencies must ensure that additional parties or agencies are properly notified. Additionally, the Contractor is responsible for ensuring that all cleanup activities required by a jurisdictional agency are satisfactorily met and provide documentation to Enbridge demonstrating this compliance.

6.0 SPILL CONTAINMENT AND CLEANUP

In the event of a spill, the Contractor will abide by all applicable federal, state and local regulations with respect to cleaning up the spill. All cleanup and other construction related spill activities must be completed by, and costs assumed by the Contractor. Specific cleanup measures for both upland and wetland/waterbody spills are described below.

6.1 SPILL CONTROL - UPLAND AREAS

- If a spill should occur during refueling operations, STOP the refueling operation until the spill can be controlled and the situation corrected.
- The source of the spill must be identified and contained immediately.

- For large spills on land, the spill must be contained and pumped immediately into tank trucks. The Contractor or, if necessary, an Emergency Response Contractor, shall excavate contaminated soil. Appendix A lists potential Emergency Response Contractors.

- The spilled material and the contaminated soil must be treated and/or disposed of in accordance with all applicable federal, state, and local agency requirements (see Section 7.0 of this Spill Plan).

- Smaller spills on land shall be cleaned up with absorbent materials. Contaminated soil or other materials associated with these releases shall also be collected and disposed of in accordance with applicable regulations (see Section 7.0 of this Spill Plan).

- Flowing spills must be contained and/or absorbed before reaching surface waters or wetlands.

- Absorbent material(s) shall be placed over spills to minimize spreading and to reduce its penetration into the soil.

- The Spill Coordinator and/or Enbridge Representative, in consultation with appropriate agencies, determine when spill sites will be evacuated as necessary to safeguard human health. Evacuation parameters shall include consideration for the potential of fire, explosion, and hazardous gases.

6.2 SPILL CONTROL - WETLANDS AND WATERBODIES

In addition to the above measures, the following conditions shall apply if a spill occurs near or into a stream, wetland or other waterbody, regardless of size:

- If a spill should occur during refueling operations, STOP the operation until the spill can be controlled and the situation corrected.

- For spills into streams, lakes or other waterbodies containing standing or flowing water, regardless of size, the Contractor Representative must apprise Enbridge of the incident and notify the National Response Center immediately.

- For spills in standing water, sorbent booms and pads shall be on hand and used by the Contractor to contain and recover released materials. In addition, other spill response materials and equipment shall be on hand as appropriate for each waterbody and used to contain and recover foreseeable spills. This may include containment booms, skimmer pumps, holding tanks, boats, and other equipment.

- If necessary, for large spills in waterbodies, an Emergency Response Contractor must be secured to further contain and clean up the spill. A list of Emergency Response Contractors is included in Appendix A.

- Contaminated soils in wetlands must be excavated and temporarily placed on plastic sheeting in a bermed area, a minimum of 100 feet away from the wetland. Contaminated soils shall be covered with plastic sheeting while being stored temporarily and properly disposed of as soon as possible, in accordance with this

Plan (see Section 7.0). Enbridge maintains spill records along its entire system. Historic leak sites may exist within the project area and the Environmental Inspector will be made aware of the location of these sites prior to work occurring in them. Unknown contamination or historic contamination encountered during construction will be managed per Enbridge's Contaminated Soils Management Plan. Water Quality and Solid Waste program staff will continue to be notified of newly discovered sites.

7.0 STORAGE AND DISPOSAL OF CONTAMINATED MATERIALS

- Appendix A of this SPCC Plan lists potential treatment and disposal facilities for contaminated materials, petroleum products, and other construction-related wastes. Enbridge will recycle those wastes, such as motor oil, where there is an established recycling program available. Wastes such as grease or oily rags shall be disposed of in accordance with state requirements.

- All contaminated soils, absorbent materials, and other wastes shall be stored and disposed of by the Contractor in accordance with all applicable state and federal regulations.

- Only licensed carriers may be used to transport contaminated material from the site to a disposal facility.

- If it is necessary to temporarily store excavated soils on site, these materials shall be placed on, and covered by, plastic sheeting, or placed in properly labeled ring-top 55-gallon drums and the storage area bermed to prevent and contain runoff.

- Any hazardous or contaminated material stored on Enbridge property or the right-of-way will be properly labeled in accordance with State and US EPA labeling requirements.

APPENDIX A

Emergency Response Contractors;

Disposal and Treatment Facilities

The Contractor must dispose of all wastes according to applicable federal, state, and local requirements. A listing of potential Emergency Spill Response Contractors and waste disposal facilities is provided below. This list was developed from state-wide data bases. This list represents firms operating at the time the data base was produced. The Contractor is responsible for verifying if a contractor or facility is currently operating under appropriate permits or licenses. The Contractor is responsible for ensuring wastes are disposed of properly.

Spill Response Contractors

Peterson Construction	Grand Forks, ND	(701) 746-6446
ACME Electric Tool Crib of the North	Grand Forks, ND	(800) 732-4287
Ziegler's Cat	Crookston, MN	(218) 281-4245
Mark II	Fosston, MN	(218) 435-1991
Thygeson Construction	Thief River Falls, MN	(218) 681-1924
Prowler Transport	Thief River Falls, MN	(218) 681-4366
Charps Welding & Fabrication Inc.	Clearbrook, MN	(218) 776-3080
Dyrdahl Brothers Inc.	Bagley, MN	(800) 914-2078
Minnesota Limited	Rogers, MN	(763) 428-4444
	Bemidji, MN	(218) 755-9595
	Superior, WI	(715) 395-2551
Beltrami Industrial	Solway, MN	(218) 751-7537
Christiansen Construction	Bemidji, MN	(218) 751-4433
OSI Environmental	Eveleth/Bemidji, MN	(800) 777-8542
Mann's Excavating and Trucking	Deer River, MN	(218) 246-8258
Trout Enterprise	Deer River, MN	(218) 246-8165
Casper Construction	Grand Rapids, MN	(218) 326-9637
Liquid Transport	Esko, MN	(218) 879-3228
Road Machinery & Supply	Duluth, MN	(218) 727-8611
United Piping INC.	Duluth, MN	(218) 727-7676
Lakehead Constructors	Superior, WI	(715) 392-5181
J.R. Jensen & Sons	Superior, WI	(715) 398-6626
Reuben Johnson & Son	Superior, WI	(715) 394-7771
Udeen Trucking Inc.	Superior, WI	(715) 394-4815
Deans Trucking	Superior, WI	(715) 394-5838
Industrial Service and Repair	Superior, WI	(715) 398-0759
Four Star Construction	Superior, WI	(715) 394-9564
TLK Industries	Superior, WI	(715) 392-6253
Stack Brothers	Superior, WI	(715) 398-2964
J. Kimmes Construction	Superior, WI	(715) 392-1989
Wes Johnson Trucking	South Range, WI	(715) 399-2993
Northern Interstate Construction	South Range, WI	(715) 398-7561
Badger State Excavating	Solon Springs, WI	(715) 378-4584
Thompson Sand & Gravel	Hayward, WI	(715) 634-3139
CEDA Inc.	Blaine, MN	(763) 434-4403
Onyx Special Services Inc.	Brooklyn, MN	(800) 401-0121

Waste Disposal/Treatment Facilities

Northstar Reclamation (Landfarm)	Fosston, MN	(800) 422-0817
Polk County Incinerator (Thermal treatment)	Fosston, MN	(218) 435-6501
Lake Area Landfill (BFI) (Landfill)	Sarona, WI	(612) 457-2778
Lakehead Blacktop (Thermal treatment)	Superior, WI	(715) 392-1989
Monarch Paving Plant 25 (Thermal treatment)	Iron River, WI	(715) 268-2687
Timberline Trail (Waste Mgmt.) (Landfill)	Weyerhaueser, WI	(800) 504-1067 ext. 7

APPENDIX B

Spill Report Form

SPILL REPORT FORM

Date of Spill:____________________________ Date of Spill Discovery:___________

Time of Spill:____________________________ Time of Spill Discovery:___________

Name and Title of Discoverer:____

Type of material spilled and manufacturer's name:_____________________________

Legal Description of spill location:____

Directions from nearest community:____

Estimated volume of spill:____

Weather conditions:____

Topography and surface conditions of spill site:_______________________________

Spill medium (pavement, sandy soil, water, etc.):_____________________________

Proximity of spill to surface waters: ______________________________________

Did the spill reach a waterbody? ________Yes ________No

If so, was a sheen present? ________Yes ________No

Describe the causes and circumstances resulting in the spill:____________________

____

____

Describe the extent of observed contamination, both horizontal and vertical (i.e., spill-stained soil in a 5-foot radius to a depth of 1 inch): ___________________________________

____

____

Describe immediate spill control and/or cleanup methods used and implementation schedule: __

____

Current status of cleanup actions:____

Name and Company for the following:

Construction Superintendent:____

____

Spill Coordinator:____

____

Enbridge Representative:____

Person Who Reported the Spill:____

____

Environmental Inspector:____

Form completed by:_______________________________________Date:__________

Spill Coordinator must complete this for any spill, regardless of size, and submit the form to the Enbridge Representative within 24 hrs of the occurrence.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
3425 Miriam Avenue
Bismarck, North Dakota 58501

NOV - 2 2006

Ms. Tracy Szela
Natural Resources Group
1000 IDS Center
80th South 8th Street
Minneapolis, Minnesota 55402

Re: Enbridge Energy Company, Inc. Southern Lights Pipeline Project Pembina County, North Dakota

Dear Ms. Szela:

The U.S. Fish and Wildlife Service (Service) has reviewed the proposed pipeline project presented in an August 29, 2006, letter from Enbridge Energy Company, Inc. (Enbridge). The proposed pipeline will be constructed adjacent to an existing Enbridge pipeline system in Pembina County, North Dakota. The pipeline project involves the transportation of a light weight petroleum project, called diluent, from refineries in the Chicago area to the oil sands region of Canada. The North Dakota portion of the project consists of a 20-or 24-inch crude oil pipeline that will run between Neche, North Dakota, and Clearbrook, Minnesota. We offer the following comments under the authority of and in accordance with the Migratory Bird Treaty Act (16 U.S.C. 703 et seq.), the Endangered Species Act (ESA) (16 U.S.C. 1531 et seq.), and the National Environmental Policy Act of 1969 (NEPA), as amended (42 U.S.C. 4321 et seq.).

The Service administers fee title and easement lands throughout North Dakota. A review of our county plat maps (photocopies enclosed) indicates Service property interests (fee title lands highlighted in green) are located along the pipeline route, (T. 162 N., R. 51 W., Section 32, NW¼). The Service requires that all wetlands and property interests under its jurisdiction be avoided during project construction, when possible. Special Use or right-of-way permits will be necessary for any construction resulting in impacts to wetlands protected by easements or fee title lands. The issuance of Special Use or right-of-way permits are subject to the final determination of a refuge compatibility review process. For specific information on Service property interests in Pembina County and to determine the need for permits, contact Roger Hollevoet, Project Leader, Devils Lake Wetland Management District, P.O. Box 908, 221 Second Street NW, Devils Lake, North Dakota 58301, (701-662-8611).

Our review of the National Wetland Inventory (NWI) maps and photographs indicate the proposed planning area includes numerous wetland basins and the Red River of the North, Pembina River, and Tongue River. You may access the NWI data directly through their website (wetlands.fws.gov). The river reaches that the proposed pipeline will cross are classified by the North Dakota Game and Fish Department (Department) as a highest-valued fishery resource. These rivers have value for forage fish production and sport fisheries. To avoid impact to these important aquatic resources, the Service recommends that these river channels be crossed using directional boring techniques.

Projects which involve the burying of a pipeline should not significantly affect wetland basins or stream channels provided precautions are taken to restore natural basin contours. Precautions should also be taken during installation of underground facilities by sufficiently compacting trenches through the wetlands to prevent drainage along the trench or through bottom seepage. The Service recommends that construction through or adjacent to these areas be avoided where possible or measures be taken (e.g. directional boring) to minimize disturbance to these areas.

To minimize disturbance to fish and wildlife resources in the project area, the Service provides the following recommendations:

- Avoid construction in river channels during the fish migration and spawning period from April 15 - June 1 and use directional boring techniques for river crossings.

- Make no stream channel alterations or changes in drainage patterns.

- Defer the timing of construction to late summer (after July 15) or fall so as not to disrupt waterfowl or other wildlife during the nesting season and to avoid high water conditions.

- Locate construction to avoid placement of fill in wetlands along the route.

- Replace unavoidable losses of wetland habitat with functionally equivalent wetlands and trees/shrubs at a ratio of two planted for each one removed.

- Install and maintain appropriate erosion control measures to reduce sediment transport to adjacent wetlands and stream channels.

- Reseed disturbed areas with a mixture of native grass and forb species.

If construction routes intersect wetlands, streams, or rivers, the Corps of Engineers (Corps) may require a Department of the Army permit for the placement of dredge or fill material into waters of the U.S., including wetlands, or other impacts to navigable waters. We suggest you contact Mr. Daniel Cimarosti, Regulatory Office, Corps of Engineers, 1513 South 12th Street, Bismarck, North Dakota 58504 (701-255-0015), to determine the Corps' permit requirements.

To minimize the electrocution hazard to birds, the Service, with support from the Rural Utilities Service, recommends that new or updated overhead power lines be constructed in accordance with the current guidelines for preventing raptor electrocutions. The recommended guidelines can be found in "Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996". To increase power line visibility and reduce bird fatalities resulting from collisions with power lines, the Service recommends power lines that cross or run adjacent to rivers or large wetlands be modified according to "Mitigating Bird Collisions with Power Lines: The State of the Art in 1994". Both publications can be obtained by writing or calling the Edison Electric Institute, P.O. Box 266, Waldorf, Maryland 20604-0266, (1-800-334-5453) or visiting their website at www.eei.org.

A list of federally endangered and threatened species that may be present within the proposed project's area of influence is attached. This list fulfills requirements of the Service under Section 7 of the Endangered Species Act.

If a Federal agency authorizes, funds, or carries out a proposed action, the responsible Federal agency, or its delegated agent, is required to evaluate whether the action "may affect" listed species. If the Federal agency determines the action "may affect" listed species, then the responsible Federal agency shall request formal section 7 consultation with this office. If the evaluation shows a "no effect" determination on listed species, further consultation is not necessary. If a private entity receives Federal funding for a construction project, or if any Federal permit is required, the Federal agency may designate the fund recipient or permittee as its agent for purposes of section 7 consultation.

Thank you for the opportunity to comment on this project. If you require further information or the project plans change, please contact Terry Ellsworth of my staff, or contact me directly, at (701) 250-4481, or at the letterhead address above.

Sincerely,

Jeffrey K. Towner

Jeffrey K. Towner
Field Supervisor
North Dakota Field Office

Enclosures

cc: Project Leader, Devils Lake WMD
Regulatory Office, Army Corps of Engineers, Bismarck
(Attn: D. Cimarosti)
Director, ND Game & Fish Department, Bismarck
(Attn: M. McKenna)

FEDERAL THREATENED AND ENDANGERED SPECIES
FOUND IN PEMBINA COUNTY
NORTH DAKOTA
November 2006

ENDANGERED SPECIES

Mammals

Gray wolf (Canis lupus): Occasional visitor in North Dakota. Most frequently observed in the Turtle Mountains area.

THREATENED SPECIES

Birds

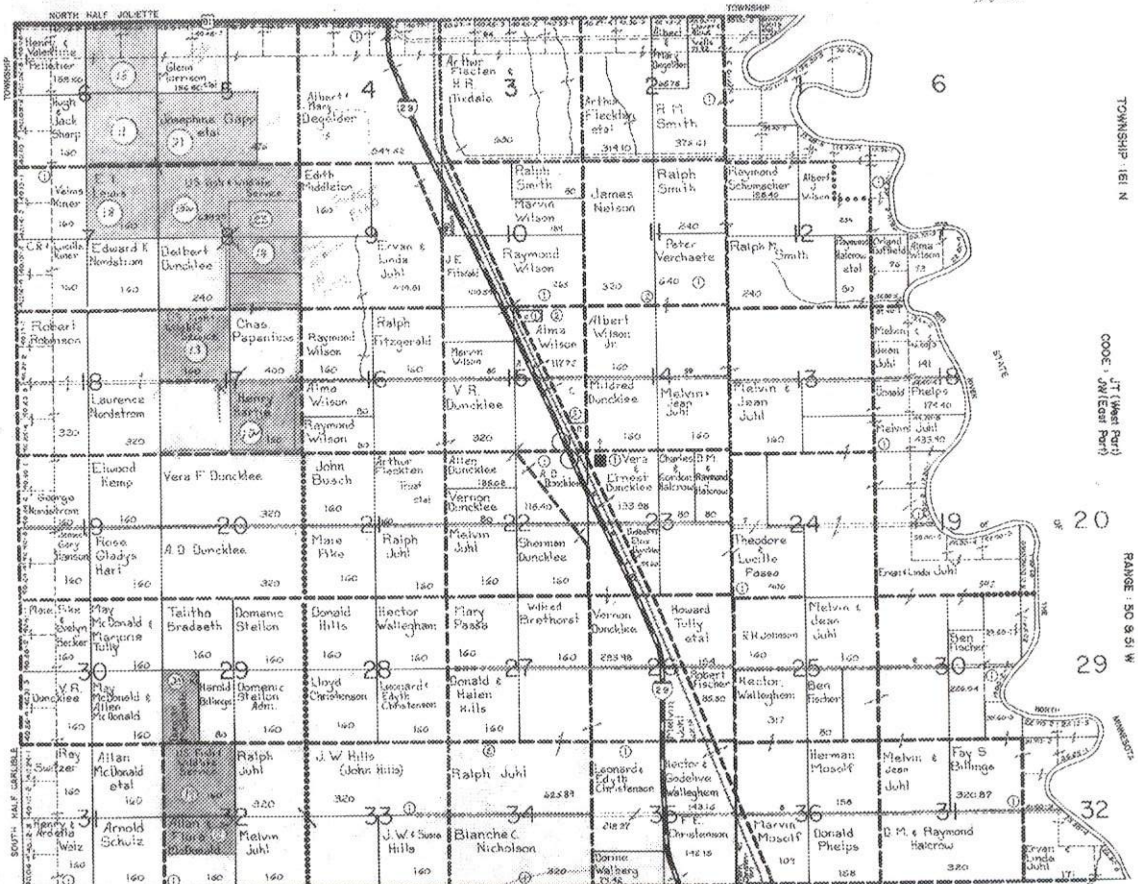
Bald eagle (Haliaeetus leucocephalus): Migrates spring and fall statewide but primarily along the major river courses. It concentrates along the Missouri River during winter and is known to nest in the floodplain forest.

JOLIETTE

CODE: JT (West Part) JW (East Part)

TOWNSHIP 161 N

RANGE: 50 & 51 W



Sec	Lot	Name	Acres
15	4	Vernon Wilson	12.00
		Melvin Juhl	8.00
		Ervan Juhl	32.00

JOLIETTE

TOWNSHIP: 162 N

CODE: JM (EAST) JL (WEST)

RANGE: 50 & 51 W

"VARIETY IN HUNTING AND FISHING"

NORTH DAKOTA GAME AND FISH DEPARTMENT

100 NORTH BISMARCK EXPRESSWAY BISMARCK, NORTH DAKOTA 58501-5095 PHONE 701-328-6300 FAX 701-328-6352

December 12, 2006

Tracy Szela
Natural Resource Group, Inc.
1000 IDS Center
80 South 8th Street
Minneapolis, MN 55402

Dear Ms. Szela:

RE: Southern Lights Pipeline Project

The North Dakota Game and Fish Department has reviewed this project for wildlife concerns. The State of North Dakota does not maintain an Endangered Species list, but instead defers to the Federal list.

As proposed, this pipeline will cross the Pembina and Tongue Rivers, both Class III fisheries, and the Red River, a Class I fishery. We recommend these streams be crossed by directional boring if possible. If this method is not feasible, construction should not take place within the waterway between April 15 and June 1, and controls should be implemented to minimize erosion and sedimentation. We suggest the US Army Corps of Engineers' North Dakota Regulatory Office be contacted for permit requirements under Section 404 of the Clean Water Act.

The National Wetland Inventory maps indicate numerous wetlands within the proposed project corridor. We recommend that steps be taken to protect any wetlands that cannot be avoided, above-ground appurtenances not be placed in wetland areas, and no alterations be made to existing drainage patterns. We also ask that every effort be made to prevent destruction of woody vegetation and any loss of trees and shrubs be replaced on a 2:1 basis.

Sincerely,

Steve Dyke

(for) Michael G. McKenna
Chief
Conservation & Communication Division

js

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
3425 Miriam Avenue
Bismarck, North Dakota 58501

NOV - 2 2006

Ms. Tracy Szela
Natural Resources Group
1000 IDS Center
80th South 8th Street
Minneapolis, Minnesota 55402

Re: Enbridge Energy Company, Inc. Southern Lights Pipeline Project Pembina County, North Dakota

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Thank you for the opportunity to comment on this project. If you require further information or the project plans change, please contact Terry Ellsworth of my staff, or contact me directly, at (701) 250-4481, or at the letterhead address above.

Sincerely,

Jeffrey K. Towner

Jeffrey K. Towner
Field Supervisor
North Dakota Field Office

Enclosures

cc: Project Leader, Devils Lake WMD
Regulatory Office, Army Corps of Engineers, Bismarck
(Attn: D. Cimarosti)
Director, ND Game & Fish Department, Bismarck
(Attn: M. McKenna)

FEDERAL THREATENED AND ENDANGERED SPECIES
FOUND IN PEMBINA COUNTY
NORTH DAKOTA
November 2006

ENDANGERED SPECIES

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Gray wolf (Canis lupus): Occasional visitor in North Dakota. Most frequently observed in the Turtle Mountains area.

THREATENED SPECIES

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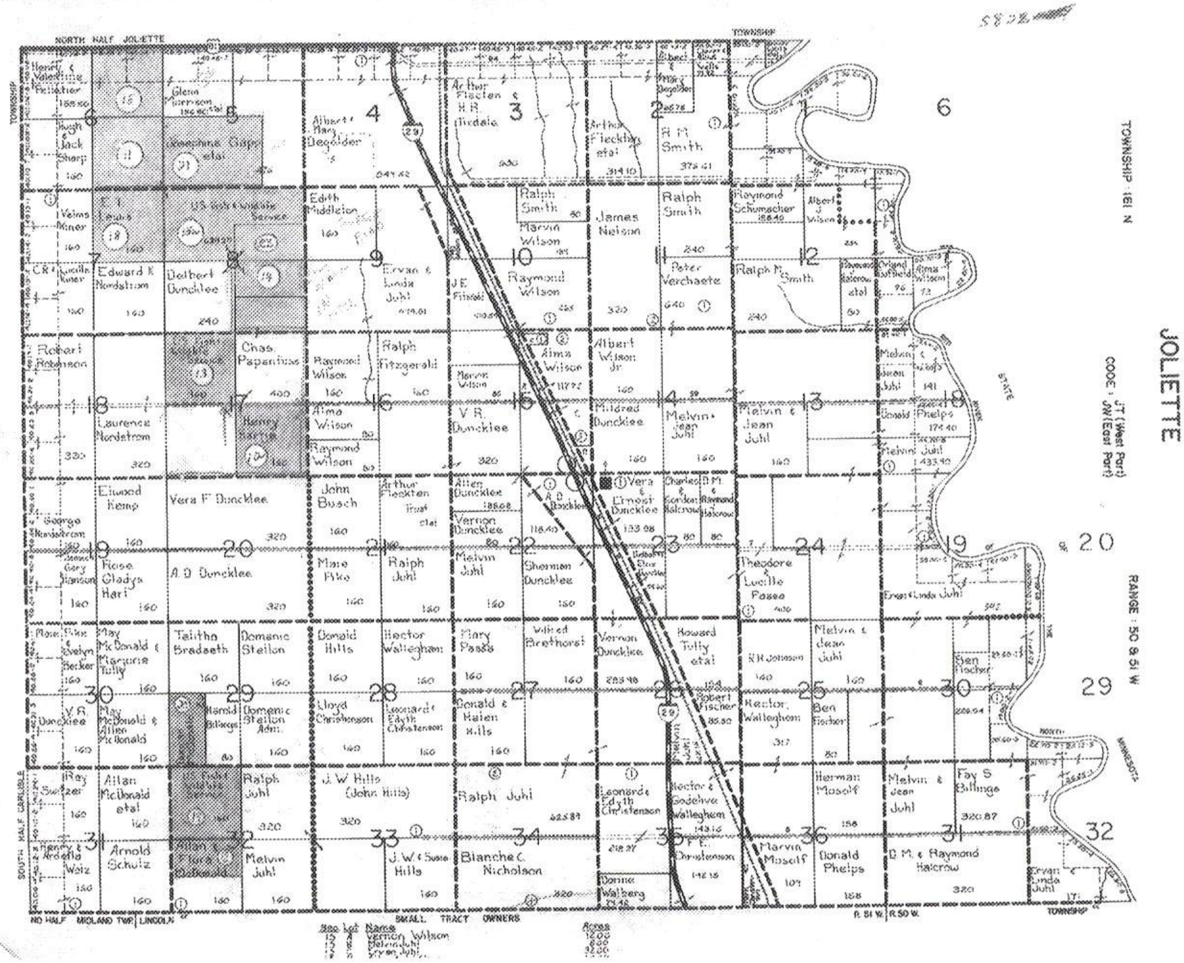
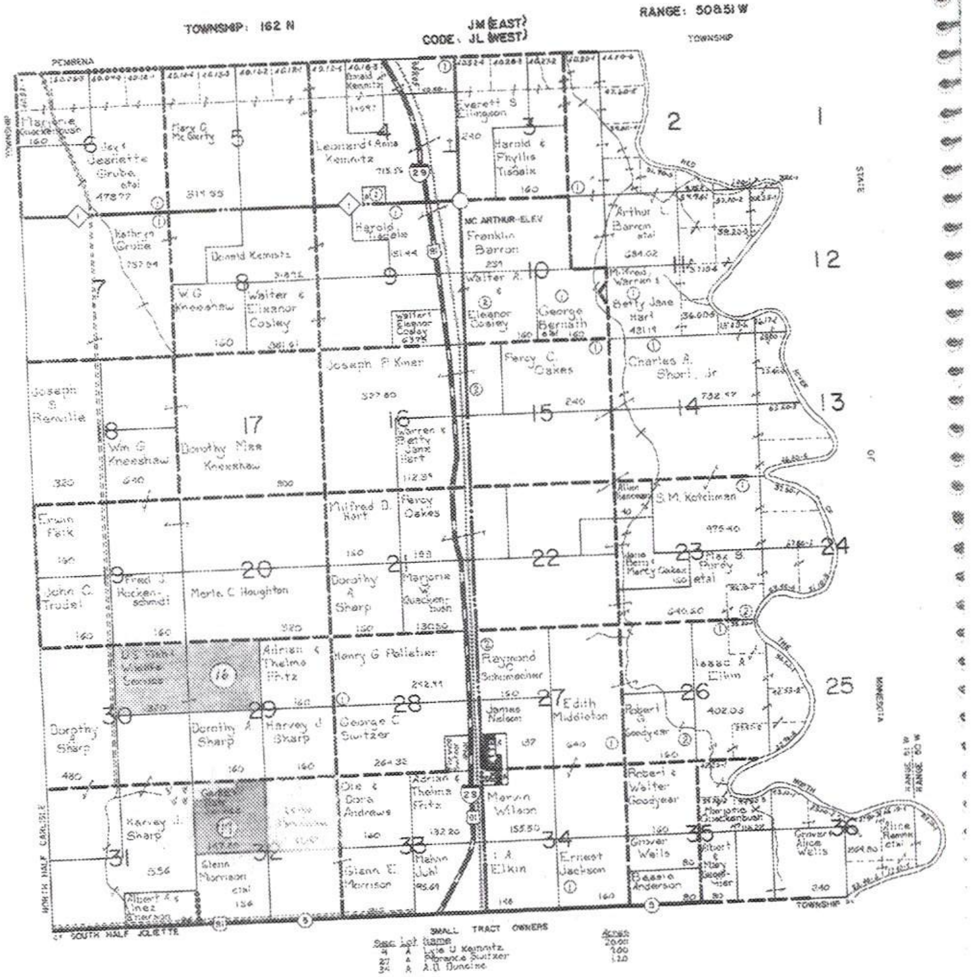

JOLIETTE
CODE : JT (West Part) JW (East Part)
TOWNSHIP 161 N
RANGE : 50 & 51 W
NORTH HALF JOLIETTE
SOUTH HALF CARLISLE
NO HALF MIDLAND TWP LINCOLN
SMALL TRACT OWNERS
Glenn Morrison
Josephine Gaps etal
Albert & Mary Degelder
Arthur Flecken & H.R. Tisdale
Arthur Flecken etal
R.M. Smith
Edith Middleton
Ralph Smith
Marvin Wilson
James Nelson
Raymond Schumacher
Edward K Nordstrom
Delbert Duncklee
Ervan & Linda Juhl
Raymond Wilson
Peter Verchaete
Ralph M. Smith
Robert Robinson
Chas. Papanikas
Ralph Fitzgerald
Alma Wilson
Albert Wilson Jr.
Laurence Nordstrom
Henry Hartje
V.R. Duncklee
Mildred Duncklee
Melvin & Jean Juhl
Melvin Juhl
Elwood Kemp
Vera F. Duncklee
John Busch
Arthur Flecken Trust etal
Allen Duncklee
Vernon Duncklee
A.D. Duncklee
Vera & Ernest Duncklee
Rose Gladys Hart
Mae Pike
Ralph Juhl
Melvin Juhl
Sherman Duncklee
Theodore & Lucille Passa
Talitha Bradseth
Domenic Steilon
Donald Hills
Hector Walleghem
Mary Passa
Wilfred Brethorst
Vernon Duncklee
Howard Tully etal
Melvin & Jean Juhl
Ben Fischer
Domenic Steilon Adm.
Lloyd Christenson
Leonard & Edyth Christenson
Donald & Helen Hills
Robert Fischer
Hector Walleghem
Allan McDonald etal
Ralph Juhl
J.W. Hills (John Hills)
Leonard & Edyth Christenson
Hector & Godelieve Walleghem
Herman Mosolf
Melvin & Jean Juhl
Fay S Billings
Arnold Schulz
Melvin Juhl
J.W. & Susie Hills
Blanche C. Nicholson
Donna Walberg
Marvin Mosolf
Donald Phelps
D.M. & Raymond Halcrow
Ervan & Linda Juhl

JOLIETTE


TOWNSHIP: 162 N
CODE: JM (EAST) JL (WEST)
RANGE: 50&51 W
PEMBINA
Marjorie Quackenbush
Jeanette Gruba etal
Mary G. McGerty
Leonard & Rena Kemnitz
Everett S. Ellingson
Harold & Phyllis Tisdale
Kathryn Gruba
Donald Kemnitz
W.G. Kneeshaw
Walter & Eleanor Cosley
Harold Tisdale
MC ARTHUR-ELEV
Franklin Barron
Walter X. & Eleanor Cosley
George Bernath
Arthur L. Barron etal
Betty Jane Hart
Charles A. Short, Jr.
Percy C. Oakes
Joseph P. Kmer
Joseph S. Remillie
Wm G. Kneeshaw
Dorothy Mae Kneeshaw
Warren & Betty Jane Hart
S.M. Ketchman
Erwin Falk
John C. Trudel
Fred J. Rockenschmidt
Merle C. Houghton
Milfred D. Hart
Percy Oakes
Dorothy A. Sharp
Marjorie Quackenbush
Max S. Purdy etal
Henry G. Pelletier
Raymond Schumacher
Adrian & Thelma Fritz
Dorothy Sharp
Dorothy A. Sharp
Harvey J. Sharp
George C. Switzer
James Nelson
Edith Middleton
Robert Goodyear
Isaac A. Elkin
Harvey J. Sharp
Glenn Morrison etal
Albert & Inez Sherwood
Ole & Dora Andrews
Adrian & Thelma Fritz
Marvin Wilson
Glenn E. Morrison
Melvin Juhl
I.A. Elkin
Ernest Jackson
Robert & Walter Goodyear
Grover Wells
Bessie Anderson
Marjorie K. Quackenbush
Grover Alice Wells
Alice Hennie etal
TOWNSHIP
MINNESOTA
NORTH HALF CARLISLE
SOUTH HALF JOLIETTE
SMALL TRACT OWNERS

"VARIETY IN HUNTING AND FISHING"

NORTH DAKOTA GAME AND FISH DEPARTMENT

100 NORTH BISMARCK EXPRESSWAY BISMARCK, NORTH DAKOTA 58501-5095 PHONE 701-328-6300 FAX 701-328-6352

December 12, 2006

Tracy Szela
Natural Resource Group, Inc.
1000 IDS Center
80 South 8th Street
Minneapolis, MN 55402

Dear Ms. Szela:

RE: Southern Lights Pipeline Project

The North Dakota Game and Fish Department has reviewed this project for wildlife concerns. The State of North Dakota does not maintain an Endangered Species list, but instead defers to the Federal list.

As proposed, this pipeline will cross the Pembina and Tongue Rivers, both Class III fisheries, and the Red River, a Class I fishery. We recommend these streams be crossed by directional boring if possible. If this method is not feasible, construction should not take place within the waterway between April 15 and June 1, and controls should be implemented to minimize erosion and sedimentation. We suggest the US Army Corps of Engineers' North Dakota Regulatory Office be contacted for permit requirements under Section 404 of the Clean Water Act.

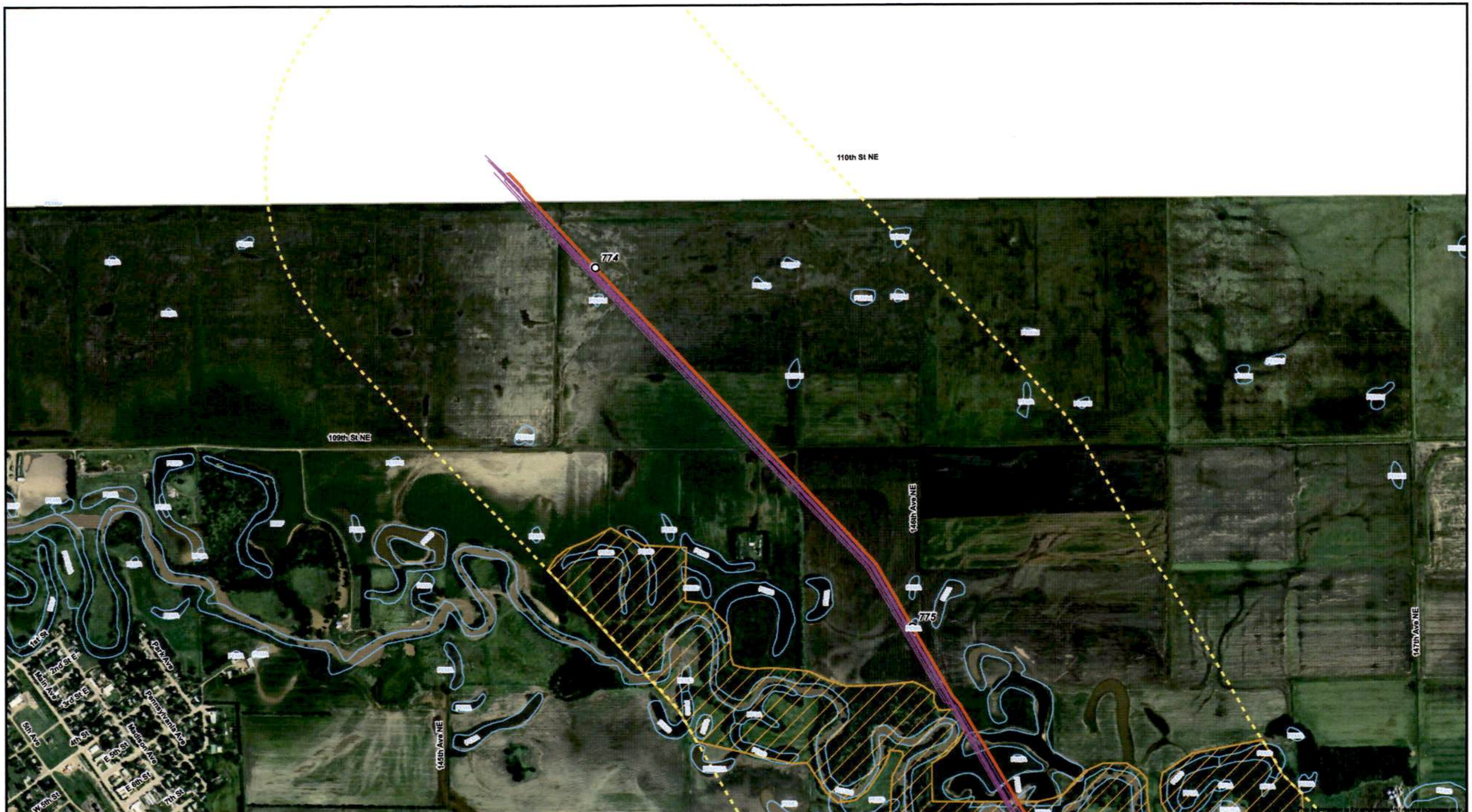
The National Wetland Inventory maps indicate numerous wetlands within the proposed project corridor. We recommend that steps be taken to protect any wetlands that cannot be avoided, above-ground appurtenances not be placed in wetland areas, and no alterations be made to existing drainage patterns. We also ask that every effort be made to prevent destruction of woody vegetation and any loss of trees and shrubs be replaced on a 2:1 basis.

Sincerely,

Steve Dyke

(for) Michael G. McKenna
Chief
Conservation & Communication Division

js



Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 1 of 14

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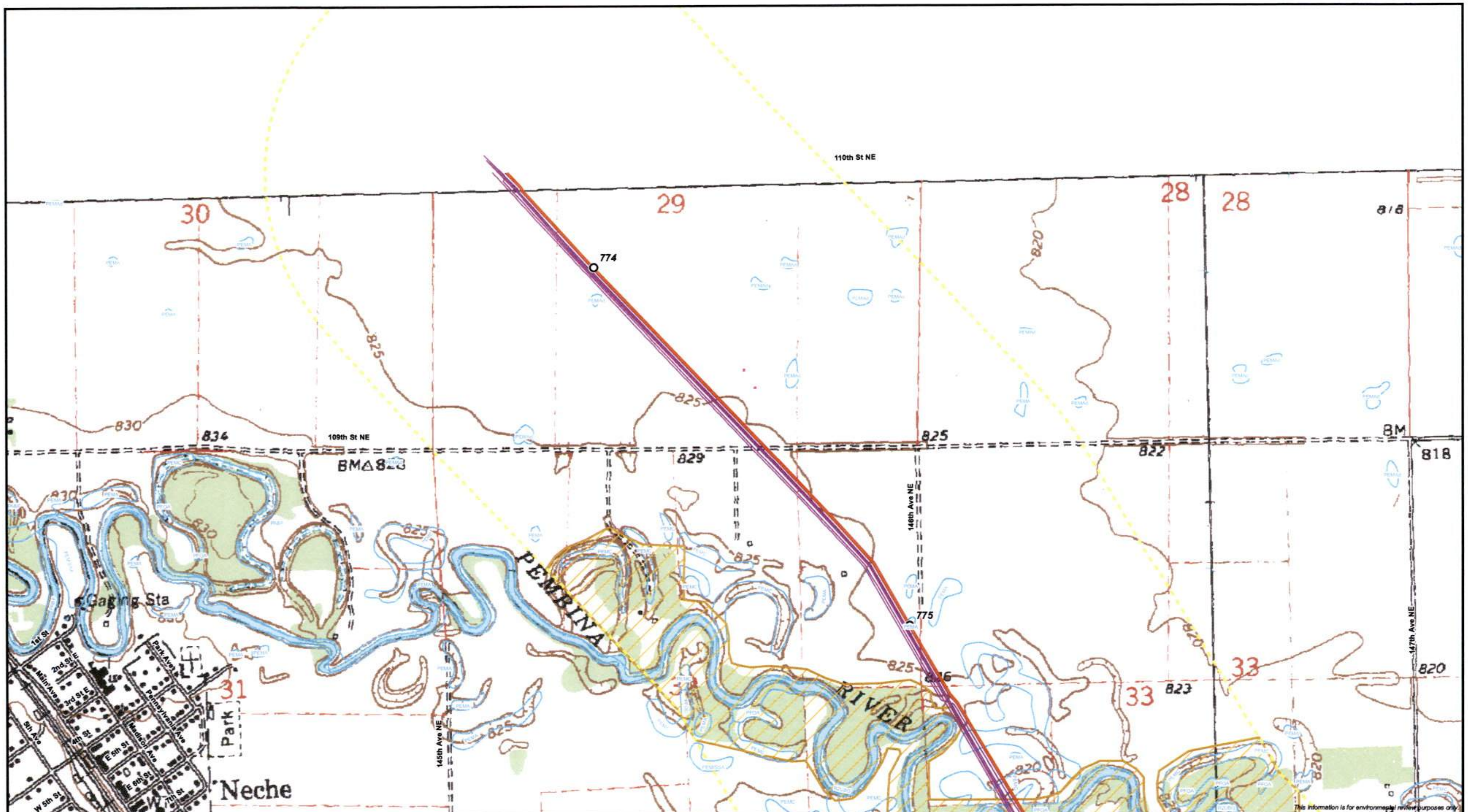

- Milepost
- Mainline Valve
- Proposed Alberta Clipper
- Existing Enbridge Lines
- Half Mile Corridor
- Avoidance Area - Wooded
- Exclusion/Avoidance Area
- National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 1 of 14

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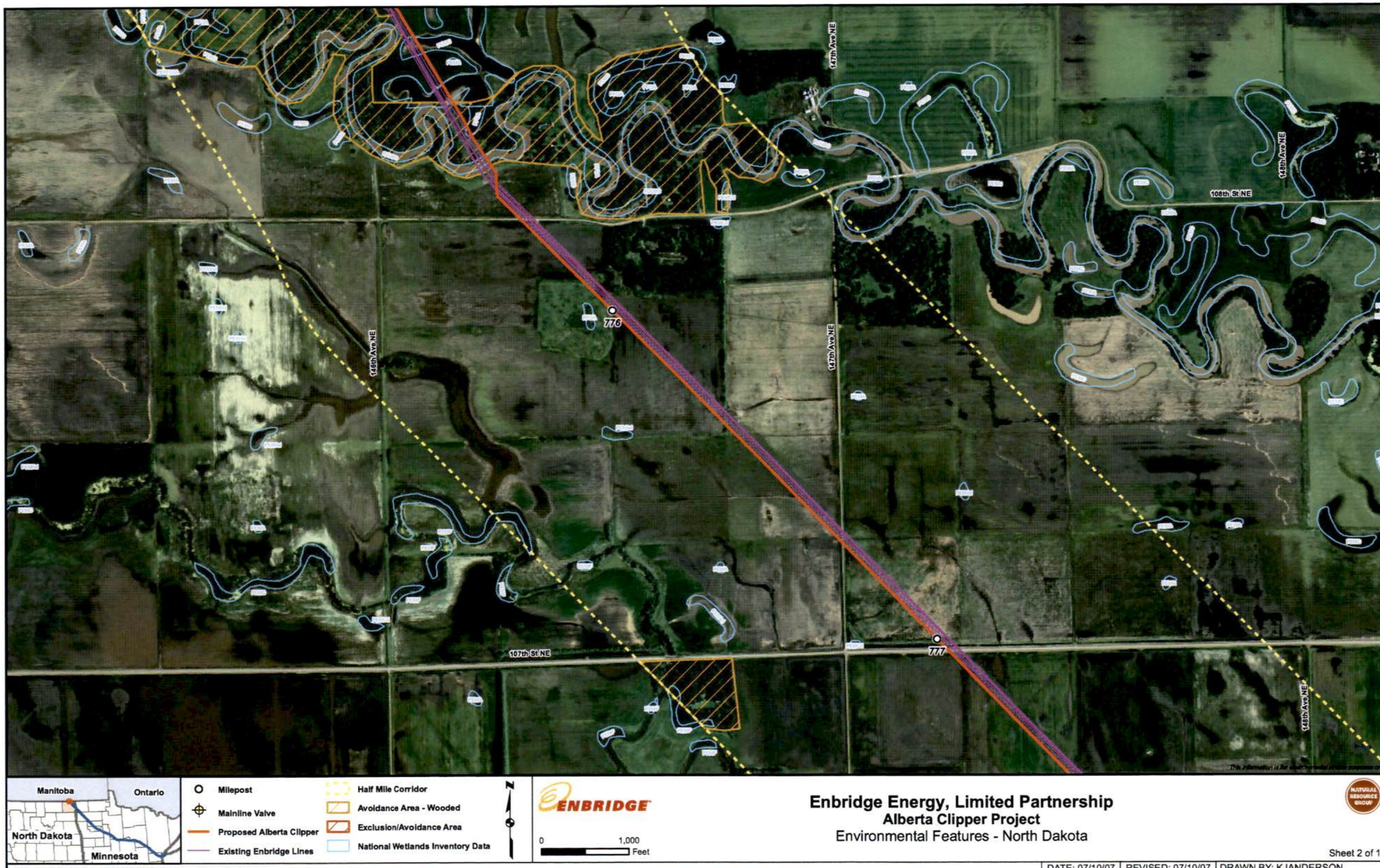

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 2 of 14

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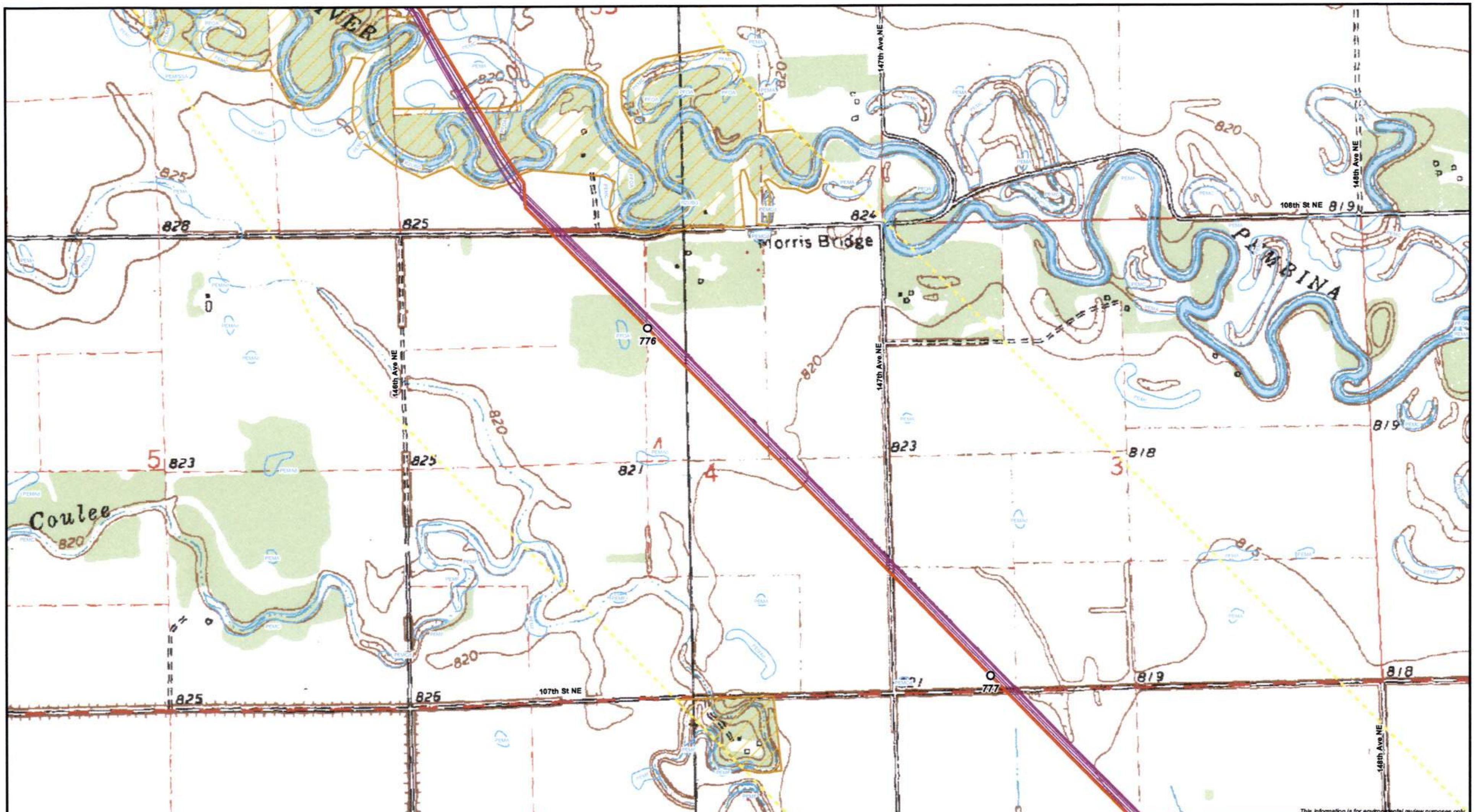

Milepost	Half Mile Corridor
Mainline Valve	Avoidance Area - Wooded
Proposed Alberta Clipper	Exclusion/Avoidance Area
Existing Enbridge Lines	National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

NATURAL RESOURCE GROUP

Sheet 2 of 14

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Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 3 of 14

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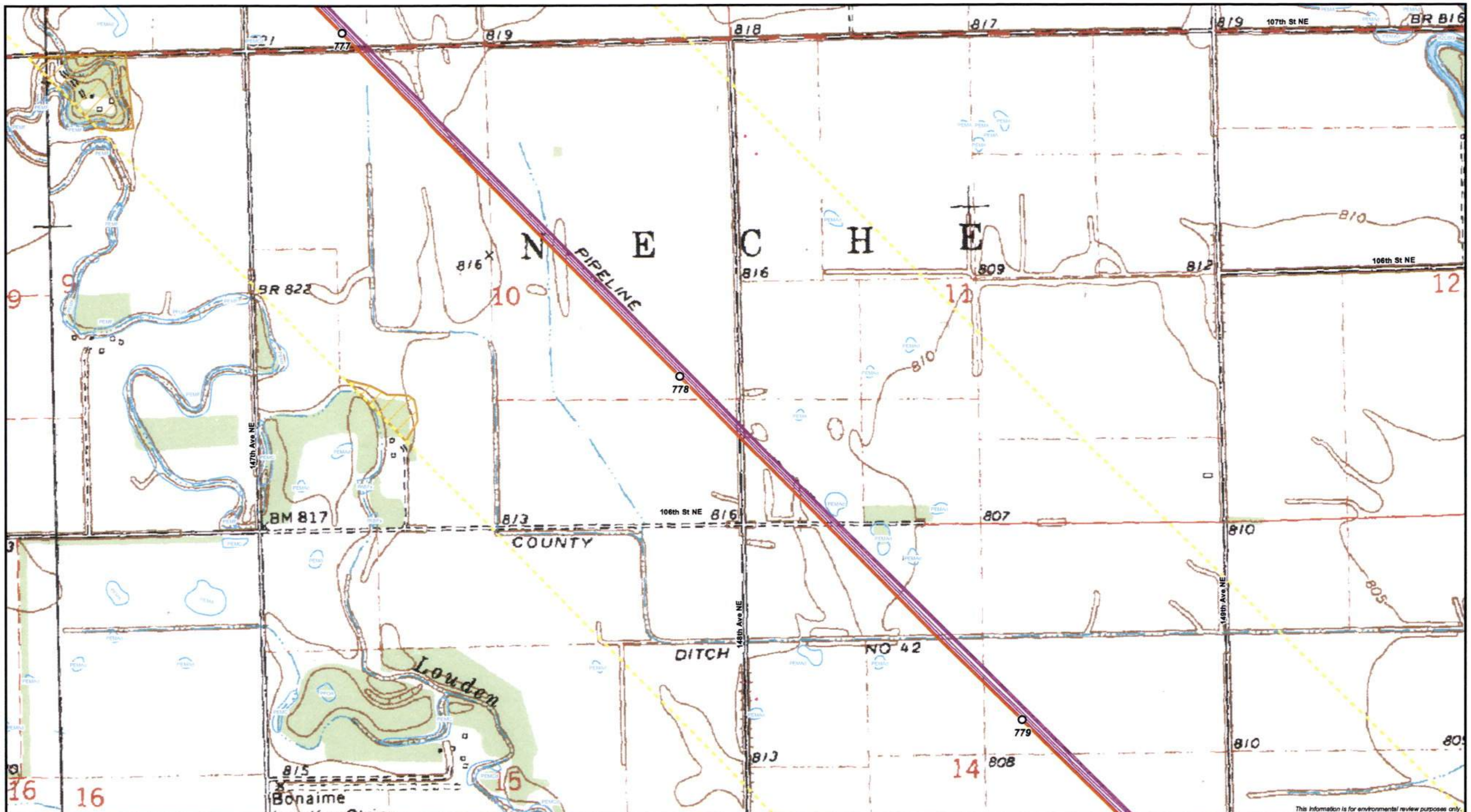

Milepost

Mainline Valve

Proposed Alberta Clipper

Existing Enbridge Lines

Half Mile Corridor

Avoidance Area - Wooded

Exclusion/Avoidance Area

National Wetlands Inventory Data

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

Sheet 3 of 14

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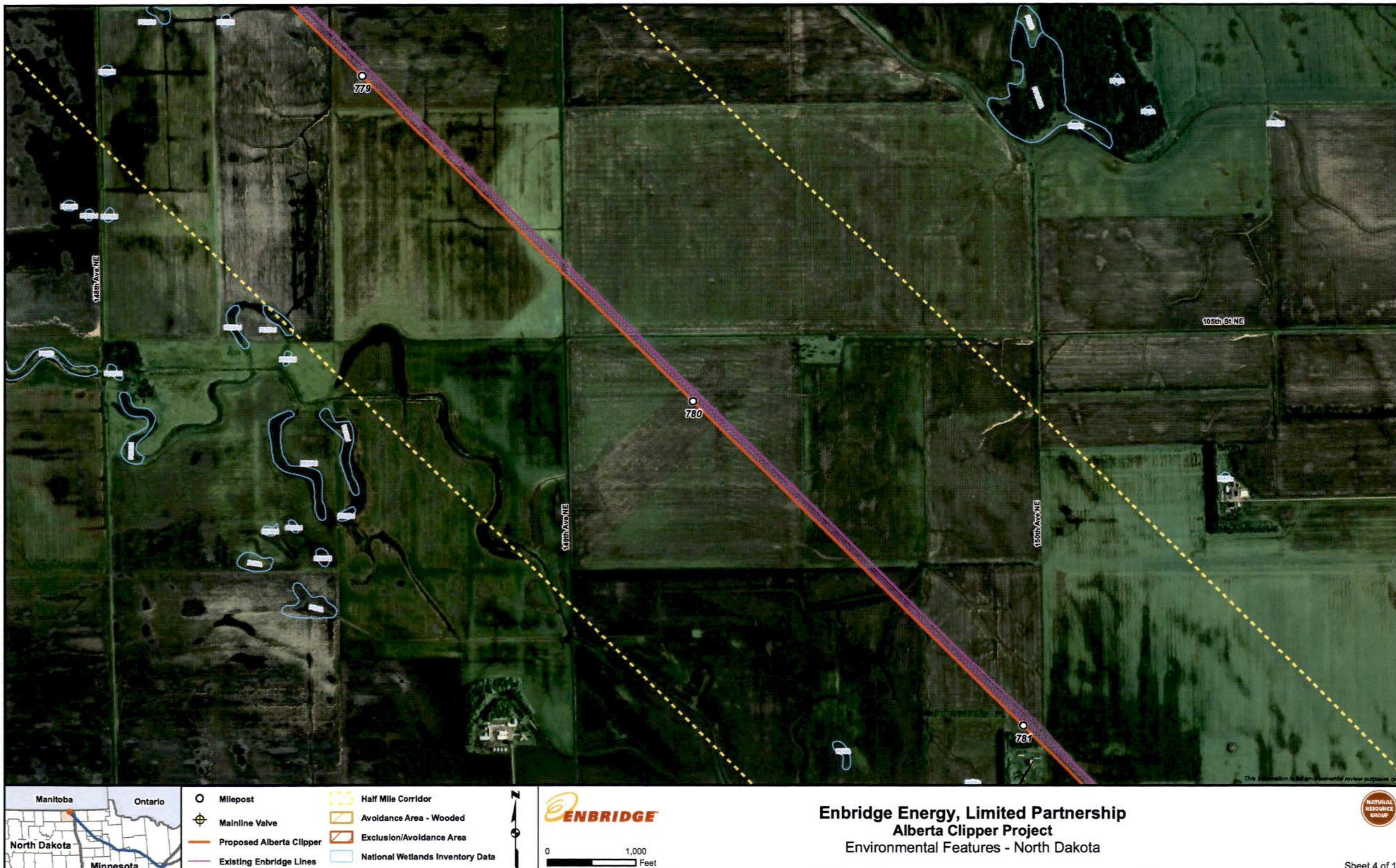

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

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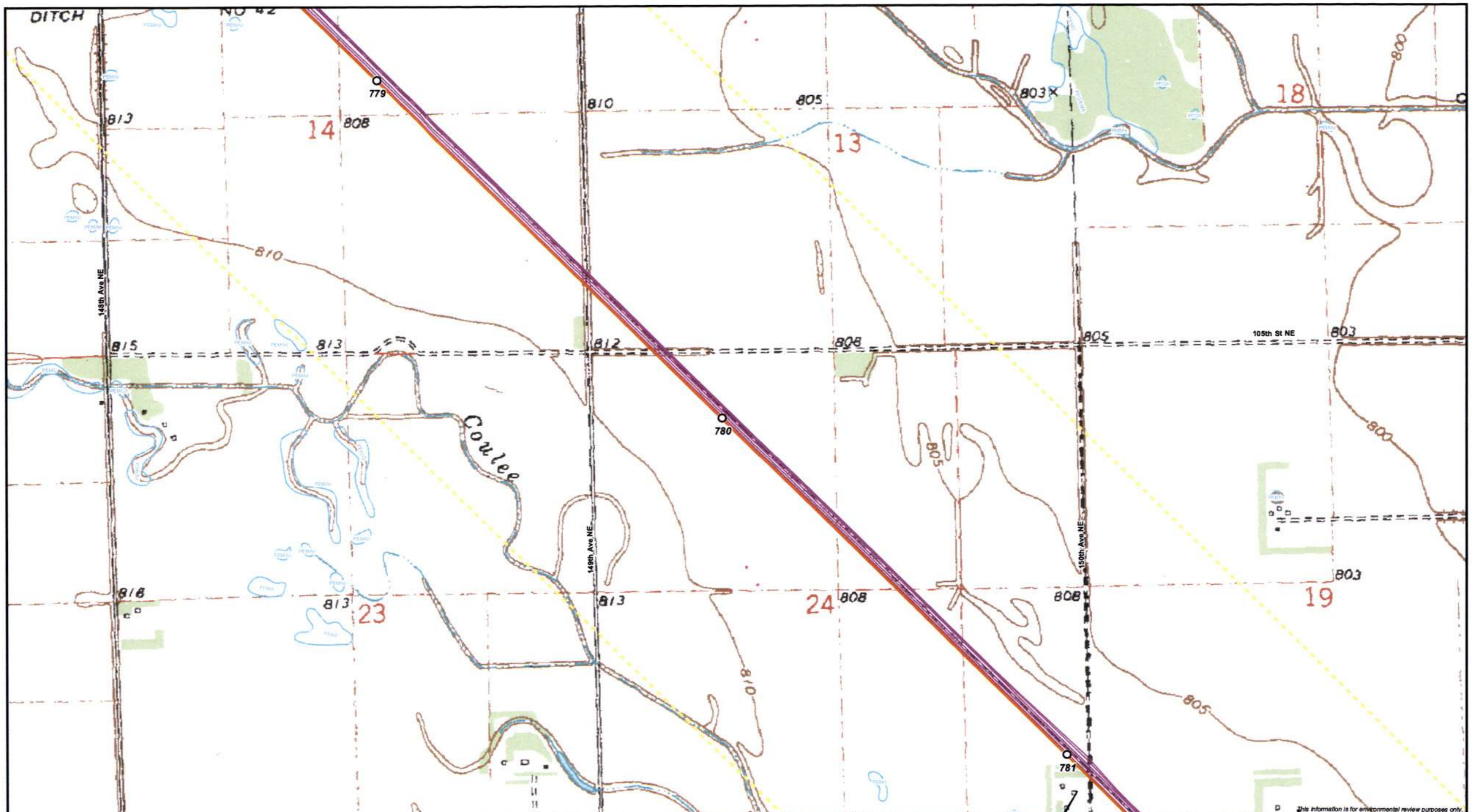

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

NATURAL RESOURCE GROUP

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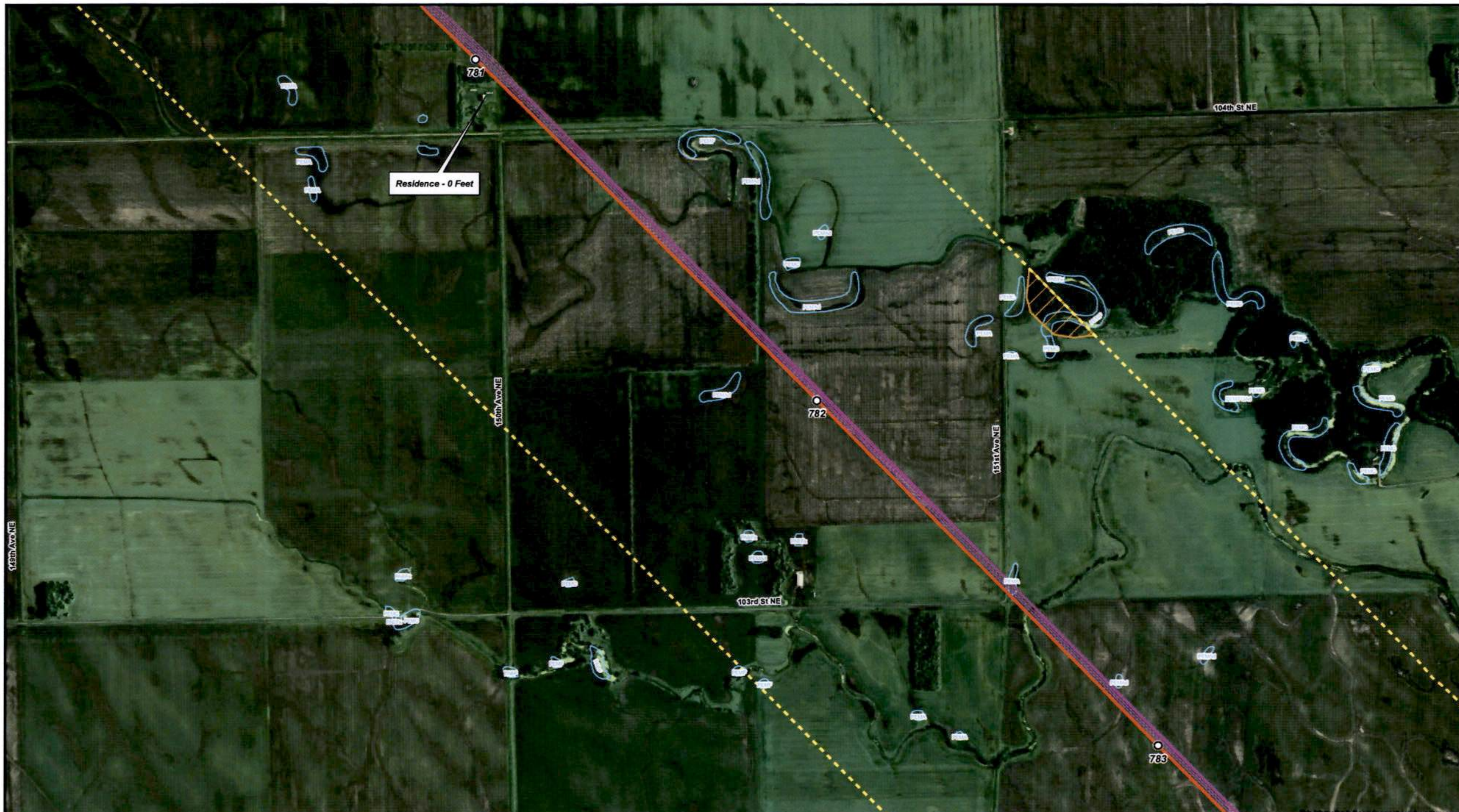

Manitoba
Ontario
North Dakota
Minnesota

- Milepost
- Mainline Valve
- Proposed Alberta Clipper
- Existing Enbridge Lines
- Half Mile Corridor
- Avoidance Area - Wooded
- Exclusion/Avoidance Area
- National Wetlands Inventory Data

N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

NATURAL RESOURCE GROUP

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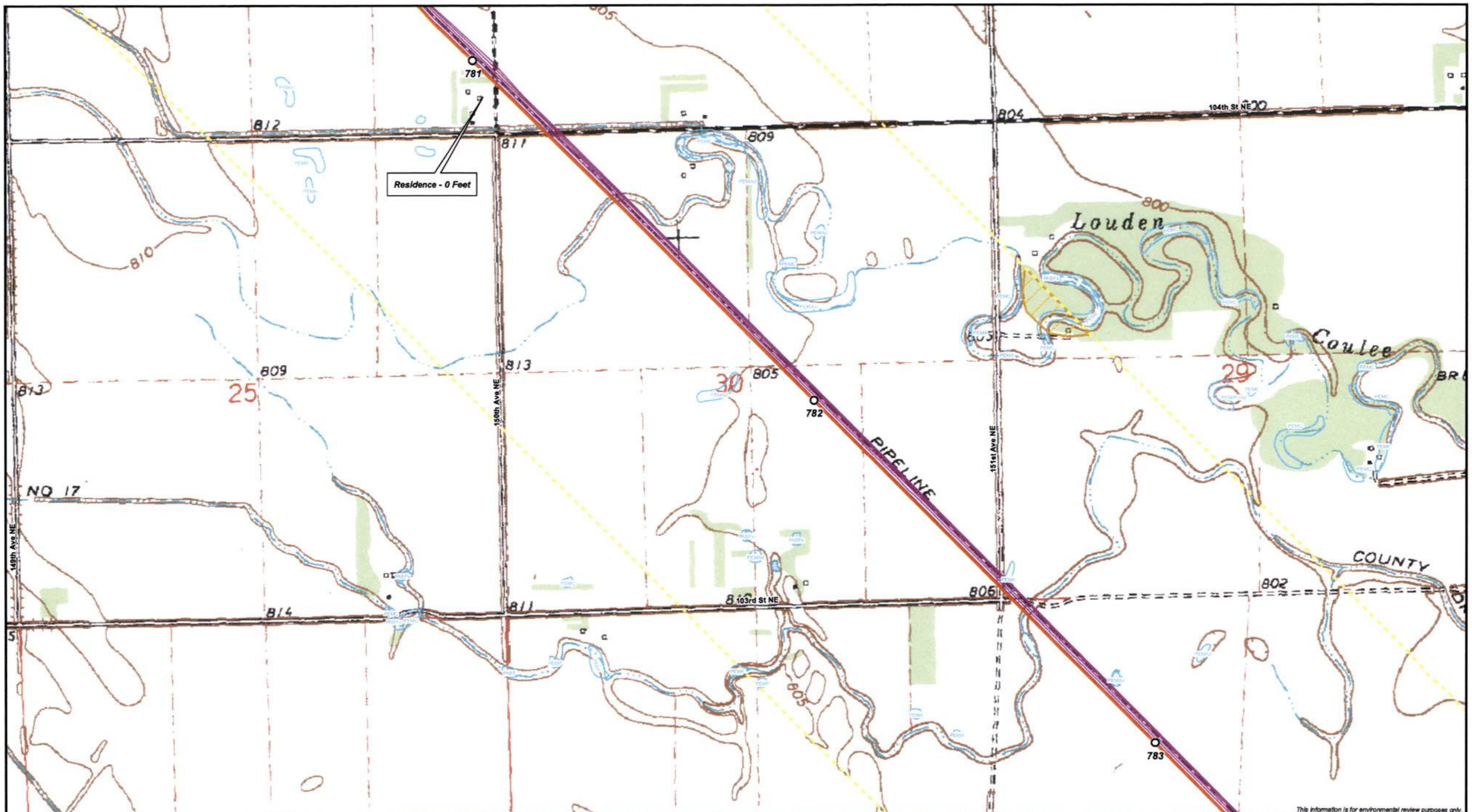

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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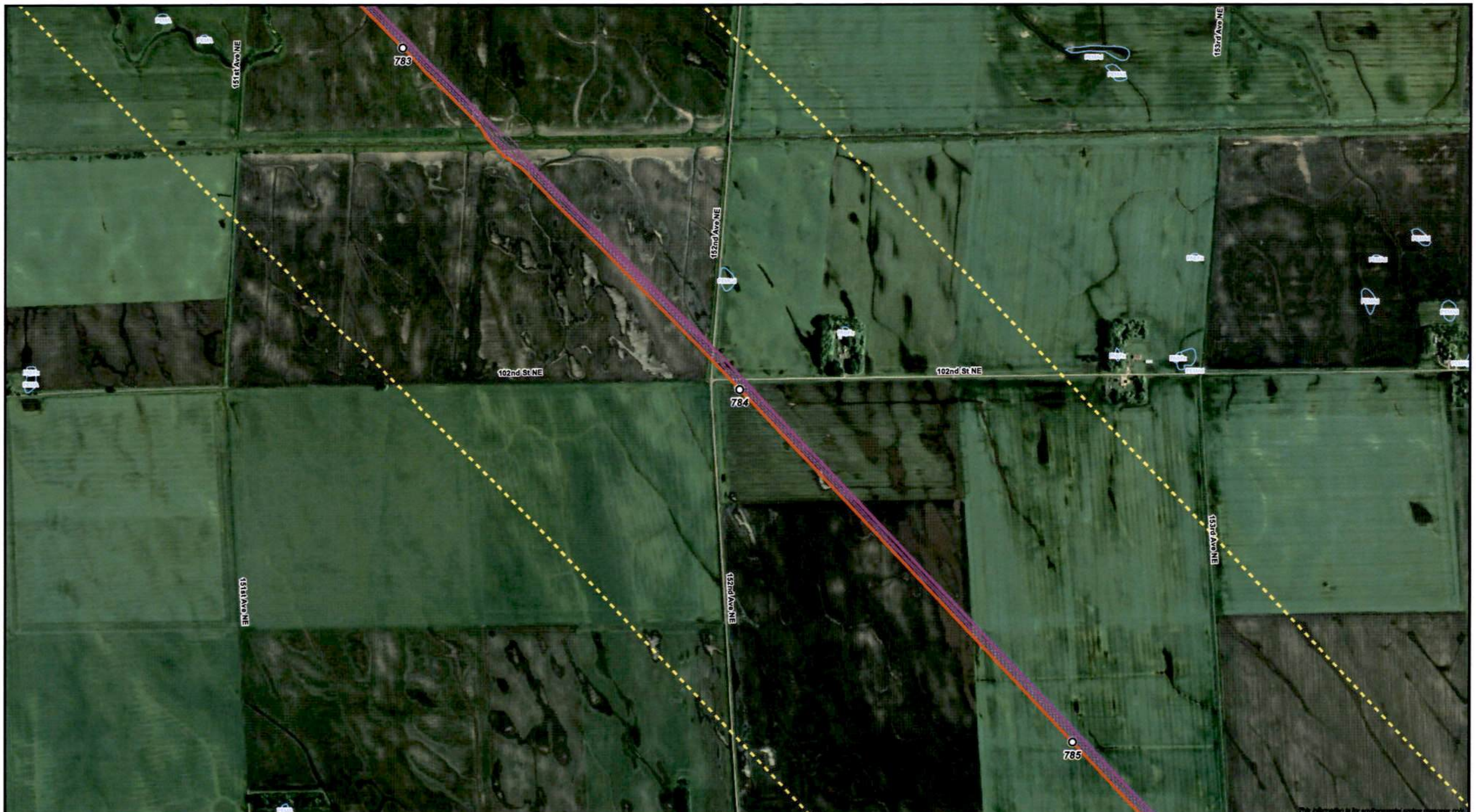

Milepost

Mainline Valve

Proposed Alberta Clipper

Existing Enbridge Lines

Half Mile Corridor

Avoidance Area - Wooded

Exclusion/Avoidance Area

National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

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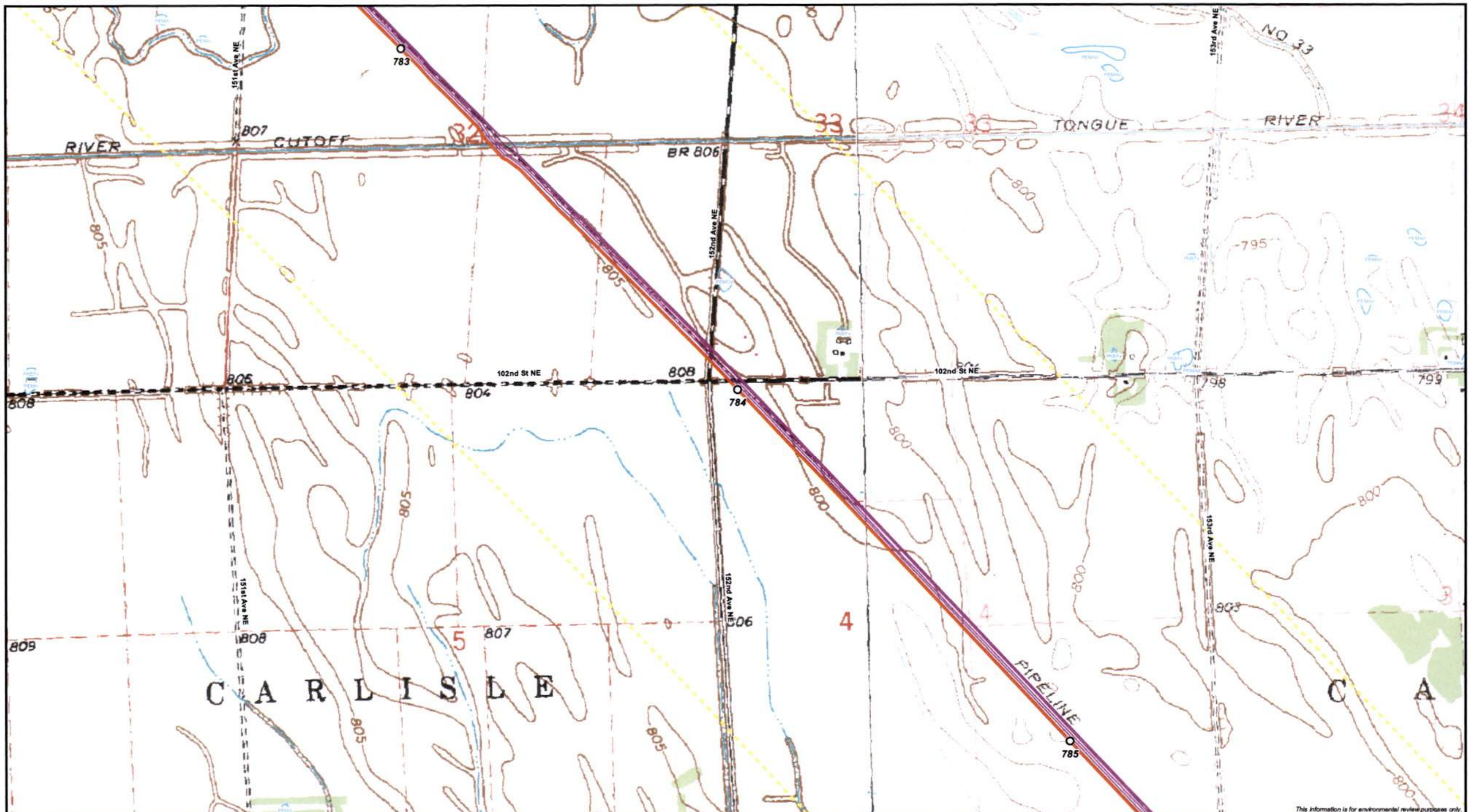

Milepost	Half Mile Corridor	
Mainline Valve	Avoidance Area - Wooded	
Proposed Alberta Clipper	Exclusion/Avoidance Area	
Existing Enbridge Lines	National Wetlands Inventory Data	

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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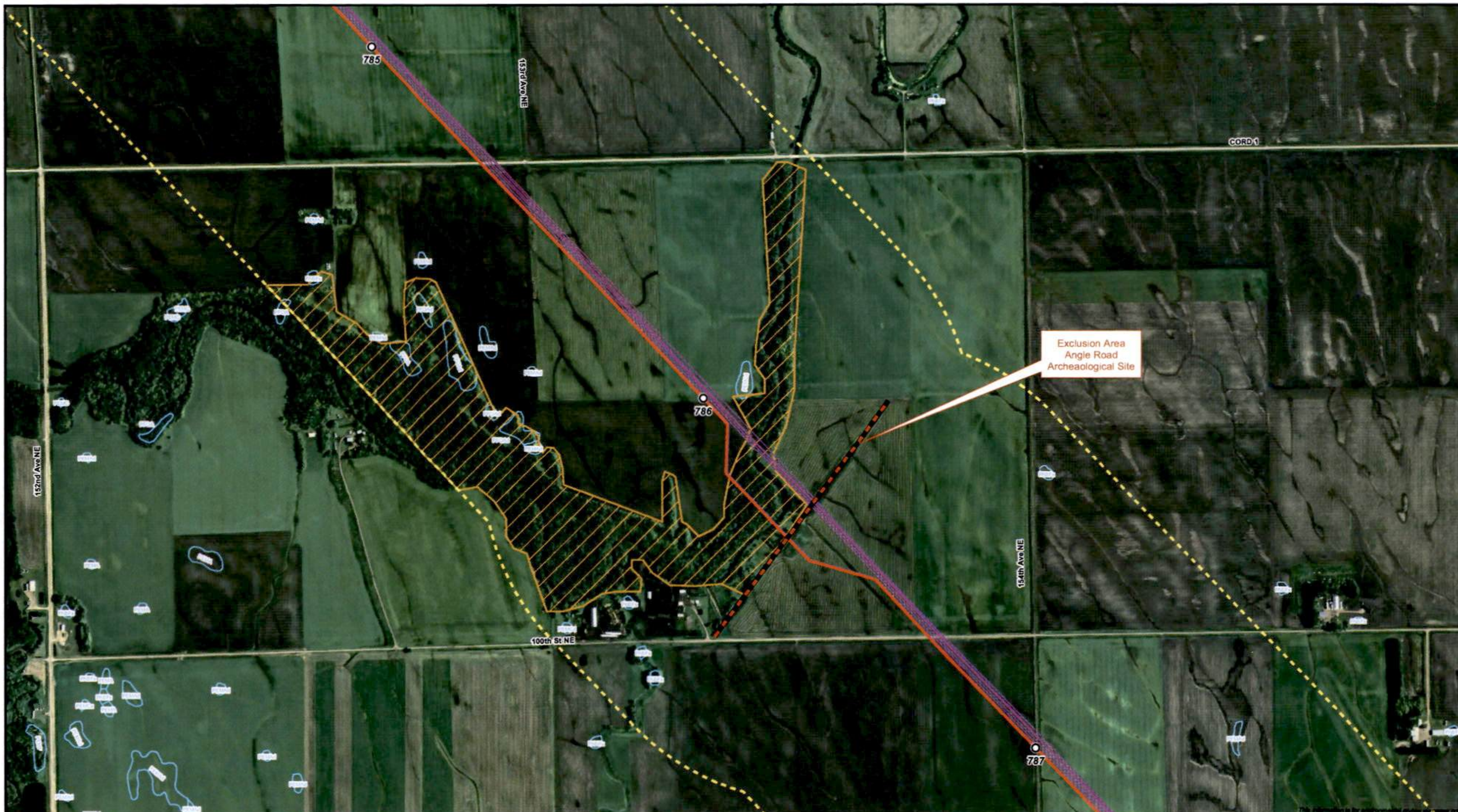

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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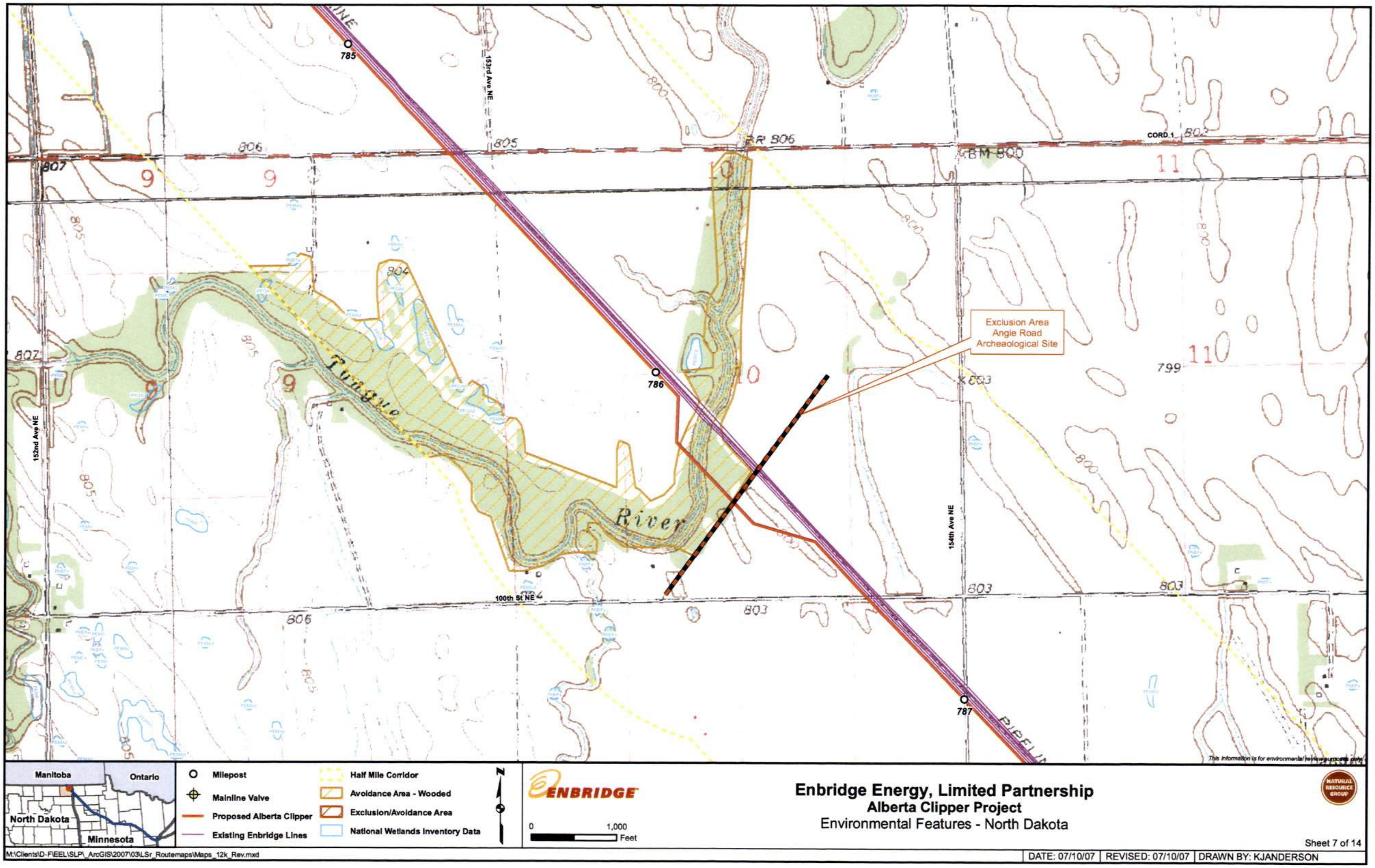
785
786
787
153rd Ave NE
152nd Ave NE
154th Ave NE
100th St NE
CORD 1
BM 800
Tongue
River
Exclusion Area
Angle Road
Archeaological Site
This information is for environmental review purposes only
Manitoba
Ontario
North Dakota
Minnesota
Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data
N
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1,000
Feet
ENBRIDGE
Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota
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NATURAL RESOURCE GROUP
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Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
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National Wetlands Inventory Data

N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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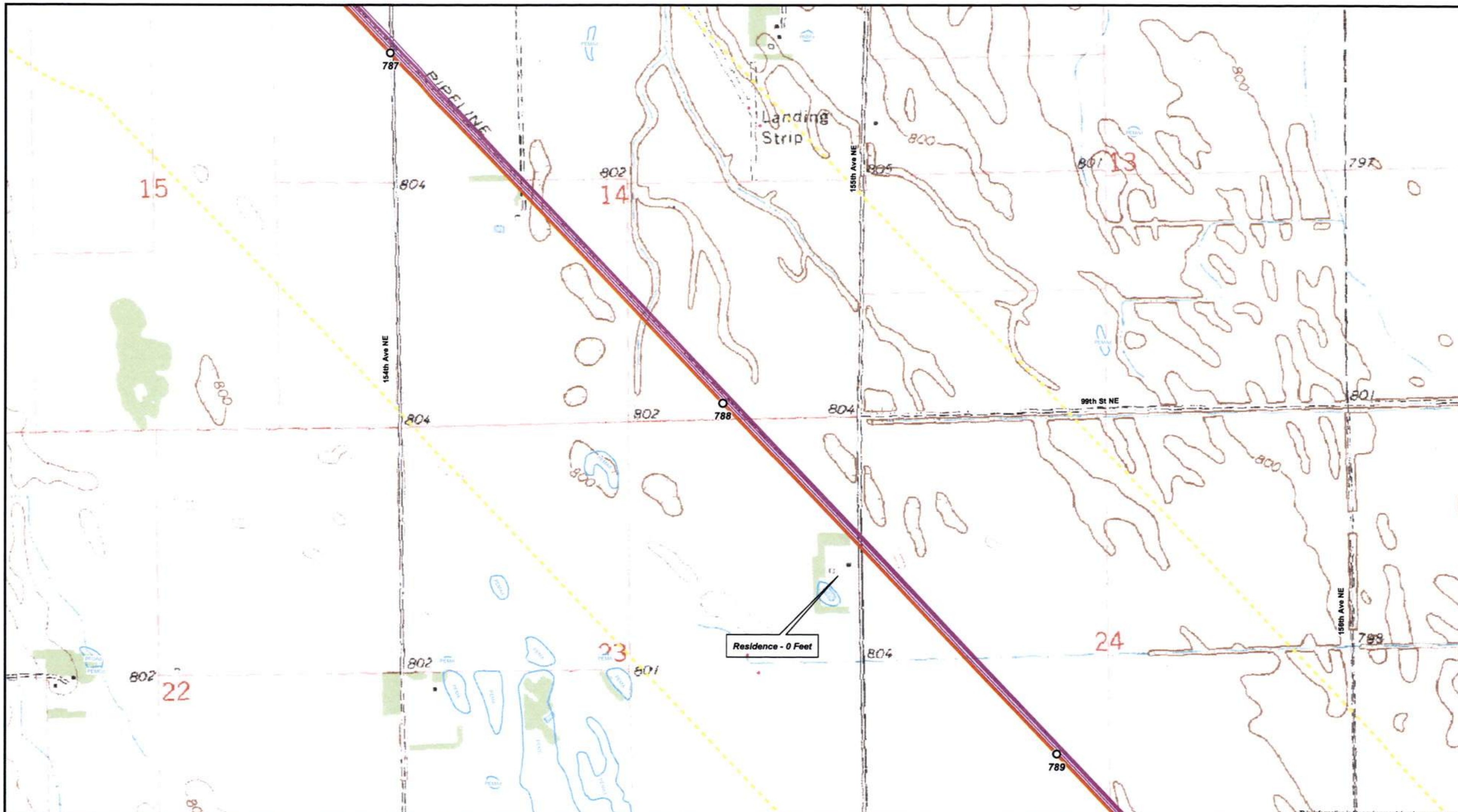

Manitoba
Ontario
North Dakota
Minnesota

Milepost
Mainline Valve
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Half Mile Corridor
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N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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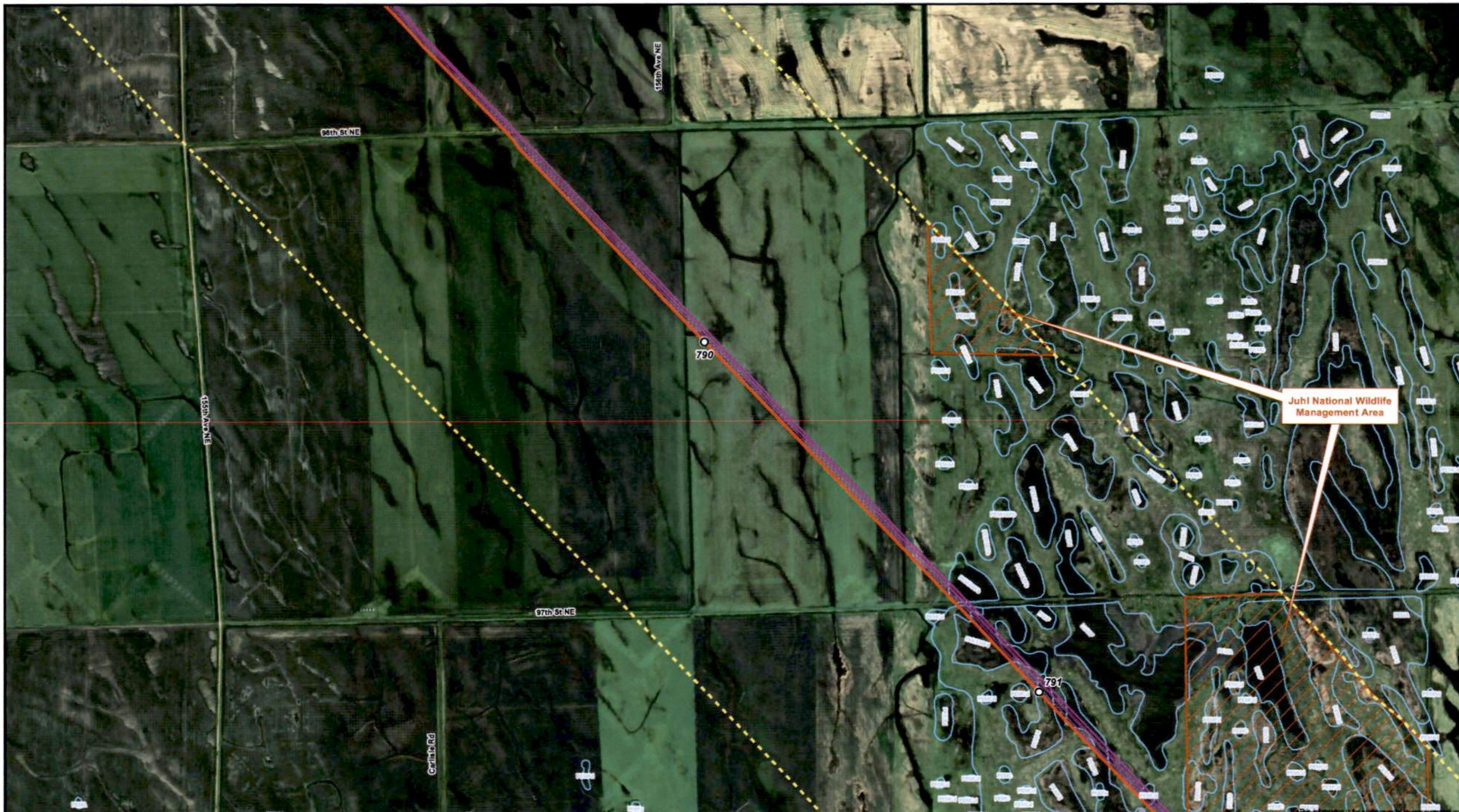

- Milepost
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- Avoidance Area - Wooded
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N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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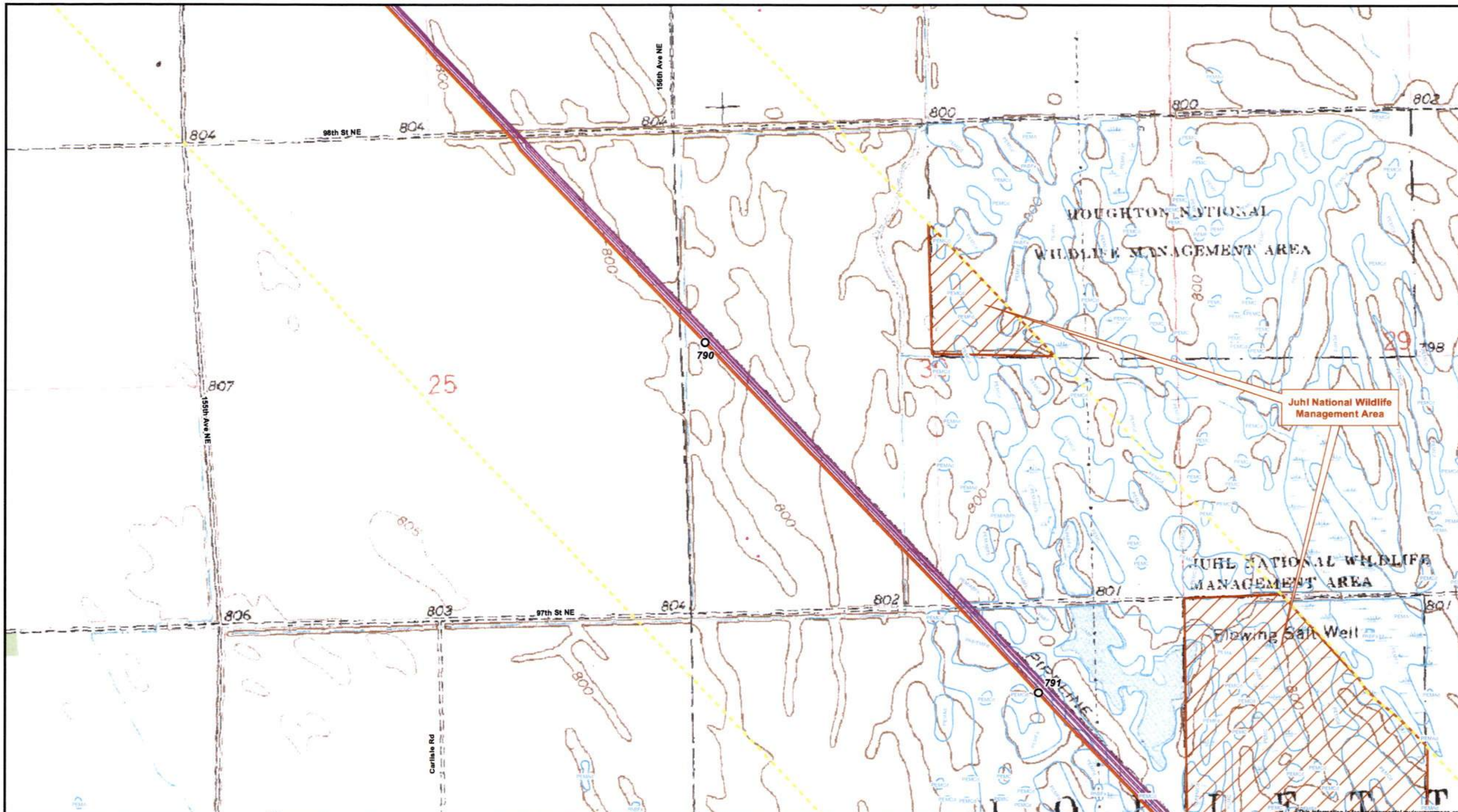

Milepost

Mainline Valve

Proposed Alberta Clipper

Existing Enbridge Lines

Half Mile Corridor

Avoidance Area - Wooded

Exclusion/Avoidance Area

National Wetlands Inventory Data

0 1,000 Feet

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

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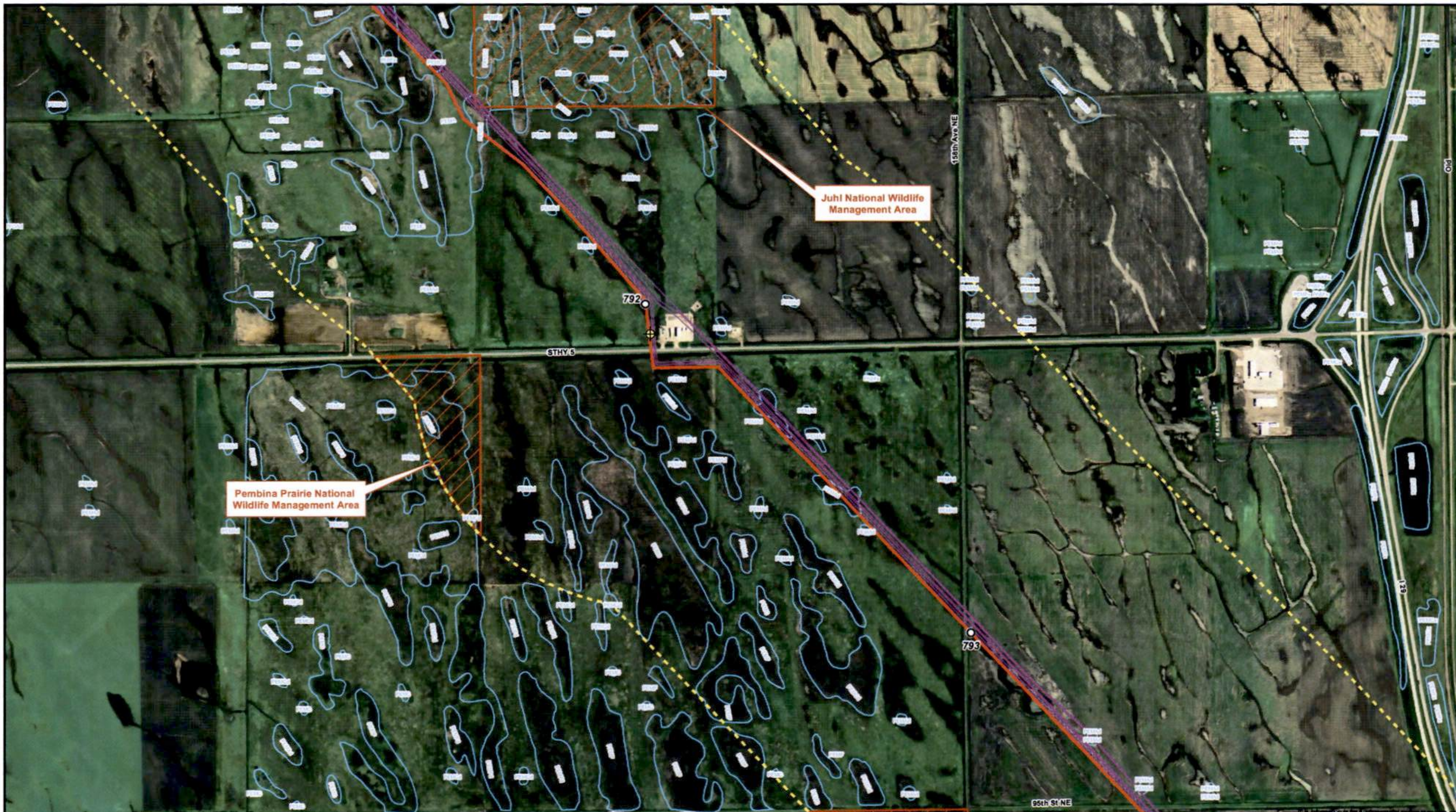

- Milepost
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N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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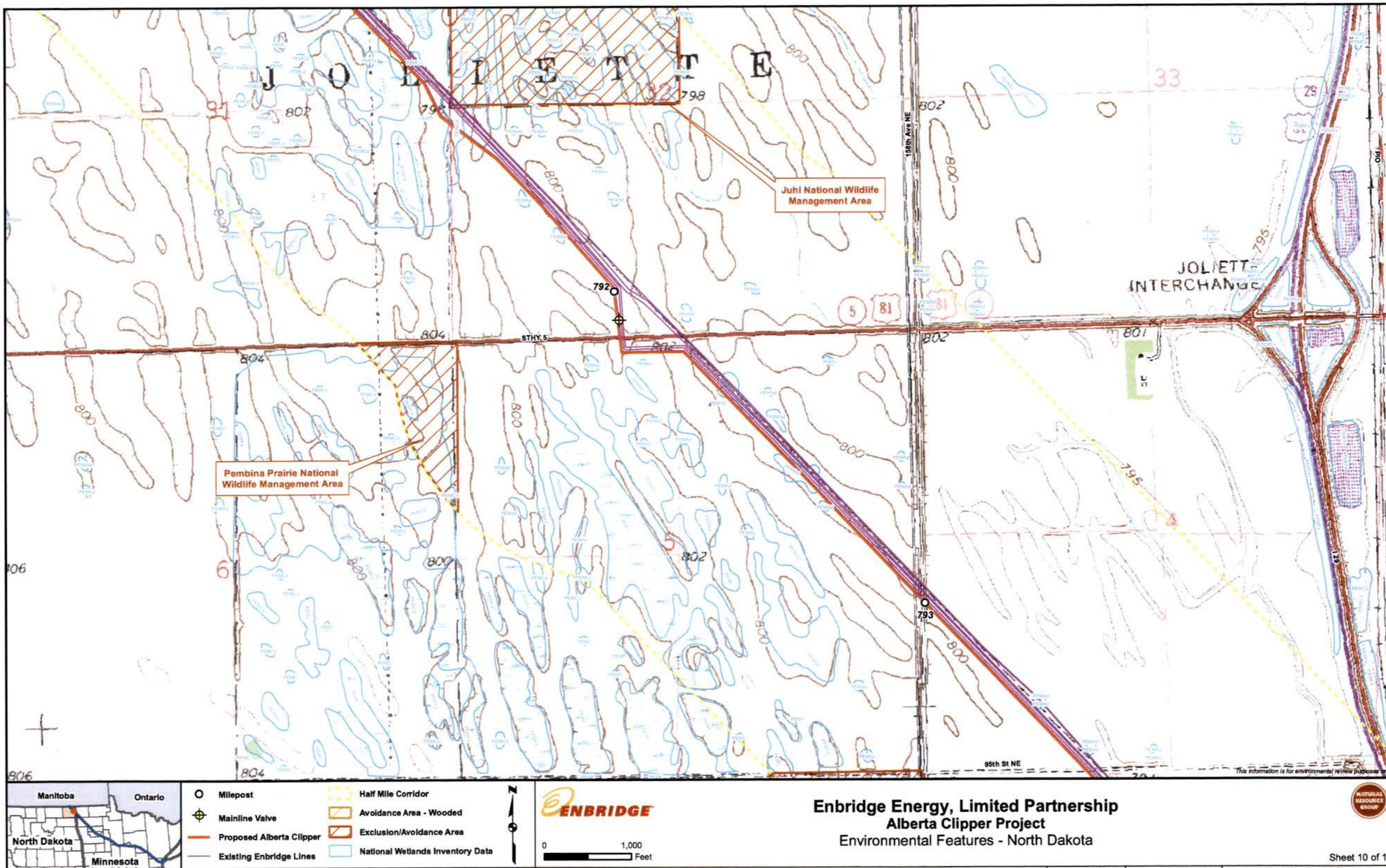

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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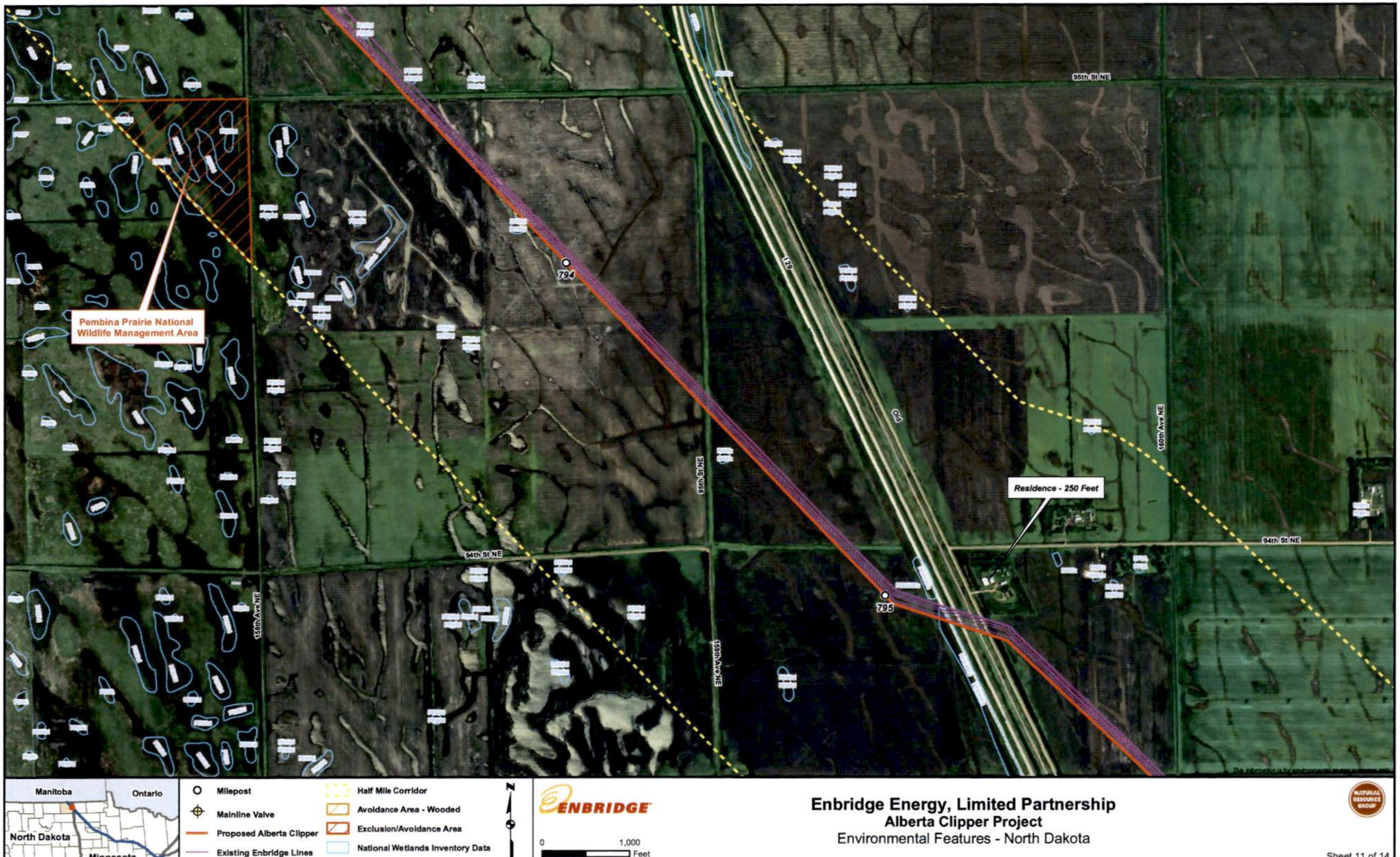

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
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National Wetlands Inventory Data

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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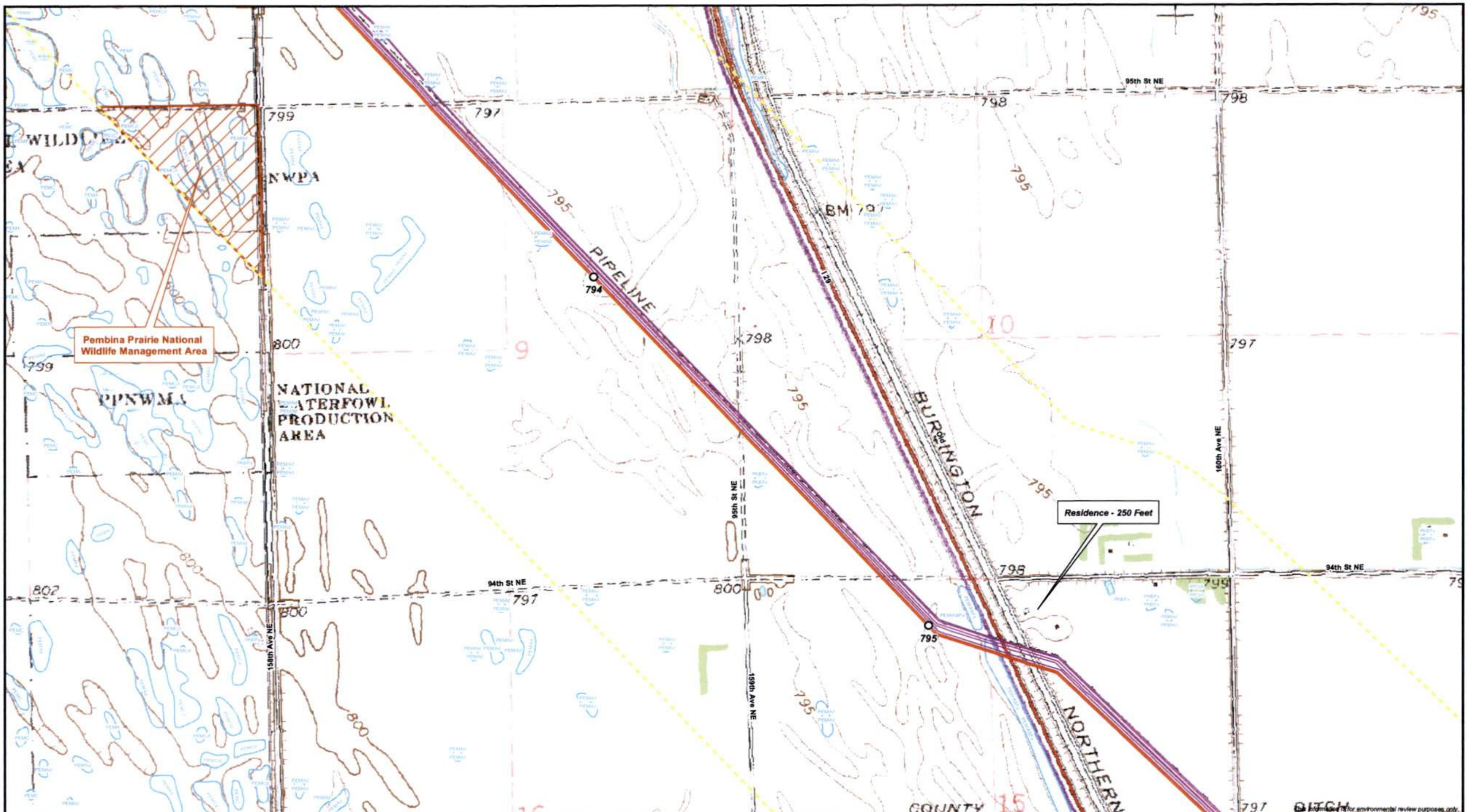

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
Exclusion/Avoidance Area
National Wetlands Inventory Data

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

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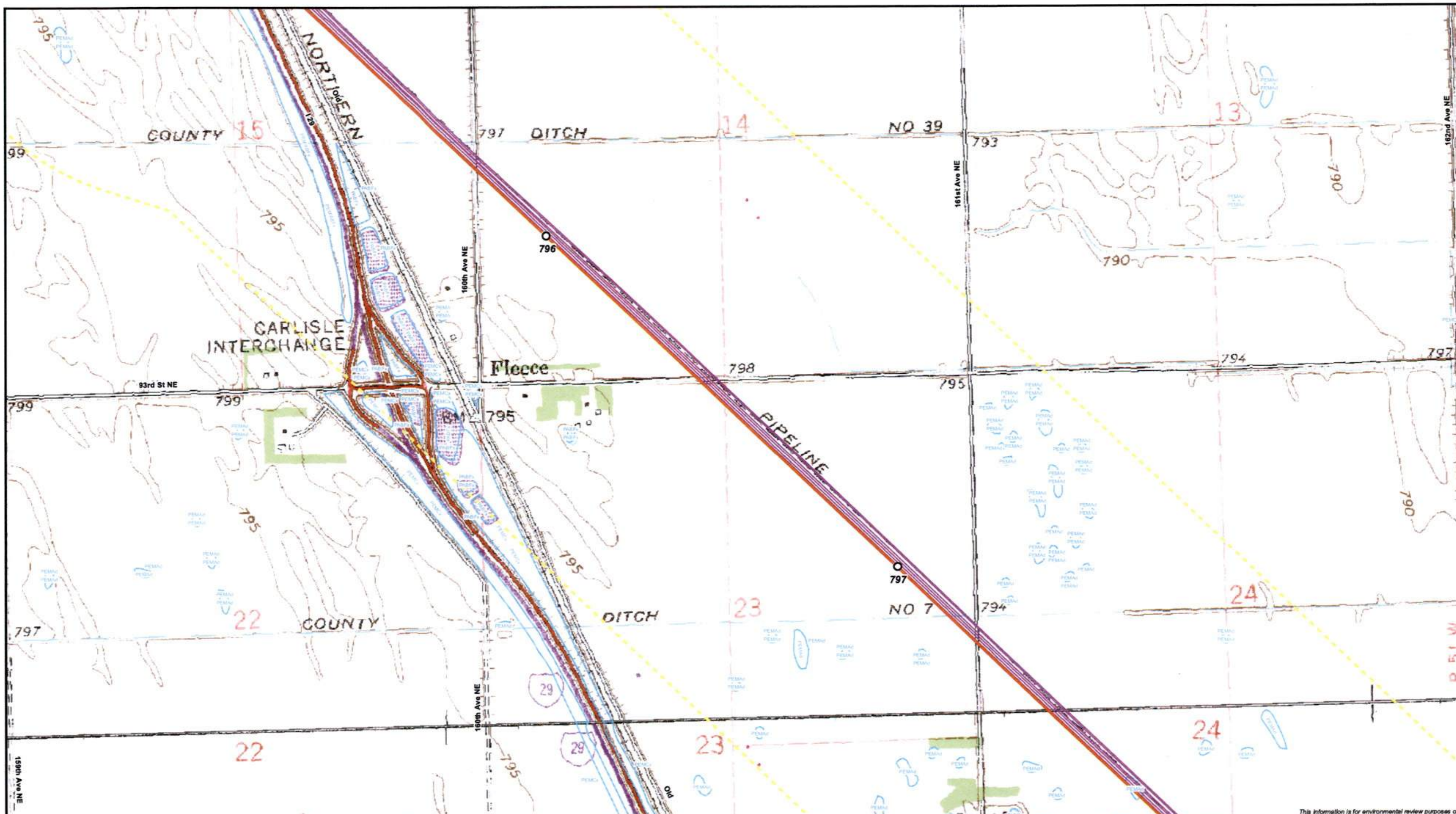

Milepost

Mainline Valve

Proposed Alberta Clipper

Existing Enbridge Lines

Half Mile Corridor

Avoidance Area - Wooded

Exclusion/Avoidance Area

National Wetlands Inventory Data

N

0 1,000 Feet

ENBRIDGE

Enbridge Energy, Limited Partnership

Alberta Clipper Project

Environmental Features - North Dakota

Sheet 12 of 14

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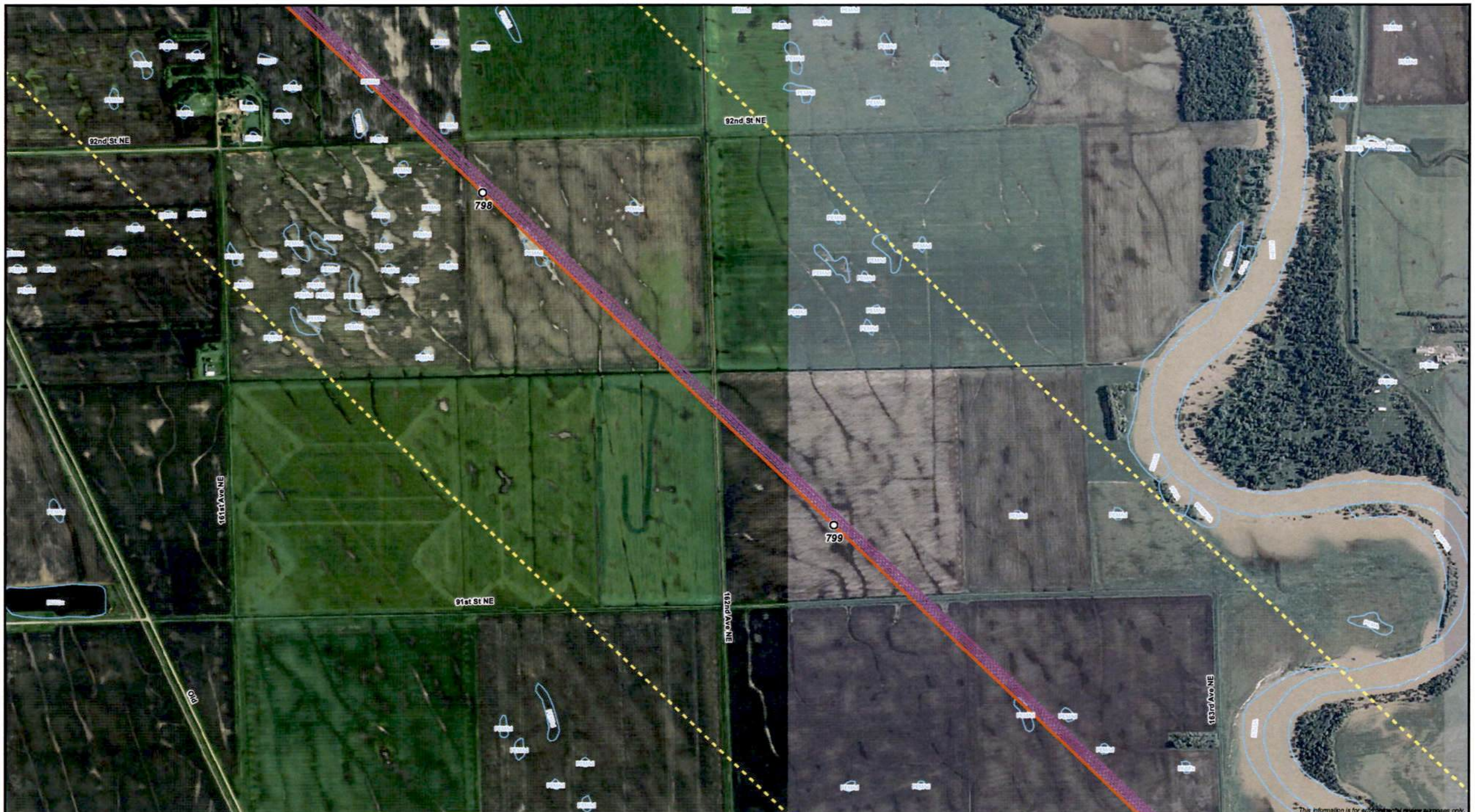

- Milepost
- Mainline Valve
- Proposed Alberta Clipper
- Existing Enbridge Lines
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- Avoidance Area - Wooded
- Exclusion/Avoidance Area
- National Wetlands Inventory Data

N

ENBRIDGE

0 1,000 Feet

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 13 of 14

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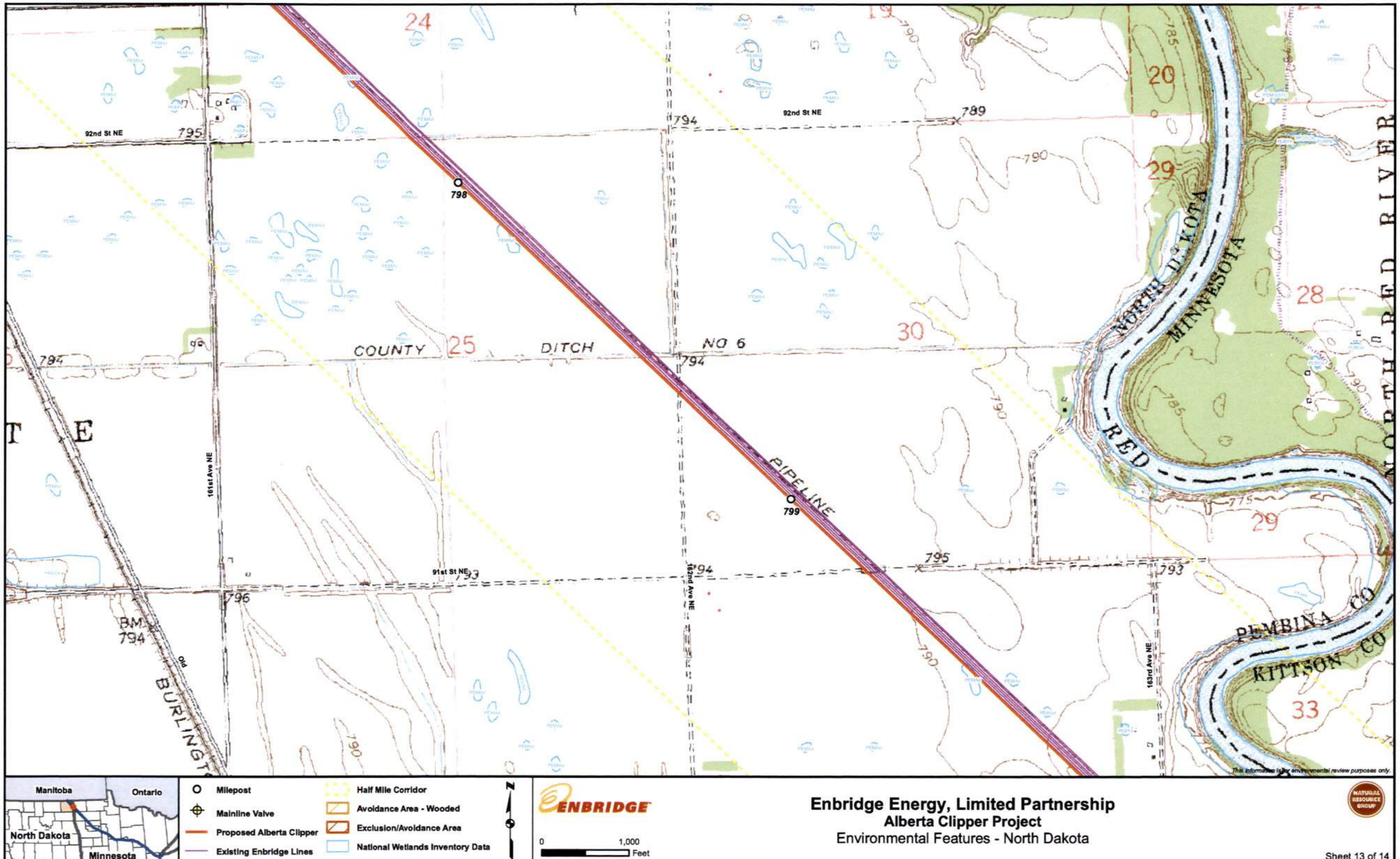

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

Sheet 13 of 14

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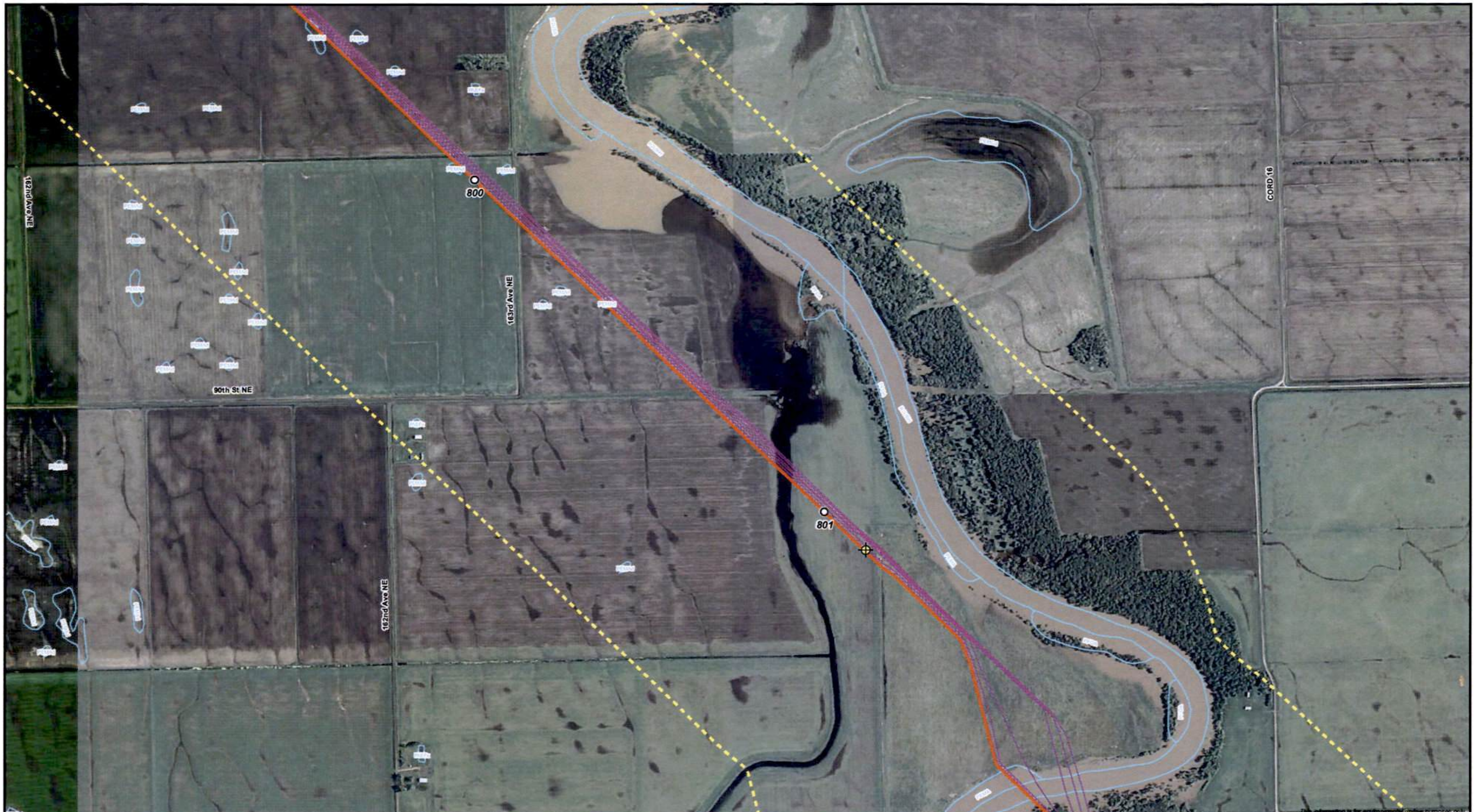

Milepost
Mainline Valve
Proposed Alberta Clipper
Existing Enbridge Lines
Half Mile Corridor
Avoidance Area - Wooded
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ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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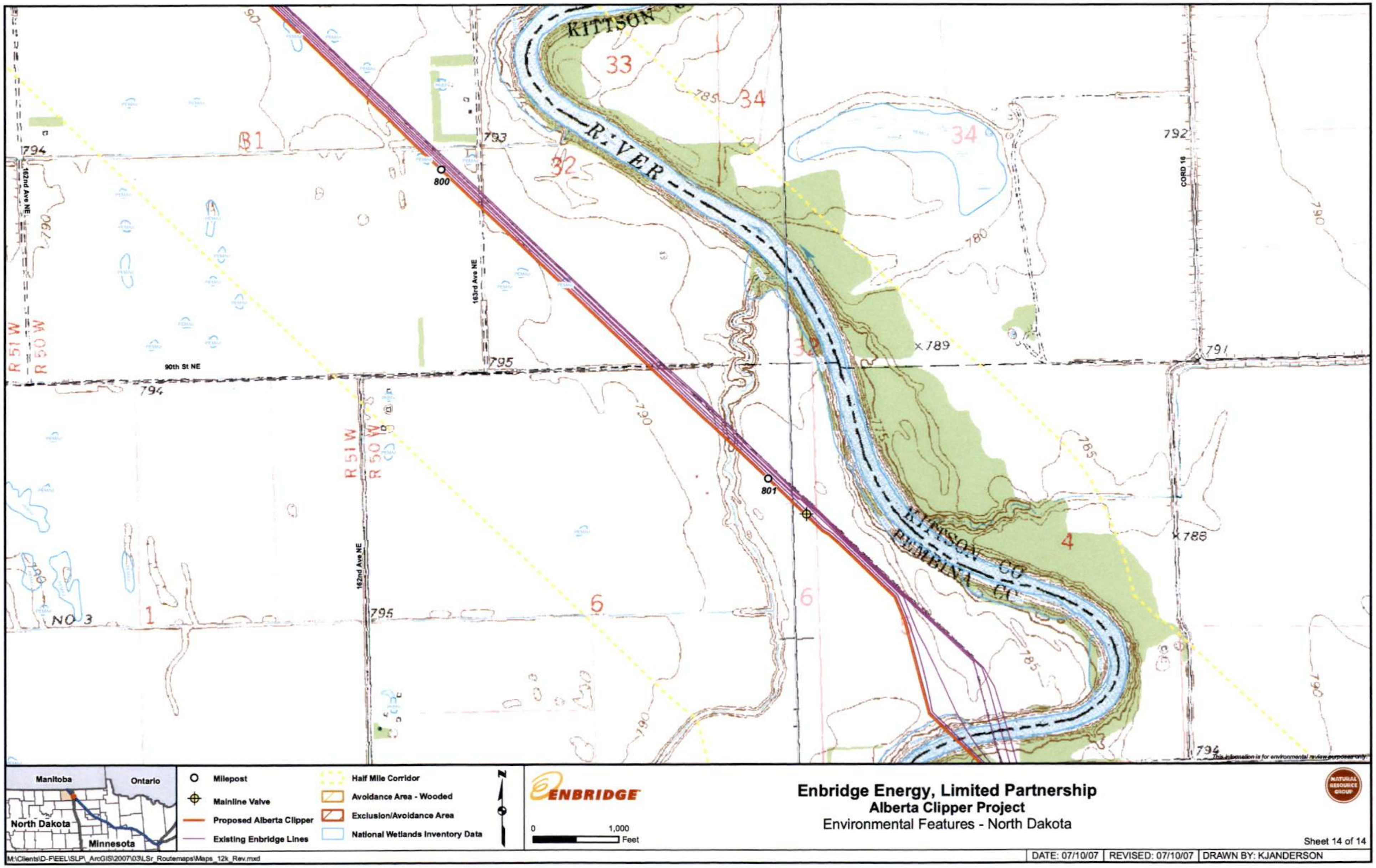

ENBRIDGE

Enbridge Energy, Limited Partnership
Alberta Clipper Project
Environmental Features - North Dakota

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Enbridge Energy, Limited Partnership
Landowner List for Pembina County, North Dakota
Docket No. PU07-108

Appendix E

Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
	T-1032	Pembina	North Dakota State Game & Fish Dept.				100 N Bismarck Expressway		Bismarck	ND	58501
	T-1032-A	Pembina	Enbridge Energy LP				119 North 25th Street East		Superior	WI	54880
	T-1034	Pembina	Leo	Stellon	Michael	Stellon	16041 County Road 3		Drayton	ND	58225
	T-1035	Pembina	Leo D.	Stellon			16041 County Road 3		Drayton	ND	58225
	T-1036	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1037	Pembina	Carolyn B.	Billings	Bryon W.	Billings	c/o Janet M. Billings	407 W. Mill Avenue	Drayton	ND	58225
	T-1038	Pembina	J. Neil	Hanson	Joyce	Hanson	15185 - 91st Street Northeast		Hamilton	ND	58238
	T-1039	Pembina	J. Neil	Hanson	Joyce	Hanson	15185 - 91st Street Northeast		Hamilton	ND	58238
	T-1040	Pembina	Jean	Juhl			c/o Ted Juhl	9326 - 162nd Avenue	Drayton	ND	58225
X	T-1040	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1041	Pembina	DeLane	Meier	Myra	Meier	c/o Lyndon Julh	16041 - 94th Street NE	Drayton	ND	58225
X	T-1041	Pembina	Lyndon	Juhl			15962 83rd Street Northeast		Drayton	ND	58225
	T-1042	Pembina	Wilwand Grain				c/o Tim Wilwand	10787 - 157th Avenue NE	Pembina	ND	58271
X	T-1042	Pembina	Leo D.	Stellon			16041 County Road 3		Drayton	ND	58225
	T-1043	Pembina	Theodore	Passa	Lucille	Passa	207 West Wallace Avenue		Drayton	ND	58225
X	T-1043	Pembina	Chris	Passa			9206 - 161st Avenue Northeast		Drayton	ND	58225
	T-1044	Pembina	Kimberly Kay	Juhl-White	Karrie Lynne	Juhl-Meyer	c/o Kent Juhl	30940 Maplewood Rod	Smithton	MO	65350
	T-1044	Pembina	Ted	Juhl			9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1044-A	Pembina	Brent	Passa	Allison	Passa	5013 West Elm Court		Grand Forks	ND	58203
X	T-1044-A	Pembina	Leo D.	Stellon			16041 County Road 3		Drayton	ND	58225
	T-1045	Pembina	Mervin	Holter	Phyllis	Holter	16022 - 93rd Street Northeast		Drayton	ND	58225

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Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
X	T-1045	Pembina	Craig	Holter			16022 - 93rd Street Northeast		Drayton	ND	58225
	T-1046	Pembina	Jean	Juhl			c/o Ted Juhl	9326 - 162nd Avenue	Drayton	ND	58225
	T-1047	Pembina	Mervin	Holter	Phyllis	Holter	16022 - 93rd Street Northeast		Drayton	ND	58225
X	T-1047	Pembina	Craig	Holter			16022 - 93rd Street Northeast		Drayton	ND	58225
	T-1049	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1050	Pembina	Albert	Wilson	Veronica R.	Wilson	3190 Minnzona Drive		Baudette	MN	56623
X	T-1050	Pembina	Dwight W.	Wilson	Debrah J.	Wilson	9686 Old Highway 81		Joliette	ND	58271
	T-1050-A	Pembina	Rayomond L.	Wilson	Zonia	Wilson	15968 - 94th Street Northeast		Drayton	ND	58225
	T-1050-B	Pembina	Marvin W.	Wilson	Maxine I.	Wilson	15904 Henry Street		Pembina	ND	58271
	T-1050-C	Pembina	Rayomond L.	Wilson	Zonia	Wilson	15968 - 94th Street Northeast		Drayton	ND	58225
	T-1050-D	Pembina	Rayomond L.	Wilson	Zonia	Wilson	15968 - 94th Street Northeast		Drayton	ND	58225
	T-1050-E	Pembina	Albert	Wilson			3190 Minnzona Drive		Baudette	MN	56623
	T-1051	Pembina	Rayomond L.	Wilson	Zonia	Wilson	15968 - 94th Street Northeast		Drayton	ND	58225
	T-1052	Pembina	Ronald	Wilson			15977 - 94th Street Northeast		Drayton	ND	58225
	T-1053	Pembina	Christenson Farms In.				16060 Water Street		Drayton	ND	58225
	T-1054	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1055	Pembina	Thomas J.	Middleton			448A - 19th Avenue West		West Fargo	ND	58078
X	T-1055	Pembina	Richard	Kemp			9432 - 155th Avenue Northeast		Hamilton	ND	58238
	T-1056	Pembina	Wayne	Chale	Barbara	Chale	PO Box 204		Pembina	ND	58271
	T-1056-A	Pembina	Lawrence D.	DuBois			PO Box 473		Cavalier	ND	58220
	T-1057	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1057-A	Pembina	Wilifred	Gapp Etal	Henry	Gapp	419 - 4th Street SE		Mayville	ND	58257
	T-1058	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1059	Pembina	Earl D.	Morrison	Margaret	Morrison	Box 299		Cavalier	ND	58220

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Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
X	T-1059	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1059-A	Pembina	Minnkota Power Cooperative, Inc.				P.O. Box 13200		Grand Forks	ND	58203
	T-1060	Pembina	Earl D.	Morrison	Margaret	Morrison	Box 299		Cavalier	ND	58220
	T-1060	Pembina	Myron J.	Morrison			29820 Glader Blvd.		Lindstrom	MN	55045
X	T-1060	Pembina	Ted	Juhl	Angela	Juhl	9326 - 162nd Avenue Northeast		Drayton	ND	58225
	T-1060-L	Pembina	Enbridge Energy LP				119 North 25th Street East		Superior	WI	54880
	T-1061	Pembina	US Fish & Wildlife Service	Mountain-Prairie Region			Wetland Management District Headquarters	P. O. Box 908	Devils Lake	ND	58301
	T-1062	Pembina	Ronald	Sharp Etal			15557 Highway 5		Hamilton	ND	58238
	T-1062-A	Pembina	Dorothy A.	Sharp			15550 Highway 5		Hamilton	ND	58238
	T-1063	Pembina	Ronald	Sharp Etal			15557 Highway 5		Hamilton	ND	58238
	T-1064	Pembina	Dorothy A.	Sharp			15550 Highway 5		Hamilton	ND	58238
X	T-1064	Pembina	Ronald	Sharp Etal			15557 Highway 5		Hamilton	ND	58238
	T-1065	Pembina	Neal L.	Martin			5004 - 6th Avenue North		Grand Forks	ND	58203
X	T-1065	Pembina	Wilwand Farms				c/o Tim Wilwand	10787 - 157th Avenue NE	Pembina	ND	58271
	T-1066	Pembina	Floyd	Hackenschmidt			9861 - 155th Avenue Northeast		Bathgate	ND	58216
X	T-1066	Pembina	William	Gunderson			P.O. Box 74		Bathgate	ND	58216
	T-1067	Pembina	Timothy	Wilwand	Lois Ann	Wilwand	10787 - 157th Avenue Northeast		Pembina	ND	58271
	T-1067-A	Pembina	Timothy	Wilwand	Lois Ann	Wilwand	10787 - 157th Avenue Northeast		Pembina	ND	58271
	T-1067-B	Pembina	Timothy	Wilwand	Lois Ann	Wilwand	10787 - 157th Avenue Northeast		Pembina	ND	58271
	T-1068	Pembina	Floyd	Hackenschmidt			9861 - 155th Avenue Northeast		Bathgate	ND	58216
X	T-1068	Pembina	Richard	Kemp	Dan	Kemp			Bathgate	ND	58216
	T-1068-A	Pembina	Melvin	Webb			9867 - 155th Avenue Northeast		Bathgate	ND	58216
X	T-1068-A	Pembina	William	Gunderson			P.O. Box 74		Bathgate	ND	58216

Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
	T-1069	Pembina	Floyd	Hackenschmidt			9861 - 155th Avenue Northeast		Bathgate	ND	58216
	T-1069	Pembina	Melvin	Webb			9867 - 155th Avenue Northeast		Bathgate	ND	58216
X	T-1069	Pembina	William	Kemp			15564 - 95th Street NE		Hamilton	ND	58238
X	T-1069	Pembina	Gregory	Kemp					Bathgate	ND	58216
	T-1070	Pembina	David	Craig			15482 - 100th Street Northeast		Bathgate	ND	58216
	T-1071	Pembina	Karl	Henschel			14989 County Road 1		Bathgate	ND	58216
X	T-1071	Pembina	Bruce A.	Henschel			P. O. Box 41		Bathgate	ND	58216
	T-1071-A	Pembina	Karl	Henschel			14989 County Road 1		Bathgate	ND	58216
X	T-1071-A	Pembina	Bruce A.	Henschel			P. O. Box 41		Bathgate	ND	58216
	T-1072	Pembina	Joel	Gunderson	Donna	Gunderson	13883 Highway 5		Cavalier	ND	58220
X	T-1072	Pembina	Scott	Gunderson			9951 County Road 4		Bathgate	ND	58216
	T-1073	Pembina	Joel	Gunderson	Donna	Gunderson	13883 Highway 5		Cavalier	ND	58220
X	T-1073	Pembina	Gunderson Farms				c/o Craig & Tim Gunderson	10011 County Road 4	Bathgate	ND	58216
	T-1074	Pembina	Glen	Gunderson	Pearl	Gunderson	Box 282		Cavalier	ND	58220
X	T-1074	Pembina	William	Gunderson			P.O. Box 74		Bathgate	ND	58216
	T-1075	Pembina	Wesley A.	Argue			PO Box 108		Hamilton	ND	58238
X	T-1075	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1076	Pembina	Marvin	Gunderson Revoc. Trust			100 Oakview Drive		Cavalier	ND	58220
	T-1077	Pembina	Wesley A.	Argue			PO Box 108		Hamilton	ND	58238
X	T-1077	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1078	Pembina	Lincoln	Edgar Life Estate			c/o Sharon Zaharia	21 West Division Street	Bathgate	ND	58216
X	T-1078	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1079	Pembina	Lincoln	Edgar Life Estate			c/o Sharon Zaharia	21 West Division Street	Bathgate	ND	58216
	T-1079	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216

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Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
	T-1080	Pembina	Wilwand Farms				c/o Tim Wilwand	10787 - 157th Avenue West	Pembina	ND	58271
X	T-1080	Pembina	Rowe Farms				Dennis Rowe	10463 - 151st Avenue Northeast	Pembina	ND	58271
	T-1081	Pembina	Bonnie	DeMars			15288 - 102nd Street NE		Bathgate	ND	58216
	T-1081	Pembina	Vernice	DeMars			102 East Oak Street		Cavalier	ND	58220
X	T-1081	Pembina	Dennis	Lindsay			P. O. Box 13		Bathgate	ND	58216
	T-1082	Pembina	Lincoln	Edgar Life Estate			c/o Sharon Zaharia	21 West Division Street	Bathgate	ND	58216
X	T-1082	Pembina	Russell	Edgar	Holly	Edgar	15301 - 100th Street Northeast		Bathgate	ND	58216
	T-1083	Pembina	Bonnie	DeMars			15288 - 102nd Street NE		Bathgate	ND	58216
	T-1083	Pembina	Vernice	DeMars			102 East Oak Street		Cavalier	ND	58220
X	T-1083	Pembina	Tim	Wilwand			10787 - 157 Avenue NE		Pembina	ND	58217
	T-1084	Pembina	Dennis	Lindsay			P. O. Box 13		Bathgate	ND	58216
	T-1084-A	Pembina	Dennis	Lindsay			P. O. Box 13		Bathgate	ND	58216
	T-1085	Pembina	Marie	Waller			720 West 2nd Street		Laurel	MT	59044
X	T-1085	Pembina	Dennis	Lindsay			P. O. Box 13		Bathgate	ND	58216
	T-1086	Pembina	Wayne	Chale	Barbara	Chale	PO Box 204		Pembina	ND	58271
X	T-1086	Pembina	Tim	Wilwand			10787 - 157 Avenue NE		Pembina	ND	58217
	T-1088	Pembina	Fred Craig	Vosper			6835 Southwest Fernbrook Court		Wilsonville	OR	97070
X	T-1088	Pembina	Douglas Kent	Vosper			10540 Hwy. 118		Neche	ND	58265
	T-1089	Pembina	Fred Craig	Vosper			6835 Southwest Fernbrook Court		Wilsonville	OR	97070
X	T-1089	Pembina	Douglas Kent	Vosper			10540 Hwy. 118		Neche	ND	58265
	T-1090	Pembina	Lucille	Chale			521 - 3rd Street North Apartment 44		Pembina	ND	58271
	T-1090	Pembina	Steve	Chale			c/o Lucille Shale	521 - 3rd Street North Apartment 4	Pembina	ND	58271
	T-1090	Pembina	Wayne	Chale	Barbara	Chale	PO Box 204		Pembina	ND	58271
	T-1091	Pembina	Lucille	Chale			521 - 3rd Street North Apartment 44		Pembina	ND	58271
	T-1091	Pembina	Steve	Chale			c/o Lucille Shale	521 - 3rd Street North Apartment 4	Pembina	ND	58271
	T-1091	Pembina	Wayne	Chale	Barbara	Chale	PO Box 204		Pembina	ND	58271
	T-1092	Pembina	Marcus	Morrisn			14887 - 104th Street NE		Bathgate	ND	58216

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Appendix E

Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
	T-1093	Pembina	Rowe Farms				Dennis Rowe	10463 - 151st Avenue Northeast	Pembina	ND	58271
	T-1094	Pembina	Beverly	Mott			706 River Street Apartment 1		Cavalier	ND	58220
X	T-1094	Pembina	Rowe Farms				Dennis Rowe	10463 - 151st Avenue Northeast	Pembina	ND	58271
	T-1095	Pembina	Rhonda	Schweitzer			PO Box 331		Cavalier	ND	58220
	T-1095	Pembina	Melvin	Lembke	Elaine	Lembke	14866 - 108th Street NE		Neche	ND	58265
X	T-1095	Pembina	Wayne	Morrison	Cathy	Morrison	14887 - 104th Street Northeast		Bathgate	ND	58216
	T-1096	Pembina	Oscar	Nord	Helen L.	Nord	40713 West Island Drive		Rochert	MN	56578
	T-1096	Pembina	Wayne	Morrison	Cathy	Morrison	14887 - 104th Street Northeast		Bathgate	ND	58216
	T-1097	Pembina	Lavonne	Morrison			824 Grace Court		Cavalier	ND	58220
	T-1097	Pembina	Wayne D.	Morrison			14887 - 104th Street NE		Bathgate	ND	58216
	T-1098	Pembina	Wayne D.	Morrison			14887 - 104th Street NE		Bathgate	ND	58216
	T-1098	Pembina	Lavonne	Morrison			824 Grace Court		Cavalier	ND	58220
X	T-1098	Pembina	Wayne	Morrison	Cathy	Morrison	14887 - 104th Street Northeast		Bathgate	ND	58216
	T-1099	Pembina	Wayne D.	Morrison			14887 - 104th Street NE		Bathgate	ND	58216
	T-1099	Pembina	Lavonne	Morrison			824 Grace Court		Cavalier	ND	58220
X	T-1099	Pembina	Wayne	Morrison	Cathy	Morrison	14887 - 104th Street Northeast		Bathgate	ND	58216
	T-1100	Pembina	Oscar	Nord	Helen L.	Nord	40713 West Island Drive		Rochert	MN	56578
X	T-1100	Pembina	Wayne	Morrison	Cathy	Morrison	14887 - 104th Street Northeast		Bathgate	ND	58216
	T-1101	Pembina	Kelly J.	Meagher			15210 - 104th Street Northeast		Bathgate	ND	58216
	T-1102	Pembina	Kelly J.	Meagher			15210 - 104th Street Northeast		Bathgate	ND	58216
	T-1103	Pembina	Richard E.	Anderson Living Trust Etal			Richard E. & Charlotte A. Anderson, Trustees	980 - 26th Avenue Northwest	Coleharbor	ND	58531
	T-1104	Pembina	David	Kelm Trust	Debrah J.	Kelm	6706 Valley Circle Blvd.		West Hills	CA	91307
X	T-1104	Pembina	Douglas Kent	Vosper			10540 Hwy. 118		Neche	ND	58265
	T-1105	Pembina	Randall	Wagner	Marion	Wagner	14006 - 108th Street Northeast		Neche	ND	58265
X	T-1105	Pembina	Art	Wagner			14008 108th Street Northeast		Neche	ND	58265

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Tenant	Tract #	County	First Name	Last Name	Spouse First Name	Spouse Last Name	Address	Address 2	City	State	Zip Code
	T-1106	Pembina	David	Kelm Trust	Debrah J.	Kelm	6706 Valley Circle Blvd.		West Hills	CA	91307
X	T-1106	Pembina	Douglas Kent	Vosper			10540 Hwy. 118		Neche	ND	58265
	T-1107	Pembina	Randall	Wagner	Marion	Wagner	14006 - 108th Street Northeast		Neche	ND	58265
X	T-1107	Pembina	Art	Wagner			14008 108th Street Northeast		Neche	ND	58265
	T-1108	Pembina	Johnson Farms				c/o Bert Johnson	P.O. Box 114	Walhalla	ND	58282
X	T-1108	Pembina	Douglas Kent	Vosper			10540 Hwy. 118		Neche	ND	58265
	T-1109	Pembina	Randall	Wagner	Marion	Wagner	14006 - 108th Street Northeast		Neche	ND	58265
	T-1110	Pembina	Fred Craig	Vosper			6835 Southwest Fernbrook Court		Wilsonville	OR	97070
	T-1110-A	Pembina	Mark David	Vosper			14230 Heritage Lane		Apple Valley	MN	55124
	T-1110-OL	Pembina	Johnson Farms				c/o Bert Johnson	P.O. Box 114	Walhalla	ND	58282
	T-1111	Pembina	Phyllis	McNamara			1009 Jefferson Avenue		Bismarck	ND	58504
X	T-1111	Pembina	Ronald P.	Symington	Linda	Symington	510 - 5th Avenue		Neche	ND	58265
	T-1112	Pembina	Ronald P.	Symington	Linda	Symington	510 - 5th Avenue		Neche	ND	58265
	T-1113	Pembina	Ronald P.	Symington	Linda	Symington	510 - 5th Avenue		Neche	ND	58265
	T-1114	Pembina	James A.	Longtin			13805 - 104th Street Northeast		Neche	ND	58265
	T-1115	Pembina	James A.	Longtin			13805 - 104th Street Northeast		Neche	ND	58265
	T-1116	Pembina	James A.	Longtin			13805 - 104th Street Northeast		Neche	ND	58265
	T-1117	Pembina	Nettie	Douville			420 Main Avenue Apartment 1		Neche	ND	58265
X	T-1117	Pembina	James A.	Longtin			13805 - 104th Street Northeast		Neche	ND	58265
	T-1118	Pembina	James A.	Longtin			13805 - 104th Street Northeast		Neche	ND	58265
	T-1118-A	Pembina	Johnson Farms				c/o Bert Johnson	P.O. Box 114	Walhalla	ND	58282
	T-1119	Pembina	Johnson Farms				c/o Bert Johnson	P.O. Box 114	Walhalla	ND	58282
	T-1120	Pembina	Johnson Farms				c/o Bert Johnson	P.O. Box 114	Walhalla	ND	58282