APPLICATION FOR APPROVAL OF THE KAI KOS DEHSEH PROJECT

SUBMITTED TO

ALBERTA ENERGY AND UTILITIES BOARD

AND

ALBERTA ENVIRONMENT

SUBMITTED BY

NORTH AMERICAN OIL SANDS CORPORATION

August 2007

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1 INTRODUCTION

North American Oil Sands Corporation (North American) is a wholly owned subsidiary of Statoil ASA and operates in northeastern Alberta. North American is currently the working interest owner and operator of approximately 12 townships of oil sands leases between Lac La Biche and Fort McMurray (Figure 1-1). North American's goal is to develop the Kai Kos Dehseh Project, ultimately producing approximately 35,000 m^3/d (220,000 barrels per day) of bitumen through steam assisted gravity drainage (SAGD) technology. All rates presented in this document are on a calendar basis unless specified otherwise.

North American's is also proposing to construct and operate a bitumen upgrader in Strathcona County, which will make North American a marketer of synthetic crude oil in addition to bitumen blend. The upgrader will be applied for under a separate regulatory application.

The North American oil sands leases are located in Townships 76 to 83, Ranges 8 to 13 West of the 4th Meridian. The oil sands leases are not contiguous and fall within the Rural Municipality of Wood Buffalo and Lakeland County.

Kai Kos Dehseh is a Chipewyan Dene name meaning Red Willow River, the local Dene name for the Christina River. A group of Dene elders honoured North American with this name for the Project in January 2006.

The Kai Kos Dehseh Project will be developed in 10 hubs, which are distributed over oil sands leases situated in four development areas – Leismer, Corner, Thornbury and Hangingstone (Table 1-1 and Figure 1-2). Each hub is comprised of a central processing facility (CPF) (which may include steam generation, water treatment, emulsion gathering and treating, and sulphur removal) and field facilities (which includes well pads, connecting roads and utilities).

The following naming conventions are used in this document:

- **Project Area**: The area including the Kai Kos Dehseh leases and immediate surrounding area (Figure 1-2).
- **The Project**: The Kai Kos Dehseh Project.
- **Development Area:** The Kai Kos Dehseh Project is split into four development areas (Leismer, Thornbury, Corner and Hangingstone) (Figure 1-2).
- **Hub:** CPF and associated field facilities over the life of the Project.
- **Initial Development Area:** The CPF and initial well pads required for production.

The purpose of the Kai Kos Dehseh Project is to efficiently recover oil sands resources from the North American leases and to supply bitumen to growing Canadian and U.S. crude oil markets, in an environmentally sound and sustainable manner.

This document (Volume 1, Application) and the environmental impact assessment (Volumes 2-5) comprise the regulatory submission for the 35,000 m^3/d (220,000 barrels per calendar day) Kai Kos Dehseh Project. These documents should be read as a set, as North American has limited duplication between sections and volumes. Further guidance to these documents is provided in Section 3.4.

This application is made jointly to the Alberta Energy & Utilities Board (EUB) and Alberta Environment (AENV) for:

- Approval from the EUB under the *Oil Sands Conservation Act* on resource recovery for the Kai Kos Dehseh Project area comprised of the 10 hubs within four development areas.

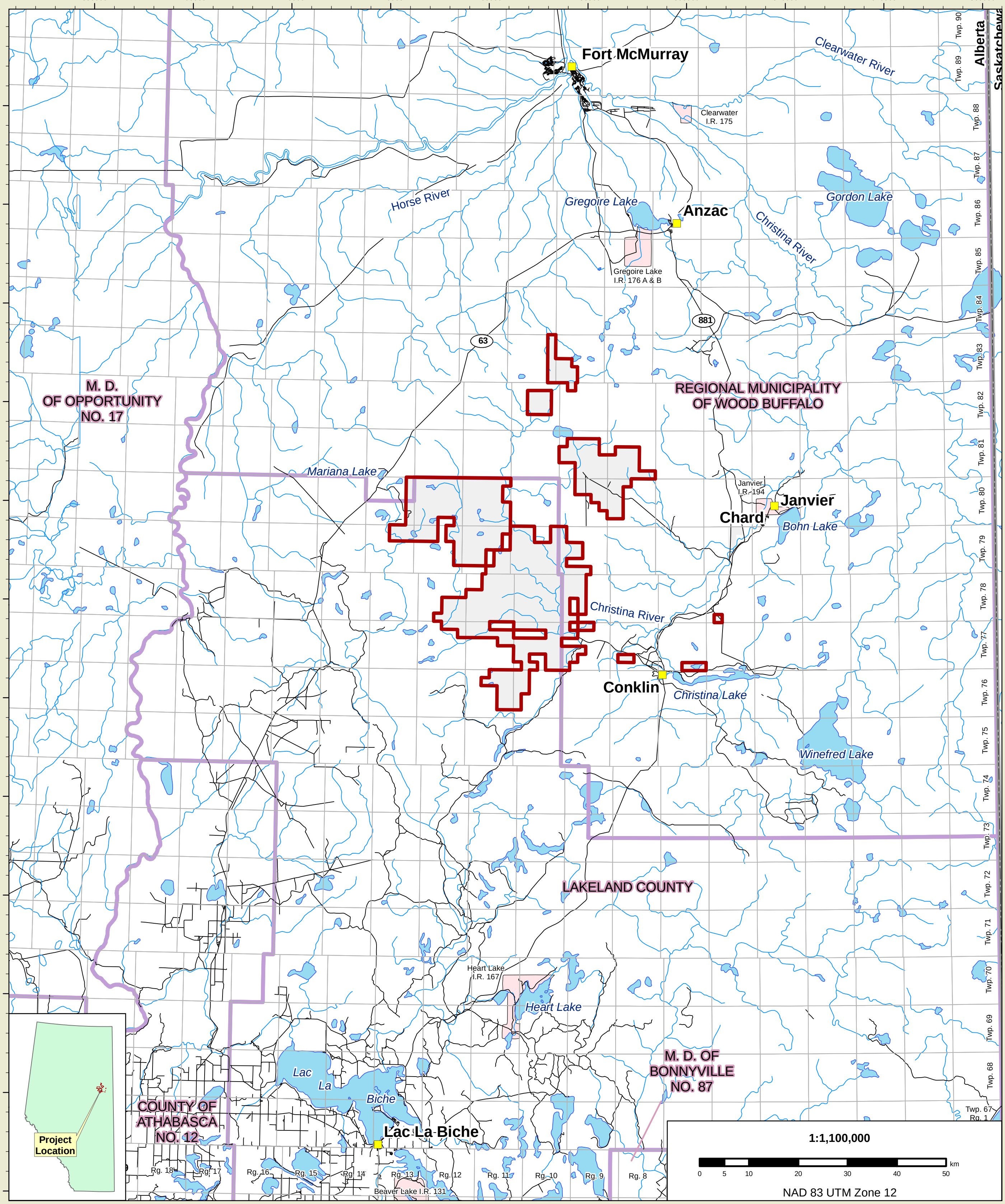
- Approval from AENV under the *Alberta Environmental Enhancement and Protection Act* to construct, operate and decommission the 10 hubs.

The first hub, the Leismer Demonstration Project was the subject of an earlier application made to the EUB and AENV in 2006, and was approved by the EUB in July 2007. Throughout this application, reference is made to 10 hubs for consistency with the project planning and design objectives (Table 1-1).

Table 1.1 Project and Development Areas and Hubs

Project Area	Development Areas (4)	Hubs (10)	Capacity (m^3/d)	Capacity (bpd)	First Steam Date
Kai Kos Dehseh	Leismer	Leismer Demonstration[1]	1,590	10,000	2009
		Leismer Commercial[2]	1,590	10,000	2010
		Leismer Expansion[3]	3,180	20,000	2011
	Corner	Corner[4]	6,360	40,000	2012
	Thornbury	Thornbury[5]	6,360	40,000	2013
		Corner Expansion[5]	6,360	40,000	2014
	Hangingstone	Hangingstone[5]	3,180	20,000	2016
		Thornbury Expansion[5]	3,180	20,000	2017
		Northwest Leismer[5]	3,180	20,000	2018
		South Leismer[5]	3,180	20,000	2034

1. Prior application in 2006; approved by the EUB in July 2007.
2. Application for the Leismer Commercial Hub is detailed in Appendix A
3. Application for the Leismer Expansion Hub is detailed in Appendix B
4. Application for the Corner Hub is detailed in Appendix C
5. Amendment applications for these hubs will be the subject of future submissions.



I:\4455-514_NAOSC\NAOSC_Maps\Maps_Volume1\Figure 1-1 NAOSC Oil Sands Leases 1.1mil_LP_20070524.mxd

Legend

North American Lease Boundary	Town
Provincial Boundary	Indian Reserve
Roads	ATS Twp./Rg.
Lake	Municipal Boundary
Stream	

Title:

NORTH AMERICAN KAI KOS DEHSEH OIL SANDS LEASES

NORTH AMERICAN OIL SANDS CORPORATION

Approved:	Revision Date:
RL/LZ	May 24, 2005

File: Figure 1-1 NAOSC Oil Sands Leases 1.1mil_LP_20070524.mxd

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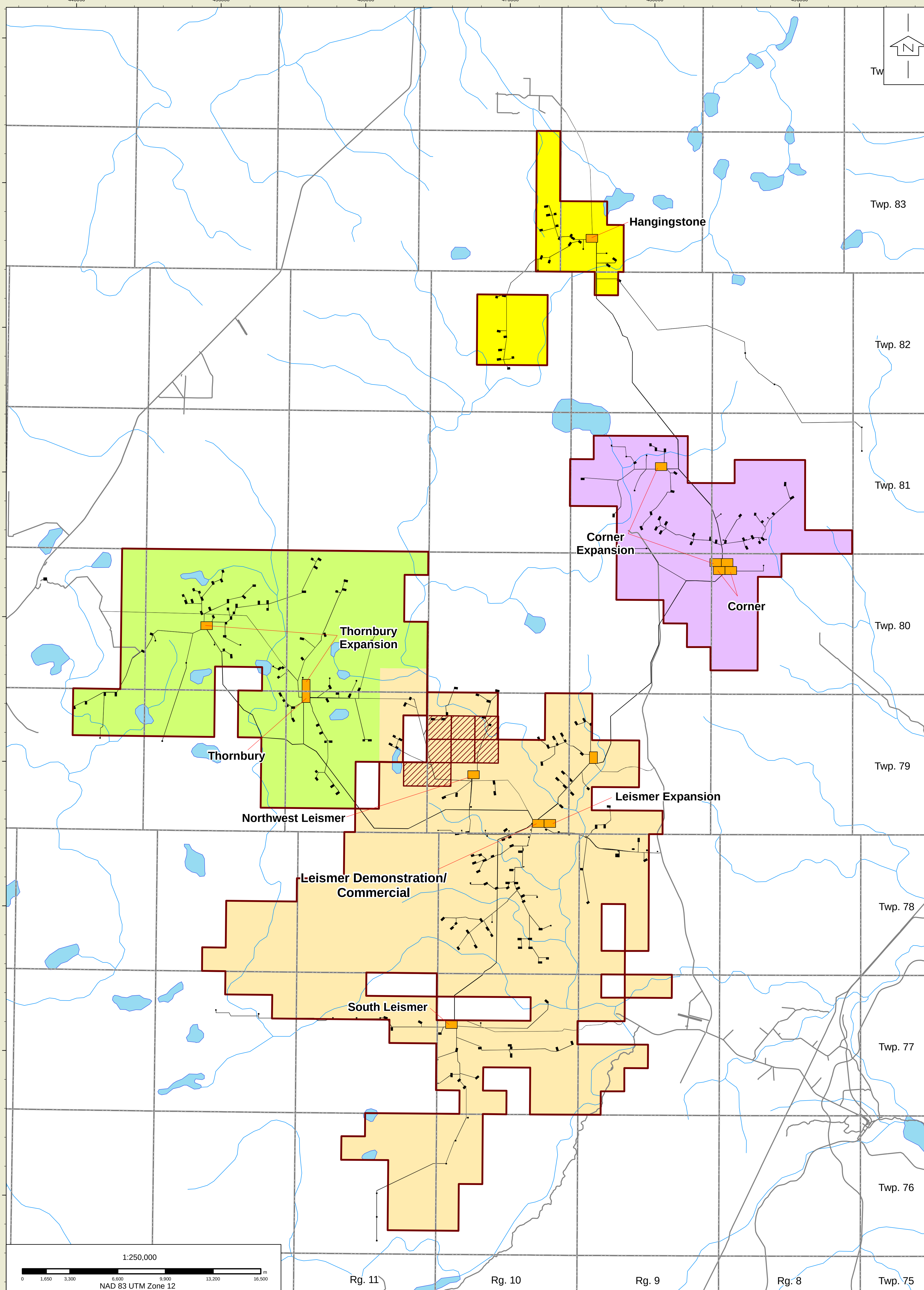

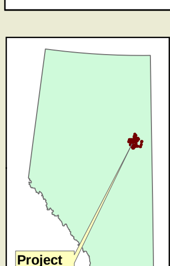

Legend

- North American Lease Boundary/ Kai Kos Dehseh Project Area
- ATS Township / Range
- Roads
- Lake
- Stream
- Hub
- Footprint Infrastructure
- Joint Venture Lands
- Corner Developmet Area
- Hangingstone Developmet Area
- Thornbury Developmet Area
- Leismer Developmet Area

Title:

PROJECT DEVELOPMENT AREAS AND HUB LOCATIONS

Approved:	Revision Date:
RL	May 15, 2007

File: Figure 2.3-2 P&NG Holdings of 3rd Parties in the Area_TP_400k_20070515.mxd

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LZ	RL/LZ	1-2

I:\4455-514_NAOSC\NAOSC_Maps\Maps_Volume1\Figure 1-2 NAOSC Project and Develoment Areas and Hub Locations 1mil_LP_20070514.mxd

2 KAI KOS DEHSEH PROJECT OVERVIEW

2.1 Kai Kos Dehseh Project Regulatory Approach

Under Alberta Regulation 276/2003, Activities Designation Regulation, the proposed Kai Kos Dehseh Project is listed in Schedule 1 and is, therefore, designated as an activity for which an approval is required. The Project is also listed as requiring an Environmental Impact Assessment (EIA) under the Alberta Regulation 111/93, Environmental Assessment (Mandatory and Exempted Activities) Regulation.

To ensure openness and transparency in the community, North American has undertaken a regional EIA that fully discloses the commercial development within the approximately 12 townships of bitumen leases held by North American. This Application and EIA discloses the development over the life of the Project (Figures 2.1-1 and 2.1-2).

The regional EIA regulatory approach was developed through consultation with regulatory agencies including the EUB, AENV and ASRD. The consultations included meetings and support, in principle, from the EUB's oil sands division, AENV's Deputy Minister and Assistant Deputy Minister, AENV's Regional Approvals Manager, AENV's Regional Environmental Manager, and ASRD Sustainable Resource and Environmental Management (SREM) office Executive Director EIA and Oil Sands.

An agreement was made, in principle, that North American would apply for the overall Project in one regional EIA followed by detailed Applications instead of phasing five stand alone EIAs over the life of the development. It was agreed that the regional EIA (Volumes 2 through 5) would be submitted with an overall Application (Volume 1) for the full scale development and specific applications for initial hub developments (Volume 1, Appendices A, B and C). Detailed amendment applications will be submitted in the future for each additional development hub. North American acknowledges that if significant changes in the region occur, AENV may request additional environmental studies up to and possibly including an EIA. Through this approach the regional EIA has provided the stakeholders full disclosure of North American's ultimate Project. North American believes this approach, of full disclosure, is in the public interest.

North American's regional EIA is based on regional data and a conceptual engineering and execution plan. The EIA has a regional focus and utilized a less intensive sampling protocol while still collecting sufficient environmental data to facilitate regulatory decisions. Several of the EIA programs, such as the wildlife monitoring for caribou, moose and wolf, were tailored to actively engage the local stakeholders and address their specific issues. The wildlife monitoring program is scientifically based and is focused on moose (based on First Nations concerns), caribou (based on endangered species concerns) and wolf (based on the predator prey relationship between them). The regional EIA approach is also clearly reflected in the soil sampling program designed for the Project. An appropriate soil sampling density was used to regionally map soils throughout the North American lands. Soil samples were initially collected based on a preliminary Project footprint as well as samples collected to verify the regional mapping. More detailed soil surveys were conducted as components of the Project footprint, in the initial development areas, were refined. As engineering design progresses, North American is committed to conducting even more detailed soil surveys (e.g., Survey Intensity Level One) as part of the pre-disturbance assessment (PDA) process.

The applications include site specific data. This concept, as illustrated in Figure 2.1-2 (a slide reproduced from the stakeholder consultation program), was to focus the level of data collected during the EIA (depicted with a "bite" out of the EIA block) and replace this detail with enhanced ongoing environmental and operational monitoring (thick line between application blocks). North American agreed to provide more specific data and a higher data density for the initial hubs and to provide subsequent enhanced amendment applications for future hubs. The intent of the future applications is to provide the standard level of application detail for each hub as their requisite geology and engineering progresses. North American also committed to including updated air and groundwater effects assessments (including cumulative effects assessment) as well as incorporating learnings (continuous improvement arrow) from previous hubs into future hub applications. Figure 2.1-3 is a slide, reproduced from the stakeholder consultation program, which illustrates the regional EIA and monitoring approach. A letter from AENV detailing their agreement to the regional EIA approach is presented in Appendix D.

Following the above model, the regional EIA has been prepared for the full 35,000 m^3/d (220,000 bpd) of bitumen production at ten hubs in four development areas. One hub, the Leismer Demonstration Hub, was previously applied for and approved. The Leismer Demonstration Hub has been included in the assessment for completeness. Appendices A, B and C apply for the Leismer Commercial Hub, Leismer Expansion Hub and the Corner Hub, respectively. These appendices provide details specific to these hubs, including specific reservoir and geology information.

North American is committed to preparing annual reports to the community that will chart the progress of the company's environmental stewardship and community engagement (Appendix D). These reports will be incorporated into all regulatory filings to ensure the community is actively involved in the regulatory process

220,000 bpd Kai Kos Dehseh Project Area Development

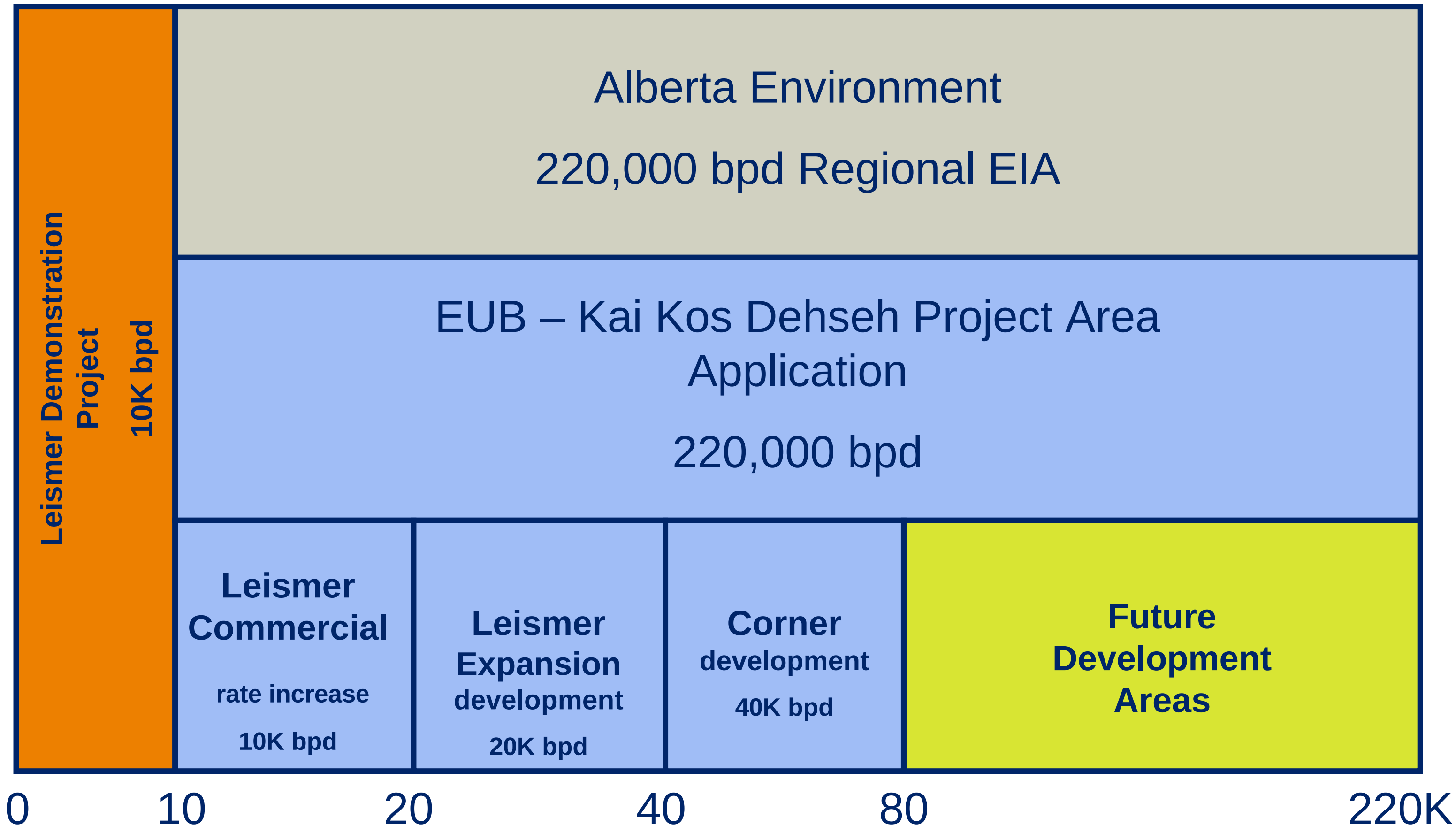
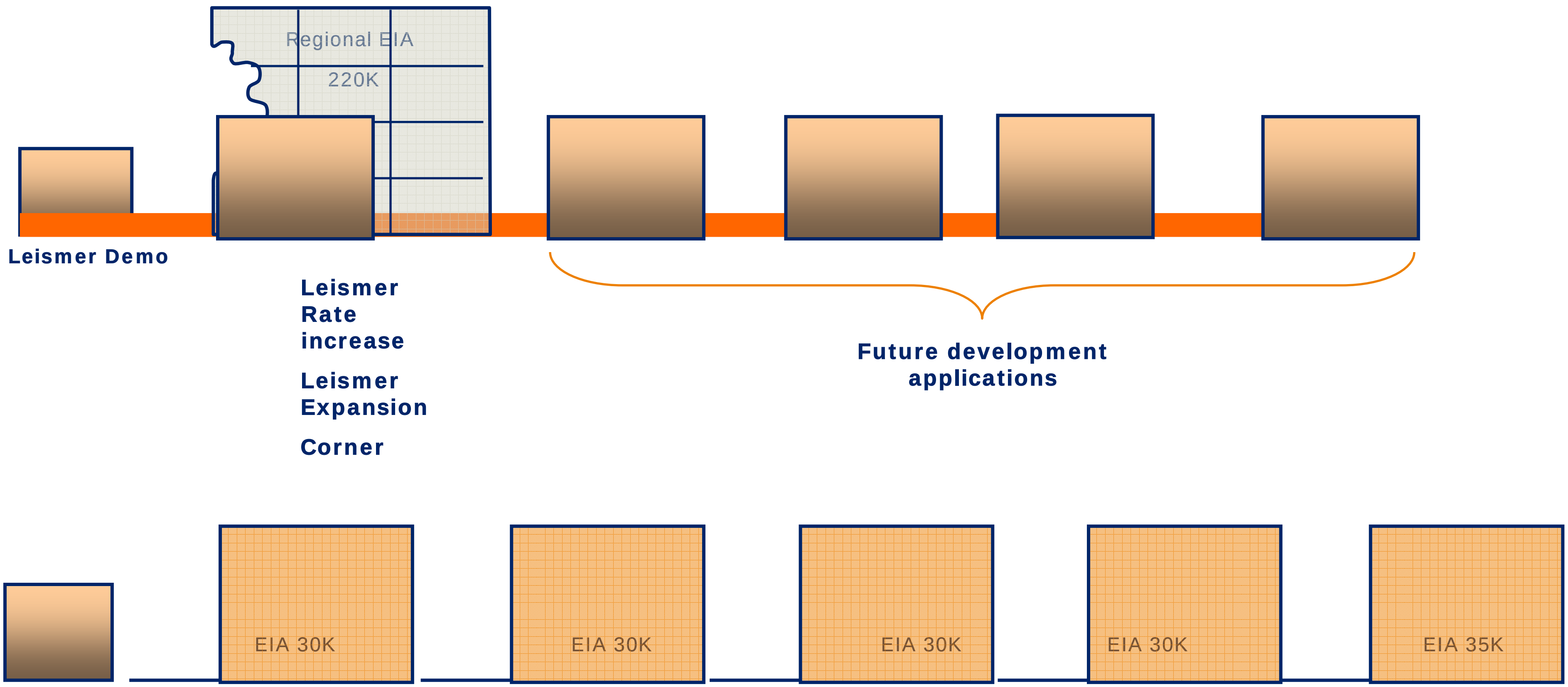


Figure 2.1-1 Project Development Plan

NORTH AMERICAN OIL SANDS CORPORATION

Our SAGD Approach

Regional EIA Approach



Current EIA Approach

Figure 2.1-2 North American EIA Approach

NORTH AMERICAN
OIL SANDS CORPORATION

EIA Approach

EIA

- Regional Approach
- Less Intensive Sampling
- Focused
- Tailor Specific Components to Engage Local Stakeholders

MONITORING

- More Comprehensive
- Long Term
- Innovative Monitoring Approaches
- More Engaged Local Community
- Annual Reporting to Community
- More Comprehensive Licence Requirements

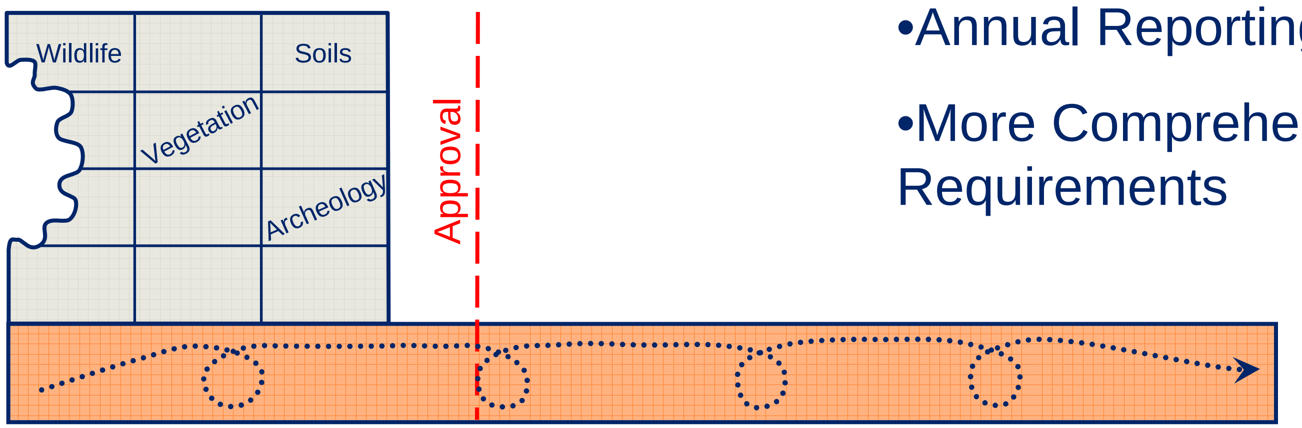


Figure 2.1-3 Regional EIA Approach

NORTH AMERICAN OIL SANDS CORPORATION

2.2 Kai Kos Dehseh Project History

In 2004, North American acquired its first mineral leases. Additional leases were acquired between 2004 and 2007, resulting in a land holding of approximately 12 townships.

In May 2006, North American applied to the EUB for approval of the Leismer Demonstration Project, which would produce up to 1,590 m^3/d (10,000 bpd) of bitumen using SAGD technology. Approval was granted by the EUB in July 2007 and construction is scheduled to begin late summer 2007.

North American has completed seismic and oil sands exploratory drilling programs in the four development areas (Leismer, Corner, Thornbury and Hangingstone). These programs have confirmed the existence of a significant bitumen resource. Upcoming drilling programs will continue to delineate these resources.

In the first quarter of 2005, North American drilled 19 wells. In the first quarter of 2006, North American acquired 24 sections of high resolution 3D seismic, 246 km of 2D seismic and drilled 121 wells. In the first quarter of 2007, North American acquired an additional 20.9 sections of 3D seismic, 617.6 km of 2D seismic and drilled 153 wells (Figure 2.2-1). Integrated geological and geophysical mapping for each development area will be supplied in future submissions.

The components of each SAGD hub include horizontal production and injection wells on multi-well pads. In addition to the horizontal wells required for a SAGD project, each hub will have surface facilities required to generate and distribute steam, gather well production, process oil and emulsions, and treat water. These facilities are made up of four components: field facilities (production pads and horizontal wells), CPF, offsite connections, services and camps. Each hub may consist of all or a portion of the following list:

Field Facilities:

- SAGD pads, wells and associated facilities;
- production flowlines;
- steam distribution flowlines;
- electrical power distribution lines; and
- pad access roads.

Central Processing Facility (CPF):

- steam generation facilities;
- production treatment (bitumen, water and gas) facilities;
- sulphur removal equipment;
- water treatment, recycle and disposal facilities;
- electrical, air, water and instrumentation utility systems;
- emergency electrical power generation;

- tankage; and
- support buildings, including warehouses and operations camp.

Interconnecting Infrastructure:

- access roads;
- in-field fuel gas pipelines;
- in-field water and gas redistribution pipelines
- in-field diluent supply pipelines;
- in-field diluted bitumen sales lines; and
- electrical power distribution line.

Camps

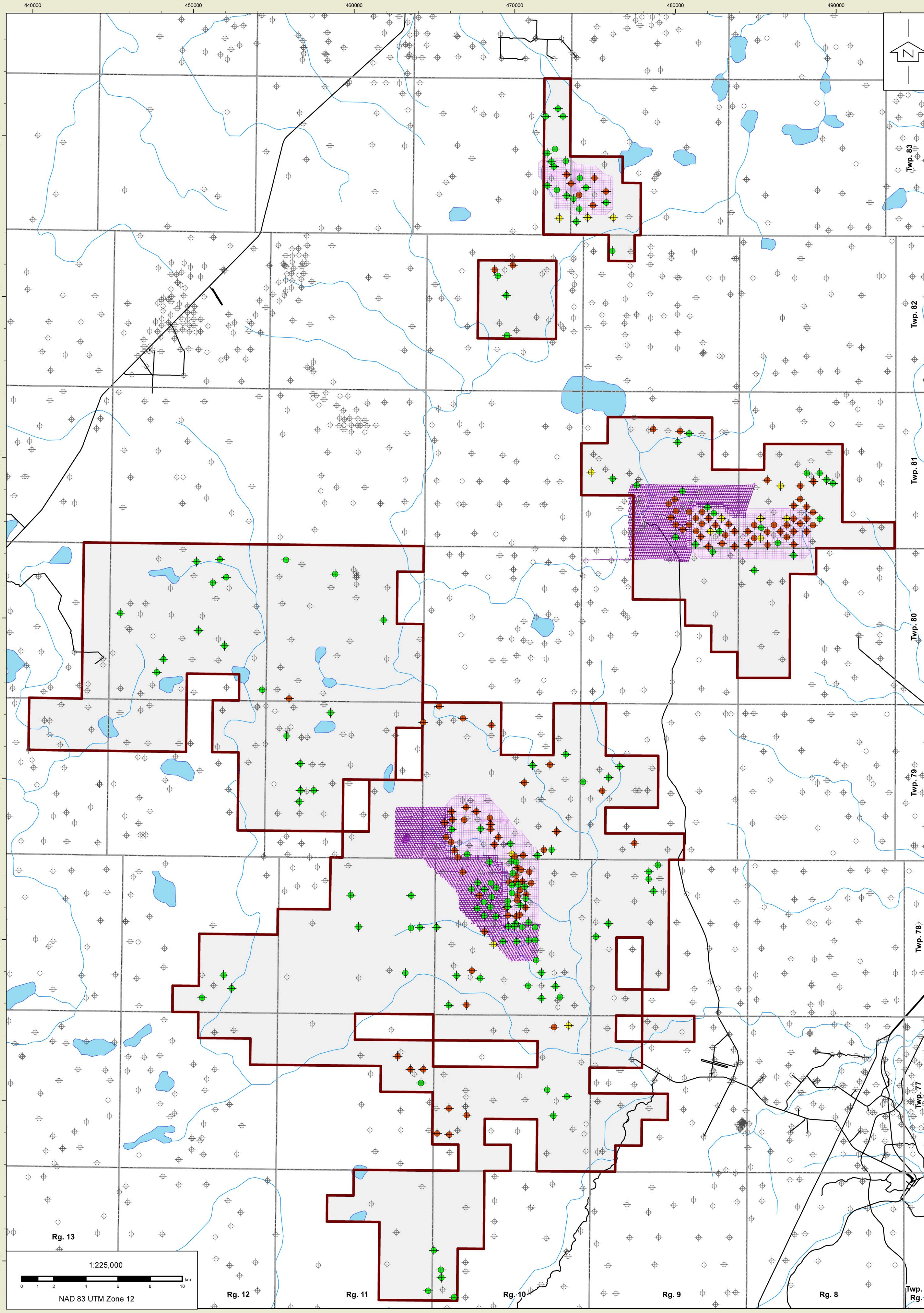
- east permanent operations camp (Leismer);
- west permanent operations camp (Mariana Lakes); and
- temporary construction/drilling camps.

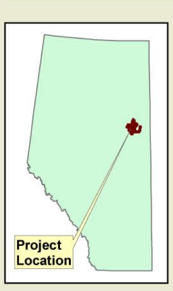
Services (included in this application)

- water disposal wells and related pipelines; and
- source water wells and related pipelines.

Services (not included in this application)

- fuel gas pipeline;
- main diluent supply pipeline;
- main diluted bitumen sales line; and
- electrical power transmission lines.





Legend

- North American Lease Boundary
- ATS Township / Range
- Roads
- Lake
- Stream

Oil Sands Expansion

- Core Well 2005
- Core Well 2006
- Core Well 2007
- Other Historical Wells
- 2006 / 2007 3D Seismic Grid

Title:

NORTH AMERICAN CORE HOLES AND 3D SEISMIC GRIDS IN THE AREA

NORTH AMERICAN OIL SANDS CORPORATION

Approved:	Revision Date:	
RL	May 15, 2007	
File: Figure 2.2-1 NAOSC COREHOLES in the Area_TP_400k_20070524.mxd		
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LZ	RL/LZ	2.2-1

14455-514_NAOSC\NAOSC_Maps\Maps_Volume1\Figure 2.2-1 CORE HOLES_TP_225k_20070524

2.3 Land and Mineral Rights

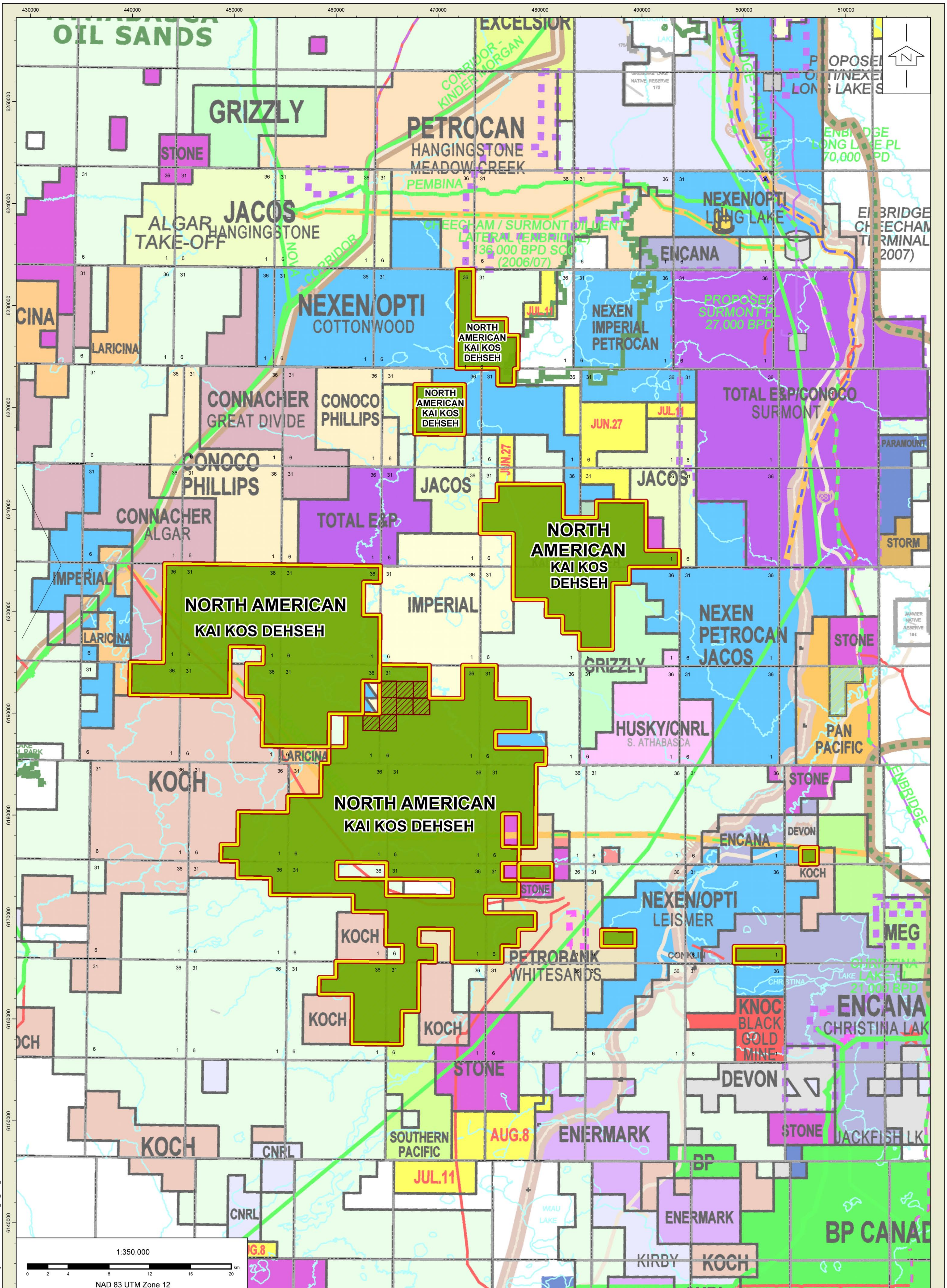
SAGD bitumen production, natural gas production and forestry are the predominant industries in the area surrounding the Kai Kos Dehseh Project. It is important that, where appropriate, operators coordinate their activities so that duplication is avoided and the development footprint is minimized. North American is participating in the Chamber of Resources integrated land management activities along with Alberta-Pacific Forest Industries Inc. (Al-Pac) and other oil and gas operators in the region referred to as the Southern Athabasca Oil Sands Group.

North American is the sole operator for the majority of the oil sands leases contained within the Kai Kos Dehseh Project, with the exception of two small parcels of land consisting of eight sections, which are partnered with Nexen and/or Imperial Oil.

North American has not entered into formal operating agreements with Nexen and/or Imperial Oil and, as such, is not proposing any development, at this time, on these jointly held lands.

Figure 2.3-1 shows adjacent oil sands leases in relation to the North American operated leases and highlights the jointly held lands.

Gas production from multiple zones is prevalent, and North American recognizes the importance of working with gas producers within the region to ensure proper resource development. North American is dedicated to responsible, cooperative resource management throughout its land holdings. North American is also a supporter of innovative solutions to the “Gas over Bitumen” issue, and is committed to working with all gas producers to that end. Figure 2.3-2 (a, b and c) shows the petroleum and natural gas holdings of third parties in the area.



Legend

- North American Leases
- Joint Venture Lands
- Brokered Lands (Held in Trust for another Company)
- Upcoming Oil Sands Land Postings
- ATS Township Line

OIL SANDS EXTRACTION METHOD

- IN-SITU
- IN-SITU (EXPERIMENTAL)
- PRIMARY PRODUCTION
- SURFACE MINING

GPS TRANSPORTATION

PRIMARY HIGHWAY
HIGHWAY # 63
GRAVEL PRIMARY HIGHWAY
PAVED SECONDARY HIGHWAY
GRAVEL SECONDARY HIGHWAY
IMPROVED ROAD
UNIMPROVED ROAD
TRUCK TRAIL
RAILWAY
RAILWAY (EDM. TO FORT MAC.)

KNOWN OIL SANDS DEPOSITS
AEUB OIL SANDS BOUNDARY
SURFACE MINABLE OIL SANDS

PIPELINES AND FACILITIES

NATURAL GAS
SOUR GAS
MISCELLANEOUS GASES
FUEL GAS
CRUDE OIL
OIL WELL EFFLUENT
SALT WATER
FRESH WATER
LVP PRODUCTS
HVP PRODUCTS
MISCELLANEOUS LIQUIDS
* PROPOSED PIPELINES ARE HIGHLIGHTED IN ORANGE *

Data/Map Background Source:
Divestco Geomatics
Oil Sands Lease Holders
Information Date: June 26, 2007

Title:

OIL SANDS HOLDINGS OF THIRD PARTIES IN THE AREA

NORTH AMERICAN OIL SANDS CORPORATION

Approved:	Revision Date:	
RL	May 15, 2007	
File: Figure 2.3-1 Oil Sands Holdings of 3rd Parties in the Area_TP_400k_20070515.mxd		
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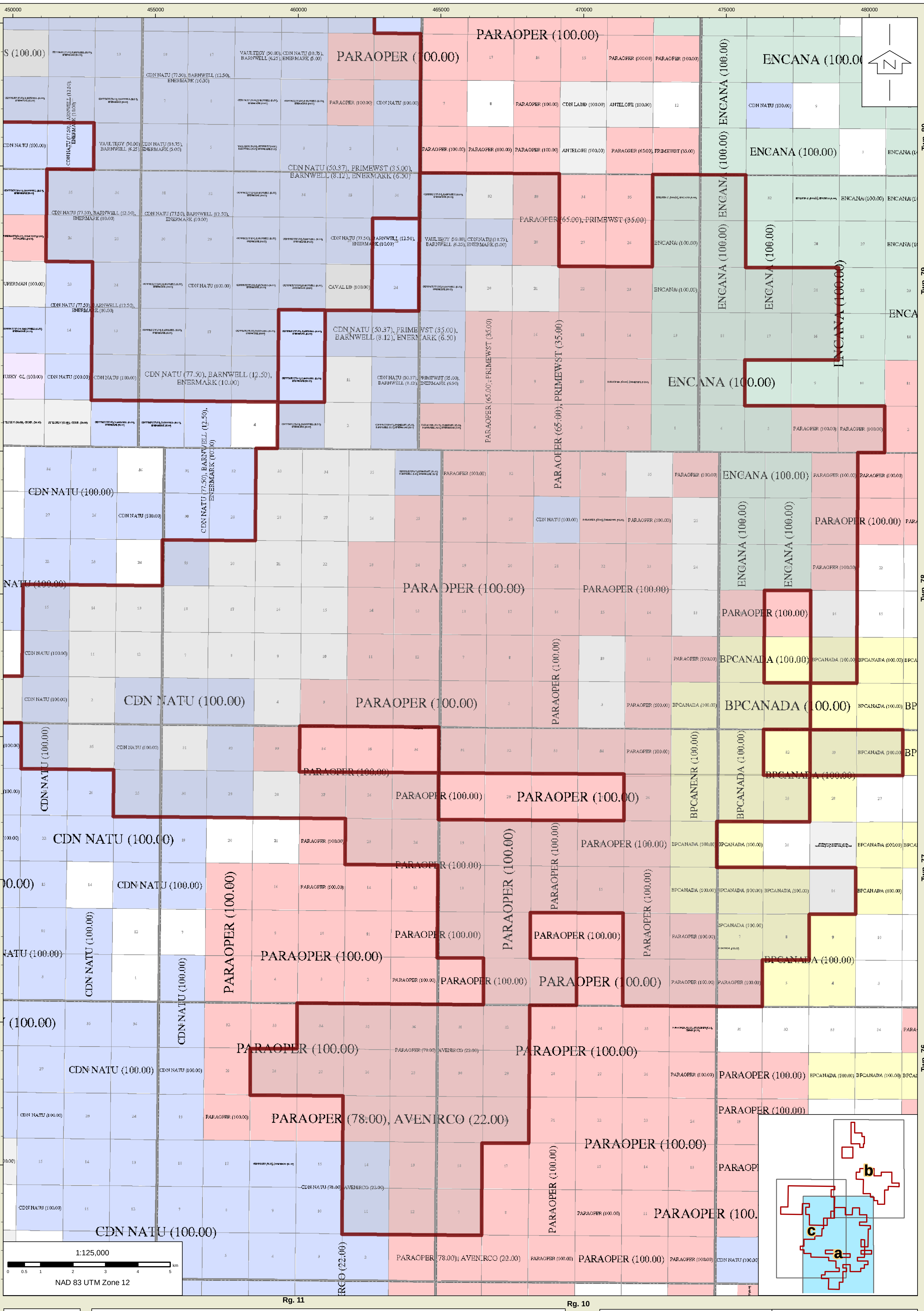
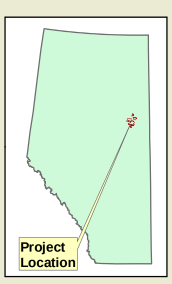
14455-514_NAOSC\NAOSC_Maps\Maps_Volume1\Figure 2.3-2 P&NG Holdings of 3rd Parties in the Area_TP_225k_20070524.mxd





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North American Leases

Title:

PETROLEUM & NATURAL GAS HOLDINGS OF THIRD PARTIES IN THE AREA

NORTH AMERICAN OIL SANDS CORPORATION

Approved: RL	Revision Date: June 13, 2007

File: Figure 2.3-2a P&NG Holdings of 3rd Parties in the Area_TP_225k_20070613.mxd

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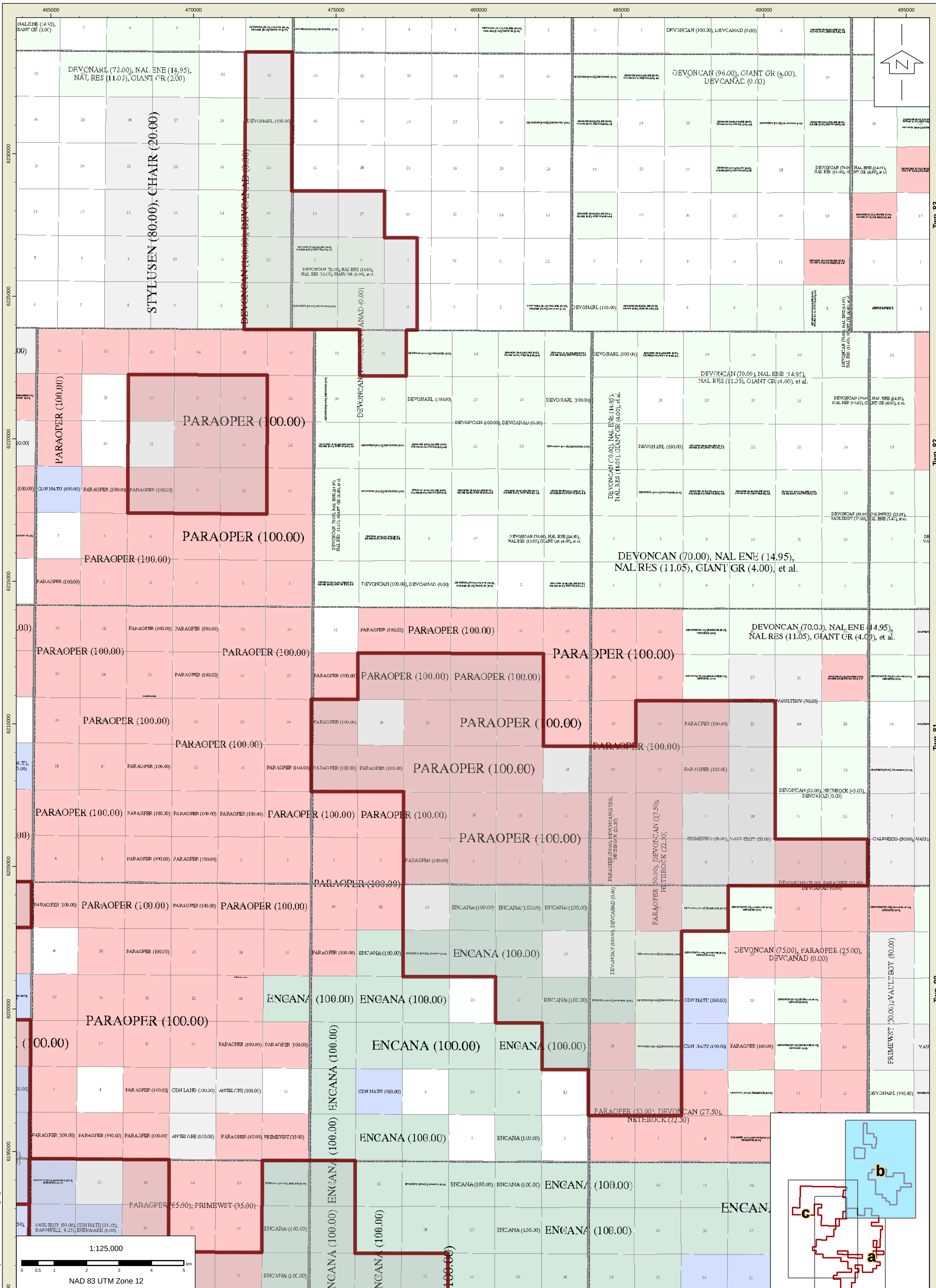
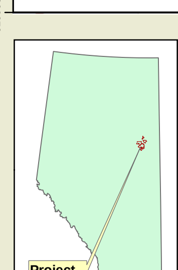
14455-514_NAOSC\FINAL_MAPS\Volume 1\Figure 2.3-2a P&NG Holdings of 3rd Parties in the Area_TP_20070613.mxd





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North American Leases

Title:

PETROLEUM & NATURAL GAS HOLDINGS OF THIRD PARTIES IN THE AREA

NORTH AMERICAN OIL SANDS CORPORATION

Approved: RL	Revision Date: June 13, 2007
File: Figure 2.3-2b P&NG Holdings of 3rd Parties in the Area_TP_20070524.mxd	

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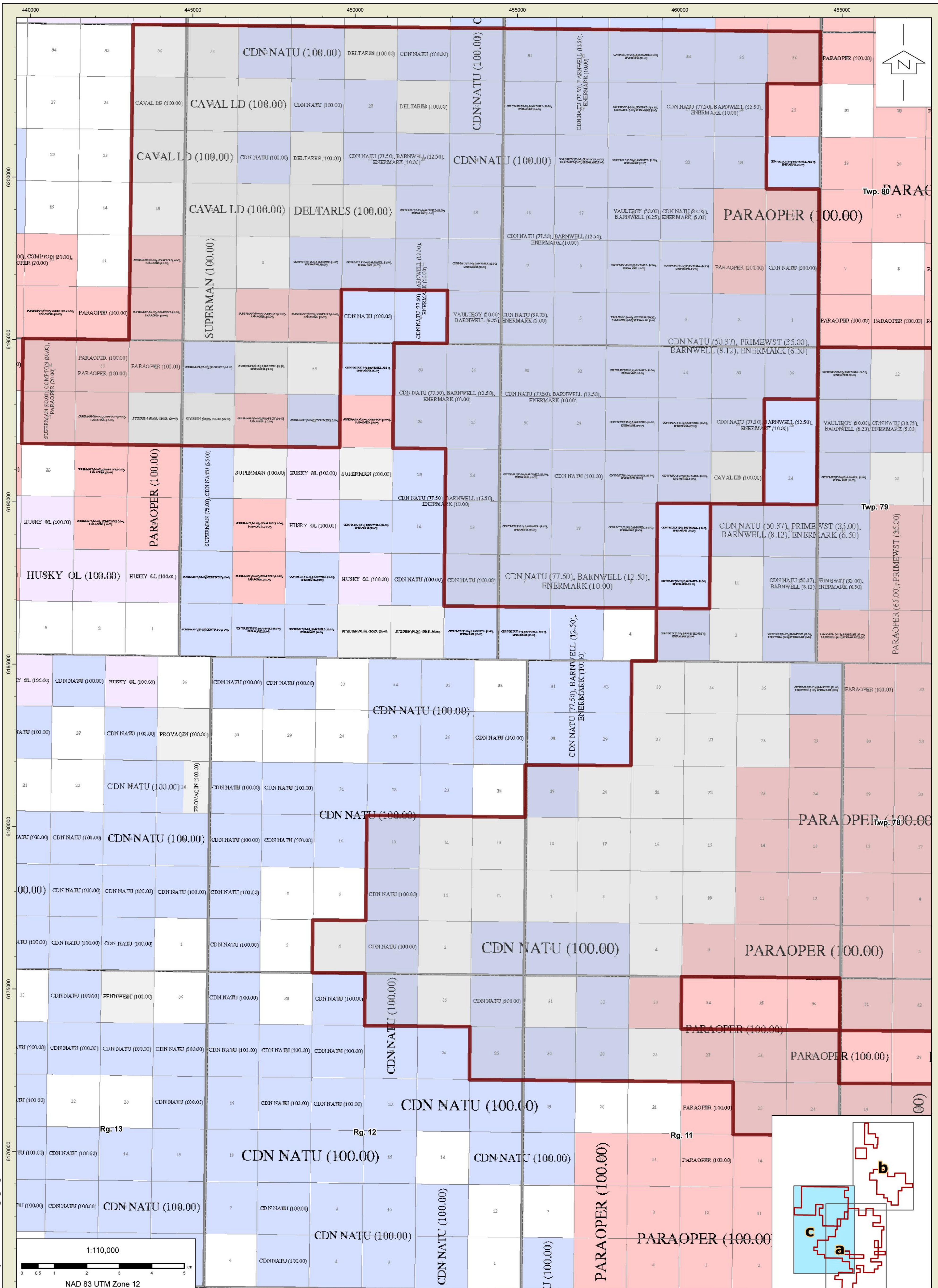
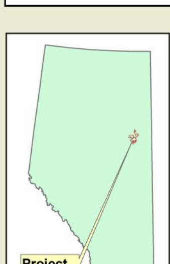
LZ	RL/LZ	2.3-2b

14455-514_NAOSCNAOSC_Maps\Maps_Volume1\Figure 2.3-2b P&NG Holdings of 3rd Parties in the Area_TP_20070524.mxd





Legend

North American Leases

Title:

PETROLEUM & NATURAL GAS HOLDINGS OF THIRD PARTIES IN THE AREA

NORTH AMERICAN OIL SANDS CORPORATION

Approved: RL	Revision Date: May 24, 2007	
File: Figure 2.3-b P&NG Holdings of 3rd Parties in the Area_TP_225k_20070524.mxd		
Drawn by: LZ	Checked: RZ/LZ	Fig. No.: 2.3-2c

14455-514_NAOSC\NAOSC_Maps\Maps_Volume1\Figure 2.3-2 c P&NG Holdings of 3rd Parties in the Area_TP_225k_20070524.mxd

2.4 Kai Kos Dehseh Project Schedule and Production Capacity

The life of the Kai Kos Dehseh Project, based on resources outlined in this application, is estimated to be 40 years as shown on the overall production profile (Figure 2.4-1), the production prediction (Table 2.4-1) and project schedule (Table 2.4-2). The resources will be exploited using ten hubs, including the previously approved Leismer Demonstration Hub. Throughout the life of the project, 218 production pads are planned to be built, and approximately 1050 horizontal well pairs will ultimately be required to exploit the resource. Up to thirty-nine (39) once through steam generators (OTSGs) rated at approximately 73 MW (250 mmBTU/h) each, will be required, spread out amongst ten surface facility sites (hubs), to generate up to approximately 124,000 m^3/d of 100% quality steam. This steam will enable SAGD production greater than 35,000 m^3/d of bitumen on an annual average calendar day basis, at an anticipated average SOR of approximately 3 m^3/m^3.

The CPF locations, the SAGD well pad placements, and the directional drilling parameters are well understood for the first hub developments. The CPF locations for future hubs have been selected based on current reservoir knowledge, environmental constraints data and not siting the CPFs on exploitable pay zones. All CPFs and interconnecting infrastructure are presented on Figure 1-2.

The Leismer Commercial Hub, Leismer Expansion Hub and Corner Hub pads have been sited based on geology, reservoir and environmental data. However, due to the complexities of the channel deposit, the placement of subsequent SAGD well pads at the future Leismer, Corner, Thornbury and Hangingstone Hubs are less well defined and will not be finalized until additional geological mapping and 3D seismic analysis have been completed. These hubs will be the subject of future commercial resource applications.

The schedule for the Kai Kos Dehseh Project is approximate and subject to modification in response to the receipt of regulatory approvals, business considerations and weather factors.

The 1,590 m^3/d (10,000 bpd) Leismer Demonstration project (approved in July 2007) will be expanded into the 3,180 m^3/d (20,000 bpd) Leismer Commercial Hub as described in Appendix A. The schedule for the Leismer Commercial Hub is also included in Appendix A.

The Leismer Commercial Hub will be expanded as outlined in Appendix B. The expansion, referred to as the Leismer Expansion Hub, will be brought on line mid-2011. This will bring the capacity in the Leismer Development Area up to approximately 6,360 m^3/d (40,000 bpd) on an annual average calendar day basis. The development in the Leismer area will ultimately include a total of 197 SAGD well pairs drilled from 61 pads. Additional phases of development in the Leismer Development Area will be the subject of future commercial resource applications.

Production at Corner as outlined in Appendix C is expected to begin mid-2012, upon approval of the Corner initial development area. The Corner Hub will have a capacity of approximately 6,360 m^3/d (40,000 bpd) on an annual average calendar day basis. Subsequent development area expansion will be sought to double the production at Corner to reach approximately 12,720 m^3/d (80,000 bpd). Corner area development will ultimately include a total of 169 SAGD well pairs drilled from 31 pads. Additional hubs in the Corner development area will be the subject of future commercial resource applications.

The Thornbury Hub, upon approval of a Thornbury development area, is expected to be developed and put on production by late 2013 and will reach a capacity of approximately 6,360 m^3/d (40,000 bpd) on an annual average calendar day basis. As additional bitumen resources are delineated, and upon approval of an expanded development area, it is expected that Thornbury production will be expanded by early 2017 to a total of approximately 9,540 m^3/d (60,000 bpd) on an annual average calendar day basis. The Thornbury area development will ultimately include a total of 181 SAGD well pairs drilled from 67 pads. The Thornbury Hub and Thornbury Expansion Hub will be the subject of future commercial resource applications.

Hangingstone, upon approval of a Hangingstone development area, is expected to be developed by early 2016 and start production at a level of approximately 3,180 m^3/d (20,000 bpd) on an annual average calendar day basis. The Hangingstone area development will ultimately include a total of 59 SAGD well pairs drilled from 23 pads. The Hangingstone Hub will be the subject of a future commercial resource application.

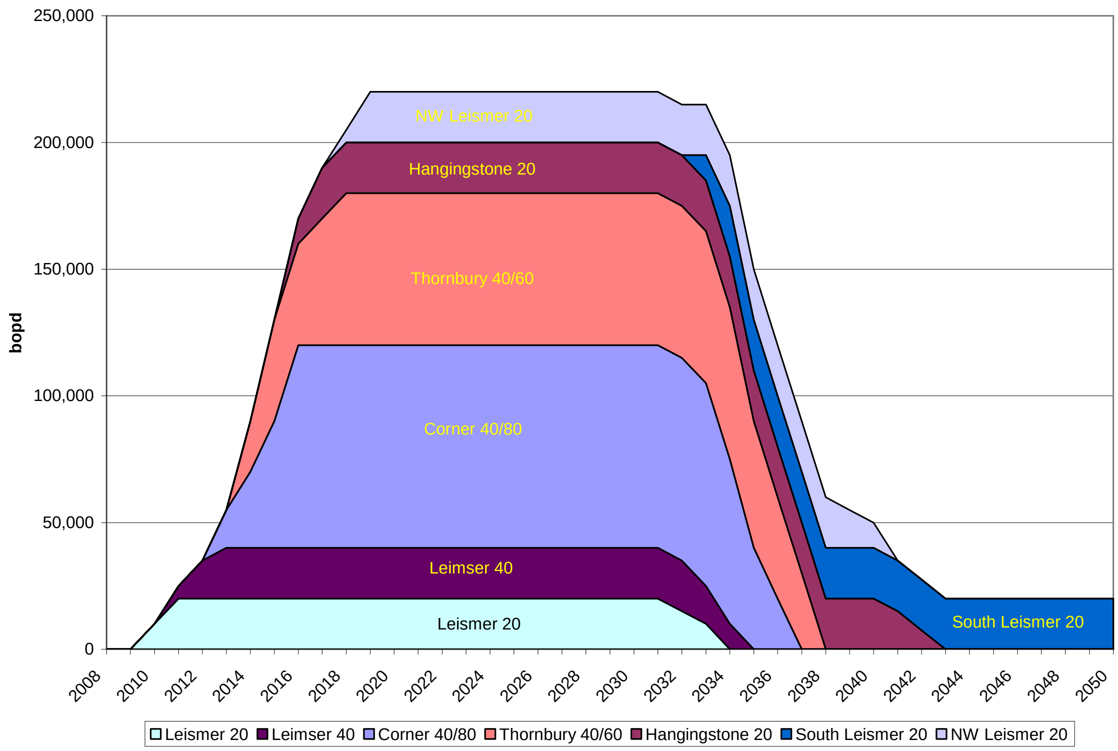
Northwest Leismer will require expansion of the Leismer development area and will be developed and put on production mid-2018 at a rate of approximately 3,180 m^3/d (20,000 bpd). Northwest Leismer area development will ultimately include a total of 81 SAGD well pairs drilled from 20 pads. The Northwest Leismer Hub will be the subject of a future commercial resource application.

In the future, projected around 2034, when processing capacity is available at the Leismer Central Processing Facility, it is expected that an additional 49 well pairs (approximately 3,180 m^3/d (20,000 bpd)) will be developed in the South Leismer area.

Table 2.4-1 Kai Kos Dehseh Productivity Prediction

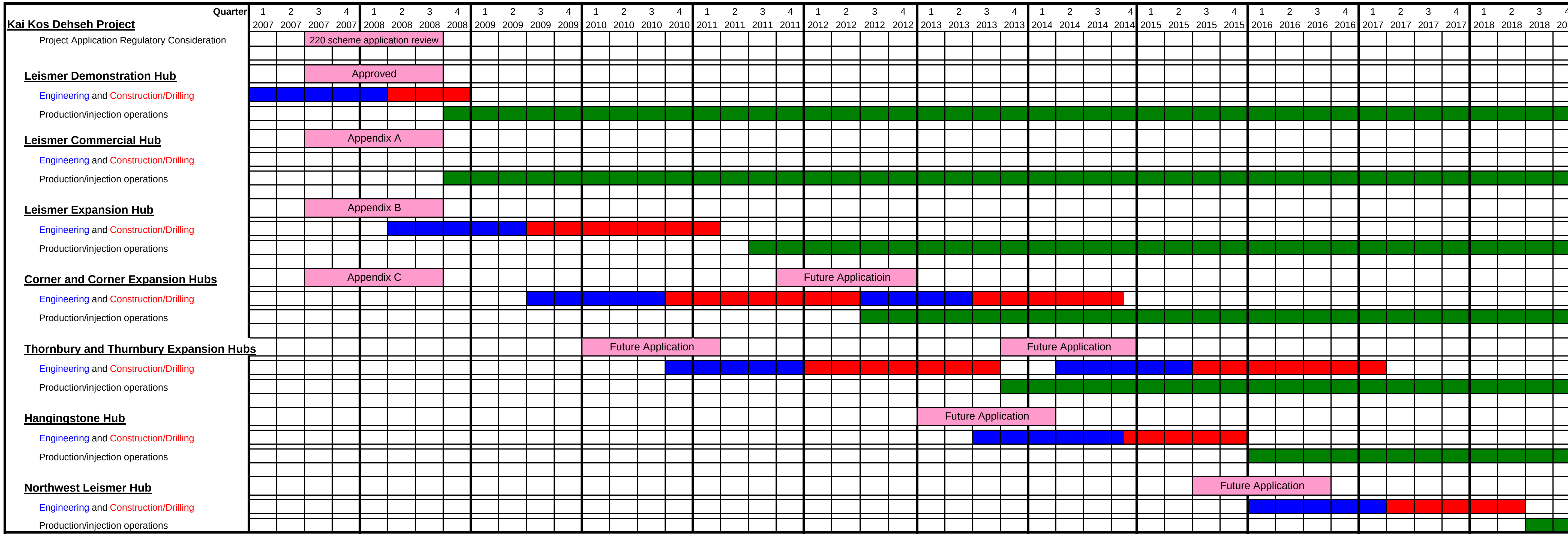
Hub	Well Length (m)	Average Well Rate (m^3/d)
Leismer Demonstration and Commercial	700	144
Leismer Expansion	1,000	130
Corner (including Expansion)	1,000	156
Thornbury (including Expansion)	1,000	150
Hangingstone	1,000	110
Northwest Leismer	1,000	130
South Leismer	1,000	128
Total		

Figure 2.4-1 Kai Kos Dehseh Production Profile



Note: Estimated production profiles in thousands of barrels per day have been smoothed for illustration.

Table 2.4-2: Schedule for Kai Kos Dehseh Project



2.5 Project Financing

North American Oil Sands Corporation is a wholly owned subsidiary of Statoil ASA and the Kai Kos Dehseh will be financed by Statoil.

2.6 Marketing Arrangements

North American initially plans to market a bitumen blend, using either condensate or synthetic crude oil as diluent. During the early years of the development, the primary markets for bitumen are expected to be refineries located in Western Canada, the U.S. Midwest and the Rocky Mountain states. North American, under a separate regulatory application, is also planning to develop an upgrader facility to convert some or all of its bitumen into a very marketable, high quality synthetic crude oil. North American is planning pipeline connections to import diluent and export blend under separate regulatory applications.

2.7 Social Development Execution Plan

Social infrastructure and services may be affected by the population changes that occur due to the Project. Two distinct population curves are associated with most oil sands developments: construction population, over approximately 2 to 5 years depending on the size and complexity of the facility; and, operations population over the operating time frame of the project. The Project will comprise ten hubs, including the Leismer Demonstration Hub, constructed over approximately 12 years between 2008 and 2019, followed by one more hub in 2033. Operation staff will be required starting in 2009. The phased construction means that a construction workforce of approximately 300 will be in the area continuously for approximately 12 years during the same time that operations will be starting up at most hubs.

The communities closest to the Project are Conklin, Janvier/Chard, the Chipewyan Prairie Dene First Nation, Anzac, the Fort McMurray First Nation at Willow Lake, and Mariana Lake. While all of these communities are located in the Regional Municipality of Wood Buffalo (RMWB) almost half of the project lands are located in Lakeland County. These communities had a combined population of approximately 1,850 in 2006 (RMWB Census, 2006; INAC, 2006). The largest community was Anzac, with just over 700 people, and the smallest community was Mariana Lake with 9 people. The level of community infrastructure and social service in these communities varies. However, these are rural communities with minimal infrastructure and social service delivery. Acute health care, high school education, post secondary education, are all available in the urban centres of Lac La Biche and Fort McMurray. The main access into the Project is equidistant to Lac la Biche and to Fort McMurray. North American's project development plan places more emphasis on goods and services sourced from Lac La Biche.

Several oil sands developments are already approved and in construction in areas near these communities, and social effects of development are already occurring. Demand for and cost of housing has been increasing in the past few years, as job opportunities arise and as cost of housing in Fort McMurray motivates some people to move to these communities. Traffic has increased on the main access road, Highway 881, and is a concern in the communities. Access to opportunities for employment and business development is also a high priority in these communities.

North American has developed its phased construction approach to dilute the effect of a single large construction force required to construct the entire scope at once. Construction related traffic on Highway 881 due to the project will remain steady over approximately 12 years, rather than peaking in a short timeframe. Kai Kos Dehseh will have two permanent camps, one near the Leismer facility to be built to accommodate a construction workforce of 300 and an operations workforce of 150. This camp is anticipated to service hub construction and operations on the east side of the project, and will effectively be a neighbouring community to Conklin. A second camp is foreseen as necessary for the Thornbury and Hangingstone construction and operations, as topography limits road building from Leismer to these facilities. Provisionally, this camp is anticipated at or near Mariana Lake, for approximately 400 persons.

North American anticipates drawing labour from all possible sources, and will provide for transportation to the camp, where possible. This includes anticipated flights to the nearest regional airstrip, provided it is upgraded to sufficient capacity. Local bussing of construction and operations personnel is also being considered.

2.8 Sustainable Development

To North American, sustainable development means integrating the environment, economics and social expectations into the Project. The company is committed to the following principles:

- Stewardship of the environment,
- Strategic planning for sustainability in business;
- Meeting social expectations of stakeholders;
- Engaging local aboriginal communities and businesses;
- Managing key public policy and government issues;
- Transferring technology for new sustainable business opportunities; and
- Training and knowledge transfer related to sustainable development.

North American has a corporate Sustainable Development Group that addresses the sustainability challenges of the oil sands business. Such action is essential to ensure that principles of sustainable development are being applied in the design process, including, but not limited to:

- Efficient equipment utilization;
- Energy conservation application;
- Effluent streams are being re-used, re-cycled or re-processed;
- Water use management; and
- Development footprints minimization.

2.9 Alternative to Project

Within the Leismer development area, the overburden thickness to the bitumen bearing resource is approximately 400 m with bitumen bearing formation thicknesses ranging from 15 to 35 m. Surface mining at the Kai Kos Dehseh Project is not an alternative for resource recovery. The regional bitumen quality is between 6 and 9 deg. API, and this type of resource is currently recoverable using SAGD technology. The alternative to the Kai Kos Dehseh Project is to forego recovery of this resource and meet forecasted energy requirements through offshore imports, which would result in the Province of Alberta and Canada foregoing the economic and development benefits of the Project.

2.9.1 Alternative Technologies

North American has committed considerable resources to the study of alternative technologies in the design and operation of the plant, field, and well site facilities. North American has focused extensively on alternative fuel options, electrical power supply, water treatment alternatives, and production methodologies. Much of this focus has been to guarantee the long term success of the project. North American feels it is both feasible and critical to continually focus on creative alternatives to diminish overall environmental impacts and enhance project economics.

Within the current atmosphere of rapidly developing technologies North American will continue to consider alternative technologies. Careful consideration of all elements is critical to continued success. North American's analysis of alternative fuel and power options concluded that the use of purchased natural gas and electrical power are the most appropriate sources of thermal energy and electrical power for each hub.

Since SAGD recoveries are the highest of any known commercial in situ recovery process, it ideally suits the resource type proposed for development. Cyclic Steam Stimulation (CSS) is not an option as it is reserved for resource envelopes that are typically thinner, and recoveries with CSS in thicker reservoirs are much lower than that of SAGD. North American is committed to applying new technologies as they emerge, if appropriate, to proposed and future developments to improve overall environmental stewardship, reserve recovery, and cost efficiencies.

2.10 Guide to the Application

The applications for approval to EUB and AENV have been integrated in accordance with EUB and AENV guidelines to facilitate efficient review of the application by regulators and the public. This application is presented in five volumes:

Kai Kos Dehseh Project

Volume 1: Application

Volume 2: EIA – Air and Health

Volume 3: EIA – Aquatics

Volume 4: EIA – Terrestrial

Volume 5: EIA – Human

The following series of tables identify the locations of the required information within the Application, cross-referenced to the following guidelines:

Table 2.10-1 EUB Directive 23 Information Requirements

Table 2.10-2 EPEA Guide to Content for Industrial Approval Applications

Table 2.10-3 Terms of Reference (TOR) Concordance Table

A copy of the final TOR issued by AENV is provided in Volume 2. A list of abbreviations, acronyms, units of measures and a glossary are provided in Appendix D.

Table 2.10-1 EUB Directive 23 Information Requirements

Guide	Requirement (abridged)	Locations in Volume 1 unless otherwise noted
1.0 GENERAL INFORMATION		
1.5	**Project description**	1.0, 2.0
1.5.1	Applicable Acts and Sections under which the application is made	1.0, 3.2, 3.3
1.5.2	Name and address of the application and any partners involved and the details of company incorporation	1.0, 3.2
1.5.3	Statement of need and project timing	1.0, 2.1
1.5.4	Overall project description and discussion of schedule Including: location, size and scope, schedule of pre-construction, construction, start up, duration of operations, and a discussion of the reasons for selecting the proposed schedule.	2.1, 2.4, Figures 2.1-1 and 2.4-1
1.5.5	Regional setting and reference to existing and proposed land use	1.0, 2.3
1.5.6	a. Maps showing freehold, leasehold, mineral and surface rights of the proposed scheme and surrounding area. b. Maps with legal descriptions showing the locations of landowners and their dwellings in relation to the proposed oil sands site	2.3, Figure 2..3-1 and 2.3-2
1.5.7	Map showing topography, existing areas of habitation, industry, the proposed site and any development in the project area	Figures 1-1 and 8.2-1
1.5.8	Aerial photomosaic at an appropriate scale to illustrate the locations of the project components including the mine area, wells, extraction plant, upgrader unit, tanks, discard storage sites including tailing ponds, access roads, railways, pipelines and utility corridors.	Figures 8.2-1
1.5.9	Description of storage and transportation facilities of the final hydrocarbon product, including detail of size and ownership of any pipeline which may be utilized	5.2.14
1.5.10	Proposed rate of production over the life of the Project	2.4
1.5.11	Description of the subject oil sands	4.1.2.1
1.5.12	Status of negotiations held or to be held with the freehold, leasehold, mineral surface rights owners	6.4.5
1.5.13	Proposed energy source, alternatives, resource use, sources and supply	2.9
1.5.14	Description and results of public information program	6.4
1.5.15	The term of the approval sought, including expected project start and completion dates	2.4, Figure 2.4-1
1.5.16	Name of responsible person to contact	3.2
2.1	Surface mining operations -	Not Applicable
2.2	Underground access and development	Not Applicable
2.3	**In Situ operations**	

Guide	Requirement (abridged)	Locations in Volume 1 unless otherwise noted
2.3.1	Geological description of zone of interest supported by: a. map showing the land surface topography b. map showing the locations of all evaluation wells and indicating those that have been cored and those that have been logged c. the log and core evaluation technique d. isopach maps of the net pay and/or bitumen metre maps over the zone of interest as well as for other potential bitumen bearing zones e. cross-sections clearly indicating the zone of interest, illustrating the top and base of porosity, fluid interfaces, pertinent test data over the zone of interest and impermeable lenses or layers f. tabulations of reservoir rock parameters, fluid properties and log interpretation cutoffs used g. structure and position of fluid interfaces within the zone of interest h. maps showing gas caps and bottom water associated with the zone of interest i. a description of the techniques used to model geological data	 Figure 8.2-1 Figure 2.2-1 4.1.1 Figures 4.3-2 to 4.3-4, 4.3-6, 4.3-7 and 4.3-10 Figures A4.1-12 to A4.1-15, B4.1-12 to B4.1-15, C4.1-12 to C4.1-15 4.3, Appendices A, B and C 4.3, Appendices A, B and C 4.3, Appendices A, B and C 4.2.3.3
2.3.2	Identification by name and depth of the target zone including any crude bitumen zone or water zone immediately above or below the zone of interest.	4.1, Appendices A, B and C
2.3.3	Criteria used in selecting the oil sands zone for recovery	4.2.1, 4.2.3
2.3.4	A description of the cut off bitumen grade and thickness criteria used to establish the in-place resource potential	4.2.1
2.3.5	A geological, engineering and economic evaluation of the bitumen reserves recoverable by the proposed scheme and a description of and rationale for the criteria employed	4.3.2
2.3.6	A geological, engineering and economic evaluation of bitumen reserves not recoverable by the proposed scheme	4.2.2
2.3.7	A discussion of the potential and requirements for any follow-up recovery of reserves from the zone of interest or other bitumen bearing zones within the scheme area	4.2.1
2.3.8	Evaluation of gas reserves associated with the oil sands to be developed, including a description of: a. the effect the proposed operations would have on the recovery of those reserves b. the effect the gas reserves would have on the recovery of the crude bitumen reserves	4.2.1
2.3.9	An evaluation (quantity and characteristics) of sand or fines production, the effects on recovery and anticipated disposal methods	5.2.15
2.3.10	A description of the recovery process to be used, including a. the objectives, the intended course of operation and the applicability of the process b. a comparison of this process with others considered, stating the technical, economic, environmental and cost reasons for the selection c. potential for follow-up processes for improved recovery d. results of computer modelling or simulation studies e. economic and production criteria used to abandon an oil sands zone	4.2, Appendices A, B and C,
2.3.11	The recovery efficiency of the process selected, including a. effects of reservoir well spacing and interwell communication b. areal, vertical and displacement efficiencies, and c. effects of reservoir properties such as pay thickness, directional permeability trends, featuring characteristics and the presence of gas caps, aquifers or shale breaks	4.2, Appendices A, B and C,

Guide	Requirement (abridged)	Locations in Volume 1 unless otherwise noted
2.3.12	A description of the Project layout with emphasis on equipment spacing and surface disturbance, including a. the sequence of development for major project components b. the well pad configuration and spacing design, well site and satellite layout, fluid treatment and handling facilities c. future pad configuration and surface facilities	2.4, 4.2.3, 4.4.1, Figure 2.4-1
2.3.13	A description of the efforts to minimize land disturbance and the collection, conservation or other disposition of produced gases	8.6.2, 8.6.3
2.3.14	A diagram and description of proposed well drilling and completion methods, including a. wellhead design b. casing and tubing with specifications and setting depths c. the cementing details proposed to ensure continued integrity of wells	5.2.2
2.3.15	A description of the proposed well performance monitoring program, including: a. routine production testing b. temperature and production logging c. surface fluid sampling d. field and laboratory analyses programs	4.2.3.4, 5.2.2
2.3.16	A description of geotechnical factors and techniques of monitoring, that may affect operations, including a. casing monitoring program to detect failures b. the method of reporting failures, ghost holes and other drilling anomalies	5.2, 8.6.4.2 and Appendices B and C
2.3.17	The volume of fluids and solids produced and the proposed disposition of each	4.4, 5.2.1
2.3.18	Material balances for hydrocarbons, sulphur and water in the central processing facility	5.2, Figures 5.2-8, 5.2-9 and 5.2-10
2.3.19	A process flow diagram for the central processing facility, including major equipment and stream composition with the proposed measurement devices and locations	5.2, Figure 5.2-1
2.3.20	A sample set of production accounting reports for the central processing facility	5.2.2
2.4	**Processing Plant**	
2.4.1	A separate description of the bitumen extraction, upgrading, utilities, refining and sulphur recovery facilities, including a. a discussion of the process b. process flow diagrams indicating major equipment, stream rates and composition, and the proposed production measurement devices, characteristics and locations c. chemical and physical characteristics and properties of feeds and product materials	5.2
2.4.2	Overall material and energy balances, including information with respect to hydrocarbon and sulphur recoveries, water use and energy efficiency	5.2
2.4.3	Quantity of products, by-products and waste and their disposition	5.2.1, 5.2.2, 5.2.10
2.4.4	Surface drainage within the areas of the processing plant, product storage and waste treatment and disposal	5.2.4, 5.2.11, 5.2.12, 5.2.13
2.4.5	Comparison of proposed process to alternatives considered on the basis of overall recovery, energy efficiency, cost, commercial availability and environmental considerations and the reasons for selecting the proposed process	2.9, 4.5, 8.6.5.9
2.4.6	This number has been omitted from G-23	
2.4.7	Example of production accounting reports	5.2.2, 5.2.8, 5.2.14
2.5	**Electrical Utilities and External Energy Sources**	
2.5.1	A description of any facilities to be provided for the generation of electricity to be used by the project.	2.4, 4.5, 5.2.6, 5.3.6
2.5.2	Identification of the source, quantity and quality of any fuel, electricity or steam to be obtained from sources beyond the project site	5.2.6, 5.2.8, 5.3.6

Guide	Requirement (abridged)	Locations in Volume 1 unless otherwise noted
2.5.3	Where energy resources from outside the project boundaries are to be supplied to the project, a detailed appraisal of the options available to eliminate the need for such resources, with consideration for overall recovery, energy balance, costs, technical limitations and environmental implications	2.9.1
2.6	**Environmental Control**	
2.6.1	A description of air and water pollution control and monitoring facilities, as well as a liquid spill contingency plan	5.3.4, 5.3.5, 5.3.6
2.6.2	A description of the water management program, including a. the proposed water source and expected withdrawal b. the source-water quality control c. the waste-water disposal program d. water balance for the proposed scheme e. the produced-water clean-up/recycle program	5.2.2, 5.2.4
2.6.3	The manner in which surface water drainage within the Project area would be collected, treated and disposed	5.2.13
2.6.4	A description of the air and water pollution control and monitoring facilities	5.3.4, 5.3.5, 5.3.6
2.6.5	A description of the emission control system, including a. stack design criteria and process data b. any additions of residue gas or natural gas to the flare system to ensure combustion of hydrogen sulphide for both normal operating conditions and maximum emission conditions c. methods proposed for the control of all air pollutants from all potential or actual emission sources at the operation (including all vents, stacks, flares, product storage tanks, sulphur handling areas, ponds, wells and other fugitive emission sources) during normal, emergency and maximum operating conditions d. monitoring program for hydrogen sulphide, sulphur dioxide, total sulphation, hydrogen sulphide sulphation, soil pH, nitrogen oxides and hydrocarbons in the surrounding area	 5.3.5 5.3.5 5.3.5, 5.3.6 5.2.2, 5.2.10, 5.3.6
3.1	**Commercial Viability**	
3.1.1	An appraisal and projections, on an annual basis of revenues, capital and operating costs (including a breakdown of fuel costs and non-fuel operating costs), royalties and taxes, net cash flow, marketing arrangements, fuel and electric power arrangements	Volume 5, Section 14
3.1.2	A description of project costs which include capital and operating cost, including a. a breakdown of capital and operating costs for each component of the project including site preparation, well drilling and completion, central processing facilities (including steam generation, waster treatment and recycling), satellite and surface facilities, production/injection distribution system, upgrading, utilities and off-sites b. depreciation	Volume 5, Section 14
3.2	**Benefit-Cost Analysis**	
3.2.1	A summary of quantifiable public benefits and costs incurred during the construction and operation of the Project	Volume 5, Section 14
3.2.2	A summary of non-quantifiable public benefits and costs incurred each year during construction and operation of the Project	Volume 5, Section 14
3.3	**Economic Impact**	
3.3.1	An appraisal of the economic impact of the Project on the region, province and nation	Volume 5, Section 14
3.3.2	A discussion of any initiatives undertaken to accommodate regional economic priorities and interests	Volume 5, Section 14

Guide	Requirement (abridged)	Locations in Volume 1 unless otherwise noted
3.3.3	An assessment of direct and indirect employment opportunities for all groups associated with the Project including a. projected max and min workforce demand by skill categories in the construction and operating phases and an analysis of how these demands shall be met b. an analysis of the indirect and induced employment generated by the project due to employment multiplier effects c. a discussion of the employment and training arrangements provided by applicant that would enable residents of the region to participate in meeting the workforce demands	Volume 5, Section 14
4.0	Environmental Impact Assessment	Volumes 2 - 5
5.0	Biophysical Impact Assessment	Volumes 2 - 5
6.0	Social Impact Assessment	Volume 5, Section 14
7.0	Describe the environmental protection plan including mitigation measures, environmental monitoring and research	Volumes 2 - 5
8.0	Conceptual Development and Reclamation Plan	8.6
9.0	Solid Waste Management Plan	5.2.15

Table 2.10-2 EPEA Guide to Content for Industrial Approval Applications

EPEA Guide to Content	Information Required	Locations in Volume 1 unless otherwise noted
3(1)(a)	Applicant Information	1.0
3(1)(b)	Location, Size and Capacity of the Activity	1.0
1	Legal land description	1.0
2	Relation to nearest town, city, village and users of the land	1.0
3	Geographical description of the surrounding topography and relation to nearby watercourses	Figures 1.1 and 8.2-1
4	Gas processing capacity	5.2.10
5	Sulphur production capacity; bitumen processing capacity	5.2.1, Figure 5.2-8
6	Material balance	5.2.1, Figure 5.2-8
7	Descriptive size of the affected area	2.4, 2.7, Figure 1-2
8	Physical dimensions of the plant site including a plot plan and number of employees working at the facility	2.4, 2.7, Figure 1-2
3(1)(c)	Nature of the Activity	5.1
1.1	Classification of this facility under EPEA Activities Designation Regulation 211/96	3.2
1.2	General purpose, products, by-products	1.0, Figure 5.2-8
1.3	Major unit operations including a process flow diagram and description of the process	5.1, 5.2
1.4	Major environmental control operations	5.3
1.5	Underground and aboveground tank details	5.2
1.6	Aboveground storage tank leak detection systems	5.2.15
1.7	Potable water source, description of water treatment system used, sanitary sewage handling procedures or septic tank details	5.2.12
1.8	Details on the reciprocating or turbine engines	5.2.11
1.9	Plot plan showing the exhaust stack locations	Figure 5.2-1
1.10	The peak height of buildings	Volume 2, Section 2
1.11	Details on all natural gas fired heaters, treaters, boilers and steam generators	5.3.6
1.12	Details on any auxiliary or standby process equipment or other sources of emission	5.2 Volume 2, Section 2
1.13	Details on flare stacks	5.2.9
1.14	Details on any active flare pit onsite	Not Applicable
1.15	Description of any on site incineration of solid waste	Not Applicable
1.16	NO_2 dispersion computer modelling input and output	Volume 2, Section 2
1.17	SO_2 dispersion computer modelling input and output; rates and composition of acid gas and fuel gas flared streams	Volume 2, Section 2
1.18	Emergency flaring scenario SO_2 dispersion modelling and rates and composition of flared streams	Volume 2, Section 2
1.19	Sulphur Storage Facilities details	5.2.10
1.20	Benzene emissions from glycol dehydrators controls	Not Applicable
1.21	Volume and composition of produced gas and method of H_2S treatment	5.3.5, 5.2.10
3(d)	EUB Approval Status	3.0
3(e)	Environmental Impact Assessment	Volumes 2 - 5
3(f)	Existing EPEA Approvals (not applicable for new plants)	3.1
3(g)	Schedule	2.4, Figure 2.4-2
3(h)	Substance Releases	5.3.4, Volume 2, Section 2
1.1	A list and quantity of substances used in the production process	5.2.15
1.2	Water demand; sources, purpose and quantities	5.2.1, Figure 5.2-9
1.3	Sources of the substances to be released to the environment	Volume 2, Section 2
1.4	Amount of the substances to be released to the environment	Volume 2, Section 2

EPEA Guide to Content	Information Required	Locations in Volume 1 unless otherwise noted
1.5	Methods of release of substances to the environment	Volume 2, Section 2
1.6	Pollution prevention and control measures	Volume 2, Section 2
1.7	Runoff volume determination	Volume 3, Section 6.7
1.8	Spill Containment details	5.2.15, 5.3.4, 8.6.4.2
3(i)	Environmental Monitoring Information	Volumes 2 - 5
1.1	Any baseline ambient environmental data that may have been collected at the site (for air, water, soils, etc.)	Volumes 2 - 5
1.2	Baseline hydrogeologic characteristics and groundwater monitoring data	4.0, Volume 3, Section 5
3(j)	Past Use of Substance Release Control Systems (not applicable to new plants)	Not Applicable
3(k)	Justification for Substance Releases	5.3.4, Volume 2, Section 2
1	Application of process technology, management practices and current environmental control technology/control systems	5.0
3(l)	Waste Minimization Measures	5.2.15
1.1	Waste Management Summary	5.2.15
1.2	Waste minimization measures to be implemented	5.2.15
3(m)	Surface Disturbance Impacts	8.6
1	Extent and nature of the surface disturbance	8.6
3(n)	Emergency Response Plans	5.3.1, 5.3.2
1	Confirmation of filing with the EUB and other agencies	3.0
3(o)	Environmental Contingency Plans	5.3.1
3(p)	Conservation and Reclamation	8.0
1.1	Potential impact of the project on landscape aesthetics	8.6
1.2	Topsoil Conservation	8.6.3.4
1.3	Plant decommissioning and reclamation	8.6
3(q)	Public Involvement Process	6.4
1.1	Proposed or conducted public involvement process	6.4
1.2	Frequency, type and purpose for the public involvement and environmental concerns identified	6.4
1.3	Newspapers for advertising the application/approval	6.4

Table 2.3-10 Terms of Reference Concordance Table

		Location in Document
1.0 INTRODUCTION		Location in Document
1.3 Public Consultation		
	The preparation of the EIA report will include a public consultation program to assist with project scoping and issue identification. The results of these consultations will be documented as part of the EIA report (see Section 9.0). To meet the public consultation requirements North American must, at a minimum, communicate with those members of the public who may be affected by the Project and to provide them with an opportunity to participate in the environmental assessment process.	Volume 1, Section 6
1.4 Proponent's Submission		
	North American is responsible for the preparation of the EIA report and related applications. The submission will be based upon these Terms of Reference and issues raised during the public consultation process.	Volumes 1 - 5
2.0 PROJECT OVERVIEW		
2.1 The Proponent and Lease History		
	Provide:	
	a) the name of the proponent;	Volume 1, Section 1
	b) the name of the legal entity that will develop, manage and operate the Project;	Volume 1, Section 1
	c) a corporate profile;	Volume 1, Section 1
	d) a brief history of North American's operations including existing facilities;	Volume 1, Section 2.1
	e) an overview of the previous (if applicable) and recent EIAs and the associated developments completed by North American and other lease holders in the Conklin area; and	Volume 1, Section 2.2
	f) an overview of the proposed Project.	Volume 1, Section 1, 2
2.2 Project Area and EIA Study Area		
	The Project Area includes all lands subject to direct disturbance from the Project including the initial commercial phases at Leismer and Corner and the subsequent facilities at Hangingstone, Thornbury and South Leismer and associated infrastructure, including access and utility corridors. For the Project Area, provide:	
	a) the legal land description;	Volume 1, Section 1 Volume 1, Appendices A, B, C
	b) the boundaries;	Volume 1, Section 1 Volume 1, Appendices A, B, C
	c) a map that identifies the locations of all proposed development activities; and	Volume 1, Section 1 Volume 1, Appendices A, B, C
	d) a map and photomosaic showing the area proposed to be disturbed in relation to existing topographic features, township grids, wetlands, watercourses and waterbodies.	Volume 1, Section 8, Figure 8.6-5
	Study Areas for the EIA report should include the Project Area and other areas based on individual environmental components where an effect from the proposed development can reasonably be expected. Provide:	
	a) the Local and Regional Study Areas chosen to assess the impacts of the Project and provide maps of appropriate scale to illustrate boundaries; and	Volumes 2 - 5
	b) the rationale used to define Local and Regional Study Areas (see Section 4.2), considering the location and range of probable Project and cumulative effects.	Volumes 2 - 5
2.3 Project Components and Development Schedule		
	Provide a development plan and description and/or figures of the Project components and activities to be approved including:	
	a) activities associated with development of the area, operations, reclamation and development closure;	Volume 1, Section 2.2, 2.4
	b) bitumen recovery;	Volume 1, Section 2.2, 4.2
	c) field maintenance operations;	Volume 1, Section 5.2 Volume 1, Appendices B2.2.9, C2.2.9
	d) processing/treating facilities;	Volume 1, Section 5.2
	e) quantification and characterization of wastes produced;	Volume 1, Section 5.2.15
	f) identification of waste storage sites and disposal sites;	Volume 1, Section 5.2.15
	g) buildings;	Volume 1, Section 5.2
	h) storage areas;	Volume 1, Section 5.2
	i) containment structures such as berms and retention ponds;	Volume 1, Section 5.3.4
	j) locations of borrow pits and salvaged soil stockpiles;	Volume 1, Section 8.2.1

Table 2.3-10 Terms of Reference Concordance Table

	k) temporary structures;	Volume 1, Section 5.2
	l) infrastructure (roads, pipelines and utilities);	Volume 1, Section 5.2
	m) transportation and access routes;	Volume 1, Section 5.2 Volume 5, Section 13.6
	n) lime sludge pond(s);	Volume 1, Section 5.2.4
	o) water source wells and intakes;	Volume 1, Section 4.4
	p) aggregate resources and road construction, identifying the material required and on-site availability; and	Volume 1, Section 8.6 Volume 5, Section 13.7
	q) proposed method of product transportation to market.	Volume 1, Section 5.2.14
	Provide a development schedule outlining the proposed phasing and sequencing of components, including:	
	a) pre-construction;	Volume 1, Section 2.4
	b) construction;	Volume 1, Section 2.4
	c) operation;	Volume 1, Section 2.4
	d) decommissioning;	Volume 1, Section 8.2.2
	e) reclamation and closure;	Volume 1, Section 8.2.2
	f) timing of key construction, operational and reclamation activities and the expected duration of each for the life of the Project;	Volume 1, Section 2.4
	g) detailed schedule for any reclamation and related activities envisaged during the first decade of operations; and	Volume 1, Section 2.4 Volume 1, Section 8.2.2
	h) the key factors controlling the schedule and uncertainties.	Volume 1, Section 2.4
2.4 Project Need and Alternatives		
	Discuss the need for the Project and the alternatives to the Project, including the alternative of not proceeding with the Project. Include the following:	
	a) an analysis of the alternative means of carrying out the Project that are technically and economically feasible and indicate their potential environmental effects and impacts. Include rationale for selecting the proposed option;	Volume 1, Section 2.9
	b) how a balance between environmental, resource recovery or conservation and economic goals has been achieved through planning and preliminary design, highlighting any areas where planning focused on one goal in exclusion of others;	Volume 1, Section 5.3
	c) contingency plans, if selected major Project components or methods during any phase proved to be unfeasible or do not perform as expected;	Volume 1, Section 5.3.1
	d) the environmental performance of the technology selected and a comparison to the alternative technologies considered; and	Volume 1, Section 2.9
	e) the implications of a delay in proceeding with the Project, or any phase of the Project.	Volume 1, Section 2.9
2.5 Regulatory Review		
	Provide the following:	
	a) identify the environmental and other specific regulatory approvals and legislation that are applicable to the Project at the municipal, provincial and federal government levels;	Volume 1, Section 3.2
	b) identify government policies, resource management, planning or study initiatives pertinent to the Project and discuss their implications;	Volume 1, Section 2.1
	c) identify and delineate major components of the Project and identify those being applied for and constructed within the duration of approvals under the:	Volume 1, Section 3.2
	i) Environmental Protection and Enhancement Act (EPEA),	Volume 1, Section 3.2, 3.3
	ii) Oil Sands Conservation Act,	Volume 1, Section 3.2, 3.3
	iii) Water Act (WA),	Volume 1, Section 3.2, 3.3
	iv) Public Lands Act (PLA),	Volume 1, Section 3.2, 3.3
	v) Canada Fisheries Act, and	Volume 1, Section 3.2, 3.3
	vi) Navigable Waters Protection Act; and	Volume 1, Section 3.2, 3.3
	d) a summary of the regional, provincial or national objectives, standards or guidelines, which have been used by North American to assist in the evaluation of any predicted environmental impacts.	Volume 2, Section 2, 3, 4 Volume 3, Section 5, 6, 7, 8
2.6 EIA Summary		
	A summary of the results of the EIA report will be provided which includes:	

Table 2.3-10 Terms of Reference Concordance Table

	a) project components and development activities which have the potential to affect the environment;	Volume 1, Section 7
	b) existing conditions in the Study Areas, including existing uses of lands, resources and other activities which have potential in combination with proposed development activities, to affect the environment;	Volume 1, Section 7
	c) the anticipated environmental effects including cumulative considerations;	Volume 1, Section 7
	d) proposed mitigation measures and appropriate monitoring plans; and	Volume 1, Section 7
	e) any residual effects and their implications for future management of regional cumulative effects.	Volume 1, Section 7
3.0 PROJECT DESCRIPTION		
3.1 Site Development		
	Describe the thermal recovery process, process facilities (including environmental abatement processes and equipment), and waste management components of the Project, and:	Volume 1, Section 4, 5
	a) provide a map showing the location of all existing infrastructure (e.g., roads) and the location of the proposed hubs and field facilities;	Volume 1, Section 2
	b) show all existing leases and clearings including exploration clearings and illustrate how North American intends to use these areas for project development to minimize additional disturbances;	Volume 1, Section 2.3
	c) locate the buildings, road access, pipeline routes, water source wells, water pipelines, utility corridors, lime sludge ponds, retention ponds and waste storage/disposal sites associated with the Project;	Volume 1, Section 2
	d) describe the process and criteria used to select the sites for facilities and infrastructure for the Project including uncertainties and alternatives, if any, associated with the selection;	Volume 1, Section 5.1
	e) list the facilities whose location will be determined later;	Volume 1, Section 2.1, 5.1
	f) describe the planned accommodation for the workforce during construction and operations;	Volume 1, Section 5.2.11 Volume 5, Section 14.9
	g) provide a description and schedule(s) of land clearing required for:	Volume 1, Section 2.4
	i) steam generation facilities,	Volume 1, Section 2.4
	ii) central processing facilities,	Volume 1, Section 2.4
	iii) well pads,	Volume 1, Section 2.4
	iv) access roads,	Volume 1, Section 2.4
	v) borrow areas,	Volume 1, Section 2.4
	vi) pipelines, and	Volume 1, Section 2.4
	vii) utilities and other site preparation activities;	Volume 1, Section 2.4
	h) indicate the amount of surface disturbance from plant, field and infrastructure-related activities; discussing:	Volume 1, Section 5.1, 8.6
	i) how surface disturbance (extent and duration) will be minimized,	Volume 1, Section 5.1, 8.6
	ii) opportunities to undertake progressive reclamation to offset new disturbance,	Volume 1, Section 8.6.2
	iii) whether the timber is merchantable and if so, indicate anticipated volumes from clearing activities, and	Volume 1, Section 8.6.3 Volume 4, Section 10.6.3
	iv) how visual aesthetics will be managed, where required;	Volume 1, Section 5.3.5
	i) discuss opportunities to integrate the Project with other resource development activities (mineral and forestry); and	Volume 1, Section 2.3
	j) identify any restrictions and, where appropriate, measures taken to control access to project areas while ensuring continued access to adjacent wildland areas.	Volume 5, Section 13.6
3.2 Infrastructure and Transportation		
	Describe and locate, on maps of appropriate scales, the infrastructure and transportation (access) requirements for the Project and how they relate to local communities or activities, and:	
	a) discuss the amount and source of energy required for the Project;	Volume 1, Section 5.2.1
	b) discuss the options considered for supplying the thermal energy and electric power required for the Project and their environmental implications;	Volume 1, Section 2.9.1
	c) describe road access to and within the Project Area and identify needs to upgrade existing roads or construct new roads;	Volume 1, Section 2.7
	d) describe any crossings of, or activities that may be undertaken in, watercourses or waterbodies that will be required for the Project. Include:	Volume 3, Section 6.11, 8.6
	i) appropriate maps and diagrams,	Volume 3, Section 6.11, 8.6

Table 2.3-10 Terms of Reference Concordance Table

	ii) timing,	Volume 3, Section 6.11, 8.6
	iii) construction standards or methods, and	Volume 3, Section 6.11, 8.6
	iv) environmental protection plans;	Volume 3, Section 6.11, 8.6
	e) describe existing and planned activities as they relate to boating and vessel navigational use of watercourses and waterbodies within the Local Study Area. Include implications on navigational safety and how this will be mitigated;	Volume 3, Section 8.6
	f) discuss the route or site selection criteria for any linear or other infrastructure development or modification and provide the rationale for selecting the proposed alignment and design;	Volume 1, Section 2.3, 5.1
	g) discuss the need for access management during and after project operations;	Volume 1, Section 8.6 Volume 5, Section 13.6, 14.9
	h) provide the results of consultation with Alberta Transportation and discussions with other industry operators;	Volume 1, Section 6
	i) describe access corridors needed and/or planned by other resource stakeholders including Forest Management Areas or Quota holders, and those under consideration by the Regional Issues Working Group. Describe how their needs are accommodated to reduce overall environmental impact from resource development. Describe the steps taken to integrate their needs into the location and design of the access;	Volume 1, Section 2.3, 5.1 Volume 5, Section 13.6, 14.9 Volume 4, Section 10.6
	j) describe the anticipated changes to traffic (e.g., type, volume) on local highways during the construction and operation of the Project. Discuss any project and cumulative effects expected on the primary and secondary highway systems and other regional roads. Consider other existing and planned operations in the region;	Volume 1, Section 2.7 Volume 5, Section 13.6, 14.9
	k) identify the type and location of road construction and restoration materials, the volume of material needed and the availability of materials in the area. Discuss how the Project will affect aggregate reserves that may be located on North American leases and reserves in the region. Provide a plan of how these potentially-affected reserves will be salvaged and stockpiled with input provided by Alberta Transportation and Alberta Sustainable Resource Development;	Volume 1, Section 1, 8.6 Volume 5, Section 13.6, 14.9
	l) discuss how the Project design will minimize the amount of disturbance;	Volume 1, Section 2.8, 5.1
	m) outline design features to prevent spills, contingencies for spill response and environmental risks associated with spills; and	Volume 1, Section 5.2, 5.3, 8.6
	n) discuss secondary effects that may result from linear development such as increased hunter, angler and other recreational access and facilitated predator movement.	Volume 4, Section 11.6 Volume 5, Section 13.6, 14.9
	3.3 Air Emissions Management	
	Develop an emissions profile (type, rate and source) for each component of the Project including point sources, fugitive emissions, construction and vehicle emissions. Consider both normal operating conditions and upset conditions. Include definitions for these conditions. Discuss the following:	
	a) any National Pollutant Release Inventory (NPRI), Priority Substance List (PSL1), PSL2 and/or Accelerated Reduction/Elimination of Toxics (ARET) substances relevant to the Project;	Volume 2, Section 2.6, 2.7
	b) the amount and nature of any acidifying emissions, probable deposition patterns and rates to soils, vegetation and waterbodies, as well as programs North American may implement to monitor the effects of this deposition;	Volume 2, Section 2.6, 2.7 Volume 3, Section 7, 8 Volume 4, Section 9, 10
	c) any odorous or visual emissions from the proposed facilities;	Volume 1, Section 5.3.5 Volume 2, Section 2.1
	d) emergency flaring scenarios (e.g., frequency and duration) and proposed measures to ensure flaring events are minimized;	Volume 1, Section 5.2.9 Volume 2, Section 2.6
	e) the systems used to monitor and quantify air emissions; and	Volume 1, Section 5.3.5 Volume 2, Section 2.8
	f) the use of alternative fuels in this project, if applicable. Provide emission profiles for each fuel under consideration.	Volume 1, Section 2.9.1
	3.3.1 Emission Control Technologies	
	Discuss the following:	
	a) the emission control technologies proposed for the Project within the following context:	
	i) minimizing air emissions such as sulphur dioxide (SO2), hydrogen sulphide (H2S), oxides of nitrogen (NOX), volatile organic compounds (VOC) and particulate matter,	Volume 1, Section 5.2.10, 5.3.5
	ii) use of low NOX technology for turbines and boilers. The applicability of Canadian Council of Ministers of the Environment (CCME) National Emissions Guidelines for Stationary Combustion Turbines and CCME National Emissions Guideline for Commercial/Industrial Boilers and Heaters, and applicable provincial guidelines,	Volume 1, Section 5.3.5
	iii) applicability of sulphur recovery, acid gas re-injection, or other technologies to reduce sulphur emissions and applicability of EUB sulphur recovery guidelines (Interim Directive ID 2001-03),	Volume 1, Section 5.2.10
	iv) gas collection, conservation and applicability of technology for vapour recovery for the Project,	Volume 1, Section 5.2.2, 5.2.7, 5.3.5
	v) control technologies for minimization of venting and flaring, and	Volume 1, Section 5.2.9

Table 2.3-10 Terms of Reference Concordance Table

	vi) fugitive emissions control program to detect, measure and control emissions and odours from equipment leaks and the applicability of the CCME Code of Practice for Measurement and Control of Fugitive VOC Emissions from Equipment Leaks, the CCME Environmental Guidelines for Controlling Emissions of Volatile Organic Compounds from Above Ground Storage Tanks, and applicable provincial guidance documents; and	Volume 1, Section 5.3.5
	b) monitoring programs North American will implement to assess the air quality and the effectiveness of mitigation during the Project's development and operation. Discuss how these monitoring programs are compatible with those in use by regional multi-stakeholder air initiatives.	Volume 1, Section 6.3 Volume 2, Section 2.8
	3.3.2 Greenhouse Gas Emissions	
	Provide the following:	
	a) expected annual and total greenhouse gas (GHG) emissions as a result of the Project;	Volume 1, Section 5.3.6
	b) the Project's contribution to total provincial and national GHG emissions on an annual basis;	Volume 2, Section 2.7.5
	c) the intensity of GHG emissions per unit of product produced and discuss how it compares with similar projects and technology performance;	Volume 1, Section 5.3.6
	d) how the Project design and GHG management plans have taken into account the need for continuous improvement with respect to GHG emissions and Albertans and Climate Change: Taking Action; and	Volume 1, Section 5.3.7
	e) North American's overall GHG management plans, including any plans for the use of offsets, (nationally or internationally) and the expected results of implementing the plans.	Volume 1, Section 5.3.7
	3.4 Water Supply, Water Management and Wastewater Management	
	3.4.1 Water Supply	
	Describe the water supply requirements for the Project, including, but not limited to, the following:	
	a) compliance with the Water Conservation and Allocation Guideline 2006 for Oilfield Injection;	Volume 1, Section 4.4
	b) the annual and seasonal water balance(s), if applicable, for each project phase and overall;	Volume 1, Section 5.2.1, 5.2.5
	c) assumptions made or methods chosen to arrive at the water balance(s), variability in the amount of water required on an annual and seasonal basis as the Project is implemented and the expected cumulative effects on water losses/gains due to the Project operations. Show the location of sources/intakes and associated infrastructure (e.g. pipelines);	Volume 1, Section 4.4.1, 5.2.5
	d) the process, non-saline and saline water requirements and sources for construction, startup, normal and emergency operating situations, decommissioning and reclamation;	Volume 1, Section 5.2.1, 5.2.5
	e) an evaluation of alternative water sources and include a description of the criteria and rationale for selecting the preferred source(s) and identify the volume of water to be withdrawn from each source while considering plans for wastewater reuse, and the locations of any water wells;	Volume 1, Section 4.4.4, 4.5
	f) contingency plans for water supply, including the potential effects of extended periods of drought on the proposed water supply; and	Volume 1, Section 4.4.4
	g) options for using saline groundwater, including the criteria used to assess the feasibility of its use.	Volume 1, Section 4.4.4
	3.4.2 Water Management	
	Provide a Water Management Plan for construction, operation and reclamation phases, including, but not limited to, the following:	
	a) factors considered in the design of water management systems, such as:	
	i) site drainage and anticipated annual runoff volumes,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	ii) road and well pad run-off,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	iii) containment,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	iv) erosion/sediment control,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	v) slumping areas,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	vi) groundwater protection,	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	vii) groundwater seepage,	Volume 1, Section 5.3.4
	viii) non-saline water	Volume 1, Section 5.3.4
	ix) produced water, and	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	x) flood protection;	Volume 1, Section 5.3.4 Volume 3, Section 6.11
	b) measures for ensuring efficient use of water including alternatives to reduce freshwater consumption such as the use of saline waters, recycle of produced water, water use minimization, conservation and synergies with other developers and/or earlier project phases;	Volume 1, Section 5.3.4

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	c) permanent or temporary alterations or realignments of watercourses, wetlands (including bogs and fens) and other waterbodies; and	Volume 1, Section 5.3.4 Volume 3, Section 6.11 Volume 4, Section 10.6
	d) potential downstream impact if water is removed from local surface waterbodies.	Volume 3, Section 6.11
	3.4.3 Wastewater Management	
	Provide a Wastewater Management Plan to address site runoff, groundwater protection, deep well disposal and wastewater discharge, including, but not limited to, the following:	
	a) source, quantity and composition of each wastewater stream from the existing and proposed facilities;	Volume 1, Section 4.4.1, 4.4.2
	b) design of facilities that will handle, treat, store and release each wastewater stream;	Volume 1, Section 5.2
	c) type and quantity of chemicals used in water and wastewater treatment, including any NPRI, PSL1, PSL2, or ARET substances relevant to the Project;	Volume 1, Section 5.2.15 Volume 2, Section 2.7
	d) options considered for treatment, wastewater management strategies and reasons (including water quality and environmental considerations) for selecting the preferred options (consider Alberta Environment's Industrial Release Limits Policy when determining whether either technology or water quality standards will define acceptable release limits);	Volume 1, Section 4.5
	e) if applicable, discuss the discharge of aqueous contaminants (quantity, quality and timing) beyond plant site boundaries and the potential environmental effects of such releases;	Volume 1, Section 5.2.13
	f) aquifers for the disposal of wastewaters, including:	
	i) formation characterization,	Volume 1, Section 4.3.6 Volume 1 Appendices B, C
	ii) local and regional hydrodynamic flow regime,	Volume 3, Section 5
	iii) water quality,	Volume 1, Section 4.3.6 Volume 1 Appendices B, C
	iv) chemical compatibility,	Volume 1, Section 4.4.4
	v) containment potential within the disposal zones, and	Volume 3, Section 5
	vi) injection capacity;	Volume 3, Section 5
	g) the chemical composition of disposal waters;	Volume 1, Section 5.2.4
	h) wastewater disposal alternatives;	Volume 1, Section 4.4.3, 4.5
	i) current and proposed monitoring programs;	Volume 1, Section 5.3.4
	j) non-saline water and sewage treatment systems that will be installed as components of the Project for both the construction and operation stages; and	Volume 1, Section 5.3.4
	k) the principles that have been incorporated into the Project's design for pollution prevention, waste minimization and recycling.	Volume 1, Section 4.4, 5.2, 5.3.4
	3.5 Hydrocarbon, Chemical and Waste Management	
	3.5.1 Management of Waste Streams	
	Provide the following:	
	a) estimate of the quantity and composition of each waste stream. Classify each waste stream according to applicable provincial regulations and guidelines. Demonstrate that plans are consistent with current industry practices;	Volume 1, Section 5.2, 5.3
	b) describe the composition and volume of specific waste streams generated by the Project, and identify how each stream will be managed. Demonstrate that the selected practices for the plant and field operations comply with provincial and federal regulations including EPEA's Waste Control Regulation and Alberta Environment's Hazardous Waste Storage Guidelines;	Volume 1, Section 5.2.15
	c) describe the proposed storage and handling methods and disposal for each waste stream. Consider both central plant and field operations;	Volume 1, Section 4.4, 5.2.2
	d) identify the amount of drilling wastes produced by the Project, the options considered for disposal and the option(s) chosen;	
	i) determine the amount of surface disturbance caused by drilling waste disposal and describe any mitigative options to reduce the disturbance, and	Volume 1, Section 5.1
	ii) describe how the disposal sites and sumps will be constructed to be in compliance with the Oil and Gas Conservation Regulation;	Volume 1, Section 5.1
	e) discuss the strategy for on-site waste disposal versus off-site waste disposal, including but not limited to the following:	
	i) the location of on-site waste disposal, including landfills, if applicable, and the general suitability of the site(s) from a groundwater protection perspective (provide geotechnical information to support siting options),	Volume 1, Section 5.1, 8.6.4

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	ii) industrial landfills,	Volume 1, Section 5.1, 8.6.4
	iii) on- and off-site waste treatment and storage areas, and	Volume 1, Section 4.5, 5.1, 8.6.4
	iv) potential effects on the environment;	Volume 1, Section 4.4, 5.1 Volume 3, Section 5, 6, 7, 8
	f) describe plans for waste minimization, recycling, and management over the life of the Project; and	Volume 1, Section 4.5, 5.2, 8.6.4
	g) discuss methods and technologies to reduce waste quantities and associated potential risks, to the lowest practical levels.	Volume 1, Section 4.5, 5.2, 8.6.4
	3.5.2 Hydrocarbons and Chemical Products	
	Provide the following:	
	a) a listing of chemical products to be used for the Project. Identify any products that may contain substances that are:	
	i) Canadian Environmental Protection Act (CEPA) toxics,	Volume 1, Section 5.2.2
	ii) on the PSL1, PSL2,	Volume 1, Section 5.2.2
	iii) ARET,	Volume 1, Section 5.2.2
	iv) those defined as dangerous goods pursuant to the federal Transportation of Dangerous Goods Act,	Volume 1, Section 5.2.2
	v) on the NPRI list, and	Volume 1, Section 5.2.2
	vi) Track 1 substances targeted under Environment Canada's Toxic Substances Management Policy for virtual elimination from the environment;	Volume 1, Section 5.2.2
	b) the wastes generated and characterize each stream in accordance with Alberta Environment's User's Guide for Waste Managers;	Volume 1, Section 5.2.15
	c) a description, in general terms, of how these items will be stored and managed to ensure adequate protection of both the environment and employee health and safety; and	Volume 1, Section 5.2.4, 5.2.15
	d) the location, nature and amount of on-site hydrocarbon storage. Discuss containment and other environmental protection measures. Demonstrate how selected practices comply with the provincial and federal regulations including EUB Guide 55 – Storage Requirements for Upstream Petroleum Industry.	Volume 1, Section 5.2
	3.6 Reclamation/Closure (See Appendix)	
	Provide a conceptual reclamation and closure plan considering the following:	
	a) reclamation requirements specified by relevant regulatory organizations and stakeholder preferences;	Volume 1, Section 8.3.3
	b) pre-development information with respect to land capability, vegetation, commercial forest land base by commercialism class, forest productivity, recreation, wildlife, aquatic resources, aesthetics and land use resources;	Volume 1, Section 8.1
	c) Project development phasing;	Volume 1, Section 2.4, 8.6.2
	d) opportunities for integration of operations, reclamation/closure planning and reclamation activities;	Volume 1, Section 8.6.4
	e) reclamation sequencing for each phase of development;	Volume 1, Section 8.6
	f) revegetation for the disturbed terrestrial and aquatic areas, identifying the species types that will be used for seeding or planting, and the vegetation management practices. Include the rationale for selection based on the need for the development of self-sustaining biologically diverse ecosystems consistent with the appropriate natural subregion (Lower Boreal Highland Natural Subregion or the Central Mixed wood Subregion) of the Boreal Forest Natural Region with reference to the use of native vegetation species;	Volume 1, Section 8.6.5
	g) soil and reclamation material salvage, soil storage areas and soil handling procedures, and a soil material balance;	Volume 1, Section 8.6.3.4
	h) areas of soil replacement indicating depth, volume and type of reclamation material;	Volume 1, Section 8.6.3.5
	i) any soil-related constraints or limitations that may affect reclamation;	Volume 1, Section 8.6.5.9
	j) pre-development and final reclaimed site drainage plans;	Volume 1, Section 8.6.3.4 Volume 3, Section 6
	k) re-establishment of self-sustaining topography, drainage and surface watercourses and vegetation communities representative of the surrounding area;	Volume 1, Section 8.6

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	l) management of waste, wastewater, and other waters;	Volume 1, Section 4.0, 5.3.4, 8.6.4.1
	m) restoration of pre-development traditional use with consideration for traditional vegetation and wildlife species in the closure landscape;	Volume 1, Section 8.6.5
	n) post-development capability for all uses;	Volume 1, Section 8.6.5.9
	o) post-development reforestation and forest productivity with information required for inclusion into the Forest Management Agreement (FMA) Detailed Forest Plan;	Volume 1, Section 2.3, 8.6.5.10
	p) wetlands or other alternatives to reclaim the land;	Volume 1, Section 8.6.5 Volume 4, Section 10.6
	q) reporting of reclamation progress through development of the Project, relating reclamation progress to pre-development expectations.	Volume 1, Section 8.6.5.14
	Discuss the conceptual closure landscape design with reference to the following:	
	a) appropriate productivity equivalent to pre-development levels having regard for regulatory requirements and stakeholder end land use preferences;	Volume 1, Section 8.3.5
	b) how North American will incorporate into the reclamation plan, the issues raised by regional environmental monitoring and management activities;	Volume 1, Section 6.3, 8.3.4
	c) promotion of biodiversity;	Volume 1, Section 8.6.5.11 Volume 4, Section 12
	d) integration and interconnectivity to the surrounding landscapes;	Volume 1, Section 8.6.5
	e) integration of surface and near-surface drainage within the development area;	Volume 1, Section 8.6.5
	f) resemblance to the pre-disturbed landscape. Identify the post-disturbance land capability on a map;	Volume 1, Section 8.6.5
	g) project planning and development;	Volume 1, Section 8.6.5
	h) anticipated timeframes for completion of reclamation phases and release of lands back to the Crown, including an outline of the key milestone dates for reclamation and a discussion of how progress will be measured in the achievement of these targets. Discuss any constraints to reclamation such as timing of activities, availability of soil materials and influence of natural processes and cycles; and	Volume 1, Section 2.4, 8.2.2, 8.6.5
	i) development of a conceptual ecological land classification (ELC) map for the post reclamation landscape considering all potential land uses and how the landscape and soils have been designed to accommodate future land use.	Volume 4, Section 10
	3.7 Environmental Management Systems and Contingency Plans	
	Summarize key elements of North American's existing or proposed environment, health and safety management system and discuss how it will be integrated into the Project, addressing the following:	
	a) plans for monitoring air emissions, wastewater releases waste tracking, process inputs and outputs. Present conceptual contingency plans that consider the environmental effects of serious malfunctions or accidents; the key elements of the operating plans and performance standards to be developed prior to the commissioning of the Project, such as:	Volume 1, Section 5.3 Volume 2, Section 2.8
	i) policies and corporate procedures,	Volume 1, Section 5.3
	ii) operator training,	Volume 1, Section 5.3
	iii) emergency reporting procedures for spill and air emission reporting, response and monitoring procedures, and	Volume 1, Section 5.3.2
	iv) emergency response, public notification protocol and safety procedures;	Volume 1, Section 5.3.2, 5.3.3
	b) plans to minimize the production or release into the environment of substances that may have an adverse effect, including:	
	i) modifying existing plans, or	Volume 1, Section 5.3
	ii) developing new conceptual contingency plans that consider environmental effects associated with operational upset conditions such as serious malfunctions or accidents that represent deviations from normal operating performance;	Volume 1, Section 5.3
	c) proposed monitoring, including:	
	i) monitoring done independently by North American,	Volume 1, Section 6.3, 8.6.5 Volume 2, Section 2.8
	ii) monitoring performed in conjunction with other stakeholders,	Volume 1, Section 6.3, 8.6.5 Volume 2, Section 2.8
	iii) publicly-available monitoring information, and	Volume 1, Section 6.3, 8.6.5 Volume 2, Section 2.8
	iv) new monitoring initiatives that may be required as a result of the Project;	Volume 1, Section 6.3, 8.6.5 Volume 2, Section 2.8
	d) an emergency response system to deal with emergency situations and minimizing adverse environmental effects, while protecting the safety of personnel. Comment on contingency plans that have been or will be developed to respond to operational upsets or unpredicted environmental impacts that are realized during and after project development;	Volume 1, Section 5.3.2
	e) a fire control plan:	Volume 1, Section 5.3.3

Table 2.3-10 Terms of Reference Concordance Table

	i) highlighting measures taken to ensure continued access for fire fighters to adjacent wildland areas,	Volume 1, Section 5.3.3
	ii) highlighting forest fire prevention measures, and	Volume 1, Section 5.3.3
	iii) using the "FireSmart" Wildfire Assessment System to assess areas adjacent to proposed facilities and identify mitigative measures;	Volume 1, Section 5.3.3
	f) how regional environmental management initiatives will be incorporated into the management practices; and	Volume 1, Section 6.3, 8.3.4
	g) a weed management plan including provisions such as those outlined in the Guidelines for Weed Management in Forestry Operations (Forest Management Division Directive - 2001-06). This will detail how North American will prevent the establishment and control the spread of restricted and noxious weeds (as listed in the Alberta Weed Control Act) within the Project Area.	Volume 1, Section 8.6.2
	3.8 Adaptive Planning	
	Describe adaptive management plans that will reduce the impact of the Project at the design stage. Describe how the adaptive management plans will be used throughout the life of the Project to site facilities and infrastructure associated with future phases of the Project.	Volume 1, Section 2.1, 5.1 8.2.2, 8.3.2
	3.9 Participation in Cooperative Efforts	
	Demonstrate and document North American's current and planned involvement in regional co-operative efforts to address environmental and socio-economic issues associated with oil and gas development during the life of the Project. Include on-going initiatives and any potential co-operative ventures that North American is participating in with oil and gas and resource users (e.g., minerals and forestry). Include:	
	a) regional air monitoring networks and studies, health studies, biomonitoring and research, aquatics monitoring, wetlands management, end land use planning and socio-economic studies;	Volume 1, Section 6.3, 8.3.4, 8.6.5 Volume 2, Section 3 and 4
	b) potential cooperative ventures that North American has initiated, could initiate or could develop with other oil sands operators and other resource users (minerals and forestry) to minimize the environmental impact of the Project or the environmental impact of regional oil sands development;	Volume 1, Section 2.3, 6.3, 8.6.5
	c) a description of how North American will rely upon regional cooperative efforts to design and implement mitigation measures (to mitigate project specific effects and cumulative effects), monitoring programs (project specific monitoring and regional mentoring), and research programs;	Volume 1, Section 2.3, 6.3
	d) a description of how North American will design and implement mitigation measures (to mitigate project specific effects and cumulative effects), monitoring programs (project specific monitoring and regional monitoring), and research programs outside of these initiatives where necessary; and	Volume 1, Section 8.6
	e) the improvements in environmental performance achieved as a result of such ventures.	Volume 1, Section 5.3
4.0 ENVIRONMENTAL ASSESSMENT		
	4.1 Scenarios	
	Define assessment scenarios including:	
	a) a Baseline Case, which includes existing environmental conditions, and existing and approved projects or activities;	Volume 2, Section 1.5.2
	b) an Application Case, which includes the Baseline Case plus the Project; and	Volume 2, Section 1.5.2
	c) a Cumulative Effects Assessment (CEA) Case or Planned Development Case, which includes , existing, planned and approved projects or activities, and the Application case. Note: For the purposes of defining assessment scenarios, "approved" means approved by the applicable federal, provincial or municipal regulatory authority. "Planned" is considered any project or activity that has been publicly disclosed during the time period ending six months prior to the submission of the Project's Application and EIA report.	Volume 2, Section 1.5
	4.2 Study Areas	
	The EIA Study Area shall include the Project Area and associated infrastructure, as well as, the spatial and temporal areas of individual environmental components outside the boundaries where an effect can be reasonably expected. The EIA Study Area includes both Regional and Local Study Areas.	
	Illustrate boundaries and identify the Local and Regional Study Areas chosen to assess impacts. Define temporal and spatial boundaries for the Study Areas. Maps of these areas shall include township and range lines for easy identification and comparisons with other information within the EIA report. Describe the rationale and assumptions used in establishing the Study Area boundaries, including those related to cumulative effects.	Volumes 2 - 5
	4.3 Information Requirements for the Environmental Assessment	
	Discuss the methods, criteria and assumptions used in North American's Environmental Assessment process, and:	Volume 2, Section 1.5
	a) provide information on the environmental resources and resource uses that could be affected by the construction, operation and reclamation of the Project;	Volume 1, Section 2.1 Volumes 2 - 5
	b) provide a sufficient base for the prediction of positive and negative impacts and the extent to which negative impacts may be mitigated by planning, project design, construction techniques, operational practices and reclamation techniques;	Volume 1, Section 2.1 Volumes 2 - 5

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	c) discuss how the EIA report ensures that the same level of information is provided for all phases of the Project;	Volume 1, Section 2.1 Volumes 2 - 5
	d) quantify and assess impact significance where possible, taking into consideration spatial, temporal and cumulative aspects;	Volume 1, Section 2.1 Volumes 2 - 5
	e) discuss the sources of information used in the assessment including a summary of previously conducted environmental baseline work related to North American's operations. Information sources will include literature and previous baseline reports and environmental studies, operating experience from current oil sands operations, industry study groups, traditional knowledge and government sources;	Volume 1, Section 2.1 Volumes 2 - 5
	f) identify any limitations or deficiencies that the information may place on the analysis or conclusions in the EIA report. Discuss how these limitations or deficiencies will be addressed within the current EIA report;	Volume 1, Section 2.1 Volumes 2 - 5
	g) describe the stakeholder consultation process (including, but not limited to, the public, Aboriginal people, industry and regulatory representatives) used to select and rationalize the Key Indicator Resources (KIRs). Where required, undertake studies and investigations to obtain additional information for establishing a sound baseline in the Study Area(s). From a broad-based examination of all ecosystem components including previous environmental baseline work, describe and rationalize the selection of key components and indicators examined; and	Volume 1, Section 2.1, 6
	h) for each environmental parameter:	
	i) describe baseline conditions(includes existing and approved facilities and activities). Comment on whether the available data are sufficient to assess impacts and mitigation measures. Identify environmental disturbance from previous activities that have become part of the baseline conditions,	Volumes 2 - 5
	ii) describe the nature and significance of the environmental effects and impacts associated with the development activities. Discuss the impacts of both the baseline case, as well as the application case,	Volumes 2 - 5
	iii) present plans to minimize, mitigate, or eliminate negative effects and impacts. Discuss the key elements of such plans,	Volumes 2 - 5
	iv) identify residual impacts and comment on their significance, and	Volumes 2 - 5
	v) present a plan to identify possible effects and impacts, monitor environmental impacts and manage environmental changes to demonstrate the Project is operating in an environmentally sound manner. Identify any follow-up programs necessary to verify the accuracy of the environmental assessment and to determine the effectiveness of any measures taken to mitigate any adverse environmental effects.	Volumes 2 - 5
4.4 Modelling		
	Document any assumptions, used in the EIA report, to obtain modelling predictions. Clearly identify the limitations of the model(s) and data used in modelling, including sources of error and relative accuracy. Discuss the applicability and reasons for using a particular model.	Volumes 2 - 5
4.5 Cumulative Environmental Effects Assessment		
	Assessment of cumulative effects will be an integral component of the EIA report. North American will conduct a cumulative environmental effects assessment of the Project based on the EUB/AENV/NRCB Information Letter Cumulative Effects Assessment in Environmental Impact Assessment Reports under the Alberta Environmental Protection and Enhancement Act (June 2000). This will include a summary of all proposed monitoring, research and other strategies or plans to minimize, mitigate and manage potential adverse effects.	Volumes 2 - 5
	The identification and assessment of the likely cumulative environmental effects of the Project will:	
	a) define the spatial and temporal Study Area boundaries with due consideration for regional environmental monitoring and management activities and provide the rationale for assumptions used to define those boundaries for each environmental component examined;	Volumes 2 - 5
	b) describe the baseline state of the environment in the Regional Study Area (used for the cumulative effects assessment);	Volumes 2 - 5
	c) provide a discussion of historic developments and activities that have created the current conditions, clearly describing the state of the environment that will be affected by the proposed development, the potential interactions of stresses created by the Project and other stresses and, if possible, predict the cumulative consequences of these combined effects;	Volumes 2 - 5
	d) assess the incremental consequences that are likely to result from the Project in combination with other existing, approved and planned projects in the region;	Volumes 2 - 5
	e) demonstrate that relevant information or data used from previous oil sands and other development projects is appropriate for use in this EIA report;	Volumes 2 - 5
	f) consider and describe deficiencies or limitations in the existing database for relevant components of the environment;	Volumes 2 - 5
	g) explain the approach and methods used to identify and assess cumulative impacts, including cooperative opportunities and initiatives undertaken to further the collective understanding of cumulative impacts, and provide a record of relevant assumptions, confidence in data and analysis to support conclusions; and	Volume 2, Section 1.5.6
	h) discuss any deviations from the EUB/AENV/NRCB Information Letter Cumulative Effects Assessment in Environmental Impact Assessment Reports under the Alberta Environmental Protection and Enhancement Act (June 2000).	Volume 1, Section 2.1

Table 2.3-10 Terms of Reference Concordance Table

4.6 Climate, Air Quality and Noise		
4.6.1 Baseline Information		
	Provide the following:	
	a) baseline climatic conditions, including the type and frequency of meteorological conditions, that may impact ambient air quality; and	Volume 2, Section 2.5.4 Volume 2, Appendix 2A
	b) identify any regional air monitoring underway in the area and North American's participation in any regional air monitoring forums.	Volume 2, Section 2.5.5, 2.8.3
4.6.2 Methodology		
	Provide the following:	
	a) describe air quality in the Study Areas and any anticipated environmental changes for air quality. Review emission sources identified in Section 3.3 and model normal and upset conditions;	Volume 2, Section 2.5, 2.6.1.4
	b) describe the selection criteria used to determine the Study Areas, including information sources and assessment methods;	Volume 2, Section 2.2
	c) provide justification of models used, model assumptions, and any model shortcomings or constraints on findings;	Volume 2, Section 2.5.4
	d) discuss the meteorological data model input set used to run the model and provide a rationale for the choice of data set;	Volume 2, Section 2.5.4
	e) provide the air dispersion modelling completed in accordance with Alberta Environment's Air Quality Model Guideline;	Volume 2, Section 2.4.2
	f) for acid deposition modelling, provide deposition data from maximum levels to areas with 0.17 keq H+ha/yr Potential Acid Input (PAI). Justify the selection of the models used and identify any model shortcomings or constraints of findings; include analysis of PAI deposition levels consistent with the most recent acid deposition management framework for the Study Areas;	Volume 2, Section 2.4.2.1
	g) identify the regional, provincial and national objectives for air quality that were used to evaluate the significance of emission levels and ground-level concentrations, including the Canada Wide Standard for particulate matter and ozone, and the CEMA Particulate Matter and Ozone Management Framework; and	Volume 2, Section 2.4.2
	h) compare predicted air quality concentrations with the appropriate air quality guidelines available.	Volume 2, Section 2.5.6
	4.6.3 Impact Assessment	
	Discuss current and approved emission sources and changes as a result of anticipated future development scenarios within the EIA Study Area(s) (CEA case). Consider emission point sources as well as fugitive emissions. Identify components of the Project that will affect air quality from local and regional perspectives. Identify, describe and discuss the following:	Volume 2, Section 2.6
	a) the appropriate air quality parameters such as:, sulphur dioxide (SO2), hydrogen sulphide (H2S), total hydrocarbons (THC), oxides of nitrogen (NOx),volatile organic compounds (VOC), individual hydrocarbons of concern in the THC and VOC mixtures, particulates (road dust, PM10 and PM2.5), ozone (O3), trace metals (including arsenic) and visibility;	Volume 2, Section 2.3.1
	b) estimates of ground-level concentrations of the appropriate air quality parameters; include frequency distributions for air quality predictions in communities and sensitive receptors; maximums for all predictions, 99.9th percentile for hourly predictions and 98th percentile for 24-hour PM2.5 predictions;	Volume 2, Section 2.6.2
	c) the formation of secondary pollutants such as ground-level ozone (O3), secondary particulate matter, and acid deposition;	Volume 2, Section 2.7.4
	d) any expected changes to particulate deposition or acidic deposition patterns;	Volume 2, Section 2.7.2.5
	e) the potential for reduced air quality (including odours) resulting from the Project and discuss any implications of the expected air quality for environmental protection and public health;	Volume 2, Section 4.6.5
	f) interactive effects that may occur as a result of co-exposure of a receptor to the emissions and discuss limitations in the present understanding of this subject;	Volume 2, Section 4.4.6
	g) project-related and cumulative air quality impacts, and their implications for other environmental resources, including habitat diversity and quantity, vegetation resources, water quality and soil conservation;	Volume 2, Section 2.6, 2.7
	h) the effect of the use of alternative fuels on the air quality in the Study Areas, if applicable;	Volume 2, Section 2.6.1.3
	i) how air quality impacts resulting from the Project will be mitigated;	Volume 2, Section 2.6, 2.9.1.1
	j) ambient air quality monitoring that will be conducted during construction and operation of the Project;	Volume 2, Section 2.8
	k) components of the Project that have the potential to affect noise levels and discuss the implications and measures to mitigate; and	Volume 2, Section 3.4

Table 2.3-10 Terms of Reference Concordance Table

	l) the results of a noise assessment based on operations, as specified by EUB ID 99-08, and EUB Guide 38, include the following:	Volume 2, Section 3.6
	i) potentially-affected people and wildlife,	Volume 2, Section 3.2, 3.4
	ii) characterization of noise sources, and noise resulting from the development,	Volume 2, Section 3.4, 3.5
	iii) the implications of any increased noise levels, and	Volume 2, Section 3.6
	iv) proposed mitigation measures; and	Volume 2, Section 3.6.2
	m) regional air monitoring underway in the area and describe North American's participation in regional forums.	Volume 2, Section 2.5.5, 2.8.3
4.6.4 Climate Change		
	Provide the following:	
	a) in accordance with the guideline document Incorporating Climate Change Considerations in Environmental Assessment: General Guidance for Practitioners, review and discuss climate change and the local and/or regional, inter-provincial/territorial changes to environmental conditions resulting from climate conditions, including trends and projections where available;	Volume 1, Section 5.3.7
	b) identify stages or elements of the Project that are sensitive to changes or variability in climate parameters. Discuss what impacts the change to climate parameters may have on elements of the Project that are sensitive to climate parameters; and	Volume 1, Section 5.3.7
	c) comment on the adaptability of the Project in the event the region's climate changes. Discuss any follow-up programs and adaptive management considerations.	Volume 1, Section 5.3.7
4.7 Aquatic Resources		
4.7.1 Hydrogeology		
4.7.1.1. Baseline Information		
	Provide the following:	
	a) an overview of the existing geologic and hydrogeologic setting in the Study Areas from the ground surface down to and including the bitumen producing zones and disposal zones;	Volume 3, Section 5.5.2, 5.5.3
	b) presentation of the geologic setting should describe depth, thickness and spatial extent of lithology, stratigraphic units and structural features including water table and potentiometric surfaces; and	Volume 3, Section 5.5.2.1
	c) presentation of the hydrogeologic setting including:	Volume 3, Section 5.5.3
	i) the spatial distribution of aquifers and aquitards, their properties and the hydraulic connections between hydrostratigraphic units (include hydrostratigraphic cross Section),	Volume 3, Section 5.5.3.1
	ii) the hydraulic head, hydraulic gradients and groundwater flow directions and velocities,	Volume 3, Section 5.5.3.1
	iii) the chemistry of groundwater including background concentrations of major ions, metals and hydrocarbon indicators,	Volume 3, Section 5.5.4
	iv) the potential discharge zones, potential recharge zones and sources, areas of groundwater-surface water interaction and areas of Quaternary aquifer-bedrock aquifer interaction,	Volume 3, Section 5.5.3.1, 5.5.5
	v) all water well development and groundwater use, including an inventory of all groundwater users (where applicable, field verification surveys will be completed),	Volume 3, Section 5.5.5
	vi) the recharge potential for Quaternary aquifers,	Volume 3, Section 5.5.4
	vii) the potential hydraulic connection between bitumen production zones, disposal formations and other aquifers,	Volume 3, Section 5.5.3.1, 5.5.5
	viii) confirmation that the disposal zones currently used for deep disposal of wastes and wastewater will be sufficient for the life of the Project. Provide descriptions of wastewater disposal formations including containment, water quality, and the chemical compatibility with the wastewater, and	Volume 3, Section 5.5.5
	ix) the locations of major facilities associated with the Project including facilities for waste storage, treatment and disposal (e.g., deep well disposal), and the site-specific aquifer and shallow groundwater beneath these proposed facilities.	Volume 1, Section 4, 5
4.7.1.2. Methodology		

Table 2.3-10 Terms of Reference Concordance Table

	Provide the following:	
	a) the selection criteria used to determine the Study Areas, including information sources and assessment methods;	Volume 3, Section 5.2
	b) structure contour maps, geologic cross-Section and isopach maps to describe specific geology in the Local and Regional Study Areas;	Volume 3, Section 5.5.2
	c) justification of hydrogeological models used for the impact assessment and the cumulative effects assessment, including the results of the sensitivity analysis and discussions of model/modelling assumptions, constraints on the results and how limitations were addressed;	Volume 3, Section 5.4.5, Volume 3, Appendix 5D
	d) details on the observation well network used to calibrate hydrogeological modelling efforts used in this assessment; and	Volume 3, Section 5.4.5, Volume 3, Appendix 5D
	e) demonstration of how, or if, figures, maps, diagrams, interpretations and concepts developed from previous work and submitted in the EIA report have been modified by the incorporation of any subsequent new data.	Volume 1, Section 4
4.7.1.3. Impact Assessment		
	Discuss the following:	
	a) the components and activities of the Project which have the potential to affect groundwater resource quantity and quality within the Study Areas during project development, operation and reclamation; and	Volume 3, Section 5.6.1, 5.6.2, 5.6.3
	b) the nature and significance of the potential project effects on groundwater with respect to:	
	i) inter-relationship between groundwater and surface water in terms of surface water quantity and quality,	Volume 3, Section 5.6.2.2, 5.7.5
	ii) potential conflicts with other groundwater users and proposed resolutions to these conflicts,	Volume 3, Section 5.6.2.3
	iii) changes in groundwater quality,	Volume 3, Section 5.6.2.4
	iv) potential implications of seasonal variations,	Volume 3, Section 5.6.2.2
	v) the suitability of on-site waste disposal and supporting geotechnical information, and	Volume 3, Section 5.6.3.3, 5.7
	vi) groundwater withdrawal for project operations.	Volume 3, Section 5.6.4
4.7.1.4. Mitigation		
	Discuss conceptual plans and implementation program to manage and protect groundwater resources including, but not limited to:	
	a) monitoring programs for groundwater quality and quantity;	Volume 3, Section 5.8
	b) response/mitigation plans that may be considered in the event that adverse effects on non-saline groundwater, other groundwater users and/or surface effects related to groundwater pumping or steam/waste injection are detected; and	Volume 3, Section 5.8.6
	c) North American’s involvement in regional groundwater initiatives in the in-situ oil sands.	Volume 1, Section 6.3 Volume 3, Section 5.8.3
4.7.2 Hydrology		
4.7.2.1. Baseline Information		
	a) Describe baseline hydrological conditions in the Study Areas;	Volume 3, Section 6.7, 6.8
	b) Provide local and regional surface flow baseline data, including low, average and peak flows and seasonal variations for key watercourses, and low, average and peak levels and seasonal variations for key waterbodies; and	Volume 3, Section 6.7
	c) Describe and map drainage patterns in the Study Areas.	Volume 3, Section 6.2
4.7.2.2. Methodology		
	Provide:	
	a) the selection criteria used to determine the Study Areas, including information sources and assessment methods;	Volume 3, Section 6.2.1, 6.2.2, 6.4.1, 6.4.2
	b) the criteria used to identify key creeks, lakes and waterbodies to be monitored;	Volume 3, Section 6.4.1.2
	c) maps of the drainage patterns in the Study Areas; and	Volume 3, Section 6.7.1, 6.7.2
	d) a topographic map of the Local Study Area with an appropriate contour interval.	Volume 3, Section 6.2
4.7.2.3. Impact Assessment		

Table 2.3-10 Terms of Reference Concordance Table

	a) Describe the changes to groundwater and surface water movement as a result of the Project:	
	i) include changes to the quantity of surface flow, water levels and channel regime in local watercourses (during minimum, average and peak flows) and water levels in local waterbodies,	Volume 3, Section 6.11.4
	ii) assess the potential impact of any alterations in flow on the local and regional hydrology and identify all temporary and permanent alterations, channel realignments, disturbances and surface water withdrawals, their magnitude, duration, frequency, and proposed mitigation measures,	Volume 3, Section 6.11.4
	iii) discuss both project and cumulative effects of these changes on hydrology (e.g. timing, volume, peak and minimum flow rates, river regime and lake levels) including the significance of effects for downstream watercourses, and	Volume 3, Section 6.11.2, 6.11.6
	iv) discuss the potential for short and long term changes in the connection between surface water, groundwater, production zones and disposal zones;	Volume 3, Section 6.11.2, 6.11.3
	b) discuss changes to watershed(s), including surface and near-surface drainage conditions, potential flow changes, and potential changes in open-water surface areas caused by construction of access roads, drilling and well pads, and other facilities;	Volume 3, Section 6.11.4
	c) if any surface water withdrawals are considered, assess the potential impact of withdrawals including cumulative effects with respect to their magnitude, duration and frequency;	Volume 3, Section 6.11.2
	d) identify any potential erosion problems in local creek channels due to existing or proposed project activities;	Volume 3, Section 6.11.4.1, 6.11.4.2
	e) discuss changes in sediment concentrations in receiving waters caused by construction, operation, and reclamation phases of the Project; and	Volume 3, Section 6.11.4.2
	f) discuss any surface water users who have existing approvals, permits or licenses including the impact on these users due to the Project. Identify any potential water use conflicts and potential solutions.	Volume 3, Section 6.6, 6.11.6
4.7.2.4. Mitigation		
	a) Describe surface water management plans, mitigation measures and monitoring programs, including participation in regional initiatives, for the start-up, operations, and reclamation phases;	Volume 3, Section 6.12.1, 6.12.2
	b) discuss how potential impacts of temporary and permanent roads and well pads on open- water hydrology (including peatland/wetland types) will be minimized, mitigated and monitored;	Volume 3, Section 6.12.1, 6.12.2
	c) discuss plans to return disturbed areas to a self-sustaining habitat, if applicable;	Volume 3, Section 6.12.1
	d) discuss remedial measures to alleviate any anticipated erosion;	Volume 3, Section 6.12.1
	e) describe mitigation measures to reduce sediment loadings; and	Volume 3, Section 6.12.1
	f) describe any monitoring programs that may be considered to assess the impacts of potential changes to surface water on aquatic resources, wildlife and vegetation.	Volume 3, Section 6.12.2
4.7.3 Surface Water Quality		
4.7.3.1. Baseline Information		
	Provide:	
	a) a summary of the baseline water quality of watercourses and waterbodies in the Study Areas, including consideration of all appropriate water quality parameters, their seasonal variations and relationships to flow and other controlling factors;	Volume 3, Section 7.5.1
	b) the identity of waterbodies that are sensitive to acid deposition; and	Volume 3, Section 7.6.5.3
	c) an inventory of surface water users in the area.	Volume 3, Section 6.6
4.7.3.2. Methodology		
	Provide:	
	a) the selection criteria used to determine the Study Areas, including information sources and assessment methods, considering the current framework for the management of acid deposition; and	Volume 3, Section 7.2, 7.4.5
	b) a comparison of existing and predicted water quality, using as appropriate, the Surface Water Quality Guidelines for Use in Alberta (November 1999) or the Canadian Water Quality Guidelines.	Volume 3, Section 7.5.1
4.7.3.3. Impact Assessment		
	a) Identify project components that may affect surface water quality during all stages of the Project; and	Volume 3, Section 7.3, 7.6
	b) describe the potential impacts of the Project on surface water quality within the Study Areas:	Volume 3, Section 7.6
	i) discuss any changes in water quality resulting from the Project and identify any parameters that are inconsistent with the Surface Water Quality Guidelines for Use in Alberta (November 1999) or the Canadian Water Quality Guidelines,	Volume 3, Section 7.6.5.3
	ii) discuss the significance of any impacts on water quality and implications to aquatic resources (e.g., biota, biodiversity and habitat),	Volume 3, Section 7.6

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	iii) assess the potential project-related and cumulative impacts of acidifying and other air emissions on surface water quality,	Volume 3, Section 7.7
	iv) distinguish between natural variability and project-related impacts to water quality including the potential effects of seasonal variations and weather extremes on surface water quality,	Volume 3, Section 8.5
	v) discuss seasonal variation and potential effects on surface water quality. Describe the cumulative effects of regional activities on surface water quality in the Study Areas;	Volume 3, Section 7.5.2, 7.7
	c) discuss the residual effects for each stage of the Project, including post-reclamation. Predict and describe water conditions and suitability for aquatic biota in constructed waterbodies; and	Volume 3, Section 7.6, 7.7
	d) discuss the effect of water quality in surface waterbodies due to the change in surface runoff or groundwater discharge.	Volume 3, Section 7.6.3, 7.6.4
4.7.3.4. Mitigation		
	a) Discuss the proposed mitigation measures to be considered, during construction, operation and reclamation phases of the Project, to maintain surface water quality;	Volume 3, Section 7.6
	b) for any monitoring implemented for the Project, justify the selection of monitoring locations, and the integration of these sites into an overall aquatic assessment and monitoring program. Describe how the methods are in accordance to Alberta Environment standards for surface water quality monitoring; and	Volume 3, Section 7.8
	c) identify any cooperative monitoring and assessment initiative(s) such as with regional stakeholders that North American may consider joining.	Volume 3, Section 7.8
4.7.4 Aquatic Biological Resources		
4.7.4.1. Baseline Information		
	a) Describe the existing fish and other aquatic resources (e.g., benthic invertebrate and aquatic vegetation) in the waters found in the Local and Regional Study Areas and in other fish-bearing waters likely to be impacted by the Project:	Volume 3, Section 8.5
	i) identify species composition, distribution, relative abundance, movements and general life history parameters,	Volume 3, Section 8.5
	ii) identify critical or sensitive areas such as spawning, rearing, and over-wintering habitats. Discuss seasonal habitat use including migration and spawning routes,	Volume 3, Section 8.5
	iii) identify key indicator species and provide the rationale and selection criteria used,	Volume 3, Section 8.6.1
	iv) describe and map, as appropriate, the fish habitat and aquatic resources of the lakes, rivers and other waters within the Local Study Area, and	Volume 3, Section 8.6.1
	v) describe the existing baseline information, any deficiencies in information, how these deficiencies will be addressed and, as applicable, any studies proposed to evaluate the status of the fish and aquatic resources in the Local Study Area;	Volume 3, Section 8.5
	b) for water course crossings, describe the fish species present and life stages of concern; and	Volume 3, Section 8.5
	c) discuss the use of the fish resources as existing or potential Aboriginal, sport or commercial fisheries.	Volume 3, Section 8.5
4.7.4.2. Methodology		
	Provide:	
	a) the selection criteria used to determine the Study Areas, including information sources and assessment methods;	Volume 3, Section 8.2, 8.4
	b) the criteria and selection process for key indicator species; and	Volume 3, Section 8.6.1
	c) a description of the timing, techniques, and the design of the inventory sampling used to determine the abundance, distribution and habitat use of aquatic biological resources.	Volume 3, Section 8.4.3
4.7.4.3. Impact Assessment		
	Discuss:	
	a) the potential for adverse impacts on the lakes and streams in the area (e.g., stream alterations and changes to substrate conditions, water quality and quantity affecting fish, fish habitat, and other aquatic resources in the Study Areas). Consider survival of eggs and fry, chronic or acute health effects, and increased stress on fish populations from release of contaminants, sedimentation, flow alterations, temperature and habitat changes;	Volume 3, Section 8.6.3
	b) potential impacts on riparian areas that could impact aquatic biological resources and productivity;	Volume 3, Section 8.6.3.3
	c) how potential changes to groundwater and surface water may affect fisheries and aquatic resources, under normal and drought conditions;	Volume 3, Section 8.6.3.2
	d) the potential effects of watercourse crossings on fish, fish habitat, and aquatic communities including habitat losses, and their potential for habitat fragmentation;	Volume 3, Section 8.6.3, 8.6.4
	e) the significance of residual environmental effects in the context of local and regional fisheries; and	Volume 3, Section 8.9

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	f) the potential for increased fishing pressures in the region that could arise from the increased workforce and improved access as a result of the Project. Identify the implications for the fish resource.	Volume 3, Section 8.6.4.3
4.7.4.4. Mitigation		
	a) Discuss, as applicable, the design, construction and operational factors to be incorporated into the Project for the protection of fish resources;	Volume 3, Section 8.6.3, 8.6.4
	b) indicate how environmental protection plans address applicable provincial and federal policies on fish habitat including the development of a "No Net Loss" fish habitat objective;	Volume 3, Section 8.6.3, 8.6.4
	c) for potential watercourse crossings, discuss the short and long term monitoring of fish, fish habitat and habitat fragmentation, including mitigation measures incorporated in the design of proposed watercourse crossings;	Volume 3, Section 8.6.3, 8.6.4, 8.8
	d) describe any mitigation strategies that might be planned to minimize the effects of improved access, increased workforce and increased fishing pressure on the fish resource;	Volume 3, Section 8.6.4.3
	e) as appropriate, discuss any cooperative mitigation strategies that might be planned or continued with other oil sands and industrial operators; and	Volume 3, Section 8.8
	f) as applicable, discuss any monitoring programs that have been initiated by North American or conducted in cooperation with stakeholders to assess fisheries impacts from the Project. Provide details of any programs and discuss how they would contribute to an overall understanding of Project impacts on fish resources.	Volume 3, Section 8.8
4.8 Terrestrial Resources		
4.8.1 Geology, Soils, Terrain		
4.8.1.1. Baseline Information		
	Describe the Local Study Area and Regional Study Area geological, terrain and soil conditions, including:	Volume 4, Section 9.3
	a) a general description of the surficial geology, including surface topography and bedrock;	Volume 4, Section 9.5
	b) a detailed description of regional soils;	Volume 4, Section 9.5
	c) a detailed description of the soil types and their distribution in the Project Area and Local Study Area;	Volume 4, Section 9.5.2, 9.5.4
	d) the sensitivity of the local and regional soil types to potential acid deposition;	Volume 4, Section 9.5.7, 9.5.10
	e) the pre- and post-disturbance land capability classes for soils in the Local Study Area;	Volume 4, Section 9.5.5
	f) the availability and suitability of soils within the Project Area for reclamation;	Volume 4, Section 9.5.6
	g) a reclamation balance for topsoils and subsoils in all phases of the Project; and	Volume 4, Section 9.5.6
	h) identification and location of erosion sensitive soils.	Volume 4, Section 9.5.8
4.8.1.2. Methodology		
	Provide the following:	
	a) the rationale used to determine the Study Areas, including information sources and assessment methods;	Volume 4, Section 9.3
	b) the sensitivity and buffering capacity of the Local and Regional soil types to potential acid deposition from the proposed development using accepted soil sensitivity analyses and modelled predictions of acid deposition patterns;	Volume 4, Section 9.4.2, 9.4.4
	c) the distribution of soil types in the Local and Regional Study Areas using appropriate soil survey intensity and classification procedures as outlined in the Soil Survey Handbook, Vol. 1 (Agriculture Canada, 1987) and The Canadian System of Soil Classification (Agriculture and Agri-Food Canada, 1999);	Volume 4, Section 9.4.2, 9.4.6
	d) a description of the suitability and availability of soils within the Project for reclamation using Soil Quality Criteria Relative to Disturbance and Reclamation (Alberta Agriculture, 1987);	Volume 4, Section 9.4.3
	e) an inventory of the pre- and post-disturbance land capability classes for soils in the Local Study Area by using the Land Capability Classification System for Forest Ecosystems in the Oil Sands, Third Edition (Leskiw, 2006); and	Volume 4, Section 9.4.2.1
	f) an ecological context of the soil resources by supplying a soil survey report and maps following Soil Survey Handbook, Vol. 1 (Agriculture Canada, 1987) at an appropriate level of detail to determine the effect of the Project on soil types and quality on the Regional Study Area.	Volume 4, Section 9.4.1
4.8.1.3. Impact Assessment		
	Discuss the following:	
	a) the significance of any changes for the Local and Regional landscapes, biodiversity, productivity, ecological integrity, aesthetics and future use resulting from disturbance during construction, operation and reclamation;	Volume 4, Section 9.7.2

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	b) the significance of predicted impacts by acidifying emissions on Local and Regional soils resulting from the Project, with reference to local studies, current guidelines and management objectives for acidifying emissions consistent with the latest acid deposition management framework;	Volume 4, Section 9.7.4
	c) any constraints or limitations to achieving vegetation/habitat restoration based on anticipated soil conditions (e.g. compaction, contaminants, soil moisture, nutrient depletion, erosion, etc.);	Volume 4, Section 9.7.3
	d) the impact of the Project development on soil types and reclamation suitability and the approximate volume of soil materials for reclamation;	Volume 4, Section 9.7.2
	e) the potential for soil erosion from the disturbance, construction, operation and reclamation of the Project;	Volume 4, Section 9.7.3
	f) the anticipated changes (type and extent) to the pre-disturbance topography, elevations and drainage patterns within the Project Area resulting from disturbance during construction, operation and reclamation;	Volume 4, Section 9.7.2
	g) the potential for changes in the ground surface during operations (e.g., temperature, ground heave and ground subsidence). Summarize applicable experience with temperature changes, surface heaving and subsidence and the factors involved in their occurrence. Describe the environmental implications of any terrain changes during the steaming and recovery operations;	Volume 1, Section 4.2.3.5
	h) the impacts to land capability in the Local Study Area due to the Project; and	Volume 4, Section 9.7.3
	i) any other issues that will affect soil capability and quality of the Study Areas and the reclaimed landscape.	Volume 4, Section 9.7.1
4.8.1.4. Mitigation		
	Provide the following:	
	a) possible mitigative measures to minimize surficial disturbance;	Volume 4, Section 9.7.2
	b) possible mitigative actions to address potential effects of acid deposition;	Volume 4, Section 9.7.4
	c) actions to mitigate effects of any constraint or limitation to habitat restoration such as compaction, contaminants, soil moisture, erosion, nutrient regime, etc.;	Volume 4, Section 9.7.3
	d) possible measures to mitigate changes to ground surface (temperature, heave and subsidence) during operations;	Volume 1, Section 4.2.3.5
	e) possible mitigative actions to address impacts to land capability; and	Volume 4, Section 9.7.3
	f) any other measures to reduce or eliminate the potential impacts that the Project may have on soil capability and/or quality.	Volume 4, Section 9.7
4.8.2 Terrestrial Vegetation, Wetlands and Forest Resources		
4.8.2.1. Baseline Information		
	a) Describe vegetation communities in the Study Areas, using, as appropriate, the Alberta Vegetation Inventory (AVI) Standard AVI 2.1 and The Field Guide to Ecosites of Northern Alberta (Beckingham and Archibald 1996);	Volume 4, Section 10.5.1
	b) describe peatlands and wetlands in the Study Areas according to the Alberta Wetland Inventory Standards Manual (AWI) Version 1.0;	Volume 4, Section 10.5.1.8
	c) identify and discuss the rare or endangered species, as listed by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) and the Alberta Natural Heritage Information Centre (ANHIC), for each landscape unit;	Volume 4, Section 10.5.3
	d) identify and discuss the ecosites considering their potential to support rare plant species, plants for traditional or medicinal purposes, old growth forests or other communities of limited distribution. Consider their importance for local and regional habitat, sustained forest growth, rare plant habitat and hydrologic regime;	Volume 4, Section 10.5.1.1, 10.6.1.6, 10.5.1.7
	e) identify and verify the presence of species of rare plants and the ecosite phases where they are found, using reliable survey methods;	Volume 4, Section 10.5.3.2
	f) where landscape units are identified as rare, or where a significant percentage of landscape units within the LSA may be removed by the Project, describe their regional significance; and	Volume 4, Section 10.5.3.3
	g) discuss the rarity or abundance of wetlands in the Local Study Area.	Volume 4, Section 10.5.1.8
4.8.2.2. Methodology		
	Provide:	
	a) a map of vegetation-related information, including vegetation communities, peatlands and wetlands in the Study Areas. Map the Project development footprint at an appropriate scale. Discuss any shortfalls in using AVI and AWI for mapping the Local Study Area;	Volume 4, Section 10.4.1

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	b) a discussion of the adequacy of the Study Areas, information sources and assessment methods for a cumulative effects assessment, including how baseline information was collected to enable a detailed ELC of the Local Study Area to be completed; and	Volume 4, Section 10.4.1, 10.4.2
	c) the selection criteria used to determine the Study Areas, including information sources and assessment methods.	Volume 4, Section 10.2.1
	4.8.2.3. Impact Assessment	
	a) Identify the amount of vegetation and wetlands to be disturbed during each stage of the Project;	Volume 4, Section 10.6
	b) discuss any potential effects the Project may have on rare plants and areas with high rare plant potential habitat;	Volume 4, Section 10.6.8
	c) produce an ELC map that shows pre-disturbance and reclaimed land surfaces. Comment on the importance of size, distribution and variety of these landscape units for timber harvesting and other land uses;	Volume 4, Section 10.6.1
	d) discuss temporary (including the timeframe) and permanent changes to vegetation and wetland communities:	Volume 4, Section 10.6, 10.6.6
	i) comment on the significance of the effects and their implications for other environmental resources (habitat diversity and quantity, water quality, erosion potential, soil conservation, recreation and other uses),	Volume 4, Section 10.6
	ii) comment on the sensitivity to disturbance (including acid deposition), as well as the techniques used to estimate sensitivity to disturbance and reclamation, of each vegetation community and discuss permanent and temporary changes,	Volume 4, Section 10.6, 10.6.10
	iii) predict the anticipated effect of the Project on wetlands, and	Volume 4, Section 10.6.6
	iv) discuss the impact of any loss of peatlands or surface wetlands, as well as how this will affect land use, fragmentation and biodiversity;	Volume 4, Section 10.6.6
	e) identify and evaluate the extent of potential effects of the Project, such as ecosystem fragmentation and introduction of non-native plant species on native species composition and changes to plant communities;	Volume 4, Section 10.6.11
	f) determine the amount of commercial and non-commercial forest land base that will be disturbed by the Project. Compare the pre-disturbance and reclaimed percentages and distribution of all forested communities in the Local Study Area. Provide Timber Productivity Ratings for the Local Study Area lands, including identification of productive forested, non-productive forested and non-forested lands;	Volume 4, Section 10.6.3
	g) determine how the project disturbance impacts Annual Allowable Cuts and quotas within the Forest Management Agreement. Discuss opportunities to integrate this project with other resource development activities such as logging; and	Volume 4, Section 10.6.3
	h) comment on the significance of the residual effects on vegetation resources, peatlands and wetlands, and their implications for other environmental resources.	Volume 4, Section 10.6
4.8.2.4. Mitigation		
	Provide:	
	a) a detailed mitigation strategy that will minimize Project impacts in the Study Areas;	Volume 4, Section 10.6
	b) a plan to mitigate the adverse effects of site clearing on rare plants, and existing cutblocks. Identify any setbacks proposed around environmentally sensitive areas such as surface waterbodies, riparian areas and peatlands/wetlands;	Volume 4, Section 10.6.8
	c) a discussion of measures and techniques that will be used to minimize the impact of peatland and wetland loss;	Volume 4, Section 10.6.6
	d) plans to return disturbed areas to a self-sustaining habitat equivalent to pre-disturbance conditions, considering factors such as biological capability and diversity, and end land use objectives; and	Volume 4, Section 10.6
	e) in addition to equivalent land capability principle, discuss from an ecological perspective the expected timelines for establishment and recovery of vegetative communities and the expected differences in the resulting vegetative community structures.	Volume 4, Section 10.6
4.8.3 Wildlife		
4.8.3.1. Baseline Information		
	Identify and describe:	
	a) existing wildlife resources (amphibians, reptiles, birds and terrestrial and aquatic mammals), their use and potential use of habitats in the Study Areas;	Volume 4, Section 11.5
	b) wildlife species composition, distribution, relative abundance, seasonal movements, movement corridors, habitat requirements, key habitat areas, and general life history in the Study Areas; and	Volume 4, Section 11.5

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	c) include current field data for all key indicator species and species of concern, including those listed by Alberta (at risk, may be at risk, and sensitive list species in the General Status of Alberta Wild Species 2005, or update) and COSEWIC (endangered, threatened, and special concern species in the Canadian Species at Risk Act (SARA)).	Volume 4, Section 11.5, 11.5.7 Volume 4, Appendix 11B
4.8.3.2. Methodology		
	Provide:	
	a) the selection criteria used to determine the Study Areas, including information sources and assessment methods;	Volume 4, Section 11.2
	b) key indicator species including rationale and selection criteria;	Volume 4, Section 11.4.2
	c) current field data to establish baseline conditions, using recognized sampling protocols; and	Volume 4, Section 11.4.1
	d) if habitat models are used to evaluate impacts, models will be modified, calibrated and validated by comparing model predictions with wildlife data from the Study Area(s). Describe data and data sources that were used to evaluate wildlife models.	Volume 4, Section 11.4.2
4.8.3.3. Impact Assessment		
	Discuss:	
	a) the anticipated changes to wildlife in the Study Areas;	Volume 4, Section 11.6
	b) the potential adverse impacts on wildlife populations (including indicator species and sensitive species), habitat use, habitat availability/quality and food supply during all phases of the Project. Consider habitat loss, abandonment, reduced effectiveness, fragmentation or alteration as it relates to reproductive potential and recruitment for regional wildlife populations over the life of the Project;	Volume 4, Section 11.6.1
	c) the spatial and temporal changes to habitat (type, quality, quantity, diversity and distribution) and to wildlife distribution, relative abundance, movements, habitat availability including:	Volume 4, Section 11.6
	i) anticipated effects on wildlife as a result of changes to air, water, including both acute and chronic effects on animal health, and	Volume 4, Section 11.6.4.2
	ii) anticipated effects on wildlife due to improved or altered access into the area, (e.g., vehicle collisions with wildlife, obstructions to daily or seasonal movements, noise effects and hunting pressure) during operations and after Project closure;	Volume 4, Section 11.6.3, 11.6.4
	d) the mapped changes in habitat distribution and fragmentation anticipated from the project and other planned activities, and their implications; and	Volume 4, Section 11.6.2
	e) residual impacts to wildlife and wildlife habitat and discuss their significance in the context of local and regional wildlife populations.	Volume 4, Section 11.6
4.8.3.4. Mitigation		
	Discuss:	
	a) a strategy and mitigation plan to minimize impacts on wildlife habitat and populations through the life of the Project and to return productive wildlife habitat to the area, considering:	Volume 4, Section 11.6
	i) habitat enhancement measures and a schedule for the return of habitat capability to areas impacted by the Project,	Volume 4, Section 11.2.3
	ii) consistency of the plan with applicable regional, provincial and federal wildlife habitat objectives and policies,	Volume 4, Section 11.6.5.2, 11.6.4.1
	iii) the need for access controls or other management strategies to protect wildlife during and after project operations, and	Volume 4, Section 11.6
	iv) monitoring programs to assess predicted wildlife impacts from the Project and the effectiveness of mitigation strategies and habitat enhancement measures, giving special attention to sensitive species in the Local Study Area;	Volume 4, Section 11.6.5.2
	b) the potential to return the Project Area to pre-disturbance wildlife habitat/population conditions;	Volume 4, Section 11.6.2, 11.2.3
	c) the use setbacks to provide for the protection of riparian habitats, interconnectivity of such habitat and the unimpeded movement by wildlife species using the habitat; and	Volume 4, Section 11.6.3.1

Table 2.3-10 Terms of Reference Concordance Table

	d) measures that will be taken to prevent habituation of wildlife, the potential for human-wildlife encounters and consequent destruction of wildlife (e.g., black bears), including any staff training programs, garbage containment or regular follow-up.	Volume 4, Section 11.6.4.1
4.9 Biodiversity and Fragmentation		
4.9.1 Baseline Information		
	Provide the following:	
	a) within selected taxonomic groups, discuss the presence and abundance of species in each ecosite phase or ecological type;	Volume 3, Section 8 Volume 4, Section 10, 11
	b) species lists and summaries of observed and estimated species richness and evenness for each ecosite phase or ecological type;	Volume 3, Section 8 Volume 4, Section 10, 11
	c) a ranking of each ecological unit for biodiversity potential;	Volume 4, Section 12.5.3
	d) a measure of biodiversity on baseline sites that are representative of the proposed reclamation ecosites;	Volume 4, Section 12.5
	e) the variety, distribution and abundance of non-biotic systems including , but not limited to, landforms and waterbodies, at the local, regional and landscape levels of biodiversity analysis; and	Volume 4, Section 12.5.1
	f) the current level of habitat fragmentation in the Study Areas.	Volume 4, Section 12.5.4
4.9.2 Methodology		
	Provide and discuss the following:	
	a) using the definition for biodiversity provided in the Canadian Biodiversity Strategy (1995), the determination of the suite of target elements that will be used to assess biodiversity in terrestrial and aquatic ecosystems in order to characterize the existing ecosystems and that will be used to represent broad taxonomic assemblages;	Volume 4, Section 12.1
	b) the process and rationale used to select biotic target elements for biodiversity;	Volume 4, Section 12.4.2
	c) the collection of baseline information in each terrestrial and aquatic community using a suitable proportional sampling method to provide sufficient plots in each ecosite phase and statistically sound data;	Volume 4, Section 12.4.2
	d) the combination of measures of species richness, overlap in species lists, significance of individual species or associations, uniqueness and other appropriate measures to rank ecological units for biodiversity potential. Provide the rationale and techniques for the chosen ranking system;	Volume 4, Section 12.4.2, 12.4.2.1, 12.4.2.2, 12.4.2.3
	e) North American's participation in regional programs that will allow for the collection and submission of baseline information in a timely manner; and	Volume 4, Section 12.8
	f) the techniques used in the fragmentation analysis.	Volume 4, Section 12.4.2.3
4.9.3 Impact Assessment		
	Discuss:	
	a) the contribution of the Project to any anticipated changes in regional biodiversity;	Volume 4, Section 12.6.2, 12.6.3
	b) how changes in biodiversity could potentially impact local and regional ecosystems; and	Volume 4, Section 12.6.2, 12.6.3
	c) the anticipated level of habitat fragmentation in the Study Areas as a result of the Project, the principle factors contributing to fragmentation and the extent of potential effects from fragmentation (e.g., potential introduction of non-native plant species on native species composition and any changes to plant communities).	Volume 4, Section 12.6
4.9.4 Mitigation		
	Discuss:	
	a) measures to minimize changes in regional biodiversity resulting from the Project; and	Volume 4, Section 12.6.3.1
	b) biodiversity monitoring programs and management thresholds that North American will implement either individually or in cooperation with other operators or regional initiatives.	Volume 4, Section 12.8
4.10 Land And Resource Use		
4.10.1 Baseline Information		
	Describe the following:	
	a) the existing recreational, commercial, residential, institutional, industrial, tourism, cultural/historical, trapping, hunting, traditional land uses and other outdoor recreational activities in the Study Areas;	Volume 5, Section 13.7

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	b) unique sites or special features in the Study Areas, such as Natural Areas, Environmentally Significant Areas archaeological sites or Heritage Rivers. Indicate the location and significance of other protected areas, if present; and	Volume 5, Section 13.6.3
	c) the quantity and quality of aggregate resources in the Study Areas.	Volume 5, Section 13.7.3
4.10.2 Methodology		
	a) Identify any land use policies and resource management initiatives that pertain to the Study Areas;	Volume 5, Section 13.6.2
	b) discuss how the proposed development will be consistent with the intent of the guidelines and objectives of these initiatives;	Volume 5, Section 13.6.2
	c) outline the process for addressing the needs of other users in the Study Areas; and	Volume 5, Section 13.6
	d) discuss the implications of those land and resource use policies for the Project, including any constraints to development.	Volume 5, Section 13.6
4.10.3 Impact Assessment		
	Discuss the following:	
	a) the potential impact of the Project on the identified land uses and public access during and after development activities;	Volume 5, Section 13.8
	b) the aesthetic characteristics of the facilities with respect to the existing landscape;	Volume 5, Section 13.8.1.1
	c) any impacts of the Project on special features in the Study Area;	Volume 5, Section 13.8.2.2
	d) the impact of development and reclamation on commercial forest harvesting in the Project Area; and	Volume 5, Section 13.8.2.6
	e) the impact of the development on aggregate resources in the Study Areas.	Volume 5, Section 13.8.2.5
	4.10.4 Mitigation	
	a) Identify measures to mitigate the potential land use impacts resulting from the Project;	Volume 5, Section 13.8.2
	b) discuss how regional environmental management initiatives will be incorporated into North American's land use plan;	Volume 1, Section 6.3
	c) discuss how reclamation will restore existing land use potentials considering any recommendations of the Oil Sands Mining End Land Use Committee and the Cumulative Environmental Management Association, Reclamation Working Group that are applicable to in-situ oil sands operations;	Volume 5, Section 13.8.1
	d) discuss opportunities for timber salvage, revegetation, reforestation and harvest for the reduction of fire hazard; and	Volume 5, Section 13.8.1.1, 13.8.2.1
	e) discuss mitigative measures to conserve aggregate resources.	Volume 5, Section 13.8.2.5
5.0 PUBLIC HEALTH AND SAFETY		
	Describe those aspects of the Project that may have implications for public health or the delivery of regional healthcare services. Determine whether there may be implications for public health arising from the Project, specifically:	
	a) identify and discuss the data and methods North American used to assess impacts of the Project on human health and safety;	Volume 2, Section 4.4
	b) assess the potential health implications of the compounds that will be released to the environment from the proposed operation in relation to exposure limits established to prevent acute and chronic adverse effects on human health;	Volume 2, Section 4.4
	c) identify the human health impact of the potential contamination of country foods and natural food sources taking into consideration all project activities;	Volume 2, Section 4.4.4.4
	d) provide the information on compounds released from the project found in samples of selected species of vegetation;	Volume 2, Section 4.6, 4.7
	e) provide results of modelling of compounds released from the Project and found in wildlife known to be consumed by humans based on chemical data from soil, vegetation, water and other available samples;	Volume 2, Section 4.6, 4.7
	f) discuss the potential to increase human exposure to contaminants from changes to water quality, air quality and soil quality taking into consideration all project activities;	Volume 2, Section 4.6, 4.7

Table 2.3-10 Terms of Reference Concordance Table

	g) during consultation on the project, document any health concerns identified by Aboriginal stakeholders due to the impacts of existing industrial development and of the Project specifically on their traditional lifestyle. Determine the impact of the Project on the health of Aboriginal stakeholders and identify possible mitigation strategies;	Volume 1, Section 6
	h) assess cumulative health effects to receptors, including First Nations and Aboriginal receptors, that are likely to result from the Project in combination with other existing, approved, and planned projects;	Volume 2, Section 4.6, 4.7
	i) identify, as appropriate, the anticipated follow-up work, including regional cooperative studies. Identify how such work will be implemented and coordinated with ongoing air, soil and water quality initiatives;	Volume 2, Section 4.8
	j) identify and discuss potential health and safety impacts due to higher regional traffic volumes and the increased risk of accidental leaks and spills;	Volume 5, Section 14.7.5
	k) document health and safety concerns raised by stakeholders during consultation on the Project;	Volume 5, Section 14.7.5
	l) provide a summary of North American's emergency response plan and discuss mitigation plans to ensure workforce and public safety during pre-construction, construction, operation and reclamation of the Project. Include prevention and safety measures for wildfire occurrences, accidental release or spill of chemicals to the environment and failures of structures retaining water or fluid wastes;	Volume 1, Section 5.3.2, 5.3.3
	m) describe how local residents will be contacted during an emergency and the type of information that will be communicated to them;	Volume 1, Section 5.3.2, 5.3.3
	n) describe the existing agreements with area municipalities or industry groups such as safety cooperatives, emergency response associations and municipal emergency response agencies; and	Volume 1, Section 6.3 Volume 5, Section 14.9
	o) describe and discuss the impacts of the proposed Project on potential shortages of affordable housing and the quality of health care services. Identify and discuss the mitigation plans that will be undertaken to address these issues. Provide a summary of any discussions that have taken place with the Municipality and the Regional Health Authority concerning potential housing shortages and health care services, respectively.	Volume 1, Section 2.7 Volume 5, Section 14.9
6.0 TRADITIONAL ECOLOGICAL KNOWLEDGE AND TRADITIONAL USE		
	Provide details on the consultation undertaken with potentially affected Aboriginal communities with respect to traditional ecological knowledge (TEK) and traditional land use including:	Volume 1, Section 6
	a) results of consultation with Aboriginal communities to identify the extent of traditional use of the Study Area(s);	Volume 1, Section 6 Volume 5, Section 16.6.2
	b) the traditional land uses including fishing, hunting, trapping and plant harvesting (nutritional and medicinal) and cultural use in the Study Area(s);	Volume 5, Section 16.6.2
	c) the vegetation and wildlife used for nutritional and medicinal purposes, and any potential effects the Project may have;	Volume 4, Section 10 Volume 5, Section 13, 16.6.2
	d) cabin sites, spiritual sites and graves;	Volume 5, Section 13, 16
	e) the project and cumulative impact of development on these uses and identify possible mitigation strategies; and	Volume 5, Section 16
	f) a description of how TEK was incorporated into the technical components of the EIA report.	Volume 2 - 5
7.0 HISTORIC RESOURCES		
	Describe those aspects of the Project that may have implications for historic resources and provide the following:	Volume 1
	a) a general overview of the results of any previous historic resource studies that have been conducted in the Local Study Area, including archaeological resources, palaeontological resources, historic period sites, and any other historic resources as defined within the Historical Resources Act, including Aboriginal traditional use sites that may be considered to be historic resources under the Historical Resources Act;	Volume 5, Section 15.4.2
	b) details of the consultation with the Historic Resources Management Branch of Alberta Tourism, Parks, Recreation and Culture, First Nations and any other Aboriginal communities with respect to historic resources;	Volume 1, Section 6 Volume 5, Section 15
	c) the final report discussing the results of the Historic Resources Impact Assessment (HRIA) to the Historic Resources Management Branch, and any other interested parties, prior to or at the same time as the submission of the EIA report to Alberta Environment. The EIA is to include a summary of the results of the HRIA;	Volume 5, Section 15.9

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	d) documentation of the participation of local Aboriginal peoples in the field component of the consultation program, and any concerns that local First Nations and other Aboriginal communities have relative to project impacts on historic resources;	Volume 1, Section 6
	e) documentation of any stakeholder concerns with respect to the development of the Project based on the historic significance of the Local Study Area; and	Volume 1, Section 6
	f) an outline of the historic resources management program and schedule of field investigations that may be required to further assess and mitigate the effects of the Project on historic resources.	Volume 5, Section 15.10
8.0 SOCIO-ECONOMIC FACTORS		
	8.1 Baseline Information	
	Describe the baseline socio-economic conditions and trends for the region and for the communities impacted by the Project.	Volume 5, Section 14.7
8.2 Methodology		
	Describe the selection criteria for the Study Areas, information sources and assessment methods.	Volume 5, Section 14.2, 14.4, 14.5
8.3 Impact Assessment		
	Provide information on the socio-economic effects of the Project:	
	a) identify any concerns related to socio-economic conditions that have been raised by the local municipality or any other stakeholder in the region;	Volume 5, Section 14.3, 14.7
	b) provide information on the socio-economic impacts of the Project on the Regional Study Area and Alberta, related to:	
	i) local employment and training,	Volume 5, Section 14.8
	ii) local business opportunities,	Volume 5, Section 14.8
	iii) population changes,	Volume 5, Section 14.9
	iv) demands on local services and infrastructure,	Volume 5, Section 14.9
	v) effects on traffic and traffic safety,	Volume 5, Section 14.9
	vi) regional and provincial economic benefits,	Volume 5, Section 14.8
	vii) housing and availability of affordable housing,	Volume 5, Section 14.9
	viii) effects on medical facilities and health services,	Volume 5, Section 14.9
	ix) effects on trapping, hunting and fishing,	Volume 5, Section 14.8, 14.9
	x) effects on recreational activities, and	Volume 5, Section 14.9
	xi) effects on First Nations and Métis (e.g., traditional land use and cultural well being);	Volume 5, Section 14.8, 14.9
	c) provide an analysis of the significance of the socio-economic impacts;	Volume 5, Section 14.8, 14.9
	d) discuss the timing of workforce requirements for construction and operation. Include a breakdown of the total number of jobs to be created along with a description of when peak activity periods will occur;	Volume 5, Section 14.8, 14.9
	e) describe the overall engineering and contracting plan for the project;	Volume 5, Section 14.2, 14.8
	f) provide a summary of any discussions that have taken place with the Municipality concerning potential housing shortages;	Volume 5, Section 14.7
	g) discuss the location of proposed construction camps, the number of workers they are intended to house and outline what services will be provided in the camp (e.g., security, recreation and leisure, medical);	Volume 5, Section 14.9
	h) evaluate the need for additional public services and infrastructure. Take into consideration other projects that are reasonably anticipated during the life of the Project. This will include consideration of housing, transportation, education/training, health and social services, urban and regional recreation use, law enforcement and emergency preparedness; discuss options for mitigating any impacts;	Volume 5, Section 14.9, 14.10
	i) discuss North American’s policies and programs respecting the use of regional and Alberta goods and services; and	Volume 5, Section 14.8
	j) provide an estimated breakdown of Alberta, other Canadian and non-Canadian industrial benefits for engineering and project management, equipment and materials, construction labour and total overall project.	Volume 5, Section 14.8
8.4 Mitigation		
	Provide the following information on:	
	a) current plans and strategies to mitigate the socio-economic impacts of the Project, including work undertaken with industry partners, local municipalities and other regional stakeholders; and	Volume 5, Section 14.9

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	b) North American's current and ongoing plans to work with First Nations and other local residents and local businesses with regard to employment, training needs, and other economic development opportunities arising from the construction and operation of the Project.	Volume 5, Section 14.8
9.0 PUBLIC CONSULTATION		
	Document the public consultation program implemented for the Project including methods, the type of information provided, the level and nature of North American's response:	
	a) describe the consultative process and show how public input was obtained and addressed;	Volume 1, Section 6
	b) provide documentation individual participation and attendance at each meeting, including records of specific comments or issues raised by individuals present at the meetings;	Volume 1, Section 6.4
	c) describe and document concerns, issues, and opportunities raised by the public, North American's analysis of those concerns and issues, and the actions taken to address those concerns and issues;	Volume 1, Section 6.4
	d) describe how the resolution of the concerns and issues was incorporated into the Project development, impact mitigation and proposed monitoring; and	Volume 1, Section 6.4
	e) provide plans to maintain the public consultation process following completion of the EIA review to ensure that the public will have an appropriate forum for expressing their views on the ongoing development, operation and reclamation of the Project.	Volume 1, Section 6.4.7 Volume 1, Appendix D
	Consultation will include discussions with the following:	
	a) Alberta provincial representatives;	Volume 1, Section 2.1, 6.2
	b) Federal government representatives;	Volume 1, Section 6.2
	c) Municipal government representatives;	Volume 1, Section 6.2
	d) Residents in surrounding areas as identified during the consultation process;	Volume 1, Section 6.2
	e) First Nations and Métis organizations;	Volume 1, Section 6.2
	f) commercial, industrial, recreational and traditional users; and	Volume 1, Section 6.2
	g) other potentially-affected parties.	Volume 1, Section 6.2
APPENDIX		
	The following information is necessary to be submitted as part of the Application under the Water Act (WA) or the Environmental Protection and Enhancement Act (EPEA). It may not be necessary to be considered as part of the EIA report completeness decision-making process under Section 53 of EPEA. Upon review of the information submitted, a final determination will be made if it is necessary for the following information to be considered as part of the EIA report completeness decision.	
AIR QUALITY ASSESSMENT		
	Provide via modelling maximum groundlevel concentration locations of nitrogen dioxide (NO2) and sulphur dioxide (SO2) near the vicinity of the central processing facility, plant or project. Provide ground-level concentrations in 50 or 100 m increments extending out from the central processing facility to 2 or 5 km.	Volume 2, Section 3
CONSERVATION AND RECLAMATION PLAN		
	The reclamation plan in the Application will address the following:	
	a) provide a soil conservation and reclamation plan for progressive reclamation in the Project Areas. Outline the anticipated major timelines for reclamation activities with reference to the life span of the proposed Project;	Volume 1, Section 8.6.3, 8.6.4
	b) provide an ecological context of the soil resource by supplying a soil survey report and maps following the Soil Survey Handbook, Volume 1 (Agriculture Canada, 1987) to include adequate sampling intensity for the development footprint;	Volume 1, Section 8.6.3
	c) provide details about soil salvage indicating areas where salvage will occur (for the pads, transportation routes, and any other similar activities), the depth and volume of soil to be salvaged, soil storage locations and methods, and relate the information to predevelopment conditions;	Volume 1, Section 8.6.3
	d) provide details on area of soil replacement indicating techniques, timing, depth, volume and type of reclamation material;	Volume 1, Section 8.6.5
	e) discuss the potential to retain coarse woody debris for use in reclamation and to reduce the need for slash burning after clearing;	Volume 1, Section 8.6.3
	f) provide information about the reclaimed topography for well pads, roads, and facilities. Identify contouring objectives, drainage restoration (surface and near-surface flow) and erosion control;	Volume 1, Section 8.6.2, 8.6.3, 8.6.5
	g) discuss the methods that may be used to deal with potential soil compaction and contamination problems in the Project Areas;	Volume 1, Section 8.6.5 Volume 4, Section 9.7

Table 2.3-10 Terms of Reference Concordance Table

	h) provide a timber salvage plan, highlighting end land users and identifying proposed volumes for removal by species and year for the Project. Provide a tracking mechanism to ensure the appropriate utilization of the timber volumes by species to salvage per year, or periodically as the Project progresses. Include opportunities for timber salvage, revegetation, reforestation and harvest for the reduction of fuel hazards;	Volume 1, Section 2.3 Volume 4, Section 10.6
	i) provide a weed management plan including provisions such as those outlined in the Guidelines for Weed Management in Forestry Operations (Forest Management Division Directive – 2001-06). This will detail how North American will prevent the establishment and control the spread of restricted and noxious weeds (as listed in the Alberta Weed Control Act) within the Project Area; and	Volume 1, Section 8.6.2 Volume 4, Section 10.6
	j) provide appropriately scaled maps of the area highlighting (where possible) the preceding points.	Volume 1, Section 8 Volume 4, Section 9, 10
WATER SUPPLY, WATER MANAGEMENT AND WASTEWATER MANAGEMENT		
	Provide the following information:	
	a) how the water requirements for the Project will be met, including annual volumes from each source (for non-saline groundwater sources, follow Alberta Environment's Groundwater Evaluation Guideline);	Volume 1, Section 4.4, 5.2
	b) if non-saline water is being considered for steam generation, then a Tier 2 evaluation using the Water Conservation and Allocation Guideline for Oilfield Injection (2006) is required;	Volume 1, Section 4.3 Volume 3, Section 5.6
	c) North American's plan to meet the objectives of the Water Conservation and Allocation Policy strategy to improve the water use efficiency and productivity;	Volume 1, Section 4.4, 5.2 Volume 3, Section 5.6
	d) the design details of facilities that will handle, treat and store wastewater streams and runoff and include appropriate annual volumes;	Volume 1, Section 5.2, 5.3.4 Volume 3, Section 6.11
	e) the type and quantity of any chemicals used in water/wastewater treatment; and	Volume 1, Section 5.2.15
	f) design details for the non-saline water and sewage treatment systems for both the construction and operation stages.	Volume 1, Section 5.2.12
GROUNDWATER		
	Provide a detailed plan and implementation program for the protection of groundwater resources, addressing;	
	a) a groundwater monitoring program for early detection of potential contamination and assistance in remediation planning;	Volume 3, Section 5.8
	b) groundwater remediation options to be considered for implementation in the event that adverse effects are detected; and	Volume 3, Section 5.8
	c) a program to monitor the sustainability of groundwater production.	Volume 3, Section 5.8
SURFACE WATER		
	Provide a detailed plan and implementation program for the protection of surface water addressing:	
	a) a surface water monitoring program to assess the performance of water management systems; and	Volume 3, Section 6.12
	b) water quality monitoring program for metals and other relevant substances.	Volume 3, Section 7.8

3 APPLICATION FOR APPROVAL

Under Alberta Regulation 276/2003, Activities Designation Regulation, the proposed Kai Kos Dehseh Project is listed in Schedule 1 and is, therefore, designated as an activity for which an approval is required. The Project is also listed as requiring an Environmental Impact Assessment (EIA) under the Alberta Regulation 111/93, Environmental Assessment (Mandatory and Exempted Activities) Regulation. The information needed to satisfy the requirements for joint EUB and AENV approval is contained herein.

3.1 Existing Approvals

North American has received EUB approval for the Leismer Demonstration Hub (Approval No. 10935), which is included within the Kai Kos Dehseh Project area.

3.2 Request for Approval

With this Application, North American is seeking approval from the EUB, under Section 10 and 13 of the Oil Sands Conservation Act for recovery of bitumen from the Athabasca Oil Sands Deposit in the McMurray Formation:

- **Kai Kos Dehseh Project:** Scheme approval to construct and operate the Kai Kos Dehseh Project area, comprised of four development areas and 10 hubs, at a bitumen production capacity of 35,000 m^3/d (220,000 bpd) on an annual average calendar day basis.

    - **Leismer Commercial Hub:** amend the Leismer Demonstration Hub Approval from 1,590 m^3/d (10,000 bpd) to a commercial production of 3,180 m^3/d (20,000 bpd). Specific technical details on the Leismer Commercial Hub are provided in Appendix A, however in summary, no additional EUB Development Area is required; instead the excess capacity will be realized through accelerated and concurrent production of all well pairs approved in the Leismer Demonstration application.

    - **Leismer Expansion Hub:** amend the Leismer Commercial Hub from 3,180 m^3/d (20,000 bpd) to an expanded size of 6,360 m^3/d (40,000 bpd). Specific technical details on the Leismer Expansion are provided in Appendix B. The process used for bitumen extraction, and emulsion and water treating will be the same as for the approved Leismer Demonstration Project, with the addition of some equipment, including sulphur removal. An amended EUB development area is required as part of the approval for drilling of the additional well pairs.

    - **Corner Hub:** approval to construct and operate the Corner Hub with a bitumen production of 6,360 m^3/d (40,000 bpd). Specific technical details on the Corner Hub are provided in Appendix C. The process used for bitumen extraction, and emulsion and water treating will be same as for the approved Leismer Demonstration Project, however, the size and number of process trains will be designed for the bitumen production of 6,360 m^3/day requested capacity and will also include sulphur removal. An EUB development area for Corner is part of the approval requested.

North American hereby applies to AENV for regulatory approval for the Kai Kos Dehseh Project under Division 2 of Part 2 and Section 63 of the *Alberta Environmental Protection and Enhancement Act.*

- **Kai Kos Dehseh Project:** Approval to construct and operate the Kai Kos Dehseh Project, comprised of four development areas and 10 hubs;
    - **Leismer Commercial Hub:** Approval to amend Leismer Demonstration Hub approval and increase the bitumen production capacity by 1,590 m3/d (10,000 bpd) to 3,180 m3/d (20,000 bpd) at the Leismer Demonstration Hub, without drilling additional SAGD wells or expanding the CPF area (Appendix A).
    - **Leismer Expansion Hub:** Approval to amend the Leismer Commercial Hub and increase the bitumen production capacity by 3,180 m3/d (20,000 bpd) to 6,360 m3/d (40,000 bpd) at the Leismer Commercial Hub (Appendix B).
    - **Corner Hub:** Approval to amend the Kai Kos Dehseh Project to construct and operate the 6,360 m3/d (40,000 bpd) Corner Hub (Appendix C).

North American hereby applies to AENV for regulatory approval for the Kai Kos Dehseh Project under Division 2 of Part 2 and Part 5 of the *Alberta Environmental Protection and Enhancement Act.*

- **Kai Kos Dehseh Project:** Conservation and Reclamation Approvals to develop, operate and reclaim components of the Kai Kos Dehseh Project.

North American hereby applies to AENV for a groundwater diversion license under Part 3, Division 1 of the *Water Act*.

- **Kai Kos Dehseh Project:** to operate a groundwater well(s) as a fresh water supply for the camps and process uses including start-up and makeup water sources.

Original Signed by

Head Office:
North American Oil Sands Corporation
Suite 900, 635 - 8 Avenue SW
Calgary, Alberta T2P 3M3
www.naosc.com

Marty Proctor, P.Eng.
Senior Vice President SAGD
Phone: [403] 234-0123
Fax: [403] 234-0103

3.3 Additional Applications

Future regulatory applications will be made to the EUB and AENV to expand current hubs and to construct, operate and decommission future hubs.

North American will file applications for other aspects of the Kai Kos Dehseh Project under various other statutes. The provincial application and approval requirements applicable to this Project that will be submitted under separate cover include, but are not limited to:

- *Public Lands Act*, for surface rights;
- *Historical Resources Act*, for clearance to construct the facilities;
- *Oil Sands Conservation Act*, for future developments and amendments to previously approved hubs.
- *Pipelines Act* and *Alberta Environmental Protection and Enhancement Act*, for the construction and operation of pipelines between the central facilities and Production Pads, water supply wells, water disposal wells, fuel gas, diluent and sales pipelines;
- *Oil and Gas Conservation Act*, for well licenses; and
- *Municipal Government Act*, Part 17, for development permits from Lakeland County (Leismer and Thornbury Hubs) and the Regional Municipality of Wood Buffalo (Corner and Hangingstone Hubs) for the construction and operation of the Kai Kos Dehseh Project and related infrastructure.
- *Water Act*, for Water Diversion Licenses; and
- *Fisheries and Navigable Waters Acts*, for watercourse crossings.

4 KAI KOS DEHSEH PROJECT GEOLOGY AND RESERVOIR

4.1 Geological Description of Project Area

4.1.1 Geological Database

North American has conducted extensive geological and geophysical investigations throughout the Kai Kos Dehseh project area including 2D and 3D seismic, and extensive exploratory and delineation drilling combined with selective coring.

Approximately 270 historic wells on North American lands were drilled deep enough to evaluate SAGD potential in the McMurray Formation. North American supplemented the well coverage by drilling an additional 19 wells in 2005, 121 wells in 2006 and 153 wells in the first quarter of 2007. A total of 83 wells were cored. In Q1 2006, North American acquired 24 sections of high resolution 3D seismic and 246 km of 2D seismic. In Q1 2007, an additional 20.9 sections of 3D and 617.6 km of 2D seismic were acquired. Figure 2.2-1 shows the corehole drilling locations and location of the 3D programs.

Drilling density is variable and is being timed with planned development schedules. The immediate Leismer Demonstration Hub and Commercial Hub development area will be on 16 ha (40 acre) spacing. The Leismer Expansion Hub and Corner Hub development areas are on 32 ha (80 acre) spacing with 3D seismic. Future project areas will be drilled to quarter section spacing along with 3D seismic over the next few years and remaining infill drilling will occur about three years before actual development.

Figure 4.1-1 displays the 15 m gross SAGD pay contour for the Kai Kos Dehseh Project as reflected in the internal fall, 2006 business plan. Updated detailed maps are included in Appendices A, B and C. Updates for future hubs will be provided as they are applied for.

4.1.2 Regional Geology

The regional geological picture is for the overall Kai Kos Dehseh Project area. This evaluation is closely aligned with the EUB's review of geological data in the area presented in Report 2003-A (EUB-Athabasca Wabiskaw – McMurray Geological Study).

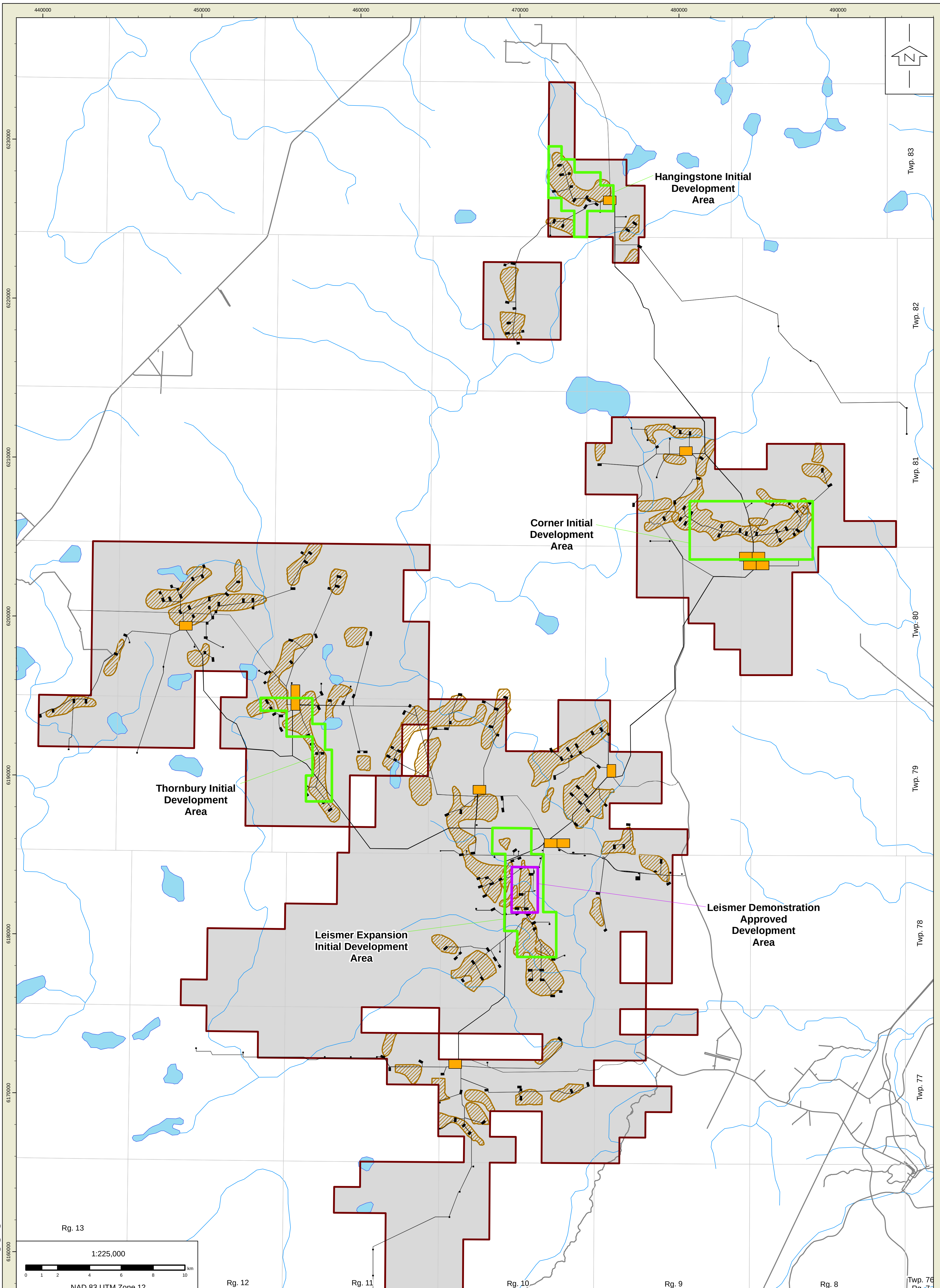
Detailed geologic and geophysical information are provided in Appendices A, B and C, for Leismer and Corner. More detailed geological and geophysical information will be provided on specific development areas in future submissions

4.1.2.1 Regional Stratigraphy

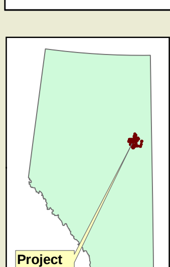
In northeastern Alberta, the Mannville Group is composed primarily of unconsolidated clastic sedimentary rocks that are divided into three formations. From oldest to youngest, these formations are the McMurray Formation, the Clearwater Formation and the Grand Rapids Formation.

The bitumen resource is in the McMurray Formation, which is the basal unit of the Lower Cretaceous Mannville Group. The McMurray Formation rests unconformably on the carbonates of the Devonian Beaverhill Lake Group. The unconformity at the base of the McMurray Formation was formed during a lengthy period of sub aerial exposure and erosion and resulted in deeply incised valleys that influenced the deposition of the lower McMurray bitumen sand reservoirs. The lower sands are fluvial in nature while the upper sediments are deposited in estuarine and interdistributary bay environments. The basic regional sequence in the project area consists of stacked progradational parasequences designated, from top down, A1, A2, B1, B2 considered to have been deposited in interdistributary bay settings. C channel deposits underlie the parasequences. McMurray estuarine channels originate at many stratigraphic levels within the stratigraphic section. If a McMurray channel is contained within two of the regional muds, it is named after the sequence it is in (a B1 channel is bound by the A2 mud and underlying B1 mud). Any channels that have cut through the B2 muds or are stacked without preserved regional muds are termed “McMurray channels”.

The Mannville Group is overlain by the shales and minor sands of the Colorado Group which are truncated in areas by pre-Quaternary erosion. The Colorado Group is overlain by Tertiary aged sand and gravel and by Quaternary glacial deposits.



I:\4455-514_NAOSC\NAOSC_Maps\FINAL_MAY_2007\Figure 4.1-2 GROSS SAGD PAY_TP_225k_20070515.mxd



Legend

- North American Lease Boundary
- ATS Township / Range
- Roads
- Lake
- Stream
- Hub (Central Plant Facility)
- Initial Development Area
- Approved Development Area
- Footprint Infrastructure (other than CPF)
- Gross SAGD Pay

Title:

GROSS SAGD PAY

NORTH AMERICAN OIL SANDS CORPORATION

Approved:	Revision Date:
RL	May 15, 2007

File: Figure 4.1-1 Gross SAGD Pay _TP_400k_20070515.mxd

Drawn by:	Checked:	Fig. No.:
LZ	RL/LZ	4.1-1

4.2 Reservoir Recovery Process

4.2.1 Reservoir Recovery Process Selection

North American will employ SAGD to recover bitumen from the McMurray formation. SAGD is an in-situ thermal process that has shown commercial viability at a number of operating projects within the province. SAGD has many technological and environmental advantages. It can economically recover on the order of 50% of the developable bitumen in place and requires less fuel for steam generation as compared to other steam processes. SAGD is a continuous process during normal operations and does not have heating and cooling cycles that could damage wellbore casings. It preserves the integrity of the reservoir cap rock because it injects steam below the pressure at which the reservoir can fracture. The process limits land disturbance and environmental impacts because it relies on horizontal wells drilled from multi-well surface pads.

North American is initially planning to develop areas with 15 m or greater of SAGD pay thickness. Areas with pay less than 15 m are being evaluated for future development and will depend on technology advancements and economic conditions at that time. Due to the immobile nature of the bitumen, areas with less than 15 m of pay will not be affected nor be stranded by the proposed developments – in fact it is anticipated that infrastructure installed for the proposed development will aid in bitumen recovery from areas with pay thinner than the current 15 m cutoff.

4.2.2 Project Resource Estimates

	Best Estimate
Original Bitumen In Place (OBIP, e^6m^3)	515
Required number of Well Pairs	736
SAGD Drainage Area (ha)	8,722
Recovery Factor (% OBIP)	46
Recoverable Bitumen (e^6m^3)	237

Note: Includes Leismer Demonstration well pairs and area

The listed resources are estimated based on existing delineation well and seismic interpretation. Total resources, including undiscovered resources are expected to be higher. Based on third party evaluations, the potential recoverable resources could be in the order of 320 to 635 e^6m^3 (2 to 4 billion barrels). The development of these additional resources beyond the levels identified in this application would likely result in an extension of the operating life of the development areas. Although SAGD recovery is among the highest of any known commercial resource recovery process, North American will continue to evaluate new or additional commercially viable processes that can increase resource recovery.

4.2.3 Description of the Process Used

4.2.3.1 Steam Assisted Gravity Drainage

The SAGD process involves drilling two long horizontal wells that are separated vertically by approximately 5 m. The upper wellbore is used to inject steam into the reservoir. The injected steam adds energy in the form of heat to the reservoir, mobilizing the bitumen. The mobilized bitumen then flows by gravity to the lower production wellbore where fluids are gathered and brought to surface.

The SAGD process can be categorized by three general operating phases: startup, production and blowdown. The startup process involves circulating steam into both the injection and production wellbores until thermal communication is established between the pair, typically occurring after approximately 90 days of circulation. The production phase involves continuous steam injection into the upper wellbore with concurrent bitumen production from the lower production well. The production phase typically runs until the costs of steam injection and associated production operations can not be offset by the revenues of bitumen production. The final phase is blowdown. Currently the injection of non-condensable gases is the leading candidate to optimize bitumen recoveries through the blowdown phase. Steam injection is shut down and replaced by non-condensable gas injection into the injection well. Non-condensable gas injection is used to maintain steam chamber pressures and support continuing bitumen production from the lower production well. The blowdown phase would continue until the costs of gas injection and associated production operations cannot be offset by the revenues of bitumen production. North American will continue to investigate other blowdown process options to maximize the economic recovery of bitumen.

4.2.3.2 Well Pair Placement

In reservoir areas with no bottom water or lower transition zones it is North American’s intention to place the SAGD production well as close to the base of the clean porous sand as possible, generally within 1 m to 3 m of the reservoir base. In reservoir areas with gradual transition between bottom water and bitumen the horizontal producers will be placed above the transition zone. This position results in a relatively high recovery factor with less risk of encountering problems with horizontal drilling operations (i.e., lost circulation). In areas with thick bottom water (> 5 m), the producer position may be adjusted upwards to approximately 3 m to 5 m above the oil water contact. Under these conditions, numerical model sensitivity studies show recoveries will be better with a slightly higher well pair placement. The higher placement limits the amount of heat lost to the bottom water and reduces the amount of bitumen draining and lost into the water zone. In all areas, SAGD production wells will be allowed to deviate a few metres up or down to maximize resource recovery wherever possible.

4.2.3.3 Reservoir Modelling

The SAGD recovery process was modelled using CMG’s STARS thermal reservoir simulator. Single SAGD well pair models as well as larger 3 to 6 well pair SAGD pad models were developed. Model flow properties were derived from North American’s log analyses specific to the region of investigation.

SAGD well pair models were built with 3 to 10 columns along the length of a well pair to capture variations in reservoir geology. Single well pair models are generally built on a half element of symmetry and contain a no-flow boundary at the assumed well pair width. Larger pad models were also developed in some cases to remove the no-flow assumption and better represent the impacts of inter-well communication on the SAGD depletion process.

SAGD depletion modelling assumed steam chamber pressures on the order of 2,500 kPa but may be further optimized based on future field performance.

4.2.3.4 Reservoir Surveillance

A fundamental component of North American's reservoir surveillance strategy is the installation and operation of observation well networks within the SAGD development areas. Observation well networks are comprised of pressure and temperature observations wells and are designed to monitor the main SAGD interval as well as connected intervals above and below prospective bitumen. Knowledge of bottom and top zone pressures are essential for properly balancing SAGD operations with adjacent zones in direct communication. SAGD operations are generally balanced with bottom water pressures to prevent a massive influx of bottom water from low SAGD pressures or a massive leak off of steam from high SAGD pressures. The same is true for top zones that are not fully bitumen saturated (top water or top gas). Like bottom water, these top lean zones generally have high fluid mobility and impose similar operating pressure constraints on the SAGD process. It is believed that pressure monitoring can be an effective tool in identifying communication between an associated gas cap and an underlying SAGD operation. Temperature monitoring wells are used primarily to quantify steam chamber growth at a fixed point in the reservoir. Temperature data is generally more applicable to SAGD optimization than to determining communication between a SAGD operation and an overlying gas zone due to the point source nature of the data. Thermocouples register temperature changes that occur in very close proximity to the wellbore and, unlike pressure observation wells, have limited lateral applicability.

It is North American's intent to design, install and commission pressure monitoring networks approximately 1 to 2 years prior to the onset of SAGD operations. This advanced installation gives adequate time for the instruments to equalize and acquire reliable baseline pressure data. Pressure data will be periodically downloaded prior to SAGD operations. After SAGD operations have been initiated most pressure and temperature data streams will be connected to the facility data archive system and be available in real time.

4.2.3.5 Surface Heave

Thermal operations will generate surface heave due to the thermal expansion of the reservoir and possibly pressure dilation. Unlike pressure depletion methods or cyclic steaming methods, SAGD tends to effect slow continuous surface heave rather than subsidence or cycles of heave and subsidence. This has been documented in other projects, the UTF project being of particular note as it is also SAGD. Surface heave may occur over the length of the horizontal well section. Heave is predicted to occur gradually, be localized to the horizontal well section and the transition area between heave and non heave affected ground will have a low slope angle.

During the selection of the CPF sites, the potential for surface heave was considered as it poses a risk to the facilities. The sites shown in this application are mostly positioned over areas of low probability for recovery of bitumen.

4.3 Hydrogeology

4.3.1 Hydrostratigraphy

Hydrostratigraphy provides a classification of the geological units according to hydrogeological characteristics. The geological column for the region, shown on the left hand side of Figure 4.3-1, has been arranged into a series of aquifers and aquitards, based on the relative hydraulic characteristics of each unit or adjacent units. Six aquifers have been identified in the region as being feasible for providing the Kai Kos Dehseh Project with some or all of its groundwater demand and meeting some or all of its disposal requirements. These aquifers are listed below (with increasing depth) and are discussed in Sections 4.3.3 to 4.3.7.

i. Empress Terrace Aquifer

ii. Empress Channel Aquifer

iii. Lower Grand Rapids Aquifer

iv. Clearwater A Aquifer

v. Clearwater B Aquifer

vi. Basal McMurray Aquifer

vii. Grosmont Aquifer

4.3.2 Methodology

North American has updated its geology since the Application for the Leismer Demonstration Project. Updated geology focussed on the Mannville Group (including the Grand Rapids, Clearwater and McMurray Formations) from Township 75, Range 6 to Township 83, Range 14.

All well logs available within North American leases were reviewed. Outside of North American leases, all well logs with geology documented down to the Devonian deposits were reviewed. In all, over 1,600 well logs in the Kai Kos Dehseh Project area were used to update geological mapping of the Mannville Group.

The geology review process paid particular attention to the Lower Grand Rapids, Clearwater A, Clearwater B and Basal McMurray Aquifers. The determination of these aquifers was based on the following criteria;

- less than 60 API gamma response;
- greater than 30% density porosity;
- resistivity less than 10 Ω (Basal McMurray Aquifer only); and
- good spontaneous potential response.

4.3.3 Empress Formation Aquifers

The Empress Formation is defined as all stratified sediments that rest on bedrock and are covered by the first occurrence of glacial till in the area (Andriashek, 2003). These drift sediments consist of Tertiary age “stratified gravel, sand, silt and clay of fluvial, lacustrine, and colluvial origin” (Whitaker and Christiansen, 1972) and exist within bedrock channels (channel aquifer) and on bedrock terraces or interfluve benches (Terrace Aquifer).

The Empress Channel and Empress Terrace Aquifers are important regional aquifers beneath the Project area. Isopach maps of the Empress Channel and Terrace Aquifers are provided as Figures 4.3-2 and 4.3-3.

Groundwater in the Empress Aquifers is considered to be non-saline with total dissolved solids (TDS) concentrations expected to be less than 1,000 mg/L. Testing of the North American 11-14-78-9 W4M camp water supply well identified TDS concentrations of 748 mg/L and 816 mg/L.

4.3.4 Lower Grand Rapids Aquifer

The Grand Rapids Formation of the upper Mannville Group represents a regional regression event (Bachu et al., 1993). The lower portion of the Grand Rapids Formation consists primarily of thick sandstone bounded at the top and bottom by shale (Bachu et al., 1993). This sandstone is regionally extensive in the Kai Kos Dehseh Project area with thicknesses ranging from 15 m to 45 m (Figure 4.3-7). Groundwater in the Lower Grand Rapids Aquifer is considered to be non-saline with expected total dissolved solids concentrations ranging from 1,000 mg/L to 3,500 mg/L (Figure 4.3-5). Tests conducted by North American, during the winter of 2007, identified TDS concentrations in the Lower Grand Rapids Aquifer ranging from 1,340 mg/L to 1,520 mg/L.

4.3.5 Clearwater A and B Aquifers

The Clearwater Formation is composed of several thick, coarsening-upwards, sand successions each separated by thin shale layers (Hitchon et. al., 1989). Beneath the Kai Kos Dehseh Project area, there are two substantial sand bodies in the Clearwater Formation known as the Clearwater A and B Aquifers (Maher, 1989). The Clearwater B Aquifer is restricted to beneath the southern portion and the Clearwater A Aquifer is limited to beneath the far northern portion of the Kai Kos Dehseh leases. Clearwater A and B isopachs are provided on Figures 4.3-6 and 4.3-7. The maximum thickness of the Clearwater A and B aquifers is approximately 30 m and 40 m, respectively.

Groundwater in the Clearwater Aquifers is considered to be transitional between non-saline and saline with expected TDS concentrations ranging from 2,500 mg/L to 8,000 mg/L. Salinity maps for the Clearwater A and B are shown in Figures 4.3-8 and 4.3-9. Tests conducted by North American, during the winter of 2007, identified TDS concentrations in the Clearwater B Aquifer ranging from 6,340 mg/L to 7,610 mg/L.

4.3.6 Basal McMurray Aquifer

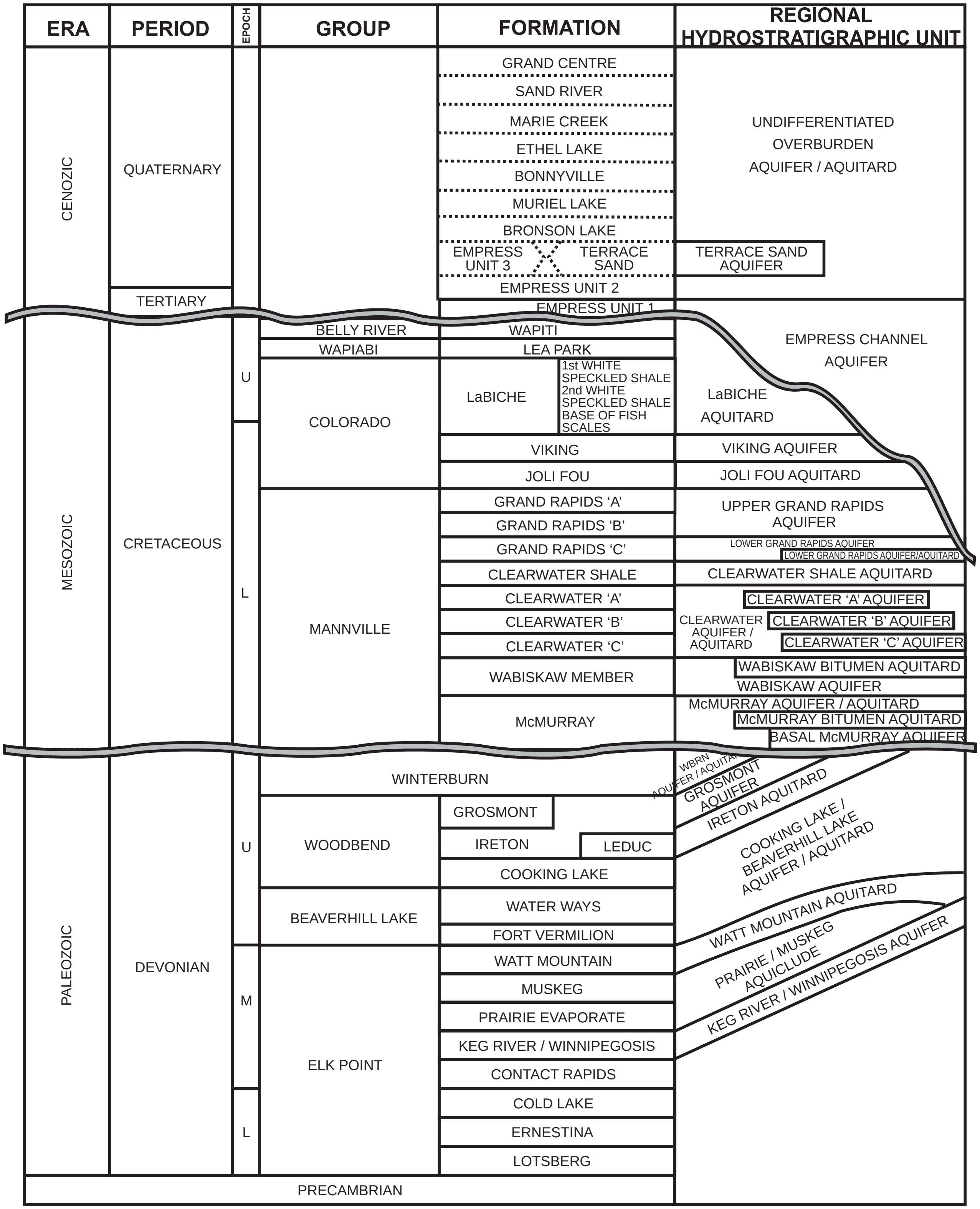
The McMurray Formation consists predominantly of fluvial and estuarine sediments deposited in the valleys of the sub-Cretaceous Unconformity surface (Hitchon et. al., 1989). The lower sands of the McMurray Formation are fluvial in nature. Fluvial sands that are water saturated are referred to as the Basal McMurray Aquifer. An isopach map of the Basal McMurray Aquifer is provided as Figure 4.3-10. Beneath the Kai Kos Dehseh Project area, the Basal McMurray is somewhat discontinuous with thicknesses generally less than 10 m. However, east of Range 7 the Basal McMurray is regional in extent and has a thickness of up to 40 m.

Groundwater in the Basal McMurray Aquifer is considered to be saline with TDS concentrations ranging from 10,000 mg/L to 15,000 mg/L. Figure 4.3-11 illustrates Basal McMurray Aquifer salinity. Tests conducted by North American, during the winter of 2007, identified TDS concentrations in the Lower Grand Rapids Aquifer ranging from 10,700 mg/L to 13,500 mg/L.

4.3.7 Grosmont Aquifer

The Grosmont Formation carbonate platform represents the uppermost Devonian deposits for the extreme west portion of the Kai Kos Dehseh Project area (Bachu et al., 1993). Given the permeability of the Grosmont Formation it is considered an aquifer. Bachu (page 30, 1993) postulates that if there is hydraulic continuity between the Grosmont Aquifer and aquifers located above it, the Grosmont Aquifer may act as a drain.

Groundwater in the Grosmont Aquifer is considered to be saline with TDS concentrations in excess of 10,000 mg/L.



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Approved: LP	Revision Date: 07/05/22
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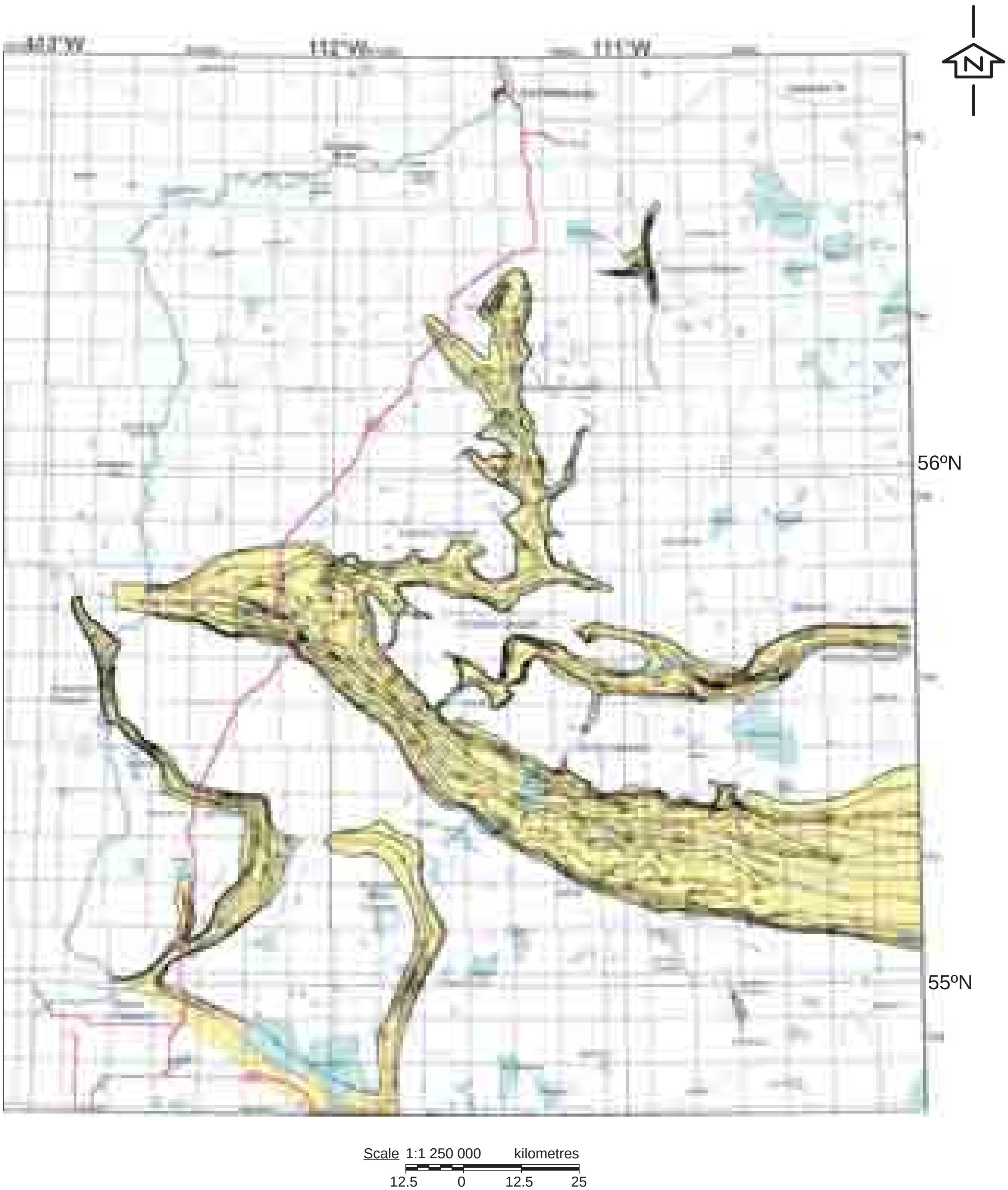

SOURCE: EUB/AGS Earth Sciences Report 2002-03, *"Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Area, Northeast Alberta"*.

Title:

EMPRESS CHANNEL SAND ISOPACH

Approved: LP	Revision Date: 07/05/22
File: 4455-Empress-07.cdr	

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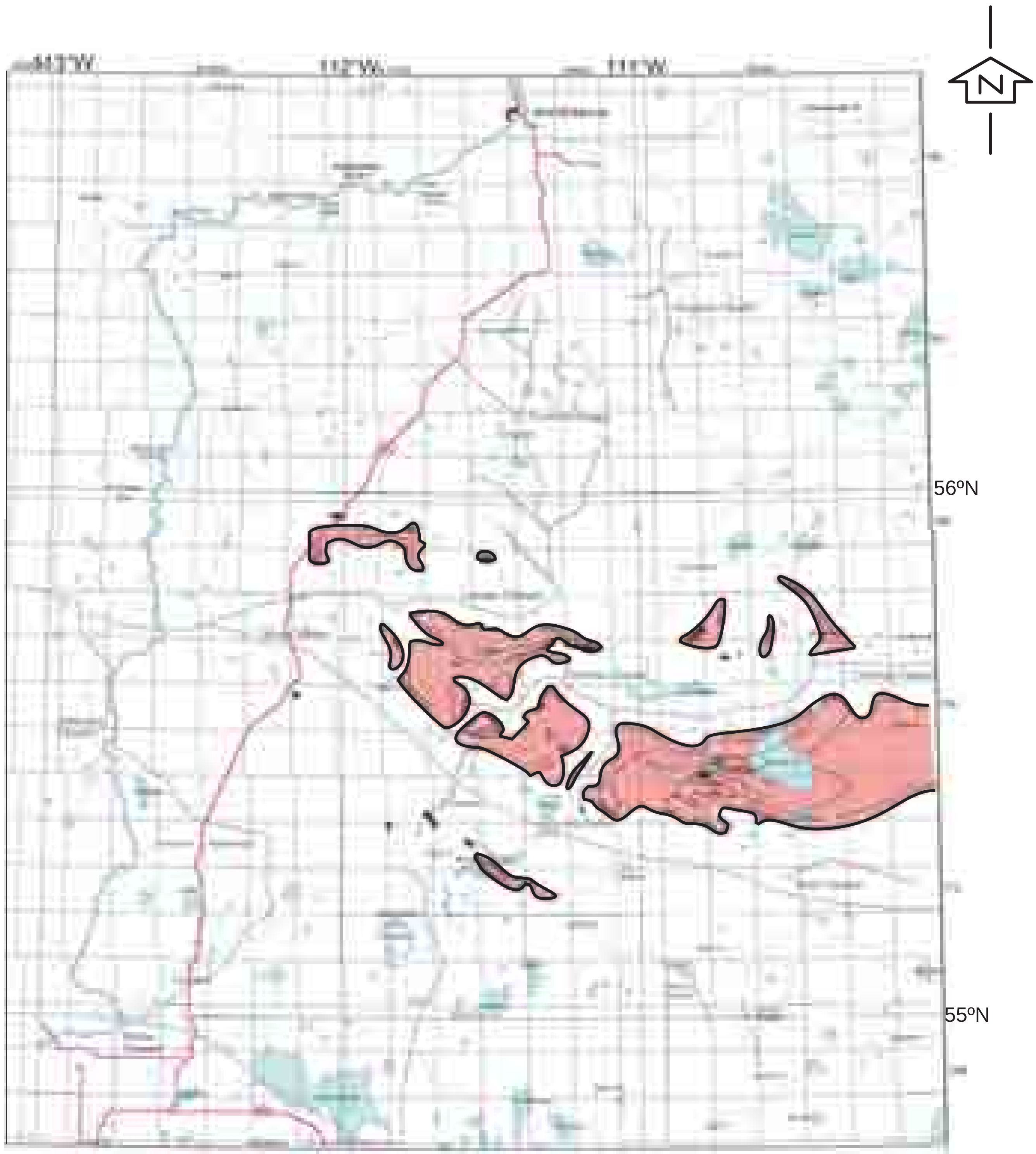
GDE	BW	**4.3-2**



Scale 1:1 250 000 kilometres

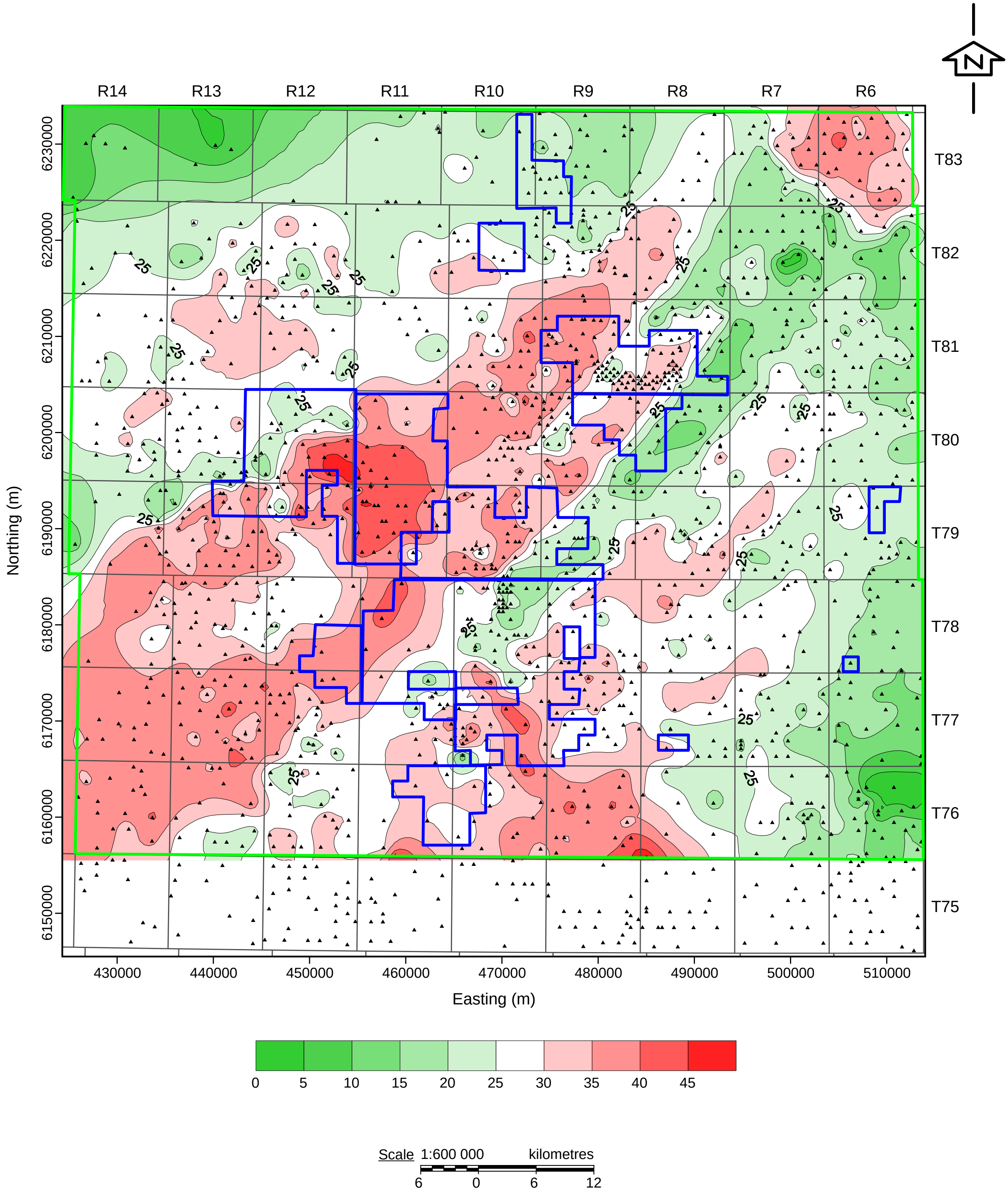
12.5 0 12.5 25

SOURCE: EUB/AGS Earth Sciences Report 2002-03, *"Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Area, Northeast Alberta"*.

Title:

EMPRESS TERRACE SAND ISOPACH

Approved: LP	Revision Date: 07/05/22	
File: 4455-Empress-07.cdr		
Drawn by: GDE	Checked: BW	Fig. No.: **4.3-3**



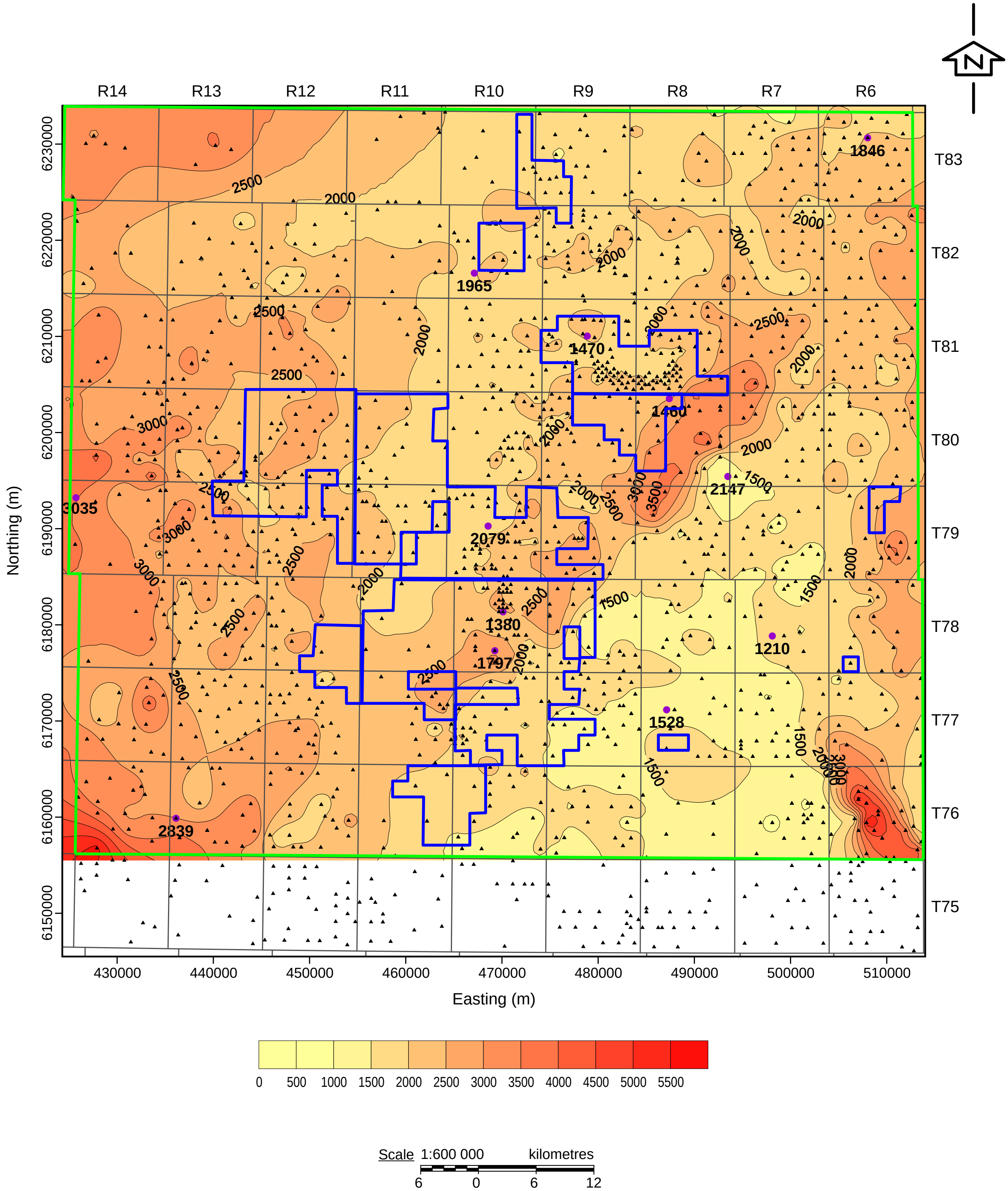
LEGEND
KAI KOS DEHSEH PROJECT
LOCAL STUDY AREA (LSA)

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

GRAND RAPIDS C UNIT POROUS SAND ISOPACH

Approved: EG	Revision Date: 07/05/22	
File: 4455-Struct2-07.cdr		
Drawn by: AP	Checked: EG	Fig. No.: **4.3-4**



LEGEND

- KAI KOS DEHSEH PROJECT
- GROUNDWATER SAMPLE
- LOCAL STUDY AREA (LSA)

NOTE:
Groundwater sample points were not honoured in contouring. Value shown for general correlation purposes.

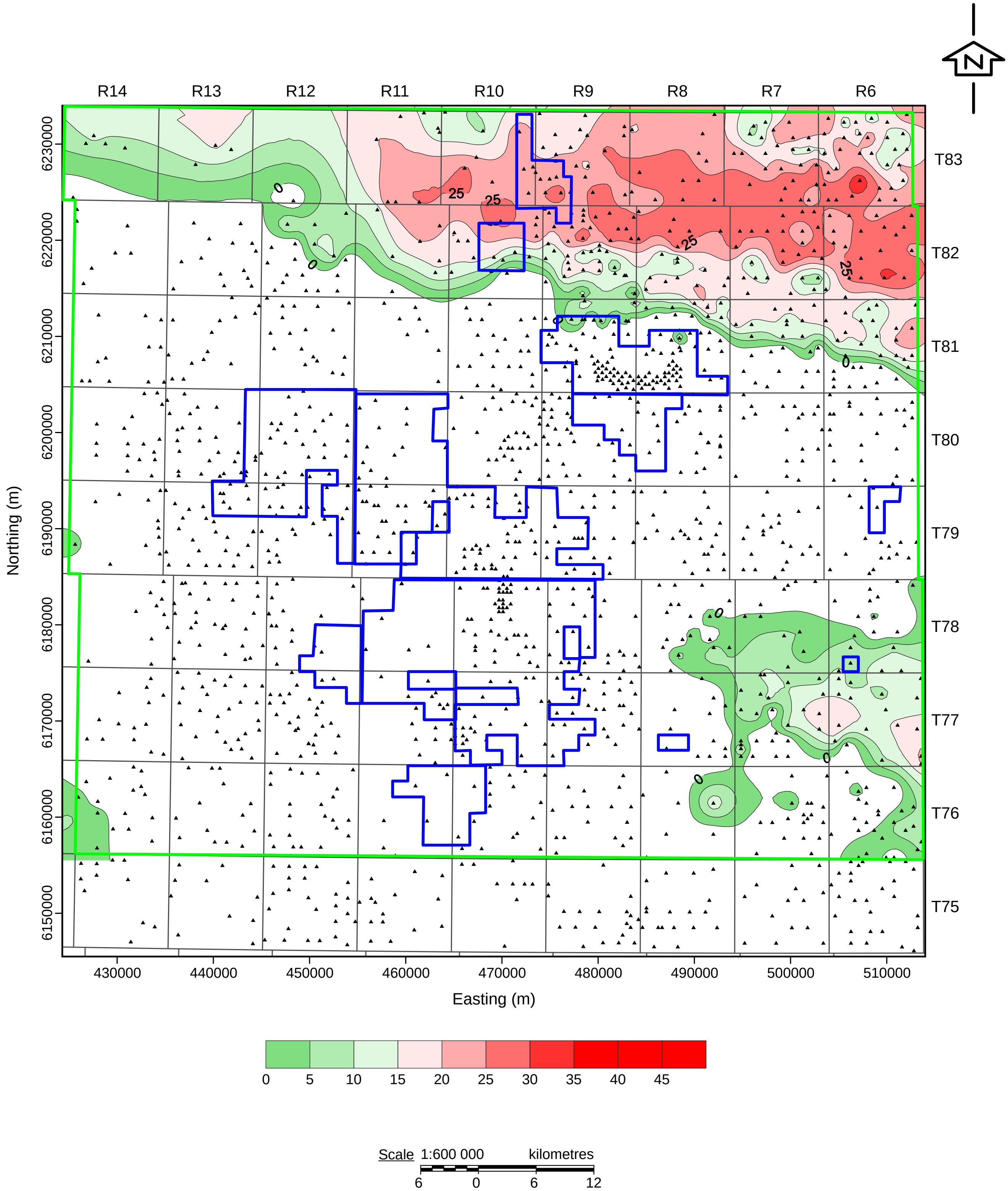
REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

LOWER GRAND RAPIDS AQUIFER SALINITY

Approved: EG	Revision Date: 07/05/22
File: 4455-Struct2-07.cdr	

Drawn by:	Checked:	Fig. No.:
AP	EG	**4.3-5**



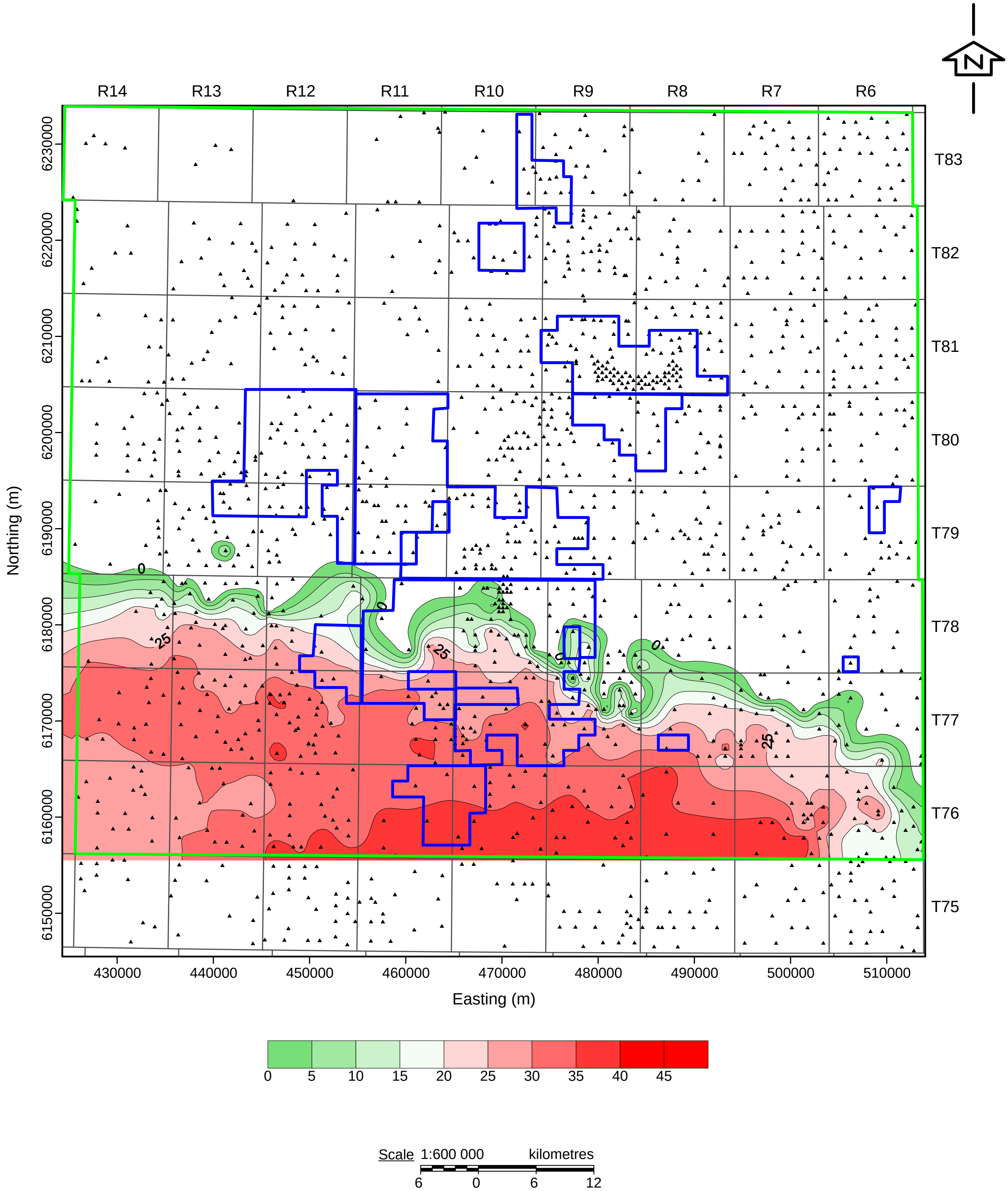
LEGEND
KAI KOS DEHSEH PROJECT
LOCAL STUDY AREA (LSA)

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

CLEARWATER A POROUS SAND ISOPACH

Approved: EG	Revision Date: 07/05/22	
File: 4455-Struct2-07.cdr		
Drawn by: AP	Checked: EG	Fig. No.: **4.3-6**



LEGEND
KAI KOS DEHSEH PROJECT
LOCAL STUDY AREA (LSA)

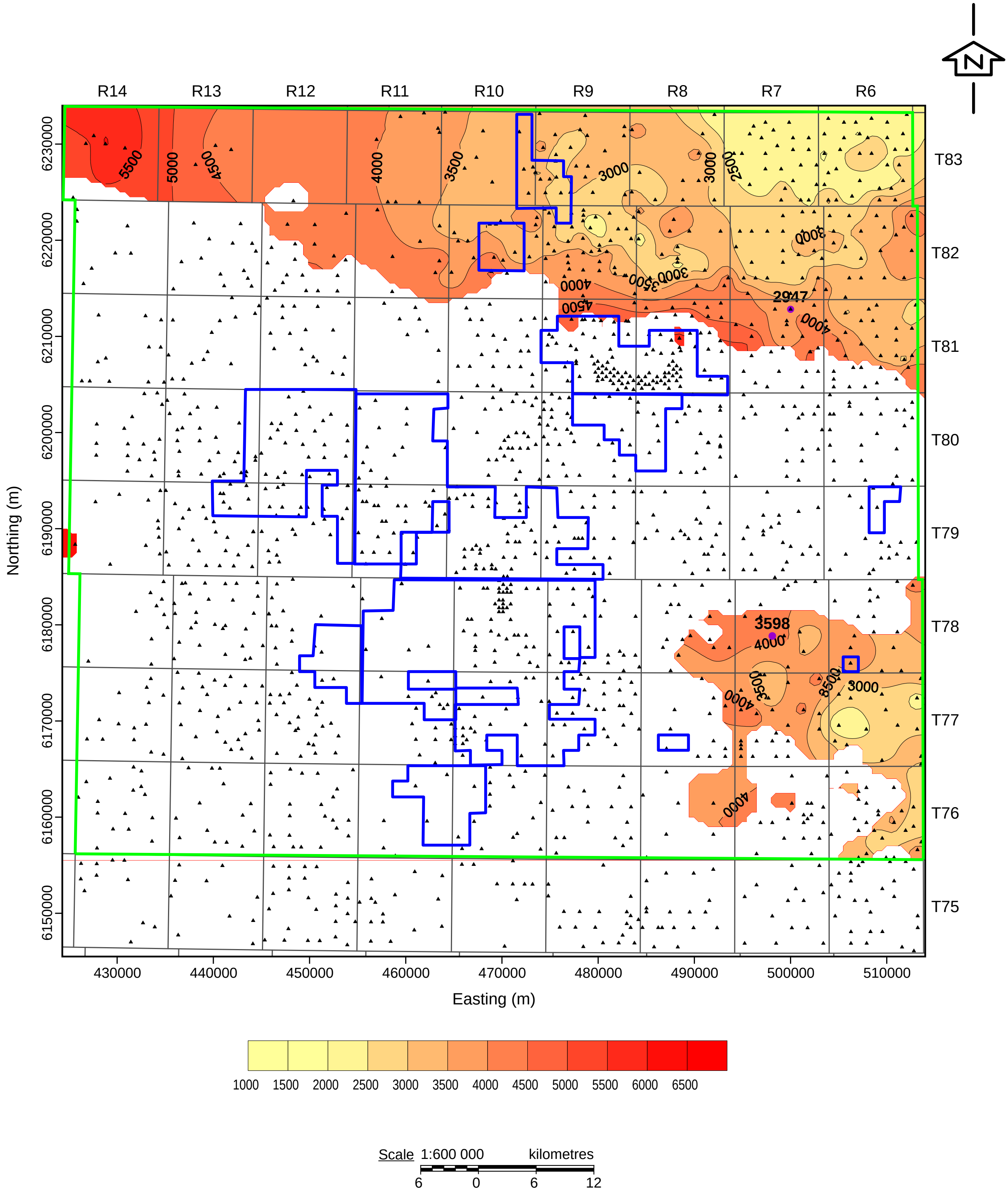
REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

CLEARWATER B POROUS SAND ISOPACH

Approved: EG	Revision Date: 07/05/22
File: 4455-Struct2-07.cdr	

Drawn by:	Checked:	Fig. No.:
AP	EG	**4.3-7**



LEGEND

- KAI KOS DEHSEH PROJECT
- GROUNDWATER SAMPLE
- LOCAL STUDY AREA (LSA)

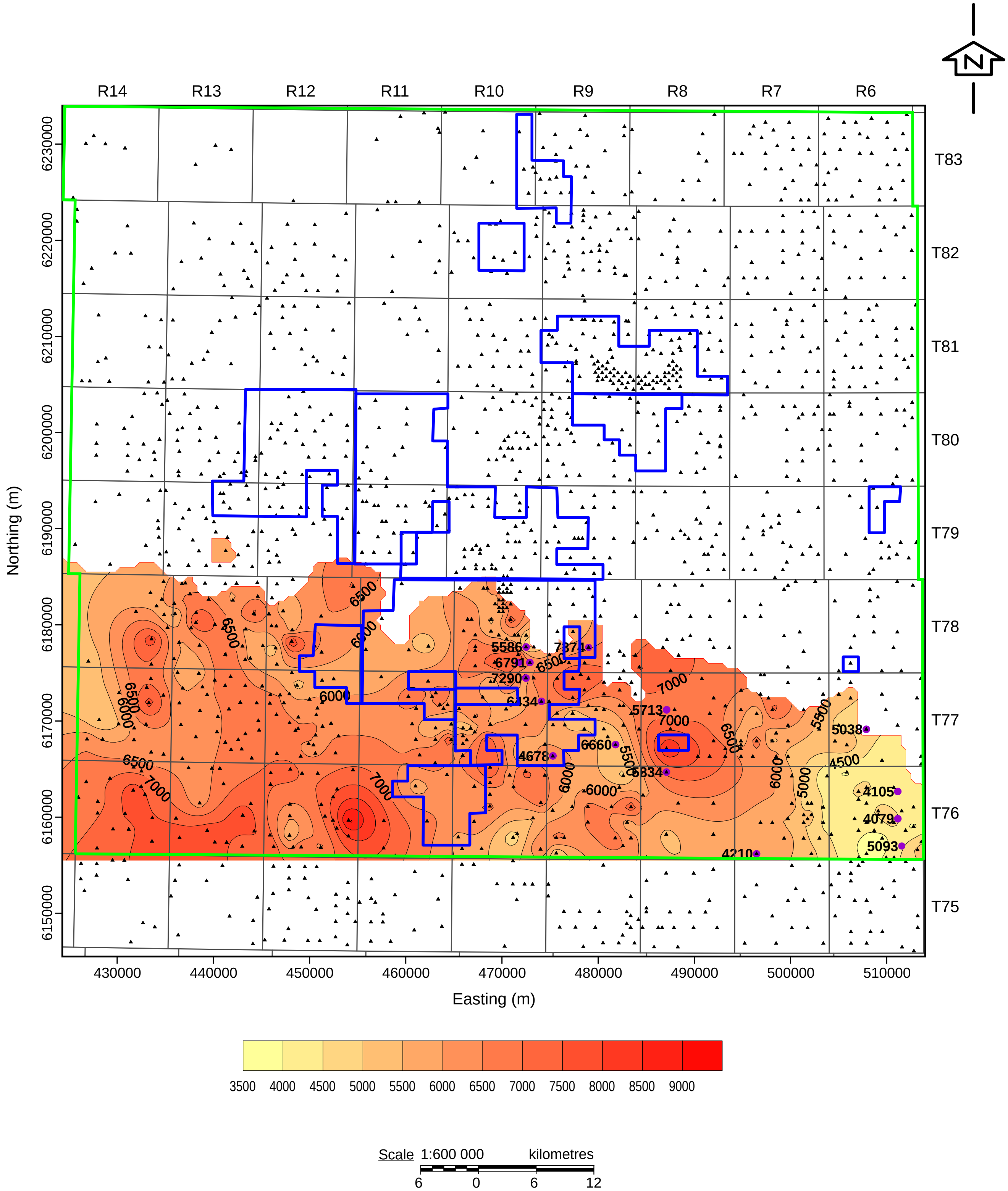
NOTE:
Groundwater sample points were not honoured in contouring. Value shown for general correlation purposes.

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

CLEARWATER A AQUIFER SALINITY

Approved: EG	Revision Date: 07/05/22	
File: 4455-Struct2-07.cdr		
Drawn by: AP	Checked: EG	Fig. No.: **4.3-8**



LEGEND

- KAI KOS DEHSEH PROJECT
- GROUNDWATER SAMPLE
- LOCAL STUDY AREA (LSA)

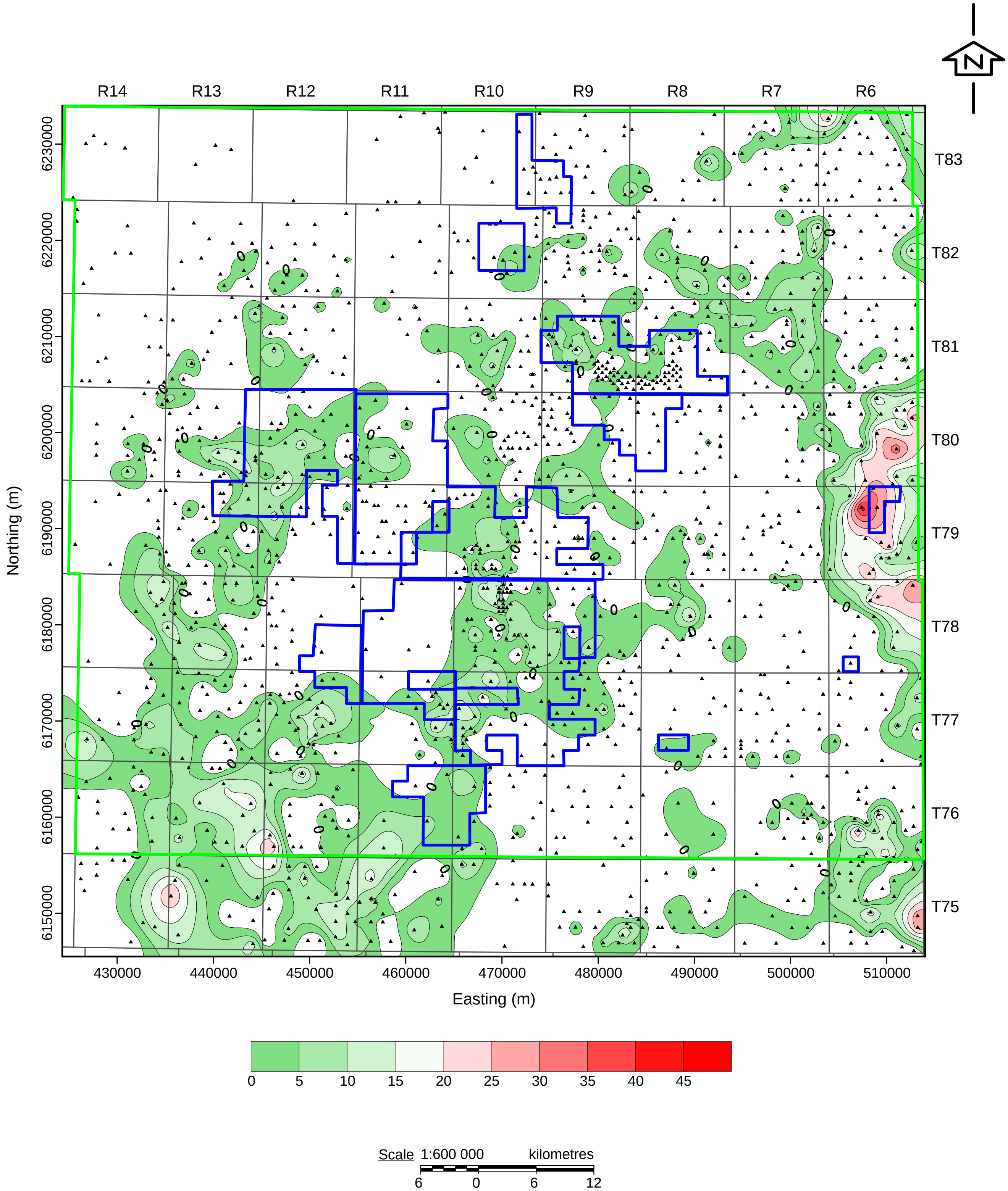
NOTE:
Groundwater sample points were not honoured in contouring. Value shown for general correlation purposes.

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

CLEARWATER B AQUIFER SALINITY

Approved: EG	Revision Date: 07/05/22	
File: 4455-Struct2-07.cdr		
Drawn by: AP	Checked: EG	Fig. No.: **4.3-9**



LEGEND

KAI KOS DEHSEH PROJECT

LOCAL STUDY AREA (LSA)

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

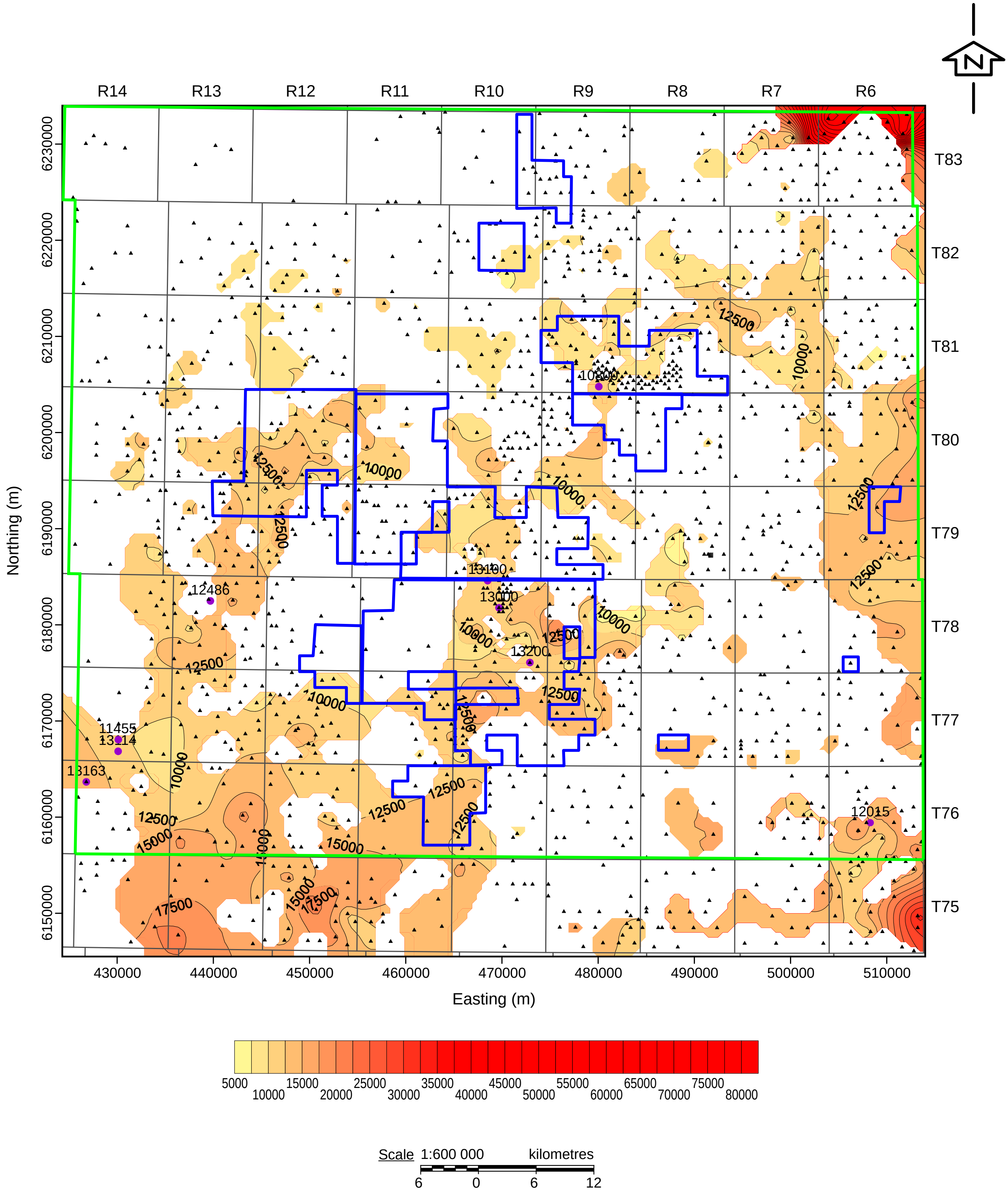
Title:

BASAL McMURRAY AQUIFER ISOPACH

Approved: EG	Revision Date: 07/05/22

File: 4455-Struct2-07.cdr

Drawn by: AP	Checked: EG	Fig. No.: **4.3-10**



LEGEND
- KAI KOS DEHSEH PROJECT
- GROUNDWATER SAMPLE
- LOCAL STUDY AREA (LSA)

NOTE:
Groundwater sample points were not honoured in contouring. Value shown for general correlation purposes.

REFERENCE: Regional Aquifer and Geology Mapping Study of the Mannville Group, Ranges 6 to 14, Townships 75 to 83, W4. April 2007, prepared by Westwater Environmental Ltd.

Title:

BASAL McMURRAY AQUIFER SALINITY

Approved: EG	Revision Date: 07/05/22	
File: 4455-Struct2-07.cdr		
Drawn by: AP	Checked: EG	Fig. No.: **4.3-11**

4.4 Source Water and Disposal Management Plan

4.4.1 Principles and Concepts

The Project source water and disposal management plan is based on the following principles and concepts.

- The disposal system is intended for excess OTSG blowdown.
- On an annual average basis, greater than 90% produced water recycle will be achieved after the start-up phase. Interconnecting pipelines between the CPFs are planned to balance water needs amongst the facilities and minimize disposal.
- Water will be supplied from the McMurray, Clearwater and Grand Rapids Formations.
- Water disposal will be into the Basal McMurray Aquifer. The concept is based on balanced push-pull into/from the Basal McMurray Aquifer without impacting resource recovery.
- Water treatment process is warm lime softening followed by two stage weak acid cation exchange. Alternative technologies such as evaporators and membrane processes will be monitored and assessed for potential application in future CPFs.
- Compliance with the Water Conservation and Allocation Guideline 2006 for Oilfield Injection.
- As applications are submitted for each new hub and/or development area expansion, the water reuse processes, water balances, water sources and disposal plans will be detailed.

4.4.2 Source and Disposal Requirements

Table 4.4-1 summarizes the estimated overall source water and disposal requirements for the development based on the Mannville Group isopachs and the assumptions listed above.

Table 4.4-1 Long-term Make-Up and Disposal Requirements - Balanced Push-Pull

			WLS + WAC Process				
			Source			Disposal	
	Size		Grand Rapids	Clearwater	Basal McMurray	Basal McMurray	
	Kbpd	Start Date	m^3/d	m^3/d	m^3/d	m^3/d	End Date
Leismer (Demonstration and Commercial)	20*	2009/2010	980		950	950	2029
Leismer Expansion	20	2011	980		950	950	2029
Corner	40	2012	1,960		1,900	1,900	2037
Thornbury	40	2013	1,960		1,900	1,900	2038
Corner Expansion	40	2014		1,960	1,900	1,900	2039
Hangingstone	20	2016		980	950	950	2041
Thornbury Expansion	20	2017	980		950	950	2042
Northwest Leismer	20	2018		980	950	950	2043
South Leismer	20	2029		980	950	950	2054
Total*	220**		6,860**	3,920**	10,450**	10,450**	

Notes:

* Includes 10,000 bpd Leismer Demonstration Hub requirements.

** Totals do not include the South Leismer Hub.

4.4.3 Aquifer Evaluation

An evaluation of each aquifer in the region in terms of meeting supply and disposal requirements for the Project is summarized on Table 4.4-2.

Table 4.4-2 Aquifer Evaluation

Aquifer	Source		Disposal	
	Pros	**Cons**	**Pros**	**Cons**
Empress Terrace Aquifer	shallow, cost effective access	non - saline groundwater (TDS<1,000 mg/L)	shallow, cost effective access	non - saline groundwater (TDS<1,000 mg/L)
Empress Channel Aquifer	shallow, cost effective access	non - saline groundwater (TDS<1,000 mg/L)	shallow, cost effective access	non - saline groundwater (TDS<1,000 mg/L)
Lower Grand Rapids Aquifer	proven groundwater source in region	non - saline groundwater (TDS 1,000 to~3,500 mg/L)	shallow, cost effective access	non - saline groundwater
Clearwater A Aquifer	near saline (TDS ~4,000 mg/L)	spatially limited to the north, gas, limited regional production history	near saline (TDS ~4,000 mg/L)	spatially limited to the north, gas
Clearwater B Aquifer	near saline (TDS ~4,000 mg/L)	spatially limited to the south, gas and swelling clay issues, limited regional production history	near saline (TDS ~4,000 mg/L)	spatially limited to the south, gas and swelling clay issues
Basal McMurray Aquifer	saline and thick to the east of the Project	limited extent locally, impacts to bitumen production possible, high TDS	saline and thick to the east of Project	limited extent locally, impacts to bitumen production possible
Grosmont Aquifer	saline and away from the bitumen production	located on extreme western edge of Project, deep, high TDS	saline and away from bitumen production	located on extreme western edge of Project, deep

4.4.4 Groundwater Supply and Wastewater Disposal Scheme

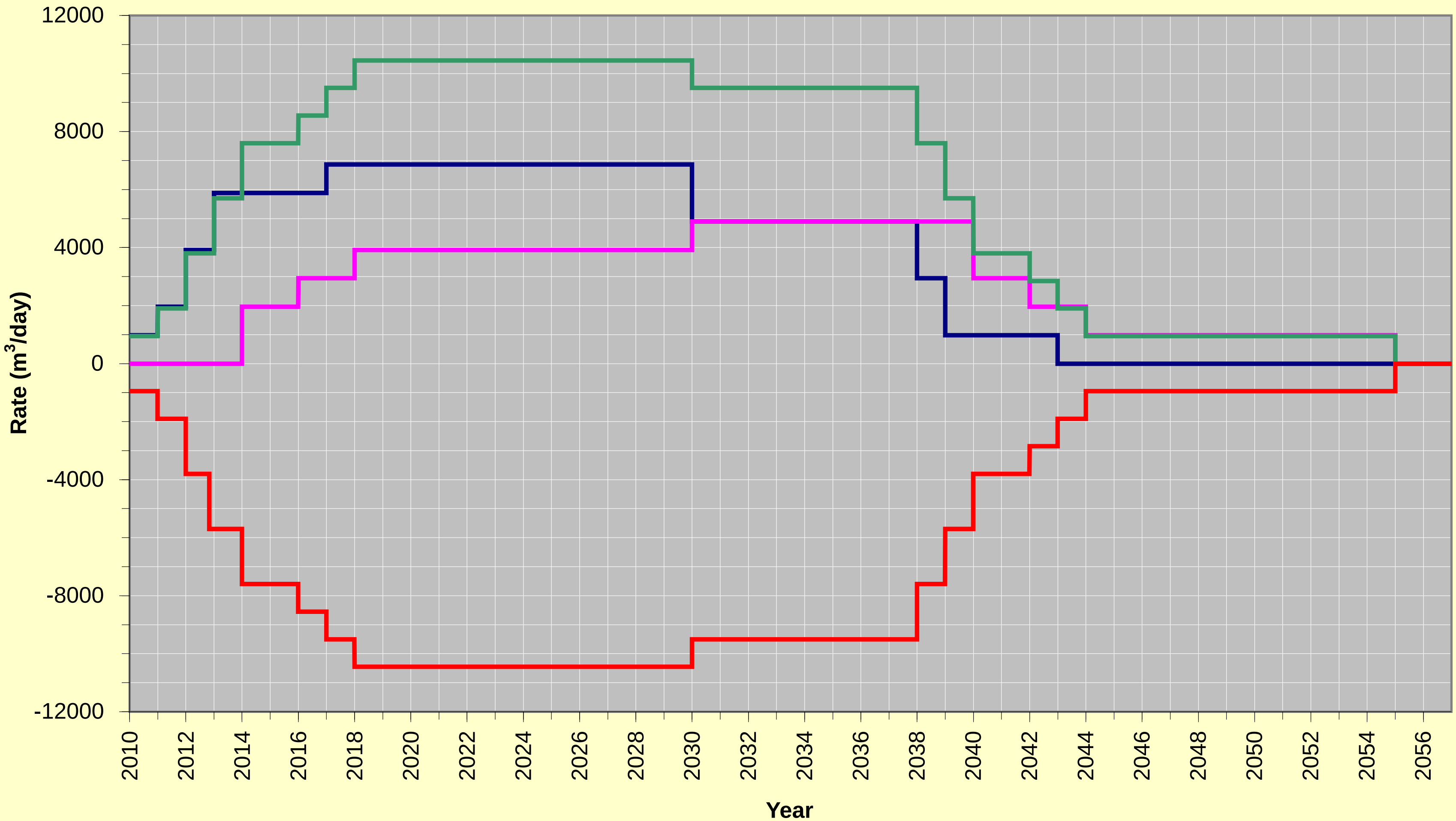
Based on the aquifer evaluation (Section 4.3.1), the Empress Channel and Terrace Aquifers are not considered for the Project because they contain potable groundwater. As previously indicated, Quaternary water would only be used for domestic, camp and utility water use. North American does not consider using water from this aquifer, for steam generation purposes, as an appropriate use of the water resource. The Grosmont Aquifer is also not considered suitable for the Project due to its location relative to the planned development. The cost for infrastructure and drilling makes it an uneconomic water source or disposal formation. In addition, no Grosmont anomalies have been seen on 2D or 3D seismic in the more immediate Project area.

The Basal McMurray Aquifer was chosen as the primary groundwater source for make-up water because the Basal McMurray Aquifer was interpreted to have the lowest potential for adverse environmental effects of the candidate aquifers due to the depth and saline nature of the aquifer. Groundwater from the Basal McMurray Aquifer in the LSA is quite saline (>10,000 mg/L TDS) and is unsuitable for potable water supply. The main disadvantage of the Basal McMurray Aquifer as a groundwater source is that it has variable thickness and is not laterally extensive in the LSA. North American proposes a balanced push-pull approach where groundwater withdrawal equals wastewater disposal in the Basal McMurray Aquifer in order to minimize pressure change in the aquifer. The target groundwater withdrawal rates for the McMurray Aquifer for each of the development areas ranges from 950 m^3/day at the Hangingstone and Thornbury development areas to 2,850 m^3/day at the Leismer development areas (Table 4.4-1)

North American also proposes that make-up water be sourced from the Clearwater A and B Aquifers. As discussed in Volume 3 Section 5.5 (Hydrogeology), the salinity of the Clearwater A and B Aquifers is variable throughout the LSA and contains both saline and non-saline groundwater and contains local accumulations of natural gas. The Clearwater A and B Aquifers are also not present throughout the entire LSA. North American proposes to source groundwater from the Clearwater A and Clearwater B aquifers where they are present and the target groundwater withdrawal rates for the Clearwater aquifers for each development area are listed in Table 4.4-1.

North American also proposes that make-up water also be sourced from the Lower Grand Rapids Aquifer to supplement water demand. Groundwater from the Lower Grand Rapids Aquifer is non-saline but unsuitable for potable water supply because of moderate TDS concentrations. The regional nature of the aquifer makes it the only aquifer that is present beneath the entire Project and therefore the only sustainable candidate aquifer for some areas. The target groundwater withdrawal rates for the Lower Grand Rapids Aquifer for each development area are listed in Table 4.4-1.

North American proposes that all wastewater be disposed/injected into the Basal McMurray Aquifer. The Basal McMurray Aquifer was chosen based on depth and groundwater chemistry (>10,000 mg/L TDS). In addition, wastewater injection into the Basal McMurray Aquifer is balanced with the Basal McMurray Aquifer target pumping rates for each development area and will offset pressure reductions due to make-up water withdrawal (Table 4.4-1).



Lower Grand Rapids Aquifer | Clearwater A and B Aquifers (Total)
Basal McMurray Aquifer Pumping | Basal McMurray Aquifer Injection

Title: KAI KOS DEHSEH PUMPING SCHEDULE		
Approved: RP	Revision Date: 07/06/02	
File: 4455-ImpAssess-07.cdr		
Drawn by: GDE	Checked: BW	Fig. No.: 4.4-1

4.5 Evaluation of the Water Reuse Alternatives

The water reuse treatment system for the Project is one of the most critical components of the SAGD project, since the water required is approximately three times the bitumen production rate, and the consequences of off-spec boiler feedwater can result in costly failures of the OTSGs. In addition, in order to conserve water resources, a minimum 90% recycle rate is strongly suggested by the EUB, as well as the use of saline make-up water.

In view of the above, North American considered the following water reuse alternatives:

- A comparison of hot lime, warm lime and Densadeg softening for the main treating unit in the conventional reuse treating train;
- Evaporation of the produced water compared to warm lime softening plus weak acid cation ion exchange conventional treatment system; and
- Saline water make-up.

In all cases, OTSGs were assumed as the steam raiser, since the use of utility boilers for raising steam using evaporator distillate from produced water, is in the demonstration phase at this time. North American has completed two water reuse alternative studies.

In the first study, hot lime, warm lime and Densadeg (proprietary softening process from Degremont Infilco) softening processes for the treatment of produced water were compared in terms of chemistry, equipment, heat balance, capital and operating costs, and operating considerations. The evaluation drew the following conclusions:

- The chemistry amongst the processes is the same, although the extent of the softening reaction is marginally more complete in the hot lime process.
- The design settling rates in decreasing order are Densadeg, hot lime and warm lime. The resultant equipment footprint is inversely proportional to the settling rates. The Densadeg has the smallest footprint and the warm lime unit the largest footprint.
- The hot lime process operates at about 98^{o}C to 100^{o}C and the Densadeg and warm lime operate at about 80 to 85^{o}C. For the SAGD process the temperature difference is not significant since there is excess low grade heat which is rejected to the atmosphere.
- The installed capital cost of these three alternate processes was not significantly different at the initial estimate level. The operating labour, chemical, sludge disposal, power, fuel, and maintenance costs were similar since the chemistry is the same.
- The deciding factor for selecting the warm lime process is that there are more warm lime softeners in the area than hot lime or Densadeg, and therefore enlisting experienced operating personnel is perceived to be easier.

In the second study, the warm lime process was compared to the mechanical vapour recompression evaporation process. The conventional warm lime process was selected based on capital cost and the concern over treatment and disposal of the concentrated evaporator brine. Again, the study was based on OTSGs and not utility boilers, so a potentially significant capital saving was not available to the evaluation. The decision to use proven OTSGs was made independent of the reuse treatment system, based on the fact that utility boilers, once fouled are very difficult to clean.

The use of saline water from the Basal McMurray and the Clearwater were investigated and modelled.

In addition to the above evaluations, North American has studied the following unit processes in the produced water treatment and reuse systems:

- Skim tank with dissolved gas flotation assist – this is incorporated into the base design.
- Induced gas flotation using micro-bubble flotation - this is incorporated into the base design.
- In-situ versus external WAC regeneration – in-situ regeneration was selected.
- Sludge pond versus WLS sludge centrifuging and off-site landfilling – sludge pond option was selected based on operating considerations.

5 PROCESS DESCRIPTION

5.1 SAGD Production Pads and Horizontal Wells

The SAGD process involves drilling two long horizontal wells that are separated vertically by approximately 5 m. The upper wellbore is used to inject steam into the reservoir. The injected steam adds energy in the form of heat to the reservoir, mobilizing the bitumen. The mobilized bitumen then flows by gravity to the lower production wellbore where fluids are gathered and brought to surface. Figures 5.1-1 and Figure 5.1-2 presents typical horizontal completions and wellbore geometries proposed by North American.

The SAGD process can be categorized into three general operating phases; SAGD startup, SAGD production and SAGD blowdown. The SAGD startup process involves circulating steam into both the injection and production wellbores until thermal communication is established between the pair, typically after approximately 90 days of circulation (Figure 5.1-3). The SAGD production phase involves continuous steam injection into an expanding steam chamber with concurrent bitumen production from the lower production well (Figure 5.1-4).

A typical six well pair well pad is shown in Figure 5.1-5. The operational area of the pad is the area shown for the wells, the pad facilities, surface runoff areas, and the berm (122 m x 254 m). The runoff on the pad would be confined by the berm and would be collected at one or more corners of the pad. Also shown is the additional area required for berm slope stabilization and soil stock piles. This would result in a total footprint of 157 m x 289 m for a typical six well pair pad. The sizing of the typical well pad is a function of a number of factors, many of which are related to the selected artificial lift system. Downhole pumping systems such as electric submersible pumps (ESPs) are limited in the pumping temperature of the produced fluids. Mechanical pumping systems such as rotoflex reciprocating pump are not temperature limited and hence will be used where needed. The outside producers of a six well pair pad are at the maximum deviation due to rod drag that is allowable in a reciprocating pump system. Consequently, the maximum number of well pairs per pad is six.

Environmental factors were considered when situating the CPFs and well pads. Based on available drilling results plus interpreted seismic data, North American has carried out an extensive review of the options for well placement to:

- Maximize resource recovery;
- Minimize well pad footprint;
- Work with topographic features;
- Avoid open water bodies; and
- Avoid defined water course channels (i.e., having defined bed and bank material).

North American has examined each development area to determine the best well trajectories, giving consideration to variability in oil/water contact, reservoir quality, and character differences in the channels. Options for well pair placements in the channel trends has considered non-reservoir shale plugs and various types of potential thief zones, such as those that have been found in the Leismer development area.

These initial well pad locations will be further refined by using a constraints mapping approach. The results of this detailed well pad placement work will be presented in each future hub application. North American will combine the knowledge acquired from the soils and vegetation surveys, with the Alberta Vegetation Inventory/Ecological Land Classification mapping, survey imagery (i.e., still photography images, aerial video, line scans and high resolution LIDAR (Fli-Map®), including topography), and combined with the geological data to make any necessary modifications to the pad site selection. These modified locations will further minimize the disturbance to fens and bogs. Additional constraints that will be considered during the detailed well pad location selection process are as follows:

- High resolution LIDAR (Fli-Map®) Fli-Map® (Fast Laser Imaging Mapping and Profiling) is a proprietary image capture process that combines low level high quality, high resolution LiDAR data with digital video and high resolution still imagery. The multiple sources of imagery data integrated with precise GPS data allow detailed assessment of ground conditions, elevation changes, and vegetation identification.

- Site soil conditions (i.e., to maximize the extent of mineral soils and minimize the extent of organic soils for each site);

- Archaeological, traditional ecological knowledge and traditional use;

- Topography (i.e., minimizing changes in elevation to limit need for cut and fill);

- Sufficient area for soil stockpiles; and

- Rare plants.

North American is committed to berming well pads and will meet the requirements of Directive 055 with regard to acceptable measures for on-site containment to prevent release of contaminants.

Disposal of all drilling fluids (fresh water based drilling fluids) will be according to EUB Directive 050. Initially the management of the fluid/cuttings incorporates a separate process for the non-contaminated hole sections (surface/intermediate) through the use of typical drilling sumps that will meet the integrity requirements. These sumps will subsequently be reclaimed and will meet the EUB Directive 050 / IL 96-13 requirements. The proposed management of the contaminated cuttings is to incorporate compost material (that meets landfill criteria) and transport them to an approved Class II landfill location. Other potential opportunities to minimize the typical sump(s) requirement such as a central processing area or cuttings cleaning process, are being reviewed. During the Project, fluid management will be a key focus to ensure fluid volume and sump requirements are kept to a minimum. A de-watering process is being reviewed with the intended purpose of attempting to optimize/minimize the total drilling fluid requirement.

Total volume of drilling waste will be approximately 450 m^3 per SAGD well pair (injector and producer). It is North American's intent to reduce these volumes by reusing drilling fluids whenever practical. Pad drilling will be conducted using a central mud system. Drilling order of the well sections will also minimize oil and cuttings contamination and maximize the use of drilling fluids.

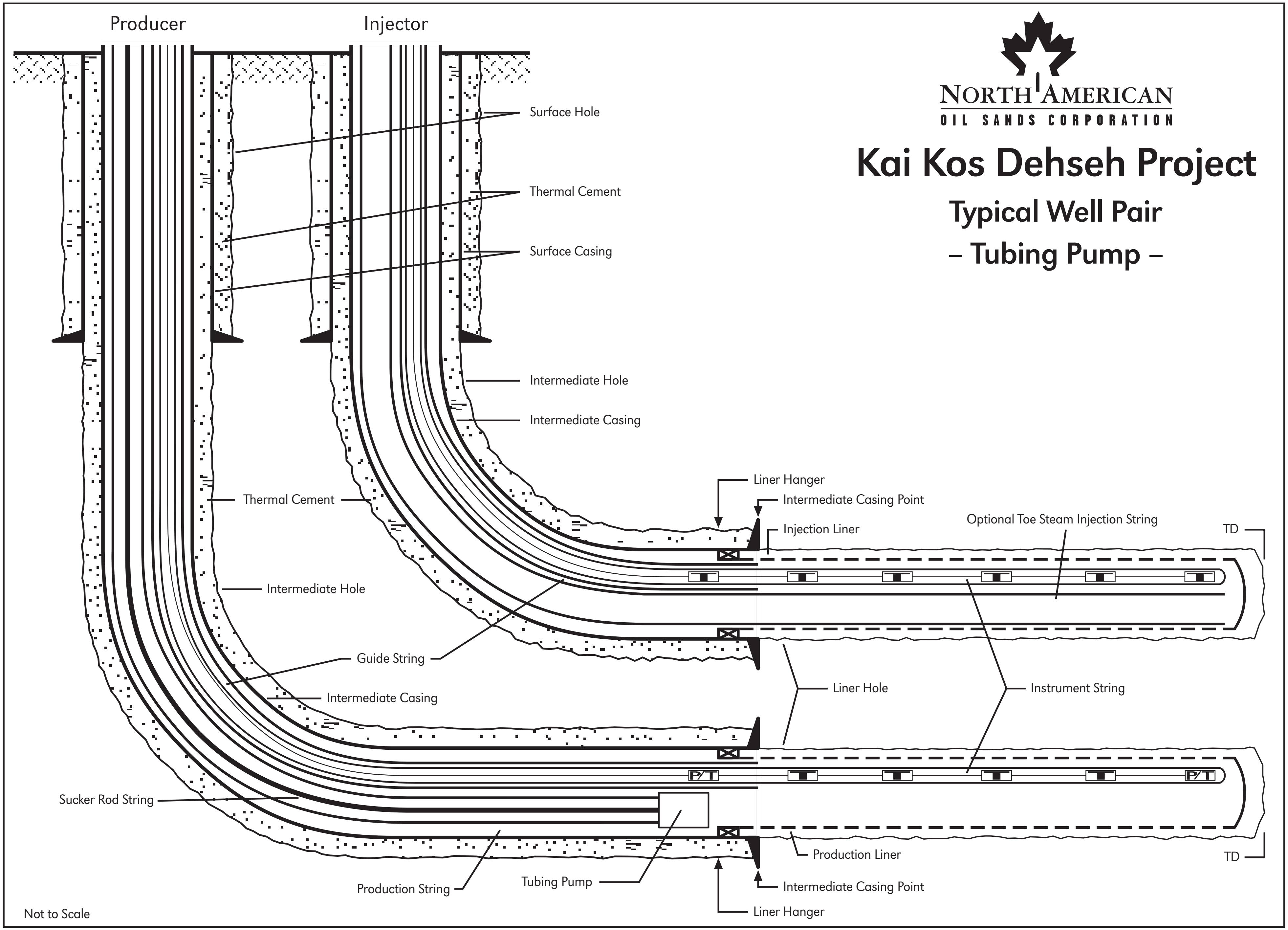


Fig A Tbg Pump P7I8Liners REV7 AEUB 220K 070117

NORTH AMERICAN
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Kai Kos Dehseh Project

Typical SAGD 6 Pair Well Pad and Well Trajectories

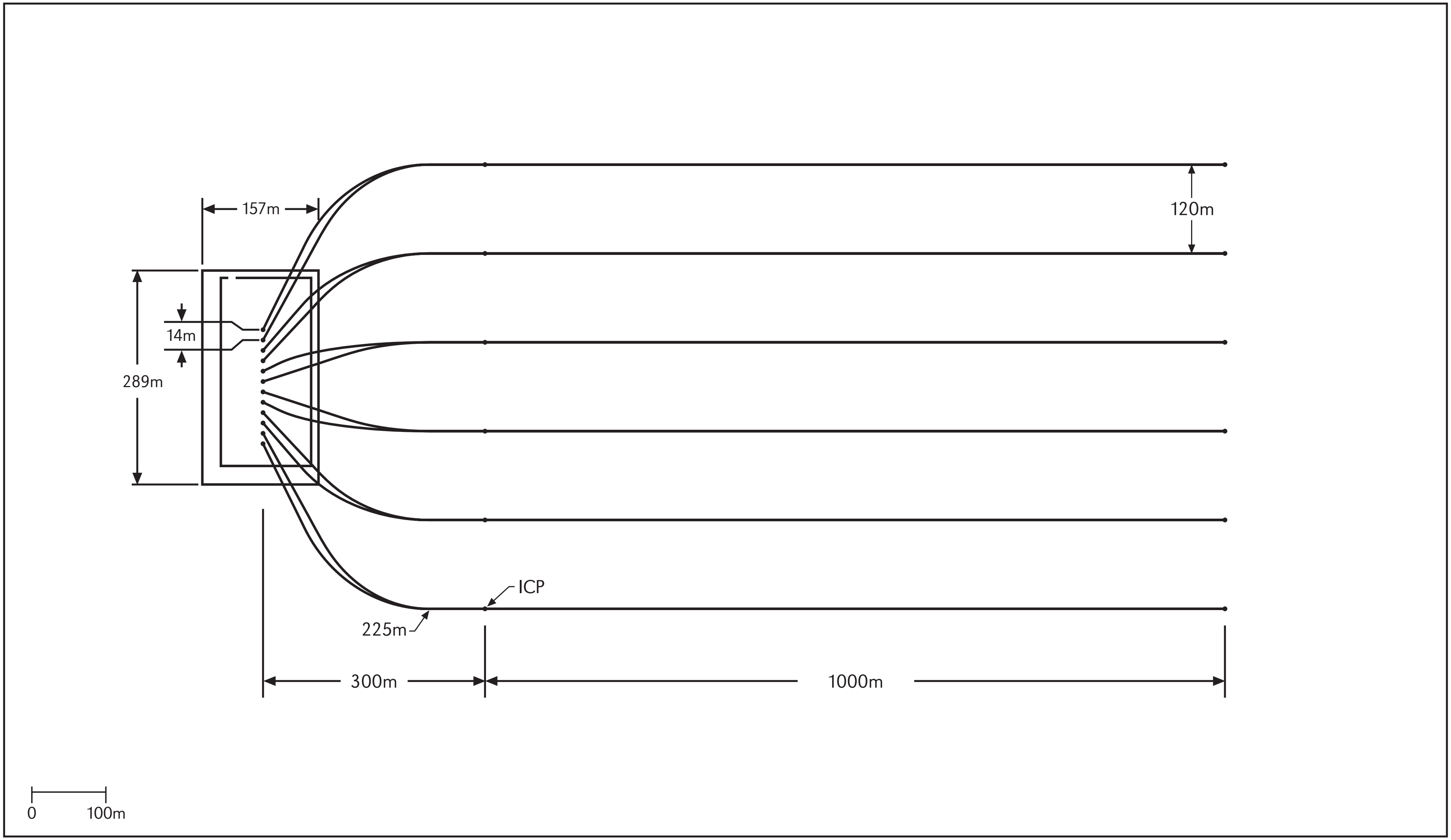


Fig B Typical 6 Pr WP&WT Dim (1:7500) AEUB 220K 070302

NORTH AMERICAN
OIL SANDS CORPORATION

Kai Kos Dehseh Project

Circulation Phase

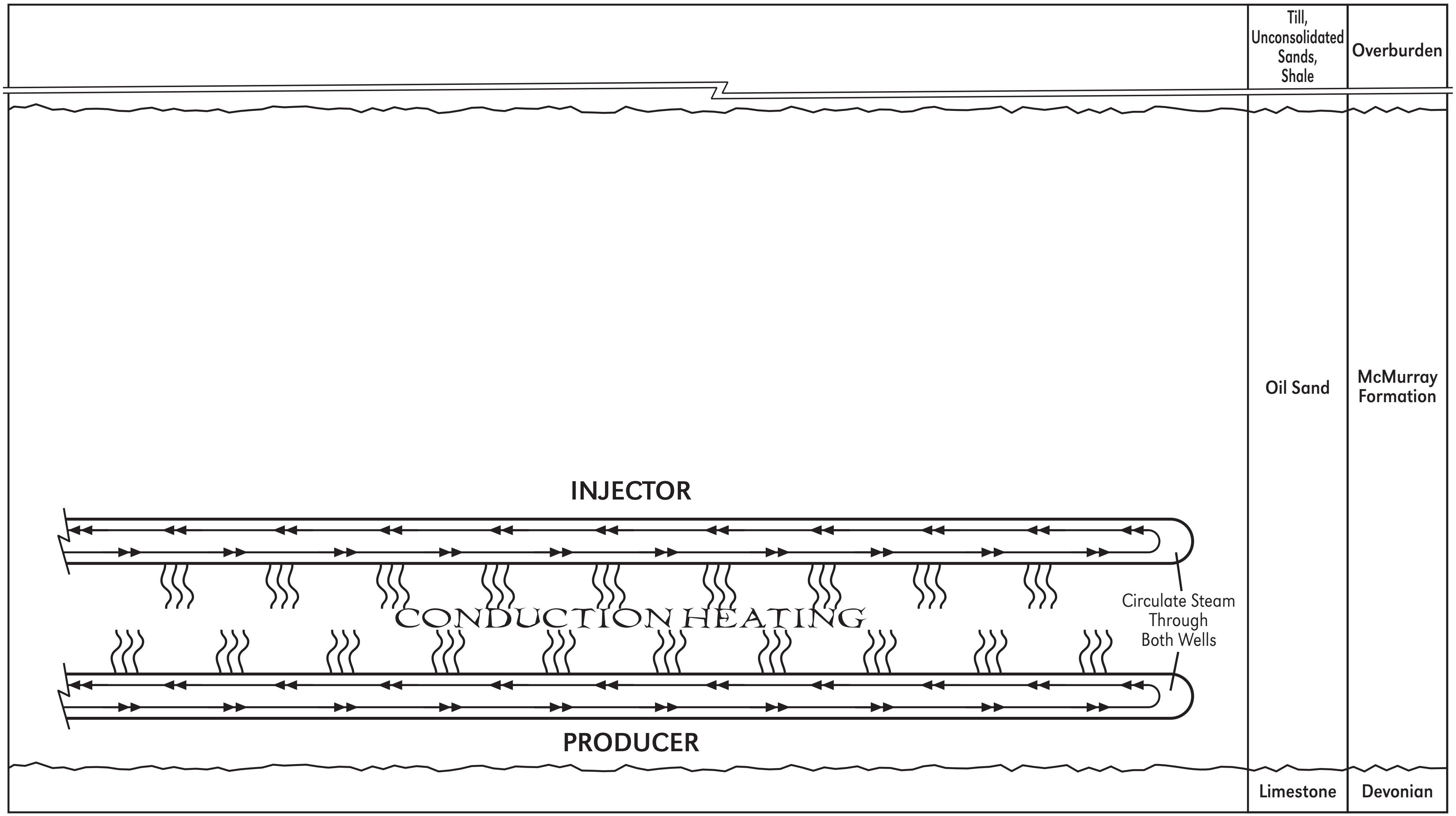


Fig C Circulation Phase AEUB 220K 070117

NORTH AMERICAN
OIL SANDS CORPORATION

Kai Kos Dehseh Project

SAGD Process Schematic

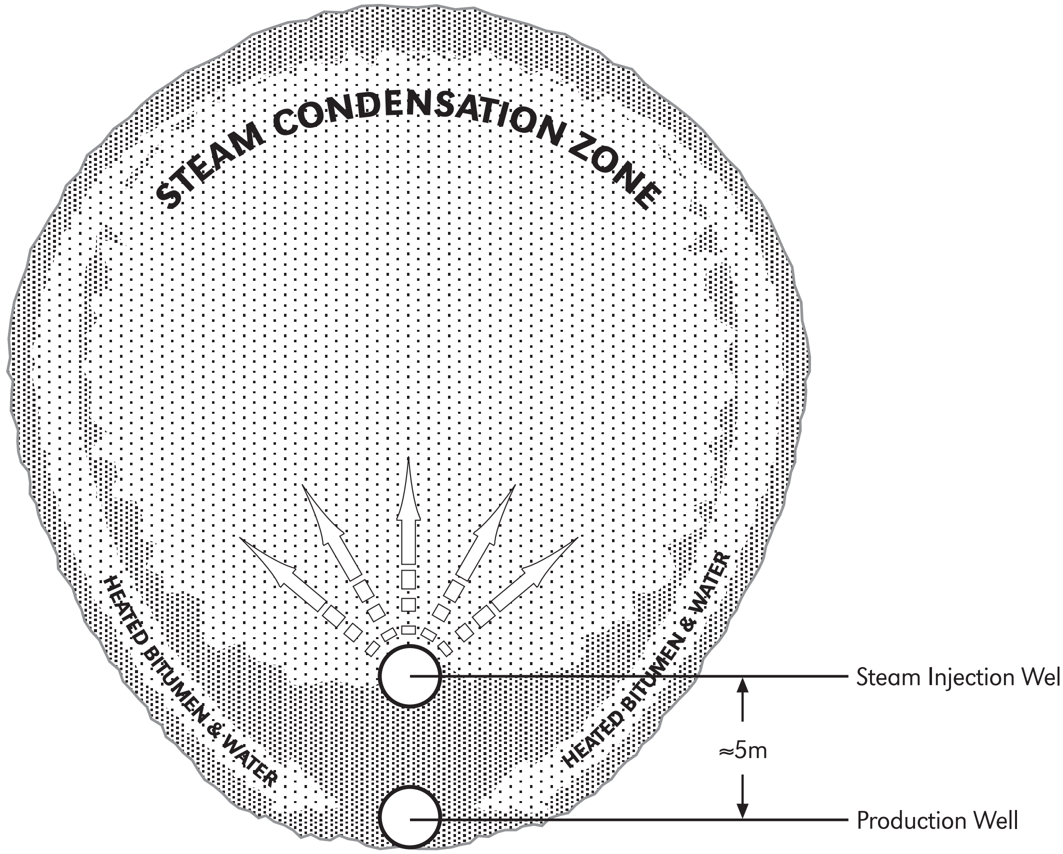
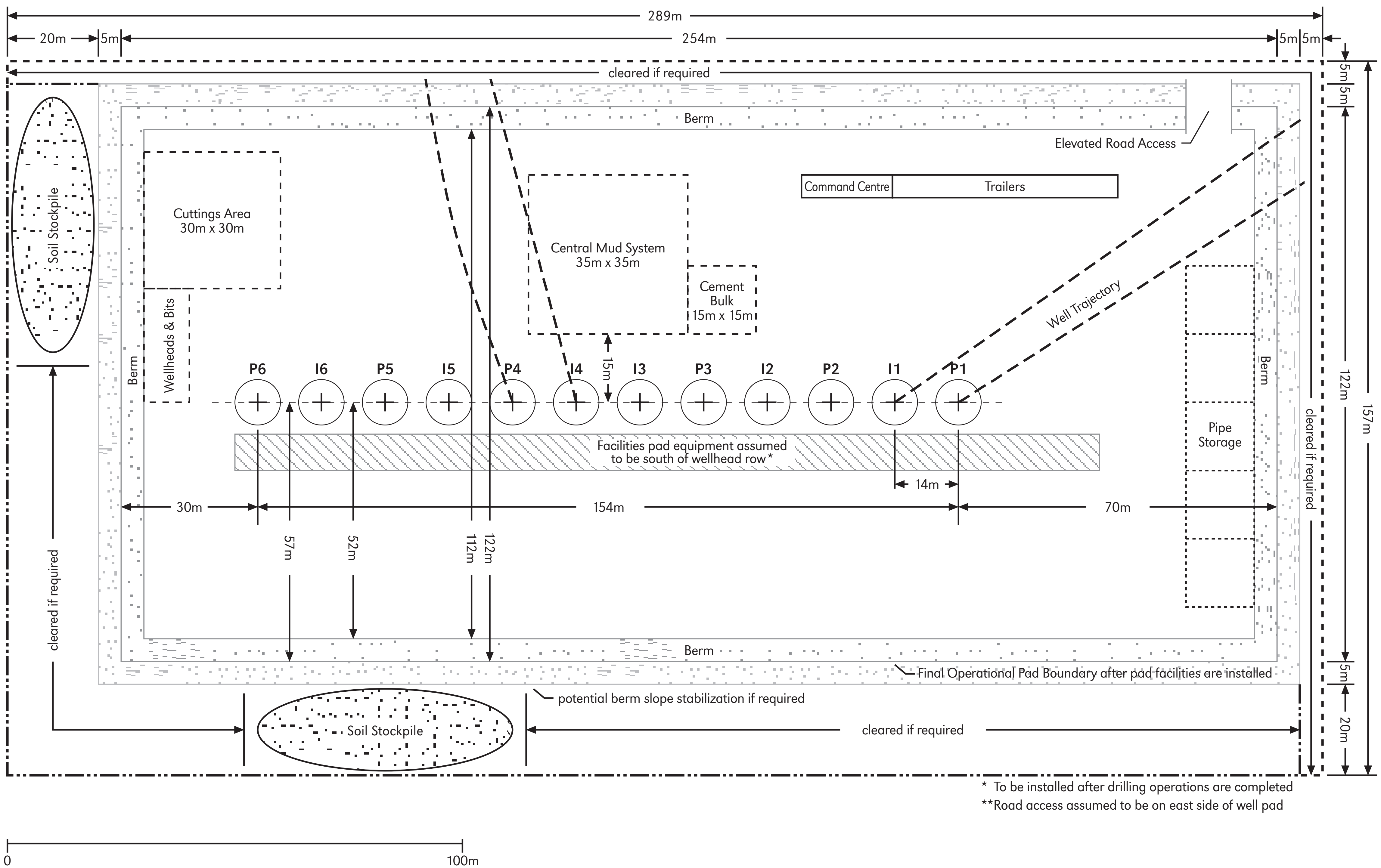


Fig D SAGD Process Schematic AEUB 220K 070117

Kai Kos Dehseh Project

Typical Well Pad Layout During Drilling Operations



* To be installed after drilling operations are completed

**Road access assumed to be on east side of well pad

5.2 Central Processing Facilities (CPF)

Environmental factors were considered when situating the CPFs. North American has carried out an extensive review of the options for CPF placement to:

- Locate on stable upland landform;
- Minimize impact to resource recovery;
- Minimize footprint;
- Work with topographic features;
- Avoid open water bodies; and
- Avoid defined water course channels (i.e., having defined bed and bank material).

North American has examined each development area to determine the best CPF placement to deliver steam to each pad site.

These CPF locations will be further refined detailed engineering in conjunction with constraints mapping. North American will combine the knowledge acquired from the soils and vegetation surveys, with the Alberta Vegetation Inventory/Ecological Land Classification mapping, survey imagery (i.e., still photography images, aerial video, line scans and high resolution LIDAR (Fli-Map®), including topography), and combined with the geological data to make any necessary modifications to the CPF site selection. Additional constraints that will be considered during the detailed CPF location selection process are as follows:

- High resolution LIDAR (Fli-Map®) Fli-Map® (Fast Laser Imaging Mapping and Profiling) is a proprietary image capture process that combines low level high quality, high resolution LiDAR data with digital video and high resolution still imagery. The multiple sources of imagery data integrated with precise GPS data allow detailed assessment of ground conditions, elevation changes, and vegetation identification.
- Site soil conditions (i.e., to maximize the extent of mineral soils and minimize the extent of organic soils for each site);
- Archaeological, traditional ecological knowledge and traditional use;
- Topography (i.e., minimizing changes in elevation to limit need for cut and fill);
- Sufficient area for soil stockpiles; and
- Rare plants.

The following description provides a general outline of all the processes that may occur at each CPF. Process flow schematics for each process are also included. A modularized 3,180 m^3/d (20,000 bpd) approach to the CPFs has been used. This provides a conservative estimate of land disturbance and emission profiles.

The CPFs are designed to deliver the bitumen production rate over a wide range of operating conditions. The produced water de-oiling facilities, water reuse, sulphur removal and steam-generation facilities will be capable of processing forecasted rates over a similarly wide range of operating conditions.

Typical CPF design includes the following seven integrated processes:

- Produced fluids collection, heat recovery, diluent blending, oil, water and gas separation, and diluted bitumen cooling;
- Produced water handling, makeup water treatment and water disposal;
- Steam generation, blow down and disposal;
- Gas collection, cooling and fuel gas systems;
- Sulphur recovery;
- Glycol heat recovery integration and winterization; and
- Storage tanks, offsite connections, truck racks and utilities.

Where additional remote steam generation is required, a remote CPF designed to collect produced fluids and generate steam only, may be used. The produced fluids collected at a remote CPF will be routed to a representative CPF (Figure 5.2-1) for processing.

CPF processes are shown in six schematics:

- Production, including oil water separation, produced water de-oiling, produced gas treatment and shipping (Figure 5.2-2);
- Steam generation (Figure 5.2-3);
- Water treatment (Figure 5.2-4);
- Fuel gas handling (Figure 5.2-5);
- Vapour recovery (Figure 5.2-6); and
- Sulphur recovery (Figure 5.2-7).

5.2.1 Heat, Material, Water and Energy Balance

Bitumen, water and steam rates will vary over the life of the Project, resulting from variations from progressive development of hubs and wells, and changes in individual well performance as the wells mature and decline. The material and energy balances provided should be viewed as a snapshot in time and not as expected conditions over the life of the Project.

A material balance for the total process is shown in Figure 5.2-8 and is based on all the hubs producing concurrently at a production rate of approximately 35,000 m^3/d (220,000 bpd) of bitumen on an annual average calendar day basis from a SAGD process operating at an average steam oil ratio (SOR) of approximately 3.0. The material balance was calculated for the four main components of the process: reservoir, steam generation, water treatment and production processing.

Figure 5.2-9 is a simplified water balance flow diagram. The proposed produced water reuse rate is greater than 90%. Figure 5.2-10 shows the equivalent energy balance. These diagrams show flow rates on a calendar day basis at the peak production of 35,000 m^3/d (220,000 bpd).

An overview of each process is included below. Specific details of future CPFs will be included in subsequent submissions as appropriate.

5.2.2 Produced Fluids Collection and Measurement

The Measurement, Accounting and Reporting plan (MARP) has been prepared for the Leismer Demonstration Project as per EUB Directive 042. It is complete and will be submitted separately from this application. Standards of accuracy, calibration and proving presented in the document will be stewarded throughout the various development areas of the Kai Kos Dehseh Project. Accounting formulas prepared to determine oil, water and gas production rates are unique to the Leismer Demonstration CPF. As such the MARP will be updated to reflect the specific orientation and tagging of subsequent central processing facilities then resubmitted prior to their construction

Produced fluids from the pads, consisting of bitumen, produced water, and small amounts of flashed steam and gas, will be pumped to the plant and cooled in the inlet feed coolers. Heat from the produced fluids will be exchanged with boiler feed water (BFW). The cooled, produced fluids will flow into the free water knockout (FWKO). A portion of the required diluent will be added to the produced fluids before they are delivered to the FWKO. The FWKO operates at approximately 130°C. Maximum heat transfer to the BFW (and consequent reduction in fuel gas requirement) is accomplished through the exchange of heat from the produced fluids into the BFW.

In all reservoir scenarios single-phase flow is established in the liquid pipeline from the well pads to the CPF by holding back pressure on the pipeline downstream of the inlet feed coolers. This allows maximum heat transfer to the BFW and avoids flashing/multiphase flow in the gathering line. The pump pressure required to maintain single phase flow will be delivered by bottom-hole pumps alone or bottom-hole pumps in combination with surface pumps.

Since there is no gas lift or steam lift in the basic design, and the produced fluids are delivered by bottom-hole pumps, there is less gas entrained and less solution gas in the produced fluids when they are delivered to the CPF. This allows easier de-gassing.

North American identifies two distinct stages of production measurement as follows:

1. the performance of individual wells/well pairs during the initial steam circulation phase; and

2. production measurement during the long-term SAGD operation phase.

During the initial steam circulation phase each wellbore is being circulated at rates on the order of 100 to 125 m^3/d (CWE) of steam. Steam returns are multiphase at the wellhead, and typically will contain bitumen staining plus unknown solids associated with drilling and completion that may be transported from the wellbore. North American wants to determine the approximate loss of the circulated steam to the McMurray Formation. Loss of injected steam or overproduction of water returns might indicate problems in the reservoir involving wet or conductive sands in the zone of interest. North American proposes to use 2 x 100% multiphase pumps at each well pad that will be capable of compressing and delivering the steam circulation returns. The multiphase pumps must have a turndown capability on the order of 12:1 (12 wells or six well pairs on a pad). A single well will be tested by routing steam circulation returns through a single multiphase pump (turned down) which will compress the multiphase flow to single phase and deliver it through an orifice plate. The calculated flow rate through the orifice plate will be compared with the simultaneous steam injection rate on the well in question.

During the long-term SAGD operation bottom-hole pumps will be used for artificial lift. These pumps can maintain single phase flow up the production tubing and through the wellhead, because of their higher discharge pressure (on the order of 2,400 kPa at surface). When a well pad is converted from steam circulation phase to long-term SAGD phase, the multiphase pumps are no longer required for compression of produced fluids to single phase. When conversion occurs, the multiphase pumps will be revised to perform casing gas compression.

Each producing well will be equipped with a quadrant-edge orifice plate which reports total fluid production from the well. The calculated total liquid flow rate obtained from the orifice plate will be corrected for stream density based on periodically-collected gas sample bombs and laboratory analysis. At wellhead conditions of 2400 kPag and 180°C, entrained reservoir gas that is not dissolved is compressed to about 6.5% of its volume at standard conditions. Assuming the entrained gas is produced at a GOR of 10 (standard conditions, m^3/m^3), the free volume of gas passing through the orifice plate at wellhead conditions will be about 0.65 m^3 of gas per cubic metre of bitumen. Allowing for a SOR of 3, the free volume of gas in the total produced fluids is on the order of 0.16 cubic metres of gas per cubic metre of produced fluids, or about 14% by volume.

Given the permissible prorationing factor of 0.75 to 1.25 on bitumen production, North American suggests that this volume fraction of gas is small enough to not significantly interfere with metering accuracy.

Each well pad will be equipped with a water cut meter and automated valving to allow any of the six producing wells to be tested for water cut. The water cut measurement technology has not been finalized but will utilize either the Agar® microwave adsorption technique or the nuclear magnetic resonance technique currently under development at the University of Calgary. The water cut meter will be located in the test header and will be used to test any of the six producing wells. The water cut meter will be arranged to accept the full flow from the production tubing of a producing well. The produced fluids will be trapped and measured for water cut in a batch-wise automated process, which take water cut measurements at a rate of approximately 3 to 10 samples per hour. At the same time, the relative production rate from the well being tested is being reported from the quadrant-edge orifice plate at the wellhead. Testing frequency will meet or exceed EUB requirements.

Produced gas reporting to the casing head (annulus) on a producing well will be routed through an individual orifice plate to a common suction header. The suction header in turn feeds into the converted multiphase pumps, which now serve as casing gas compressors. Individual wells will be periodically sampled with pressurized bombs. The reported produced gas flow is on a wet basis, and as such, North American plans to develop appropriate calculations to obtain an approximate dry gas flow.

Prorationing of produced oil, produced water, and produced gas back to individual producing wells will be accomplished by using specific flow meters in the CPF. This will allocate production based on ratios observed during individual well tests. Calculation methods and determination of uncertainty factors will also conform to EUB Directive 017. All production reporting will follow EUB standard production accounting requirements.

The following table defines North American's plan for metering specific streams within the overall facility.

Table 5.2-1 Metering

Stream	Meter type proposed and installation location details	Turndown req'd	Single Pt uncertainty	Max. Monthly uncertainty	Proving Frequency
Individual Well Tests, fluids	Quadrant-edge orifice plate at each producing wellhead	3:1	N/A (density > 920 kg/m³)	N/A (density > 920 kg/m³)	Periodic plate inspection
Well Pad test header water cut meter	Agar® radio frequency or nuclear magnetic resonance techniques.	N/A	N/A (density > 920 kg/m³)	N/A (density > 920 kg/m³)	Annually, per Dir-017, Section 2.10
Individual wells, casing gas	Orifice plate at each producing casing head	3:1	N/A (density > 920 kg/m³)	N/A (density > 920 kg/m³)	Periodic plate inspection
Total diluted bitumen	LACT unit	N/A	N/A	N/A	N/A
Diluent receipts (incoming)	Truck weigh scale	N/A	0.5% Scale ticket from supplier, annotated for density and BS&W	N/A	Per EUB Dir-017, Section 2.13
Diluent Pipeline	LACT unit	N/A	N/A	N/A	N/A
Total Water to Disposal	Turbine-type metering	3:1	5% per EUB Dir-017, Section 1.7.1	N/A	< 3 months, then annually.
Water to an individual Disposal Well	Turbine-type metering	3:1	5% per EUB Dir-017, Section 1.7.1	N/A	< 3 months, then annually.
Purchased Fuel Gas	Orifice Plate meter run	3:1	3%	5%	< 1 month, then annually
Recovered Solution Gas	Orifice Plate meter run	3:1	3%	5%	< 1 month, then annually
Flared Gas	Orifice Plate meter run on branched connections into flare system	3:1	3%	5%	< 1 month, then annually
Source Water delivered to CPF from individual water wells	Either of turbine-type or magnetic flow	3:1	5% per EUB Dir-017, Section 1.7.1	N/A	< 3 months, then annually.
Steam injected into individual injection wells	Flow Nozzle or Orifice Plate or Pitot-type device	3:1	3% per EUB Dir-017, Section 1.7.3	N/A	< 3 months, then annually.

5.2.3 Bitumen Treating

The bulk of the produced water is removed in the FWKO vessel and routed through heat exchangers where more heat is recovered to the BFW, thereby reducing fuel gas requirements, and then sent to the skim tank. The remainder of the produced fluids, which is a blended bitumen emulsion consisting of approximately 10% water, is fed to two parallel treaters and dehydrated to 0.5% basic sediment and water (BS&W). Additional diluent will be added upstream of the treaters to improve separation. The sales oil product is cooled to approximately 60°C and sent to sales tanks. Diluent will be added to the produced fluids to aid separation by increasing the density difference between the oil and water. Gas separated and produced from the FWKO and treaters are mixed and sent to the mixed fuel gas separator.

Three slop oil tanks are provided in the design of each CPF. The streams flowing into the slop oil tanks include skim oil, bottom sludge and water from the sales oil tanks, interface draws from the FWKO/treater vessels and recovered liquids from the flare knockout drum. The streams are normally intermittent. The slop tanks provide additional settling to remove water, which is directed back to the skim tank. Oil emulsions remaining in the slop tanks can be fed to the FWKO/treater or directed to the slop oil treater.

5.2.4 Produced Water Handling and Treatment

Most of the produced water is recovered in the FWKO and treater vessels. A much smaller portion of produced water is recovered from other parts of the process, including sales oil storage, diluent storage, produced vapour handling and treatment, as well as the slop oil recycle system.

The produced water is deoiled in skim tanks followed by induced gas flotation and infiltration. The skimmed oil is then recovered to the slop system. The skim tank also provides surge storage.

The treated produced water is stored in the deoiled water tank which also accepts the sludge pond supernatant recycle, off-spec storm water and raw make-up water. The deoiled water tank provides produced water surge storage to allow more constant water reuse system operation.

The selected process for produced water treatment is warm lime softening. The produced water is directed to the warm lime softener (WLS), where it is blended with the portion of OTSG blowdown being reused. The function of the WLS is to reduce hardness and silica. Soda ash, lime, magnesium oxide, coagulant and flocculant chemicals are dosed as required for the chemical and physical process. The excess sludge produced in the WLS is wasted to the sludge pond where the solids settle and the supernatant is recycled.

The water from the WLS is filtered for final solids removal and then softened to less than 0.5 mg/L dissolved hardness through two-stage weak acid cation (WAC) softeners. The finished water meets the OTSG specification for silica, hardness, oil, iron, oxygen and total dissolved solids (TDS). The treated water is stored in the boiler feedwater (BFW) tank prior to being used as feed water for the steam generators.

5.2.5 Startup and Operating Water Demand

Startup water demand will be greater than during normal operations. Once produced water is recycled, the demand for make-up water will decrease. Figure 5.2-9 presents a water balance (based on the selected process of warm lime softening) for the Project during normal continuous operations.

5.2.6 Steam Generation

SAGD injection steam will be generated in OTSG's using the treated produced water as the primary source of BFW. Steam will be generated at 75% to 80% (mass) quality and approximately 9,500 kPa (g). The un-vapourized mass fraction (20%-25%) will be separated and 100% quality (saturated) steam will then be sent to the well pads by the steam distribution pipeline network. The resulting quality of the steam injected into the upper well of each SAGD pair will be approximately 96% to 98% (mass fraction as vapour).

The un-vapourized mass fraction is referred to as boiler blowdown. This hot stream will be routed to heat exchangers where additional heat will be recovered to the BFW.

After the hot boiler blowdown has surrendered its heat to the BFW, it will be flashed and separated. Flashed steam will be condensed and used primarily as BFW. A slipstream will be used for lime slurry and magnesium oxide slurry preparation.

The remainder of the boiler blowdown liquid contains high levels of chlorides and silica as it has been concentrated roughly four to five times above BFW levels, and then further concentrated in the blowdown flash separation process. This liquid will be cooled and partially recycled back to the water-treatment facility. The reuse of blowdown is limited by the concentration of dissolved solids in the produced water reuse system. The normal limit is 8,000 mg/L TDS. As the TDS concentration approaches this limit, a greater portion of the blowdown will be sent to deep well disposal.

The efficiency of the steam generation process will be increased by recovering heat from progressively hotter process streams into the BFW stream before the BFW is pumped to the OTSG’s. Hotter BFW requires less fuel gas to produce steam.

Fuel gas will be supplied from the fuel gas mix drum, which consists of recovered, treated and produced gases as well as natural gas supplied from offsite utilities.

The combustion air to the OTSGs will also be preheated by low-grade heat from the glycol system. This further improves the efficiency of the steam generation process.

5.2.7 Produced Vapour Handling and Treatment

A large portion of the vapour produced in the SAGD process is released in the production wells and is collected off the well head annulus and then routed to a gas compressor. The gas is compressed and cooled from each well pad and combined with the produced fluids for transportation to the CPF. This gas is then separated along with diluent light ends in the FWKO and treaters. It is then further cooled in the produced gas cooler at the CPF. Sour streams will be desulphurized prior to mixing with cool dry purchased fuel gas. This allows all produced gas to be conserved, and used as steam generator fuel.

Produced vapour and light hydrocarbon vapour from the diluent also separate in the skim tank, produced water tanks, sales oil tanks, and diluent tank. These vapours are collected, cooled and compressed in the vapour recovery unit (VRU). The VRU separates gas, recovered diluent, and water. The recovered diluent is returned to the diluent tanks. The separated water is sent to the skim tank. The separated gas is sent to the desulphurization unit prior to mixing with cool dry purchased fuel gas.

5.2.8 Fuel Gas and Produced Gas

Current plans use dry natural gas as the primary fuel for the Project. A small volume of produced gas from the SAGD process will be collected and used to supplement the purchased fuel gas.

The largest gas volume consumed by the process will be for fueling the steam generators. Purchased gas will also be used for blanketing tanks and vessels and providing fuel gas for winterization at the well pads and for CPF utilities.

The produced gas from the SAGD process typically contains carbon dioxide (CO_2) and hydrogen sulphide (H_2S). The CO_2 and H_2S are produced through the reaction of aquathermolysis between the steam and bitumen in the formation. The aquathermolysis reaction tends to slowly increase the concentration of H_2S in the produced gas as the reservoir becomes progressively hotter. Using experience from other SAGD operations, the CPF design anticipates a maximum sulphur content of 1.75% (Volume/Volume) H_2S in the produced gases. The maximum sulphur emissions usually increase slowly and coincide with maximum production rates.

5.2.9 Flare Systems

Two flare systems are provided at each CPF to protect containment systems in the event of process upset. A low-pressure flare is used to protect tanks in the event of a VRU upset. The flow rate to the low-pressure flare includes only the vented gas from the VRU system. A high-pressure flare system is used to protect the FWKO, treaters and fuel gas systems. Operating experience in SAGD facilities has shown that the frequency of emergency pressure relief events from the FWKO and treaters can be reasonably expected to be less than once every two years.

5.2.10 Sulphur Removal

The maximum sulphur inlet for each individual hub is in the 1-3 t/d range and, as such, based on EUB Interim Directive 2001-3, requires 70% sulphur recovery. In its entirety, the Project will have an overall inlet sulphur rate greater than 10 t/d, and, as such, North American has designed each sulphur removal package to meet the 90% removal rate.

Sulphur will be removed from the produced gas prior to mixing the produced gas with natural gas for combustion in the steam generators. The sulphur recovery unit is a small skid mounted, package unit capable of capturing a minimum of 90% of the sulphur as elemental sulphur of suitable quality for sale. This unit operates similarly to the larger scale Claus type units where H_2S is oxidized to elemental sulphur over a fixed bed catalytic reactor. The gas phase process maintains the sulphur in the gas phase until it is recovered in the sulphur condenser. The treated gas leaves the process for the fuel gas mixed drum prior to being consumed as fuel in the steam generators.

Pretreatment absorbers are expected to be required to remove unwanted volatile organic compounds present in the produced gas. This would consist of two parallel packed towers upstream of the line labelled “sour gas”. These vessels capture heavy hydrocarbons in the inlet gas stream. The activated carbon media is periodically regenerated and the captured hydrocarbons recycled back into the oil treatment process.

Molten sulphur storage will be provided on CPFs that have sulphur removal equipment. The product will be trucked off site for sale.

5.2.11 Storage Tanks, Offsites and Utilities

Each CPF will be provided with the necessary tankage, including diluted bitumen sales oil storage tanks, slop tanks, produced water skim tank, BFW tank, and diluent tank. All tanks will comply with secondary containment as required by EUB Directive 055.

Electrical power will be supplied to the Project from the provincial power grid. Electrical diesel generators will be used for backup power at each CPF.

5.2.11.1 Camps for Construction, Drilling and Operations

Camps for the development are planned to be integrated facilities for construction, drilling and operations. They will be sized to house the required personnel in a safe and comfortable manner. Two main camps are proposed. One will be located in the Leismer Development area to service Leismer and Corner and the other at Mariana Lake to service Thornbury and Hangingstone. The existing North American winter drilling base camp in Section 14-78-9 W4 may be used periodically to provide extra accommodation during peak personnel periods outside of the winter program activity period. The camps will be self-contained and provide potable water sourced from local licensed quaternary water wells. The potable water will be treated and tested to meet the Potable Water Regulation AR122/93.

The domestic wastewater treatment system will be designed and operated in accordance with the latest edition of “Standards and Guidelines for Municipal Waterworks, Wastewater and Storm Drainage Systems”. The treated effluent from the wastewater treatment plant will be discharged to the environment down-gradient of the water well in a safe manner. The sampling frequency and effluent from the wastewater plant will meet Domestic Wastewater Management Guidelines for Industrial Operations latest edition.

Separate camp facilities for drilling crews may be required depending on travel time to the main camps and proximity to the work area.

5.2.12 Domestic, Utility and Potable Water at the CPFs

Each CPF will have a domestic and utility water supply system. Where the make-up water is too saline, a Quaternary water well will be licensed for domestic and utility use. The utility water system will be sized for the clean service uses such as pump seal water and critical chemical dilution. The domestic supply will meet Potable Water Regulation AR122/93, and will be used for personal contact services such as safety showers, lavatories and kitchen/eating areas. Bottled potable water will be supplied at the CPF for operations personnel.

At each CPF, the domestic wastewater treatment system will be a septic tank and filtration system designed in accordance with the Alberta Private Sewage Systems Standard of Practice 1999. The two 100% infiltration mounds will be dosed with a pressure dosing system, allowing one tile field to be in-service, and the second resting.

The domestic wastewater system will be sized based on the expected site occupancy times the flow rate per site person, which will be in the range of 70 L/d to 90 L/d.

5.2.13 Stormwater and Secondary Containment

Surface water runoff from the site outside of process areas is generally free of oil and chemicals. This water will be redirected to the storm water retention pond on each CPF where it will be collected. It may then be discharged to the existing natural watercourses pending testing per applicable Regulation. Water collected in the storm water retention pond can also be returned to the process if it does not meet applicable limits for surface discharge.

Industrial runoff from process areas within the CPFs will be directed to the sludge pond. Water collected in the sludge pond will be recovered for reuse.

5.2.14 Product Movements

North American has entered discussions with local pipeline operators to arrange for product pipelines to convey diluted bitumen (bitumen blended with diluent) to major pipeline hubs and/or upgrader operations. This includes returning diluent to the field. Product movements are divided into either diluted bitumen or diluent. The pipeline facilities are further classified as “gathering system” or “mainline”. A gathering system will be required to transport diluted bitumen from the SAGD hubs to a local pipeline hub for further transport. Shipments of diluted bitumen on a mainline transmission system are required to deliver the bitumen to markets via Edmonton or Hardisty. This may include shipments to upgraders.

To accommodate initial bitumen production North American plans to enter into agreements with existing nearby mainline systems to transport bitumen blend. Existing mainline systems are not expected to have sufficient capacity to accommodate all bitumen blend from the Kai Kos Dehseh Project. For this reason, North American intends to reach arrangements to have new mainline pipeline capacity constructed to carry all of its production to its planned upgrader near Fort Saskatchewan or markets originating from the Edmonton pipeline hub.

5.2.14.1 Trucking

While it may be necessary to truck diluted bitumen and diluent during initial operations, North American does not consider this to be a long-term option. North American plans to have a gathering system pipeline in place for diluted bitumen when the Leismer Commercial Hub production comes on-stream. This would limit the trucking of bitumen to 10,000 bpd (excluding diluent) except as necessary for short periods of time to cover disruptions of the gathering system. North American may need to continue trucking diluent for several years until a suitable diluent delivery pipeline has been constructed.

5.2.14.2 Gathering System

North American has developed plans to separately apply for regulatory approval to construct a local gathering system to support the diluted bitumen product movement needs of both the Leismer and Corner Hubs. North American has performed route selection and completed the preliminary engineering on an NPS 12 pipeline system for transport of diluted bitumen from Leismer to a terminal at Cheecham via North American’s Corner Hub.

North American has had discussions regarding access to a terminal at Cheecham. While, at this time, commercial arrangements are not in place, North American believes that an agreement can be reached. The terminal offers suitable access to market North American’s diluted bitumen. North American is also in discussions with other existing pipeline operators regarding similar arrangements.

Diluted Bitumen

North American intends to build a local gathering system to coincide with the operation of the Leismer Commercial Hub. It will have sufficient capacity to also move the diluted bitumen from the Leismer Demonstration facility. From the time the gathering system is commissioned it is expected that diluted bitumen trucking operations will cease. The truck rack in the Leismer Demonstration Hub will remain on standby and may be used intermittently in the case of pipeline emergencies.

Diluent

Initially, the local gathering system will not include a diluent line until diluent becomes commercially available at one of the local pipeline hubs, or until the diluent portion of a mainline pipeline system is constructed. Until that time, diluent will be delivered to each SAGD hub by truck. Once diluent is available in the area, diluent lines will be constructed to each hub as required. At that point, diluent trucking will cease. The diluent lines will be covered under a separate regulatory application.

North American has designed its SAGD operation to use both natural gas condensate and synthetic crude oil as diluent. Condensate is the preferred diluent until the upgrader is operational. At that time, a naphtha stream will be separated at the upgrader and returned to the field to be used as diluent. Prior to the planned startup of the upgrader, synthetic crude oil may be used as an alternative diluent.

5.2.14.3 Mainline

Once North American's bitumen production has reached a volume that cannot be shipped on an existing mainline transmission line without significant investment being required to expand that system, North American plans to contract a new transmission line that would originate at the Leismer Hub. This system would be sized to handle all of North American's predicted volumes and would also include a diluent return line. This transmission line would be connected to the field production at its origin and would terminate at North American's proposed upgrader in the Ft. Saskatchewan area. North American has had discussions with several transmission pipeline companies about such a new mainline system. North American will work closely with these and possibly other pipeline companies, in order to reach a commercial agreement. As an alternative, North American may elect to construct the mainline system itself to support its own production. The upgrader is proposed to be onstream in 2012 and North American is targeting the completion of a long-term mainline pipeline in place by the time the upgrader is operational.

5.2.14.4 Custody Transfer

North American will construct equipment suitable for financial and physical custody transfer as required. During those periods of time that diluted bitumen is shipped by trucks off site, financial custody transfer will be at the receiving truck terminal. North American will provide metering and sampling to ensure that the physical volume is adequately accounted for. During any other period of time, North American will provide full metering and sampling at each hub to satisfy the EUB reporting requirements as well as utilize those meters for financial custody and accounting purposes.

5.2.15 Chemical Consumption and Waste Management

5.2.15.1 Chemical Consumption

A variety of chemicals, lubricating oils and domestic and office supplies are required for operations of the CPFs. Storage and tracking of the supplies and disposal of waste products will include secondary containment, leak detection and inventory reconciliation as necessary, and as required by regulation. The largest chemical consumption streams include hydrated lime, magnesium oxide (dry), hydrochloric acid (HCl) and sodium hydroxide (NaOH). Storage capacity for chemicals is generally based on ten to fourteen days supply plus one bulk truckload. Smaller amounts of secondary chemicals such as filtration coagulants, demulsifiers, dispersants, and water treatment aids are also consumed. Chemical consumption estimates for these secondary chemicals are provided as part of the detailed design of the CPF. Table 5.2-2 presents the estimated chemicals that will be consumed during operation of the Kai Kos Dehseh Project.

Table 5.2-2 Chemical Consumption

Chemical	Consumption for 35,000 m^3/d (220,000 bpd) of bitumen production (t/d)
Hydrated lime	80.93
Magox	41.68
Soda Ash	18.19

Chemical	Consumption for 35,000 m^3/d (220,000 bpd) of bitumen production (t/d)
HCl (32%)[1]	52.15
Caustic (50%)[1]	37.82
Demulsifier[2]	5.25
Reverse demulsifier[2]	12.27
Flocculant	0.21
Hypochlorite	1.65
Coagulant	2.18
Polymer	2.78
O_2 scavenger	1.57
After filter aid	0.16
Chelant	0.52
Filming amine	0.52

1 NPRI, TDG

2 Potentially NPRI, PSL1, TDG (depending on toluene or xylene content)

5.2.15.2 Waste Management

North American is committed to minimizing waste production and will reduce, reuse and recycle where practical. Regulatory provincial and federal waste handling requirements will be met. Some examples of these requirements include EUB Directive 050 (EUB, 1996a), EUB Directive 051 (EUB, 1994), EUB Directive 058 (EUB, 1996b), Directive 055 (EUB, 1995), EPEA Waste Control Regulation (AR 192/1996) and AENV Approval conditions.

A water-based drilling fluid will be used in pad drilling, equipped with a central mud collection system. To reduce volumes, drilling fluids will be re-used whenever practical. Drilling fluids will be directed to remote sump locations based on suitable soil condition. Locations will be chosen based on soil sampling indicating the sump base will meet regulatory requirements. Drilling wastes will be monitored and analyzed and disposed of in compliance with EUB Directive 050 (EUB, 1996a). Special attention will be paid to hydrocarbon levels in drilling waste to minimize drilling mud contamination and drilling waste disposal. North American will separate drilling muds contacting oil bearing formations. Materials that comply with Alberta Tier I soil and water quality guidelines for hydrocarbons (AENV, 1994) will be disposed of using the mix-bury-cover method. Waste not meeting Directive 050 requirements for hydrocarbons levels will be disposed of at an approved waste disposal facility or treated to the guideline levels.

Sour gas will be treated at the Leismer, Thornbury and Corner Hubs. Molten sulphur storage will be provided onsite. Discussions have been undertaken with a sulphur marketing firm to purchase recovered molten sulphur. Sulphur will be trucked offsite and as such, environmental problems associated with long-term storage of sulphur are not anticipated.

The main wastes produced during operations are associated with the water recycle system and in particular spent lime sludge from the WLS. The chemical composition of the spent lime sludge will depend on final chemistry results of the various source waters and operational parameters, which will vary during start-up of future pads, and as such a precise analytical breakdown of this sludge is not currently available. Based on operational experience from similar SAGD projects in the Athabasca region, the resultant sludge will primarily be calcium carbonate and will be suitable for disposal into a Class 2 disposal facility. North American plans on following the procedures outlined in the Leismer Demonstration application for long term handling of lime sludge waste which includes dewatering the sludge and trucking it to a suitable offsite licensed landfill. The water recycle system also produces a waste stream off the WAC unit regeneration. The WAC regenerant stream will be a neutralized effluent comprised of the minerals extracted after softening. Again the precise composition of the WAC regenerant will depend on final chemistry results of the various source waters and operational parameters, however operational experience from the region indicates the wastes will be suitable for deep well disposal and compatible with the disposal formation.

The operational wastes handling system includes process drains and building floor drains. Drains from process equipment will be directed to the flare knock-out drum (FKOD) through closed and pressurized drainage systems or will be collected in individual buildings in double-walled steel sumps, which can be pumped to the FKOD. Drains for acids, caustics, oily streams and other unusual contaminated streams will be segregated from each other and directed as required for the process design and applicable Regulations. Floor drain systems for concrete floor buildings and for steel floor buildings (i.e. modular construction) are designed in similar but distinct ways. Buildings with concrete will be equipped with building drainage systems consisting of floor drains, sump tanks and sump pumps. All other are equipped with building drainage systems consisting of floor drains, tanks and sump pumps. These drains are directed to the flare knockout drum or sludge pond, depending on hydrocarbon potential.

North American does not anticipate the production of sand to be an operational issues for the SAGD wells, however desanding facilities have been included in the design as a contingency. If waste sand is collected at the surface it will be disposed of at an EUB licensed facility.

The Project will produce construction and operational wastes. Wastes will be classified and segregated on site and tracked according to provincial requirements. Where possible these wastes will be reused or recycled. Some small quantities of Class I wastes may also be produced and these will be handled, stored and disposed of as per appropriate regulations. The majority of the wastes will be suitable for Class II landfill disposal.

Temporary waste storage sites will be located on the CPFs. These sites will include spill containment, surface runoff control and weather protection as required.

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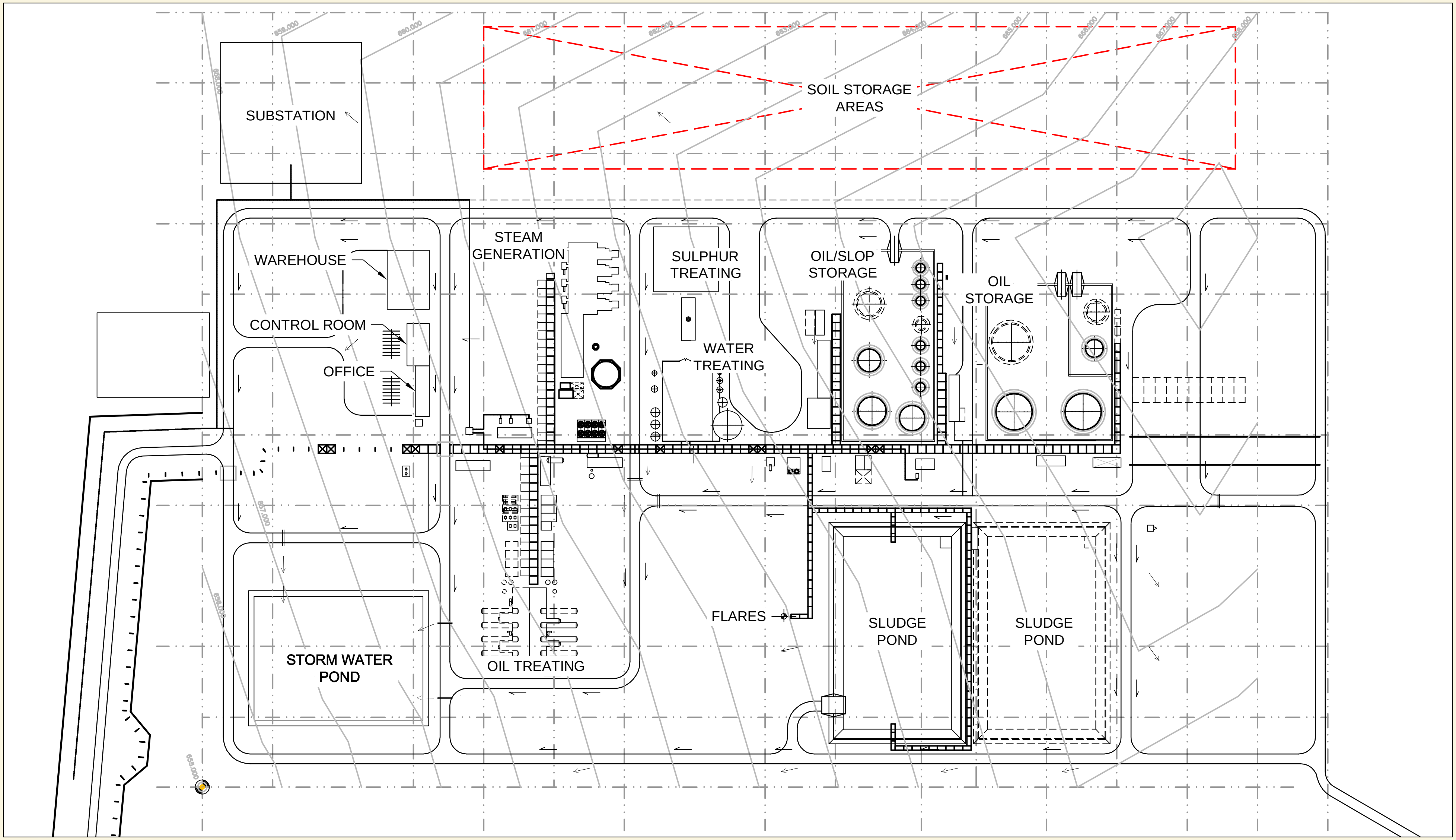
*PLOT 1:1 = Letter (P)



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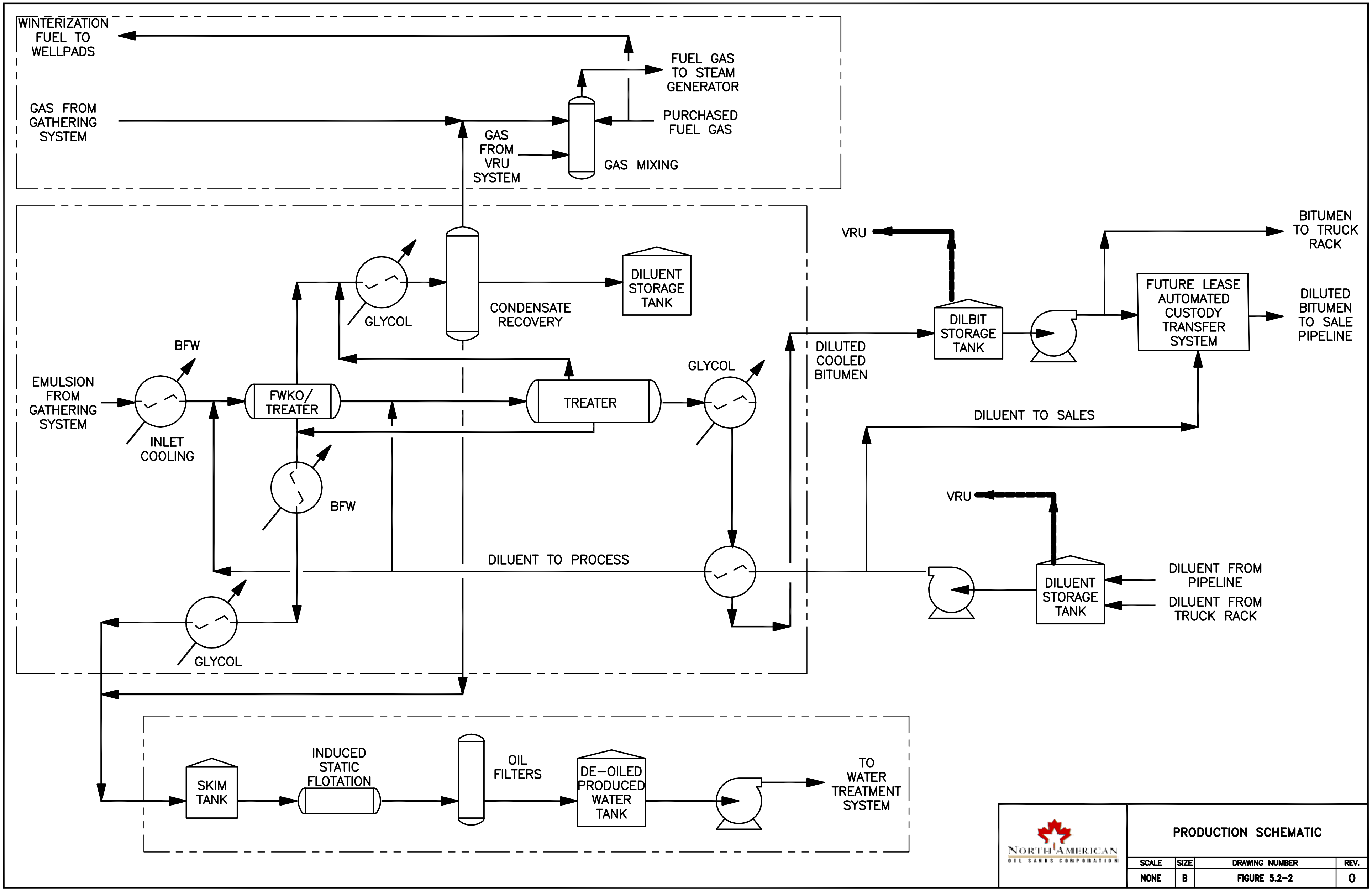
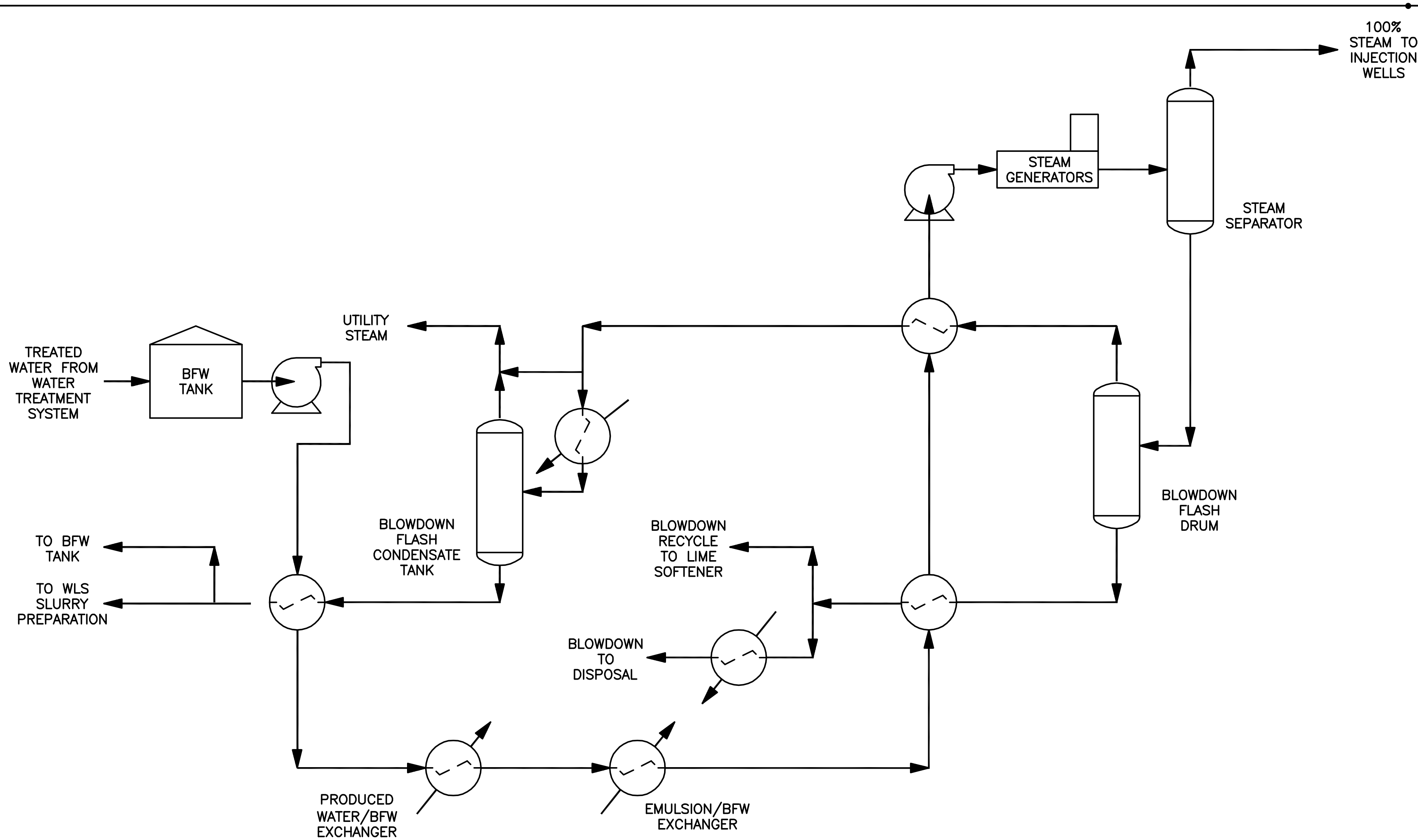
Title: **REPRESENTATIVE CENTRAL PROCESSING FACILITY PLOT PLAN**	
Approved: LP	Revision Date: 07/05/07
File: 4455-PROCESS-07.DWG	
Drawn by: ADF	Checked: BW
Fig. No.: **5.2-1**	


WINTERIZATION FUEL TO WELLPADS
FUEL GAS TO STEAM GENERATOR
GAS FROM GATHERING SYSTEM
PURCHASED FUEL GAS
GAS FROM VRU SYSTEM
GAS MIXING
GLYCOL
DILUENT STORAGE TANK
CONDENSATE RECOVERY
BFW
EMULSION FROM GATHERING SYSTEM
FWKO/ TREATER
TREATER
GLYCOL
INLET COOLING
BFW
DILUENT TO PROCESS
GLYCOL
VRU
DILBIT STORAGE TANK
DILUTED COOLED BITUMEN
BITUMEN TO TRUCK RACK
FUTURE LEASE AUTOMATED CUSTODY TRANSFER SYSTEM
DILUTED BITUMEN TO SALE PIPELINE
DILUENT TO SALES
VRU
DILUENT STORAGE TANK
DILUENT FROM PIPELINE
DILUENT FROM TRUCK RACK
SKIM TANK
INDUCED STATIC FLOTATION
OIL FILTERS
DE-OILED PRODUCED WATER TANK
TO WATER TREATMENT SYSTEM
NORTH AMERICAN OIL SANDS CORPORATION
PRODUCTION SCHEMATIC
SCALE NONE
SIZE B
DRAWING NUMBER FIGURE 5.2-2
REV. 0

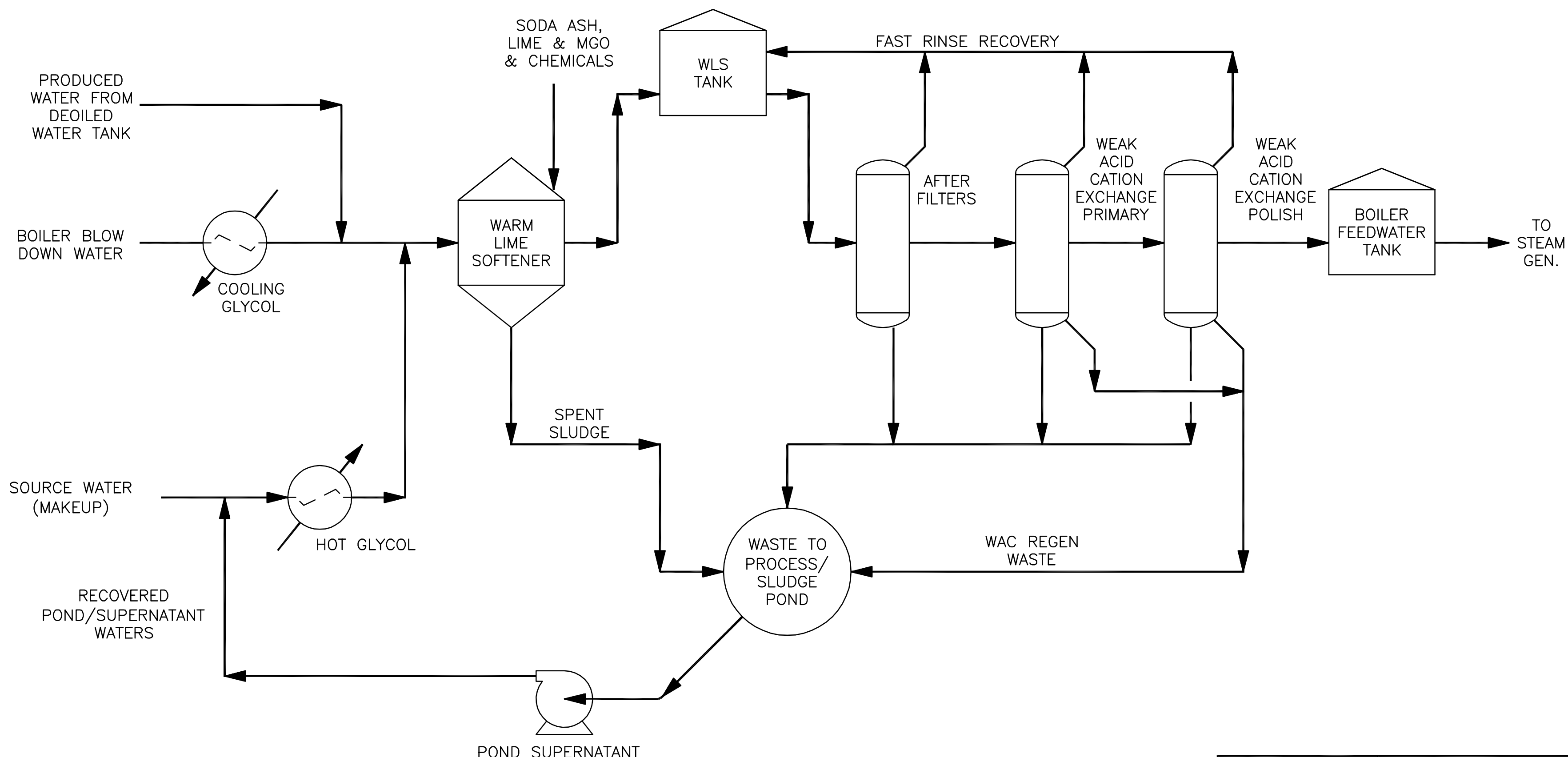


NORTH AMERICAN OIL SANDS CORPORATION

STEAM GENERATION

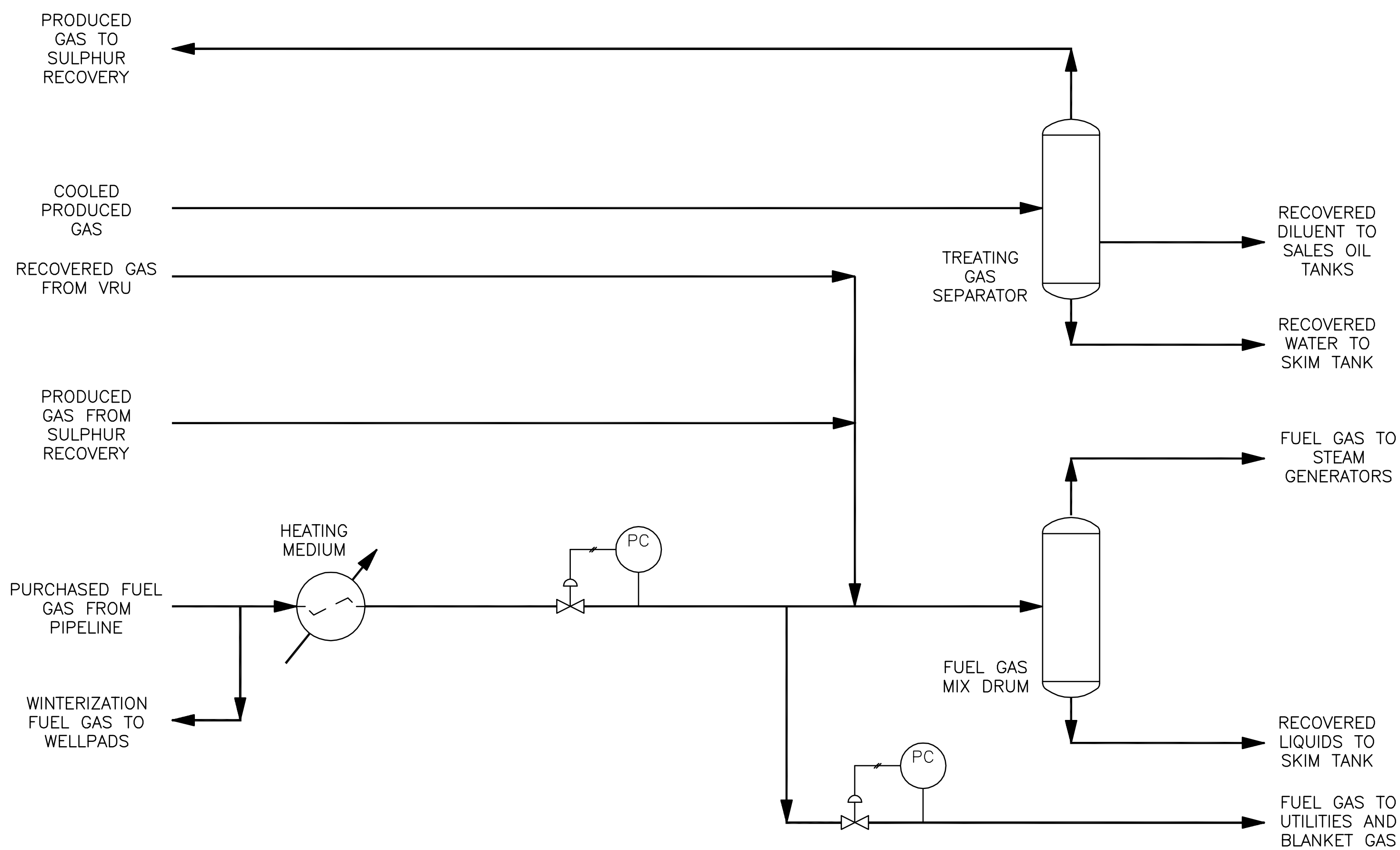
SCALE	SIZE	DRAWING NUMBER	REV.
NONE	B	FIGURE 5.2-3	0

F:\4455 NAOSC\514 North American\Application – Leismer Demo\Old\Draft Sections and Figures\Matrix\FIGURE 5.2-2.dwg – Model – Monday, May 07, 2007 11:57:56 AM – Jason White



NORTH AMERICAN OIL SANDS CORPORATION	WATER TREATMENT SYSTEM		
SCALE	SIZE	DRAWING NUMBER	REV.
NONE	B	FIGURE 5.2-4	0

F:\4455 NAOSC\514 North American\Application – Leismer Demo\Old\Draft Sections and Figures\Matrix\FIGURE 5.2-3.dwg – Model – Monday, May 07, 2007 12:32:33 PM – Jason White



NORTH AMERICAN OIL SANDS CORPORATION

FUEL GAS SYSTEM

SCALE	SIZE	DRAWING NUMBER	REV.
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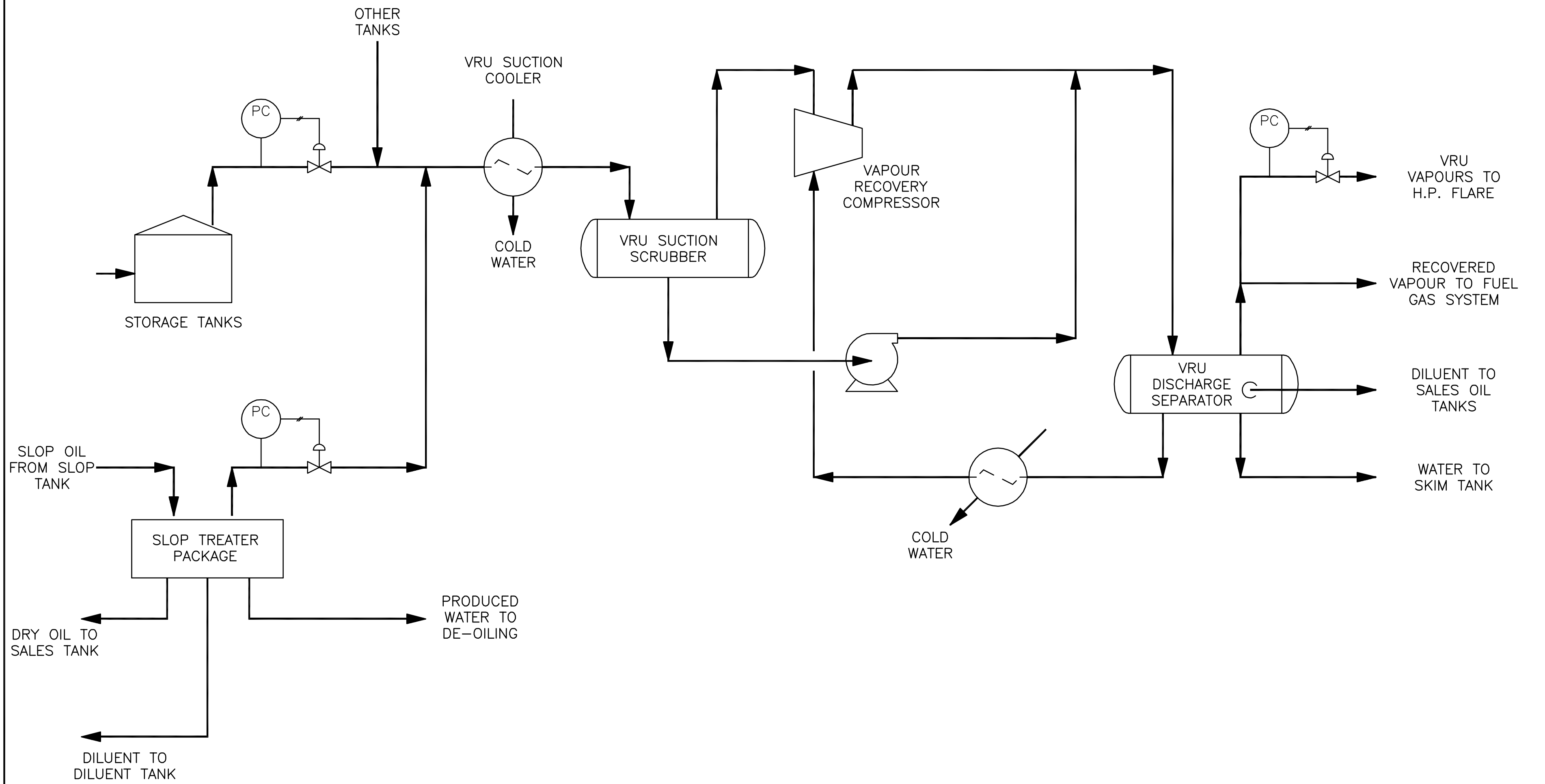

NORTH AMERICAN OIL SANDS CORPORATION

VAPOUR RECOVERY SYSTEM

SCALE	SIZE	DRAWING NUMBER	REV.
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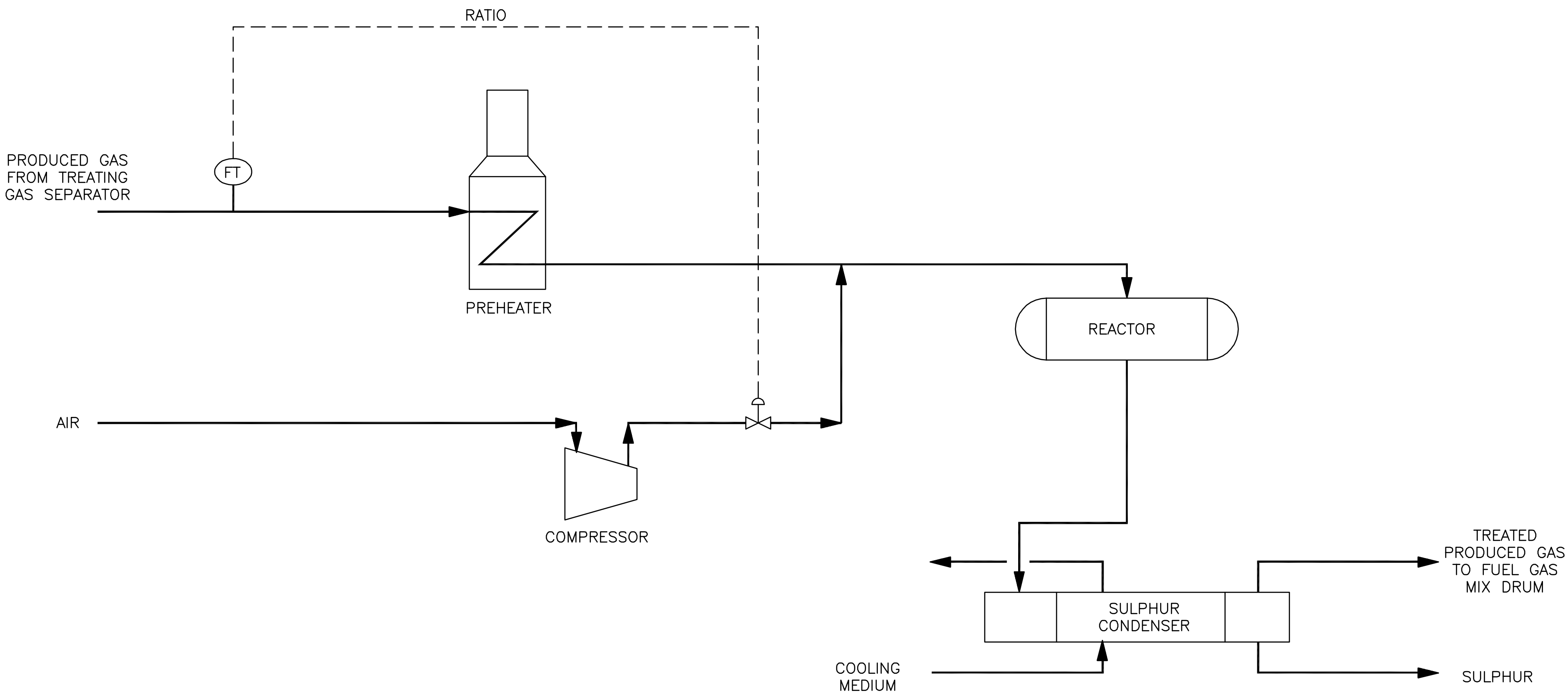
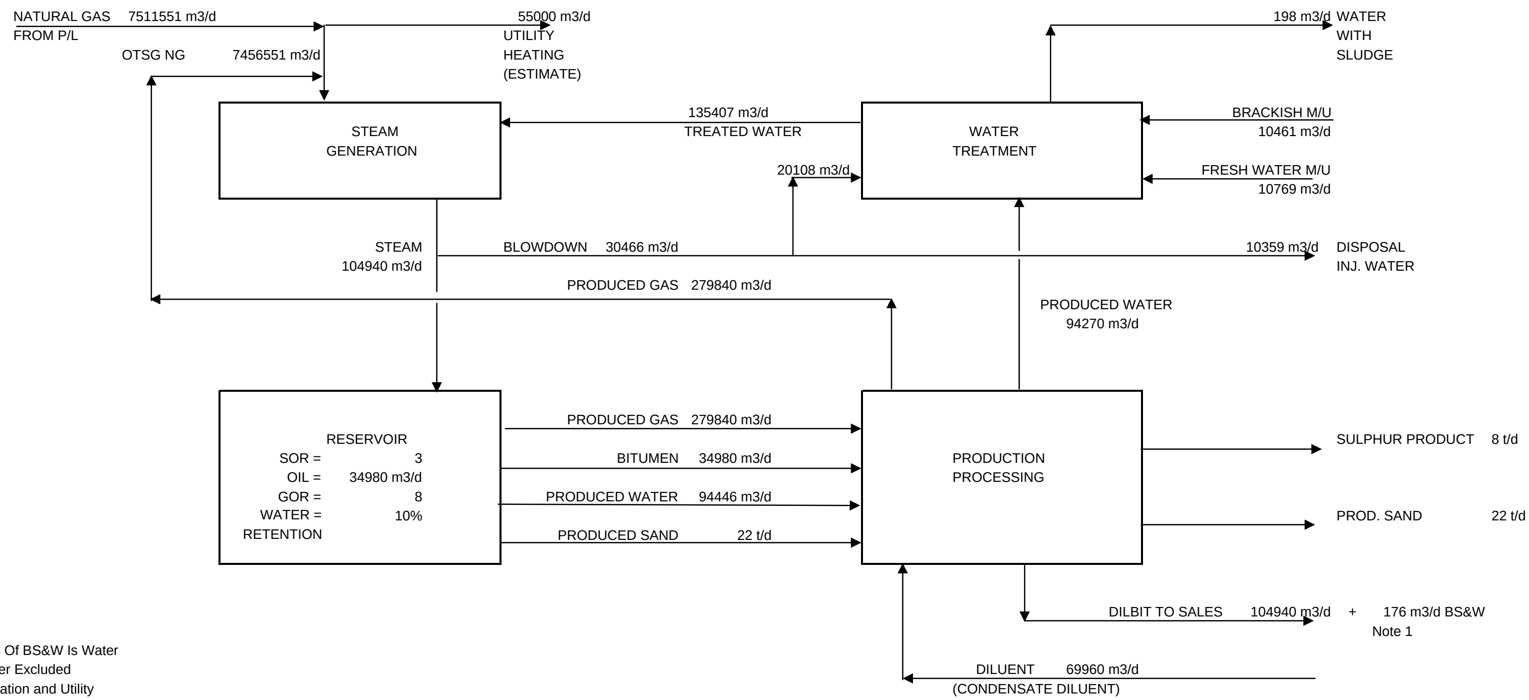


NORTH AMERICAN
OIL SANDS CORPORATION

SULPHUR RECOVERY

SCALE	SIZE	DRAWING NUMBER	REV.
NONE	B	FIGURE 5.2-7	0

F:\4455 NAOSC\514 North American\Application – Leismer Demo\Old\Draft Sections and Figures\Matrix\FIGURE 5.2-6.dwg – Model – Monday, May 07, 2007 12:58:11 PM – Jason White

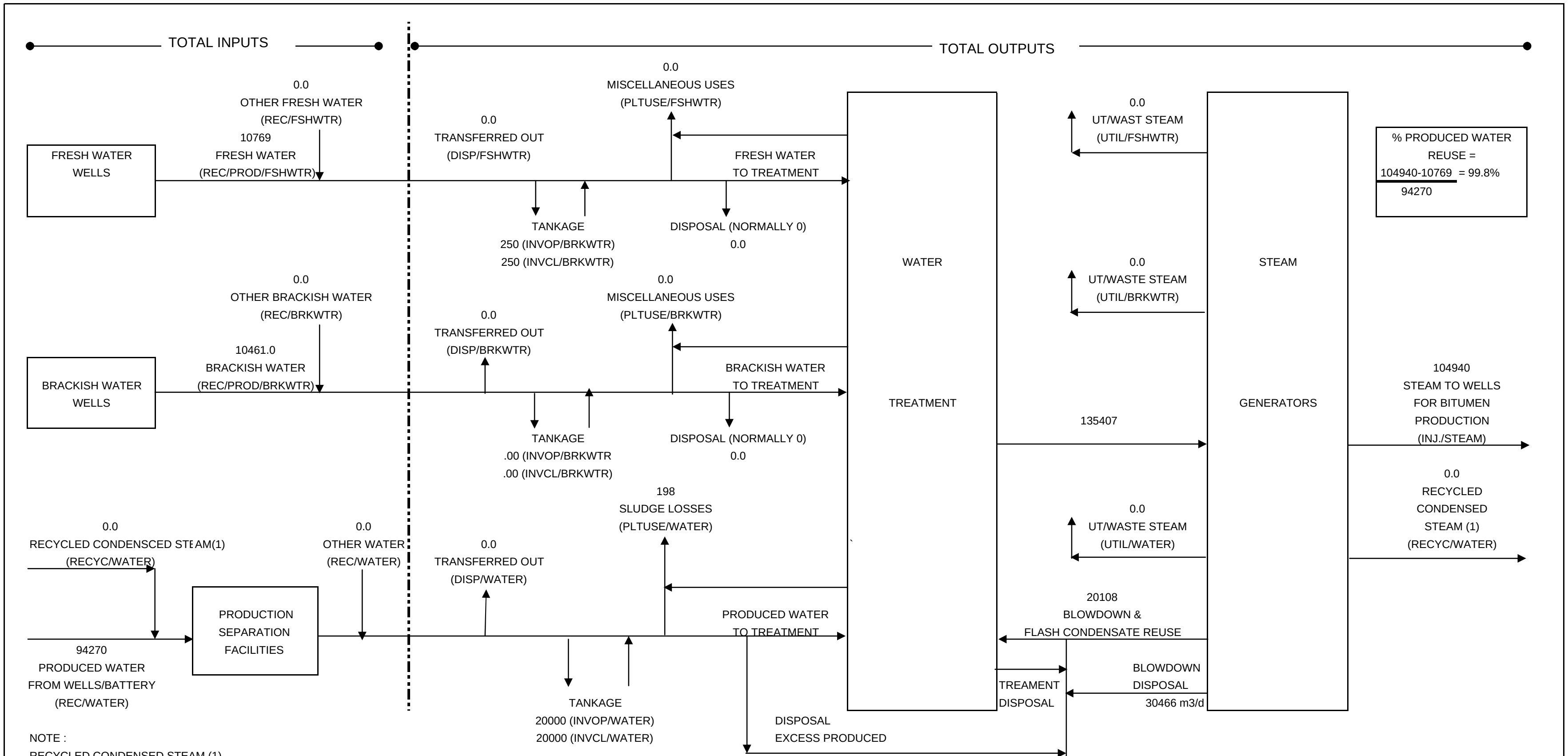


Notes:
1.) Assumes 50% Of BS&W Is Water
2.) Domestic Water Excluded
3.) Pond Evapouration and Utility Losses Excluded

Approximate Stream Rates

NOTE: CALENDAR DAY

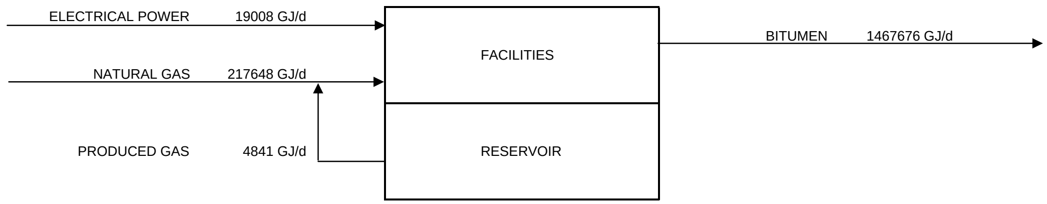
MATERIAL BALANCE BITUMEN PRODUCTION 34,980 m^3/d (220,000 bpd) SOR = 3, RR = 10%			
SCALE	SIZE	DRAWING NUMBER	REV
NONE	B	FIGURE 5.2-8	A



NOTE :
RECYCLED CONDENSED STEAM (1)
(RECY/WATER) RECYCLED CONDENSED UTILITY STEAM THAT ENTERS THE PROCUCED WATER STREAM COMING BACK INTO THE FACILITY
DISPOSAL (2)
(INJ/WATER) DISPOSAL OF FRESH+BRACKISH+PRODUCED WATER
DISPOSAL FRESH PORTION IS CALCULATED FROM TOTAL FRESH IN - OTHER FRESH WATER USES +/- TANKAGE - FRESH WATER INJECTED. NORMALLY 0
DISPOSAL BRACKISH PORTION IS CALCULATED FROM TOTAL BRACKISH IN - OTHER BRACKISH WATER USES +/- TANKAGE - BRACKISH WATER INJECTED NORMALLY
DISPOSAL PRODUCED PORTION IS CALCULATED FROM TOTAL DISPOSAL - DISPOSAL PRESH - DISPOSAL BRACKISH

SIMPLIFIED WATER BALANCE
BITUMEN PRODUCTION 34,980 m^3/d (220,000 bpd)
SOR = 3, RR = 10%

SCALE	SIZE	DRAWING NUMBER	REV
NONE	B	FIGURE 5.2-9	A



ENERGY BALANCE BITUMEN PRODUCTION 34,980 m^3/d (220,000 bpd) SOR = 3, RR = 10%				
SCALE	SIZE	DRAWING NUMBER	REV	
NONE	B	FIGURE 5.2-10	A	

5.3 Environmental and Management Controls

North American is implementing a comprehensive Corporate Health, Safety and Environmental (HS&E) Management System. The HS&E Management System will reflect North American's high priority to minimize the impact of the Project, ensure that the health and safety of all individuals and communities affected are safeguarded, and protect the environment.

Programs developed within the HS&E Management System will ensure continued compliance with regulations by identifying the requirements, ensuring required approvals are in place, and providing appropriate training and equipment for employees and contractors

5.3.1 Contingency Planning

North American has developed a company-wide approach to contingency planning based on operations-specific hazard/risk analysis. Under the umbrella of the HS&E Management System, contingency planning for SAGD operations will include the following priority items:

- Corporate emergency notification procedures;
- Facility emergency response plan; and
- Standard operating procedures.

These contingency plans will be in place prior to the commencement of operations of the Leismer Hub. During the construction phase, the plan will incorporate temporary measures to address potential emergencies specific to construction activities. These temporary measures will account for the increased travel to and from the site, the heavy construction modules and equipment, and the construction workforce. Special efforts during the construction phase will include communications with protective and emergency service providers, additional medical and security personnel for the camp and facility, and measures to mitigate the impact of increased traffic on area roads. Full compliance with all applicable regulations will be required at all times.

5.3.2 Emergency Response Plan

The North American Corporate Emergency Response Plan has been developed to facilitate an effective response by North American operations, management and support personnel in the event of an emergency occurrence that may affect the company. To ensure a state of emergency preparedness throughout the company, North American has developed these emergency procedures to protect the public, employees, contract employees, property and the environment.

With development of the Corporate Emergency Response Plan, North American is prepared to:

- Ensure immediate competent responses to, and handling of an emergency occurrence;
- Minimize danger to the public, employees, contractors and environment;
- Establish and maintain effective communications with all parties in an emergency; and
- Make maximum use of the combined resources of North American, Government agencies and other non-company services.

5.3.3 Fire Control Management

Minor and major fire risks, and their handling, are detailed in the North American corporate Emergency Response Plan. North American has identified two major fire risks associated with the Project:

- Project as a source of fire
    - Electrical and natural gas fired equipment, steam, diluent, and oil transmission lines
- Project impact from wildfire
    - Evacuation plan, shutdown, and other risk assessment
    - Risk to people, environment, wildlife, and project equipment.
    - Facility housekeeping to guard from fire entering facilities

North American will incorporate fire-reduction strategies into the Project design. These strategies address the risk of fire in the plant process, as well as the risk of causing a forest fire from the various Project electrical distribution systems, flare systems and steam piping. A FireSmart Wildfire Assessment was conducted for the Leismer Demonstration Hub which is considered representative for each hub in the Project. The Leismer Demonstration Hub FireSmart assessment predicted a low fire rating for the Structure and Site Hazard and a moderate rating for the Area Hazard.

North American will work with industry operators, the county and the government to develop a comprehensive, coordinated fire response strategy and to ensure access into the area for emergency crews.

North American is committed to a comprehensive fire reduction strategy. This starts with fire prevention in every aspect of facility design, construction and operation. Engineering design of all facilities will provide special attention to prevention tools such as fire detection, proper facility planning, and continuous risk assessment. Facility equipment identified as high risk for fire ignition will be situated and designed to minimize associated risks.

Combustible gas and smoke detection will also be a focus throughout the plant and field facility sites.

The flare systems at each hub incorporate design features to reduce the potential for starting wildfires. The flare system will incorporate a flare knockout to ensure hydrocarbon liquids are not carried through to the flare tip. Liquid level in the flare knockout will be monitored and accumulated liquids removed when necessary. The flare stack will have a continuous burning pilot flame to ensure combustion of all hydrocarbons sent to the flare system. Flare ignition will be by an electrical igniter located at the flare tip.

Prime consideration will be given to the following fire reduction strategies in design, construction and operation of each hub and facilities:

- Using non-combustible building materials;

- Removing combustible ground cover, and proper housekeeping to prevent combustible vegetation buildup;
- Ensuring setback of all facilities from any natural combustible materials; and
- Ensuring building separation, tank farm placement, and combustible equipment setbacks are well designed.

Plans for fire suppression during the operation of the Project require a combination of wall-mounted and wheeled fire extinguishers located around the various facilities, including each CPF and production pad. In addition, operators' trucks will be outfitted with portable fire extinguishers. Fire blankets will be located strategically around the various facilities of the Project.

North American will also ensure continuous assessment of fire risks during construction, commissioning, and operation of the Project, both within and outside the project footprint. North American will also work with the appropriate regulatory bodies, lease holders and land managers to continue the assessment of fire risk potential.

5.3.4 Water Management

North American recognizes water management as an important part of oilfield operations. North American's water management plan focuses on the design of water management systems, reducing fresh water consumption, non-saline water consumption, produced water reuse, water supply management and surface water protection. The principals and concepts of the Source Water and Disposal Management Plan are outlined in Volume 1, Section 4.4.1.

5.3.4.1 Water Management System Design

The topography over much of the Project area consists of low-lying terrain (e.g., bog and fen); however, plant sites will be located in areas of higher ground for increased stability. Field facilities will also utilize existing disturbed/cleared sites or share corridors to minimize site disturbance.

The collection of surface runoff from the CPF and production pads is designed as a precautionary measure and is not intended to prevent runoff from returning to the natural environment on a permanent basis. Ditching, berms and contouring will be used to manage surface water drainage collection. Runoff will be collected, tested, and if deemed suitable, released into the surrounding watershed. Runoff that is not deemed suitable for release will be recycled to the process or sent for proper disposal.

The Project includes a temporary alteration of surface runoff through the incorporation of ditches and surface runoff impoundments. Ditches are designed to maintain natural drainage patterns and avoid ponding of water along roads.

Well pad and CPF storm water retention pond design, operating concepts, and other mitigation measures are as follows:

- Drainage management plans will be developed that address the containment of surface runoff and potential contaminant release. All stormwater runoff from pad/plant areas will be collected, tested, and if suitable, released into the surrounding environment. Runoff not suitable for release will either be recycled or sent for proper disposal. Retention ponds are designed to fully retain a 1:25 year, 24-hour storm event (equivalent to 77 mm based on the rainfall intensity duration frequency curves for the LSA).

- Runoff for the well pads is estimated to be 33% to 66% higher than natural watershed runoff rates, which typically range between 39 mm and 95 mm (Table 6.7-12). However, delayed and controlled releases from the ponds to the surrounding forest will occur. The ponds are not directly hydraulically connected to waterbodies (streams or lakes); rather, pond release is dispersed over an open, low gradient slope. Therefore, the actual volume of runoff that may reach a defined watercourse may be comparable to natural conditions. In low flow periods, the net runoff may be reduced slightly due to higher evaporative losses or from ground infiltration, although fall or early winter releases to drain the ponds may be locally beneficial in dry years. In wet years, there may be slightly more runoff with more frequent releases and less opportunity for downstream losses due to saturated ground conditions, thus, more direct local flow paths to streams may develop. In both dry and wet years, the delayed release effect of the ponds may be considered beneficial by either extending low flow or reducing peak events in the watersheds. In terms of magnitude, the net effect of a typical pond operation might be considered similar to the effects of a small beaver dam.

A network of groundwater monitoring wells will be installed at the CPFs to determine the direction and average groundwater flow velocity and quality of the groundwater. This will ensure an understanding of the local hydrogeology and, in the unlikely event of a spill or plant upset, monitoring systems will be in place to detect impacts to groundwater. The preliminary locations of the monitoring wells will be finalized during detailed engineering however they will be focussed around ponds and areas of potential spills or leaks.

The disposal of waste water into the Basal McMurray aquifer is proposed. This aquifer is over 450 m below the surface and well below the base of groundwater protection.

In addition, water use will be measured. An annual environmental report to the community will be used to disclose North American's water use.

5.3.4.2 Reduction of Fresh Water Consumption

North American's reduces fresh water consumption through both the drilling and operation phases of the Project. An example of a successful water reduction initiative is the Central Fluids Processing Facility (CFPF) set up for the 2006/2007 core hole program. The CFPF reconditions drilling fluids for reuse. The CFPF was located at a remote sump site, in the northern portion of the Leismer area, where the majority of the drilling activities took place. Throughout the 2006/2007 winter drilling season, a total of 8,900 m^3 of used drilling fluids were reconditioned and 5,200 m^3 of the drilling fluids were reused. North American intends on incorporating the lessons learned from the 2006/2007 fresh water reduction initiative into future phases of exploration and development.

Produced water recycling and reuse is a major component of the Project. North American is committed to meeting the EUB's target of 90% water recycling. The efficient recycling of produced water also reduces the Project's makeup water demands. North American will continue to explore the Clearwater, as discussed in Section 4.3, as a potential source of saline water supply for the Project.

5.3.4.3 Surface Water Protection

Mitigation measures, as part of the surface water management plan, to minimize potential changes to water levels, flows, erosion potential, and sediment loading to receiving streams and waterbodies; and the implementation of a surface water monitoring plan are outlined in Volume 3, Section 6.12.

5.3.5 Air Emissions Management

The largest air emissions sources for the Project are the steam generators with minor sources such as the flare systems. As part of the detailed engineering phase, North American will select steam generator manufacturers that can supply energy-efficient units with a low NO_x burner; that comply with theCanadian Council of Ministers of the Environment (CCME) National Emissions Guidelines for Stationary Combustion Turbines and CCME National Emissions Guideline for Commercial/Industrial Boilers and Heaters, and applicable provincial guidelines. Vapours from tanks containing hydrocarbons will be controlled with a natural gas pressure blanket in conjunction with a vapour recovery system. Hot exhaust gasses from the steam generator stacks may at times be visible. The visibility depends on ambient weather conditions and amount of entrained water vapour in exhaust gasses. Visible exhaust emissions are not expected to present any ground level visibility or safety issues on nearby roads. The gas blanket allows for effective collection of any liberated gas to be burned in steam generation. A small quantity of H_2S will be routed to the flare system during shutdown and emergency situations. Quantities of H_2S in the produced gas used to augment the steam generator fuel supply will be reduced by recovering sulphur from the produced gas stream. A Leak Detection and Repair (LDAR) program will be implemented on the facility which will adhere to the requirements of the EUB.

The maximum sulphur inlet for each individual hub is in the 1-3 t/d range and, as such, based on EUB Interim Directive 2001-3 requires 70% sulphur recovery. In its entirety, the Project will have an overall inlet sulphur rate greater than 10 t/d, and, as such, North American has designed each sulphur removal package to meet the 90% removal rate.

Sulphur will be removed from the produced gas prior to mixing the produced gas with natural gas for combustion in the steam generators. The sulphur recovery unit is a small skid mounted, package unit capable of capturing a minimum of 90% of the sulphur as elemental sulphur of suitable quality for sale. This unit operates similarly to the larger scale Claus type units where H_2S is oxidized to elemental sulphur over a fixed bed catalytic reactor. The gas phase process maintains the sulphur in the gas phase until it is recovered in the sulphur condenser. The treated gas leaves the process for the fuel gas mixed drum prior to being consumed as fuel in the steam generators.

5.3.6 Greenhouse Gas Emissions Management

North American plans to use natural gas to generate steam. Currently, natural gas remains the most economical energy source, with the lowest greenhouse gas (GHG) emissions, to produce steam for the SAGD project. North American is designing to achieve a high level of energy efficiency in the production of bitumen. This will assist in mitigating the production of GHG emissions.

North American plans to build an upgrader in Alberta to convert bitumen into a high quality sweet synthetic crude oil. The upgrading plan includes gasification of coke with GHG emissions capture for sequestration. North American believes that upgrading in Alberta is the best approach to deal with GHG emissions produced from the oil sands as it provides for the recovery of CO_2 allowing sequestration to occur in Alberta’s depleting light crude oil fields. North American is preparing a separate application for the upgrader project.

Greenhouse gas emissions will vary over the life of the project as additional hubs come on stream. Table 5.3-1 presents an estimate of the greenhouse emissions over the life of the Project. For comparison, as requested by the TOR, the Projects average GHG intensity of 0.06 t CO_2E/bbl is the same as Nexen/OPTI’s Long Lake South predicted intensity.

Table 5.3-1 Greenhouse Gas Emissions for the Kai Kos Dehseh Project

Year	CO_2 (Megatonnes)								Production	CO_2
	Leismer Demo and Commercial	Leismer Expansion	Corner	Thornbury	Hangingstone	NW Leismer	South Leismer	Total	(million barrels of bitumen)	(t/barrel)
2006	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0
2010	0.28	0.00	0	0	0	0	0	0.28	1.56	0.18
2011	0.43	0.17	0	0	0	0	0	0.60	6.62	0.09
2012	0.43	0.46	0.11	0	0	0	0	1.00	12.97	0.08
2013	0.43	0.46	0.85	0.10	0	0	0	1.84	23.25	0.08
2014	0.43	0.46	0.85	0.83	0	0	0	2.57	35.36	0.07
2015	0.35	0.46	1.62	0.83	0	0	0	3.27	44.94	0.07
2016	0.39	0.46	1.73	0.83	0.28	0	0	3.70	56.43	0.07
2017	0.39	0.44	1.73	1.11	0.45	0	0	4.13	62.93	0.07
2018	0.39	0.43	1.73	1.28	0.45	0	0	4.29	67.76	0.06
2019	0.39	0.43	1.73	1.28	0.45	0	0	4.29	66.73	0.06
2020	0.39	0.43	1.71	1.26	0.45	0	0	4.24	69.12	0.06
2021	0.47	0.43	1.69	1.26	0.45	0	0	4.30	76.70	0.06
2022	0.43	0.43	1.67	1.26	0.45	0	0	4.24	66.07	0.06
2023	0.43	0.41	1.63	1.22	0.45	0	0	4.13	73.79	0.06
2024	0.43	0.41	1.63	1.30	0.45	0	0	4.22	70.42	0.06
2025	0.43	0.41	1.63	1.30	0.45	0	0	4.22	65.68	0.06
2026	0.37	0.41	1.63	1.30	0.45	0	0	4.16	67.46	0.06
2027	0.39	0.41	1.63	1.30	0.45	0	0	4.18	70.54	0.06
2028	0.39	0.41	1.13	1.30	0.44	0	0	3.68	66.38	0.06
2029	0.39	0.41	1.13	1.25	0.43	0	0.16	3.77	69.65	0.05
2030	0.39	0.41	0.51	1.10	0.43	0	0.42	3.26	61.94	0.05
2031	0.39	0.41	0.30	1.10	0.43	0	0.42	3.06	55.68	0.05
2032	0.20	0.41	0.30	0.28	0.43	0	0.42	2.05	41.64	0.05
2033	0	0.31	0.30	0.28	0.43	0.18	0.42	1.93	35.05	0.06
2034	0	0	0.30	0.28	0.43	0.48	0.42	1.92	32.07	0.06
2035	0	0	0.15	0.21	0.43	0.48	0.37	1.65	28.10	0.06
2036	0	0	0	0	0.43	0.48	0.43	1.35	27.72	0.05
2037	0	0	0	0	0.43	0.48	0.43	1.35	21.35	0.06
2038	0	0	0	0	0.43	0.48	0.43	1.35	20.74	0.06
2039	0	0	0	0	0.43	0.39	0.43	1.25	20.69	0.06

Year	CO_2 (Megatonnes)								Production	CO_2
	Leismer Demo and Commercial	Leismer Expansion	Corner	Thornbury	Hangingstone	NW Leismer	South Leismer	Total	(million barrels of bitumen)	(t/barrel)
2040	0	0	0	0	0.43	0.43	0.43	1.30	20.95	0.06
2041	0	0	0	0	0	0.43	0.22	0.65	20.51	0.03
2042	0	0	0	0	0	0.43	0	0.43	13.17	0.03
2043	0	0	0	0	0	0.43	0	0.43	6.49	0.07
2044	0	0	0	0	0	0.43	0	0.43	6.49	0.07
2045	0	0	0	0	0	0.42	0	0.42	7.69	0.05
2046	0	0	0	0	0	0.48	0	0.48	7.26	0.07
2047	0	0	0	0	0	0.48	0	0.48	7.26	0.07
2048	0	0	0	0	0	0.48	0	0.48	7.26	0.07
2049	0	0	0	0	0	0.48	0	0.48	7.26	0.07
2050	0	0	0	0	0	0.36	0	0.36	6.84	0.05
2051	0	0	0	0	0	0	0	0	4.17	0
Total	**9.03**	**9.53**	**27.69**	**22.31**	**10.81**	**7.83**	**5.01**	**92.20**	**1534.71**	

5.3.7 Climate Change

North American's understanding of the proposed provincial and federal climate change regulatory regimes is as follows.

North American will be subject to both the proposed provincial and federal legislation pertaining to climate change. The regulatory approaches are fairly similar at a high level: both are intensity-based, have similar reduction targets, utilize baselines to calculate emissions profiles, and allocate a percentage of taxation revenue to a technology fund that can be accessed to initiate development of various climate change projects (e.g., carbon capture and sequestration, etc.)

Under the proposed provincial regime, large emitters (i.e., over 100,000 tonnes per year, including all North American facilities) must reduce their total combustible CO_2 emissions by 2% per year until a total reduction of 12% is achieved. Any emissions over the 2% reduction are taxed at $15 per tonne, and current policy direction is to allocate this revenue into a technology fund that industry can apply for in order to fund approved climate change projects. Additionally, industry may also utilize offsets to reduce net emissions (i.e., as an alternative to paying the tax). The list of approved offsets is to be developed by the fall of 2007. Credits accrue where emissions are below the targeted reduction amount. Clarity has not been provided at this stage as to whether or not carbon trading will be considered.

North American is also subject to the federal regime, which has several key differences. A 2% annual reduction is applied, however, the 2% is compounded over the life of the facility. A "cap", or target reduction amount has not been established by the federal government. Rather the government has indicated that this approach will be reviewed every five years to determine whether or not national targets are being achieved. A tax is applied to any emissions over the calculated baseline (i.e., the 2% compounded reduction) which has been set at $15 a tonne until 2012, then $20 a tonne in 2013, and a yearly incremental increase linked to the economy thereafter.

The proposed federal regime also allows for offsets to be utilized, similar to the provincial approach. The current policy direction is to encourage domestic offsets versus international offsets. As a result, only a small percentage of total emissions can be offset through international trading. The federal government is anticipated to be in consultations with industry throughout 2007 to develop a list of approved offsets.

Similar to the provincial regime, credits accrue where emissions are below the reduction target. It is anticipated that these credits will be tradable, however the approach, rules or regulations for a carbon market have not been developed yet.

5.3.7.1 Background

Acceptance of climate change as global in scale led to the establishment of the Intergovernmental Panel on Climate Change (IPCC) by the United Nations in 1988. Beginning in 1996, the IPCC introduced a new set of emissions scenarios that covered a wide range of demographic, economic and technological driving forces of greenhouse gases and sulphur emissions.

The IPCC issued a *Special Report on Emissions Scenarios* (SRES) in 2000 that represented the range of driving forces. There are four narrative storylines that represent different demographic (e.g., population growth), economic, technological and environmental developments. Each of the four storylines yields four sets of scenarios called families A1, A2, B1 and B2. Within each family are scenario groups that characterize alternative developments of energy technologies: A1F1 (fossil fuel intensive), A1B (balanced) and A1T (predominantly non-fossil fuel). The A2 storyline describe a heterogeneous world with an underlying theme of self-reliance. The emphasis of the B2 storyline is on global solutions to economic, social and environmental sustainability, while the B2 storyline describes a world with more local solutions to economic, social and environmental sustainability. There are also harmonized scenarios (HS) that share assumptions on global population and other scenarios (OS) that explore uncertainties in driving forces. Altogether, 40 scenarios were developed by modellers who use them in global climate models (GCM) to create a vision of future climate.

This section summarizes GCM results of SRES emission scenarios to estimate climate change in the Project study area, and compares those estimates with historic climate trends derived from long-term data averaged between Fort McMurray and Cold Lake.

Key Climate Factors

Temperature, precipitation, evaporation and evapotranspiration are the primary climatic factors considered in this assessment. The latter three parameters are also important in the water balance equation as can be seen below:

Runoff = $P - E - E_T - \Delta S$

Where:

Runoff = surface flow

P = precipitation over the total area

E = evaporation from the open water areas

E_T = evapotranspiration from the vegetated areas

ΔS = change in storage in both the groundwater and lakes

5.3.7.2 Methods

The magnitude of projected climate change in the Project area was examined using both historic trends from existing data and GCMs. Projected climate change was examined in 30 year increments from 2010-2039 (2020s), 2040-2069 (2050s) and 2070-2099 (2080s). As the 2050s time period spans the economic life of the North American project, it will be used to define climate change and compare between the GCMs and historic trends. Change is compared to a 30 year baseline period 1961-1990; a positive value indicates an increase and a negative value denotes a decrease.

5.3.7.3 Historic Trends

The Project area is situated approximately midway between Fort McMurray and Cold Lake. Therefore, temperature, precipitation, evaporation and evapotranspiration data were averaged between the two communities to represent a baseline (1961-1990) period. This is also considered the 30 year climate normal period. Temperature and precipitation data were obtained from Environment Canada and data for evaporation and evapotranspiration were from Alberta Environment (Bothe and Abraham, 1987; Bothe and Abraham, 1993). Although the evaporation and evapotranspiration data were available only for the period from 1974 to 1994, values are considered to be representative of the baseline period (1961-1990) for purposes of this assessment.

Projected climate change was estimated by extending the trend curve, developed from the historic baseline data up to the 2050s time period. Available temperature and precipitation data spans a period from 1953 to 2005, and evaporation and evapotranspiration extends from 1974 to 1994.

5.3.7.4 Global Climate Models

Projected changes in temperature and precipitation were obtained from the Climate Change Scenario Network website (CCSN, at http://cccsn.ca). Ground resolution is approximately 200 km by 200 km. The website produces scatterplots of 31 different global climate models that show the range of model/scenario results for changes in temperature and precipitation over each time period. Model results were averaged between Fort McMurray and Cold Lake to represent the Project area. Estimates of the change in evaporation were also obtained from the CCSN website, however results from only eight climate models were available.

To provide a range of the predicted climate, the results of the 31 temperature and precipitation models and the nine evaporation models were stratified into 10th, 50th and 90th percentile values. The percentile values represent low, average (median) and high projected change, respectively, of the climate parameters.

5.3.7.5 Results

Historic trend curves and annual variations around the central trend are shown in Figure 5.3-1. The GCM simulation model results are illustrated in Figure 5.3-2, shown as a range of projected results expressed as the 10th, 50th and 90th percentile values for each time period.

Table 5.3-2 summarizes and compares results of the historic trend analysis to the median (50th percentile- red squares in Figure 5.3-2) GCM simulations. The table presents temperature change calculated over an 80 year period, from the mid-point of the baseline period (1961-1990) to the mid point of the 2050s time period (2040-2069).

Temperature

The average annual temperature for the baseline period between 1961 and 1990 is 0.8^{o}C. The historic temperature trend curve shows a wide range of inter-annual variation and an average annual temperature increase of 0.03^{o}C (Figure 5.3-1). This trend, if continued over the 2050s time period, would result in an increase in annual average temperature of approximately 2.6^{o}C. This compares to a GCM median modelled temperature increase of 3.0^{o}C over the same period of time (Figure 5.3-2).

Precipitation

The annual average baseline value for precipitation, using the data from Environment Canada and a baseline period between 1961 and 1990, is 449 mm. If the historic trend were to continue over the 2050s period, it would result in a decrease of approximately 101 mm/y or a 23% decrease. This is contrary to the GCM simulations, which forecast a median increase in precipitation of 8.2 mm, or 2% by the 2050s time period.

Lake Evaporation and Areal Evapotranspiration

The annual average baseline value for lake evaporation, using the data from AENV and a baseline period between 1974 and 1994, is 602 mm. If the historic trend were to continue over the 80 year period to the 2050s time period, it would result in an annual decrease of approximately 27 mm or 4.5%. The historic evapotranspiration trend suggests a decrease of 160 mm at the 2050s time period compared to the baseline value of 320 mm, representing a 50% drop from baseline.

The GCM predicts that, in the 2050s time period, there will be an average annual evaporation increase of approximately 0.11 mm, which is a negligible change from baseline evaporation. The evaporation model results are less reliable than for precipitation or temperature, due in part to the grid cell resolution of 200 km by 200 km, the greater number of assumptions involved (e.g., soil moisture, surface temperature, vegetation type and coverage) (Neil Comer, personal communication, 2007) and fewer model results available. For example, because of the cell resolution size, the model cannot distinguish between lake and areal evaporation. Therefore, it is difficult to make direct comparisons of evaporation or evapotranspiration change between the modelled results and the historic data. However, the bioclimate profiles feature of the CCSN website models an increasing annual water deficit in the study area (19 mm) by the 2050s time period, along with a 10 mm increase in the annual maximum evapotranspiration in July. An increase in estimated evapotranspiration is consistent with the GCM model results of an increase in temperature and precipitation over the same time period.

Table 5.3-2 Estimated Change[1] in Average Annual Climate Factors Between Baseline (1961-1990) and the 2050s Time Period

Method	Temperature (°C)	Precipitation (mm)	Evaporation[2] (mm)
Historic trend	2.6	-101	-27 to -160
GCM (median)	3.0	8.2	0.1

1 A positive value indicates an increase, and a negative value denotes a decrease in comparison to the baseline period.

2 Historic values are for lake (-27) and areal evaporation (-160). The GCM value (0.1) represents lake and areal evaporation combined.

5.3.7.6 Projected Change in Runoff

The impact of estimated climate change on runoff is assessed from the results of the historic trends and the GCM simulations. Change is evaluated relative to the 2050s time period.

For use in the water balance equation, approximately 15% of the LSA is assumed to consist of open water at lakes and wetlands, where lake evaporation will dominate, and the remaining 85% of the LSA is vegetated and subject to evapotranspiration losses. Using data from Volume 3, Section 6.9, the current water balance equation in the project area is expressed as:

1961-2006 runoff (mm) = 481 mm – 602 mm*0.15 – 322 mm *0.85 – 18 mm = 99 mm

Note that in the following comparisons and for the purpose of this assessment, ΔS (change in storage in both the groundwater and lakes) is assumed to remain constant at an annual rate of 18 mm. Also, the 1961-2006 period is longer than the baseline period used in the historic trend and model comparisons. This period of time is consistent with the total period of runoff record, allowing comparisons to the present day average.

Based on Historic Trends

The historic data suggests a 23% decrease in precipitation, 4.5% decrease in lake evaporation and 50% drop in areal evapotranspiration. This yields a runoff value of 129 mm by the 2050s as shown below:

2040-2069 runoff (mm) = 481 mm *0.77– 0.955*602 mm*0.15– 0.5*322*0.85 -18 mm = 129 mm

When compared to the 1961-2006 runoff, this results in an increase of 30% or 30 mm.

Based on GCMs

The GCM simulation predict a median increase of 2% in precipitation and no change in the combined lake evaporation and areal evapotranspiration. Applying these values to the water balance equation yields a runoff of 109 mm, shown below:

2040-2069 runoff (mm) = 481 mm *1.02 – 602 mm*0.15 – 322*0.85 – 18 mm = 109 mm

The estimated change in runoff is 10 mm or 10% higher than the 1961-2006 period.

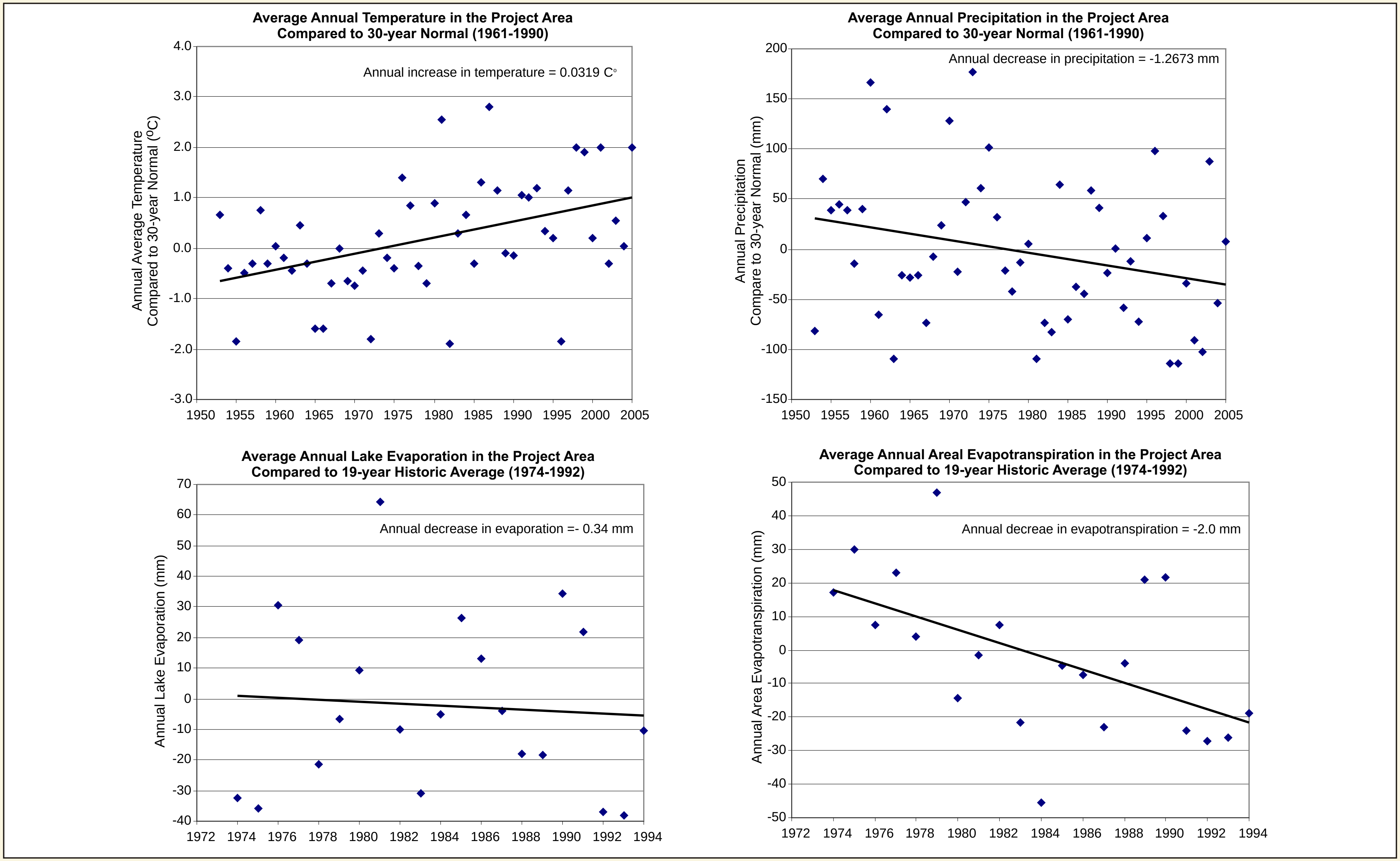
5.3.7.7 Climate Change Impacts in the Project Area

Runoff

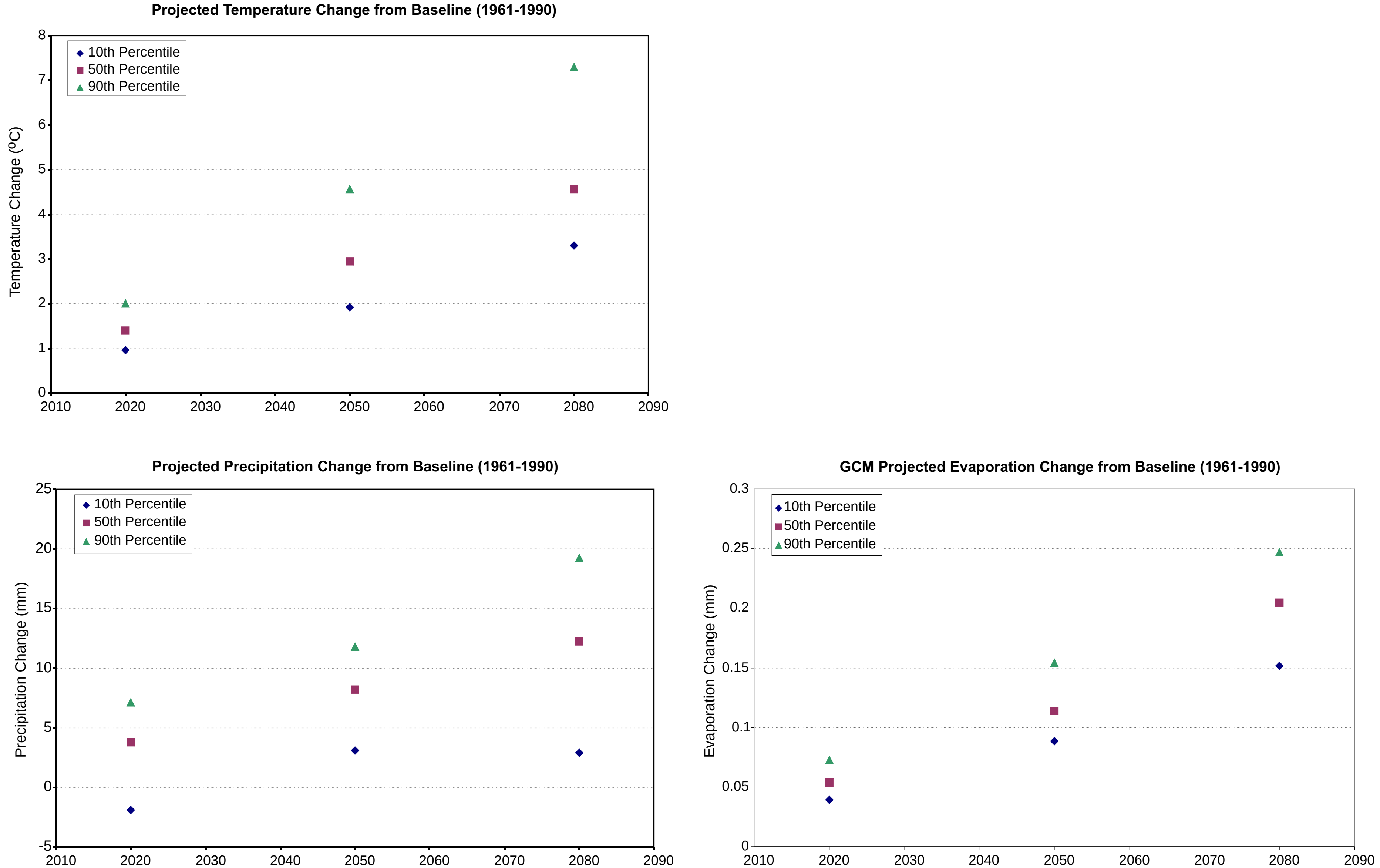
Based on the historic trends and the GCM simulations, runoff is expected to increase by 10% (GCM models) to 30% (historic trends) over the life of the Project. The higher runoff values are obtained by different processes, according to the prediction method. These values are lower precipitation combined with reduced evaporation in the case of the historic trends, or from higher precipitation and almost no change in evaporation, as predicted by the GCMs. The variation in runoff by method reflects a level of uncertainty as the basis for assumptions of both historic trends and models becomes increasingly speculative as the time horizon increases. However, results are consistent with a recent IPCC report (IPCC, 2007) that predicts increased runoff by 10% to 40% in high latitudes by mid-century, along with decreased snowpack, heavier precipitation events, increased winter flooding and reduced summer flows. An adaptation strategy for the Project could be to plan for an average 20% increase in runoff at long-term drainage structures.

Other Potential Impacts

The global temperature models and the historic trends consistently predict an increase in mean annual temperature. Potential impacts to the Project from increased temperatures could include a shorter frozen ground period, less snow, and a reduced winter drilling and construction season. Adaptation and mitigation strategies could include construction of all weather roads to access drilling pads and revised scheduling of winter works.



Title:			
CLIMATE CHANGE GLOBAL CHANGE MODEL (GCM) SIMULATION RESULTS	Approved: RL	Revision Date: 07/07/03	
	File: 4455-HydCharts-07-2.cdr		
	Drawn by: GDE	Checked: GH	Fig. No.: **5.3-1**



Title:

CLIMATE CHANGE HISTORIC TRENDS AND VARIABILITY IN CLIMATE FACTORS

Approved: RL		Revision Date: 07/07/03	
File: 4455-HydCharts-07-2.cdr			
Drawn by: GDE	Checked: GH	Fig. No.: **5.3-2**	

6 PUBLIC CONSULTATION

North American is committed to developing and maintaining constructive dialogue with all relevant stakeholders associated with the Project. The consultation process is designed to be ongoing from initial planning through construction, operation and decommissioning of the Kai Kos Dehseh Project.

6.1 Goals and Objectives

The goals of North American's public consultation process are:

- To be a good neighbour and the preferred employer in the region;
- To involve community stakeholders in planning, design and implementation of projects in order to identify issues and address concerns;
- To ensure that maximum positive impacts are realized; and
- To assist North American's project planning.

The objective of the public consultation is to establish a constructive and mutually beneficial relationship between North American and project affected stakeholders by implementing an effective process of information exchange and decision-making. Through this process, stakeholders have the opportunity to:

- Review information relative to the planning, development and implementation of projects;
- Identify issues and concerns relative to the planning and implementation of project processes;
- Provide feedback to the project planning process and, where possible, improve North American's overall plans in the area; and
- Receive feedback from North American on community concerns.

6.2 Stakeholder Identification

The following stakeholders have been identified during the course of the public consultation process:

6.2.1 Community Stakeholders

North American's stakeholder focus is on communities within 30 km of the process. These stakeholder communities include:

- Conklin
    - Conklin Community Association
    - Conklin Métis Local

- Janvier/Chard
    - Chipewyan Prairie Dené First Nation (CPDFN), Chipewyan Prairie Dené First Nation Industrial Relations Corporation (CPDFN-IRC)
    - Community of Chard and Chard Métis Local 214
- Fort McMurray No. 468 First Nation (FMFN), Fort McMurray No. 468 First Nation Industrial Relations Corporation (FMFN-IRC)
- Anzac

North American also engages communities within a larger local area outside of the immediate 30 km radius of the operating lease holdings. These community stakeholders include:

- Métis Nation of Alberta (MNA), Region 1
- Lac La Biche
- County of Lakeland
- Heart Lake First Nation
- Ft. McMurray
- Regional Municipality of Wood Buffalo

6.2.2 Industry Stakeholders

North American has consulted with the following industry stakeholders:

- 297917 AB Ltd.
- Alberta Infrastructure & Transportation
- Alberta Pacific Forest Industries Inc.
- Alta Gas Ltd
- Altalink Management
- Arthur Layman
- ATCO Electric Ltd.
- Avenir Operating Corp.
- Barnwell of Canada
- Bounty Developments Ltd.
- BP Canada Energy Company
- Burlington Resources Canada Ltd.
- Canadian Coastal Resources
- Canadian Forest Oil Ltd.
- Canadian Natural Resources Limited
- Cavalier Land Ltd.

- Chair Resources Inc.
- Compton Petroleum Corporation
- Connacher Oil and Gas
- ConocoPhillips Canada
- Consun Contracting Ltd.
- County of Lakeland
- Devon Canada Corporation
- Edmonton Office - Public Lands
- Enbridge Pipelines (Athabasca) Inc.
- EnCana
- Fortisalberta Inc
- Husky Oil Operations Ltd.
- Imperial Oil Resources
- JACOS
- Koch Exploration Canada Corp
- Lac La Biche - Land Use
- Lac La Biche Regional Community Development Corporation
- Laricina Energy
- MD of Wood Buffalo
- MEG Energy Corp.
- Meridian Land Services Ltd.
- Millar Western Forest Products
- Nal Resource Management Ltd.
- Nexen Inc.
- Northrock Resources Ltd.
- Northstar Energy Corp.
- OPTI Canada Inc.
- Paramount Energy Trust
- Paramount Resources
- Petrobank Energy and Resource Ltd.
- Petro-Canada
- Petroland Services Ltd.
- Primewest Energy Corp.
- Provident Acquisitions Inc.

- Regional Municipality of Wood Buffalo
- Saskatoon Assets Ltd.
- Scott Land and Lease Ltd.
- Stone Valley Contracting Ltd.
- Stylus Energy Inc.
- Suncor
- Superman Resources Inc
- Talisman Energy Inc.
- Telus Communications
- Total E&P Canada Ltd.
- Town of Lac La Biche
- TransCanada Pipeline
- Vault Energy Inc
- Whitesands Insitu

6.3 Membership in Associations

North American worked with the Chipewyan Prairie First Nation Industrial Relations Corporation (CPDFN-IRC) throughout 2006 to reach a working agreement. The agreement was not signed due to a change in leadership with CPDFN-IRC. North American continues to pursue a working agreement with the CPDFN-IRC. In September 2006 North American participated in a program funding initiative with the Fort McMurray #468 First Nation Industrial Relations Committee (FMFN-IRC), as a first step in becoming an Industry member and working with FMFN-IRC Traditional Land Use Study information. North American formally committed to becoming an Associated Member of the FMFN IRC in July 2007.

North American is engaging the Heart Lake First Nation as a stakeholder at a distant proximity to the Project. In December 2006 North American signed a consultation agreement in principle with the Heart Lake First Nation Consultation Office.

North American is involved with the Southern Athabasca Oil Sands Group and the Lac La Biche Regional Industry Consultation committee.

6.4 Community Engagement

North American has disclosed information regarding development of the Kai Kos Dehseh Project since public consultation began with local communities over three years ago. Throughout the last year, North American has used the following to disclose project information to local communities:

- North American’s presentation to the communities at Elders Meeting and Communities Open Houses
- North American’s 2006 and 2007 Newsletters
- North American’s Public Disclosure Document

- North American's Project Schedule Brochure
- North American's website www.naosc.com

6.4.1 Stakeholder Engagement

Formal community engagement has continued throughout 2006 and into 2007 between North American and identified stakeholder communities. North American will report in each Application to the EUB, on all consultation initiatives undertaken with the stakeholder communities since the previous Application was submitted to the EUB. All the stakeholders listed in Table 6.4-1 received the Public Disclosure document in January 2007, which coincided with the media release. A detailed database of community engagement is maintained by North American.

Table 6.4-1 Community Engagement

Community Stakeholder	Activities
Fort McMurray	• July 2006-June 2007, on going contact and information sharing with Mayor Blake and various city departments.
Anzac	• July 2006 – June 2007, Contact with Anzac Community Association and Municipal Office. Community Reports, Newsletter, Employment & Training Initiatives and Public Disclosure Document available to community at Municipal Office.
Fort McMurray #469 First Nation	• July 2006-June 2007, On going efforts to work with FMFN and becoming a member of the FMFN Industry Relations Corporation.
Chipewyan Prairie Dene First Nation	• July 2006- June 2007, On-going meetings and discussions.
Hamlet of Chard Chard Métis Local 214	• July 2006-June 2007, On-going meetings and discussions.
Hamlet of Conklin	• September 12, 2006, held Information evening at a community meeting at the Nakewin Community Centre. • July 2006-June 2007, North American has continued contact and meetings with the Conklin Community Association and community members.
Métis Nation of Alberta (MNA), Zone 1	• On-going meetings and discussions from September 2005.
Lac La Biche	• July 2006-June 2007, on going meetings and discussions with community. • September 21, 2006, held Community Information Evening at McArthur Place, Lac La Biche.
Heart Lake First Nation	• July 2006-June 2007, on-going community meetings and discussion.

6.4.2 Conklin Community Open House

North American held an open house in Conklin on September 12, 2006, with 67 community members attending a dinner and information session. North American representatives shared plans regarding company drilling, seismic, and potential construction plans for the 2006/2007 work season. North American also informed the attendees that the Leismer Demonstration Application had been submitted to the EUB and AENV for approval. Elder Edward Adby translated North American's presentation into Cree so Elders could understand. Throughout the evening six North American representatives met one-on-on with Elders, young people, business owners, community members looking for employment, and many other community members with related questions. North American also held discussions with community members about North American's long-term development plans in Leismer, Corner, Thornbury and Hangingstone. Questions about North American's water/land use and animal/plant monitoring were asked by some community members. North American representatives took these opportunities to share environmental stewardship plans for the Project. North American committed to donating a copy of an art print by Cynthia Quintal artwork for the Mayor's Picnic on September 23, 2006 in Conklin.

6.4.3 Lac La Biche Open House

On September 21, 2006 North American held an open house in Lac La Biche with about 60 community members attending. North American's six representatives shared with the community members regarding upcoming drilling, seismic and potential construction plans for the 2006/2007 work season. Many community members attending were interested in employment and contract opportunities. North American collected business and resume information for consideration. Other people attending included a number of community leaders and members of local community organizations. North American held discussions with community members about North American's long-term development plans in Leismer, Corner, Thornbury and Hangingstone. Questions about North American's water/land use and animal/plant monitoring were asked by some community members. North American representatives took these opportunities to share environmental stewardship plans for the Project.

6.4.4 Janvier/Chard Meetings

North American met with our Elders group, Chief, Council and some members of the community of Janvier/Chard on June 1, 2006. North American presented information about the drilling and seismic operations that took place in the 2005/2006 season. North American also informed the attendees that the Leismer Demonstration Application had been submitted to the EUB and AENV for approval. After the meeting, North American took all six Elders and other community members on a helicopter tour to show them the areas North American would be considering for future development.

On December 15, 2006, North American attended a meeting with Chard Elders and some community members. This meeting was called by community members organizing the Chard Métis Local. There were 11 Elders in attendance and many other community members joined the meeting. A number of community concerns, not directly related to North American, were voiced. North American encouraged the community members to have discussions as a group to find solutions to their concerns.

6.4.5 Industry Consultation

McMurray net gas pay mapping, provided in Appendices A, B, and C, shows associated and non-associated natural gas caps encountered in the McMurray formation. The development rights to these natural gas resources are not held by North American and it is recognized that gas-over-bitumen issues need to be addressed to the satisfaction of the natural gas rights owners within the vicinity of North American's project area. Accordingly, North American has initiated consultation with natural gas rights holders regarding the potential impact of SAGD development on overlying gas caps. Based on feedback received from North American's industry notification efforts, discussions on joint evaluations strategies for quantifying remaining gas reserves, strategies for realizing value from these reserves within the current regulatory framework and methods for identifying communication between an associated gas cap and bitumen recovery have taken place. North American will use the consultation framework established to continue discussions with all gas rights owners as the SAGD development proceeds. It is expected that industry consultation will be ongoing throughout the regulatory application process and North American will provide updates as required by the EUB.

6.4.6 EIA Public Disclosure Document and Proposed Terms of Reference

In January 2007, North American filed both the Public Disclosure Document and the Proposed Terms of Reference to all community stakeholders noted in Section 6.2. Accompanying the release of these documents, North American published the public notice for the North American Oil Sands Corporation Proposed Kai Kos Dehseh SAGD Project Environmental Impact Assessment Report Proposed Terms of Reference in major Alberta newspapers, local newspapers and local newsletters. Copies of the public notice were also posted in local community centers in stakeholder communities in close proximity to the project. The Kai Kos Dehseh Project Public Disclosure Document and the Terms of Reference Document were also delivered to each Trapper within North American's lease areas.

6.4.7 North American Report to the Community

In June 2006 North American published its first Report to the Community and Environment Report to the Communities (Appendix D). Theses reports were written and published to openly show and update communities about North American's activities, the successes, challenges, lessons learned and future plans. North American delivered a copy of each report to each house hold/family via mail in the communities of Janvier/Chard and Conklin. Copies were also given to the Municipal Offices in Fort McMurray, Anzac, Chard and Conklin, to Fort McMurray First Nation Office, Chipewyan Prairie Dene First Nation IRC Office, Town of Lac La Biche, Métis Zone 1 Office, Industry Stakeholders and many other interested parties.

The response from community members who read North American's reports was positive. It also resulted in a number of people, who did not know about North American, enquiring about contract and employment opportunities. North American remains committed to publishing both reports to the community annually.

6.4.8 Aboriginal Community Consultation Reporting to Alberta Government

North American is aware of and commits to fulfilling the Alberta Government's Guidelines/Policy for First Nation Consultation on Land Management and Resource Development released in September 2006. Upon review of these guidelines set for Alberta Environment, Alberta Energy, Alberta Sustainable Resources Development and Alberta Community Development, North American is confident the company has been and will continue to meet and exceed the guidelines applying to industry proponents.

North American will continue to report to the EUB by regularly submitting Community Consultation Matrixes, Newsletters and Reports to the Communities. Accordingly, Alberta

Environment, Alberta Energy, Alberta Sustainable Resources Development and Alberta Community Development will receive copies of these documents.

7 EIA SUMMARY

7.1 Introduction to Impact Assessment Approach

The purpose of the North American Project Environmental Impact Assessment (EIA) (Volumes 2 through 5) is to explain the environmental and socio-economic effects of the proposed Project individually, as well as in conjunction with other existing and planned projects in the area.

The EIA has been prepared in accordance with the requirements prescribed under the *Alberta Environmental Protection and Enhancement Act* and the Final Terms of Reference (TOR) for the Project (Volume 1, Appendix D). The EIA forms part of North American's joint application to the Alberta Energy and Utilities Board (EUB) and Alberta Environment (AENV).

Preliminary work for the Project was initiated in 2005 to evaluate Project alternatives, identify pertinent data sources and define required data collection programs. Initial discussions were held with government departments to scope out the Project requirements, application procedures and regulatory processes.

Consultation was conducted with local residents, government representatives, First Nations, Métis Associations and other public representatives during this period to identify biophysical and socio-economic issues and to confirm study requirements (Volume 1, Section 6).

Field work was undertaken from 2005 through 2007 to enhance regional water, fisheries, soil, vegetation, wildlife and historical information.

Potential environmental and socio-economic impacts for both the Project alone and the Project contribution to cumulative effects were identified and assessed by team members using the following steps:

- Issues of greatest concern to stakeholders and regulators were identified in each discipline in order to focus the assessment.
- Ecological or socio-economic indicators (i.e., selected variables or parameters for in-depth analysis) were identified for each discipline to help quantify or evaluate the potential effect of disturbances.
- Spatial and temporal boundaries were considered for each indicator. A Local Study Area (LSA) and a Regional Study Area (RSA) were spatially defined for the purpose of the environmental assessment. Similarly, temporal boundaries were defined for a number of the Project phases.
- Management methods including construction, design or scheduling principles were applied to prevent, minimize or mitigate adverse effects.
- Quantitative or qualitative assessments were made by comparing predicted residual effects (i.e., effects remaining after the application of management methods) to determine environmental or socio-economic consequence. Consequence and a final impact rating was defined based on established objectives or scientific criteria.
- Identification of monitoring or follow up programs, if required.

There are numerous measurable parameters which may contribute in the assessment of environmental or socio-economic conditions and potential effects. Measuring and assessing all of the possible parameters and interactions is impractical. An accepted approach is to select key parameters or variables that are indicators for a broader group of parameters. Indicators are useful in quantifying or evaluating the effects of disturbances on ecological and socio-economic conditions. Selected indicators for each component are described in the applicable section.

Assessment criteria were used to describe and evaluate the predicted significance of project effects and the cumulative effects for various indicators.

The integration of the various effects criteria ratings result in a final impact rating for each potential Project effect. The possible final impact ratings are: no impact, negligible impact low impact, medium impact or high impact. The result of combining objective and quantitative assessments with subjective evaluations and best professional judgment provides a conclusion for each predicted Project effect.

Cumulative effects likely to result from the combination of the Project and other existing and proposed projects in the area and reasonably foreseeable environmental changes were considered and evaluated for each discipline using methods suitable to the discipline-specific issues.

7.2 Air

The air quality assessment provides an understanding of the magnitude and the spatial variation of potential air quality changes associated with the Project emissions. These emissions will overlap with emissions from other local and more distant emission sources; therefore, the ambient air quality assessment for the project considers all of these sources. Dispersion modelling was conducted for baseline (existing and approved sources), application (baseline plus project) and cumulative (baseline plus project plus other planned projects) scenarios. The air quality assessment focuses on determining air quality changes due to operation of the project and providing the information required to assess the potential effects of these air quality changes on terrestrial resources, aquatic resources and human health.

The comparison between the baseline and application scenarios indicates that the air quality impacts due to project emissions are low relative to other existing or approved sources in the air RSA. The effect of Project emissions on ambient concentrations of SO_2, NO_2, and $PM_{2.5}$ outside the air LSA is so small that it is unlikely to be detected. Within the LSA, the increase in SO_2, NO_2 and $PM_{2.5}$ are predicted to be low; and all predicted concentrations are below applicable regulatory criteria. As a result of the predicted increased SO_2 and NO_2, the potential acid input (PAI) is expected to increase in the LSA with the addition of the Project; however, this increase is low in magnitude and limited to a small area surrounding the project.

In addition to the existing and approved sources, there are a number of proposed projects located in the air RSA and LSA that are currently in the approval process or have been publicly disclosed. The cumulative scenario assessed effects of these projects along with the Project. The results of modelling indicate that there are increases in predicted concentrations of SO_2 and NO_2 in the RSA and LSA. NO_2 concentrations are predicted to still be below AAAQO's; however, new exceedances of SO_2 objectives are predicted. $PM_{2.5}$ concentrations are also predicted to increase in the LSA and RSA for the cumulative scenario. Due to the increase in NO_2 and SO_2, PAI is predicted to increase in the LSA. However, this increase is primarily associated with other proposed projects in the LSA and RSA and not the Kai Kos Dehseh Project.

Ambient concentrations of selected compounds at representative community and recreational area locations in the air LSA are predicted to be less than the applicable ambient air quality objectives. While naturally high ozone concentrations can occur in the area, the incremental impact due to the Project NOx emissions is expected to be low. GHG emissions from the Kai Kos

Dehseh Project, which will reach their peak in 2018, are estimated to contribute 1.8% and 0.6% to the 2003 provincial and 2004 national totals, respectively.

7.3 Noise

Noise modelling was conducted for the CPFs separately since each one is far enough from the others that there is negligible impact from the others. There are no permanent dwellings near the study area and neighbouring industrial facilities are too far away to have an appreciable impact.

The noise modelling results indicate noise levels for each CPF to be well below the EUB Directive 038 permissible sound level (PSL) of 40 dBA $L_{eqNight}$ at 1.5 km from the fence-line. In all but one case, the noise levels were less than 35 dBA, allowing for an acceptable factor of safety for modelling error and potential low frequency tonal components typically associated with large boiler and heater exhaust. Further, the noise levels at the nearby Trappers Cabins are even lower than at the 1.5 km perimeter, with most being at the typical ambient noise levels for the area. As such, the overall noise impact on the surrounding area will be minimal.

7.4 Health

The human health risk assessment for the Project focused on direct and indirect (airborne and multi-media) health risks associated with industrial and community air emissions in the RSA. In addition, an assessment of potential health effects associated with existing background environmental chemical concentrations was conducted. Health risks associated with airborne emissions of the chemicals of potential concern (COPCs) were characterized through the comparison of predicted acute and chronic air concentrations with exposure limits considered protective of the sensitive individuals. Health risks from the consumption of traditional foods and wild game were characterized using a multi-media exposure model used to predict long-term exposures from COPCs that may enter the food chain. Estimated long-term exposures were also compared to recognized exposure limits that are considered protective for sensitive individuals.

A total of 79 discrete receptor locations were identified. These locations were classified as being a member of one of the following receptor groups: First Nations, Residential, Commercial or Recreational. For the inhalation assessment, the maximum predicted air concentration in each group was selected and evaluated. To ensure that the most conservative estimate of COPCs in media other than air was evaluated, the maximum predicted annual air concentration for each COPC (regardless of receptor group or location) was used in the multi-media assessment.

Overall, the Project is anticipated to have a negligible effect on human health on both an acute and chronic basis.

Potential health risks were identified for some COPCs as a result of either existing background conditions or contributions from area sources to the predicted air concentrations in the baseline, application and CEA cases. The Project on its own is anticipated to contribute to minimal or no health risks in addition to background concentrations or predicted concentrations (baseline, application and CEA cases) of the COPCs.

7.5 Hydrogeology

The potential impacts of the Project on groundwater were assessed with respect to water levels and water quality for the following: surface waterbodies, undifferentiated overburden aquifer/aquitard, Empress Terrace Aquifer, Empress Channel Aquifer, Lower Grand Rapids Aquifer, Clearwater A Aquifer, Clearwater B Aquifer and Basal McMurray Aquifer.

Through the lifespan of the Project, components which have the potential to affect indicator resources include:

- operation of surface facilities;
- potable water withdrawal;
- make-up water withdrawal;
- wastewater injection; and
- production and steaming.

Of the above components, the operation of surface facilities, potable water withdrawal, wastewater injection and production and steaming were each given a final impact rating of no impact or low impact.

Make-up water withdrawal activities at SAGD operations generally have impacts that extend beyond their project boundaries (i.e., on a subregional scale). Several subregional scale impacts can cumulatively add up to one regional impact. As such, it was necessary to assess the impacts of the Project's make-up water demand by including adjacent SAGD projects.

In order to assess the impacts of the Project's make-up water demand, three groundwater simulations were completed using the numerical groundwater model.

1. The baseline case simulation implemented the pumping schedules from all existing and approved SAGD projects in the region.

2. The application case simulation combined the baseline case simulation with the pumping schedule for the Project.

3. The cumulative effects case simulation combined the application case with the planned projects in the RSA.

The application case simulation predicted localized high magnitude impacts to water levels in the Basal McMurray Aquifer, Clearwater A Aquifer and Clearwater B Aquifer. A decrease in aquifer productivity of 15% to 70% is not a concern for SAGD water supply because there would be still be at least 30% of available drawdown remaining in the aquifer in the vicinity of the supply wells. As such, the final impact assessment rating given was low impact with regard to make-up water withdrawal for these aquifers.

On the other hand, the application case simulation predicted a high magnitude of impact for the Lower Grand Rapids Aquifer and it was not considered localized. The application case simulation predicted a greater than 70% change in aquifer productivity for an area encompassing the OPTI/Nexen Long Lake, ConocoPhillips Surmont and Petro-Canada Meadow Creek projects. A final impact rating of medium was given with regard to make-up water withdrawal on the Lower Grand Rapids Aquifer. However, the baseline case simulation predicted a very similar result suggesting the Project has a relatively small incremental impact on baseline conditions. Hence, the point of control and mitigation of this final impact rating does not lie with the Project.

The baseline case simulation and application case predicted very similar results regarding change in flux at surface suggesting the Project has a relatively small incremental impact on surface waterbodies. Therefore, the point of control and mitigation of this impact does not lie with the Project.

Overburden and bedrock groundwater monitoring will be required during the operation phase of the Project to confirm that changes in hydraulic head, temperature and/or water quality are consistent with results of the impact assessment and evaluate the environmental performance of operations and engineered structures.

7.6 Hydrology

Project facilities with potential to affect the surface water hydrology include plant sites, camps, linear corridors such as roads and pipelines, and well pads. The hydrologic impacts of infrastructure will be highly localized and will be mitigated by application of best management practices, water management techniques, and erosion and sediment control during construction and operations. Follow-up monitoring is proposed to document the effectiveness of mitigation measures and to identify any areas where increased protection is required. These measures, combined with the natural moderating hydrologic conditions of the regional terrain, are expected to result in non-detectable impacts to the current hydrology. Similarly, pumping of groundwater from deep aquifers will have a negligible impact on surface waterbodies. Overall, long-term surface water hydrologic effects of the Project are expected to be low to negligible.

7.7 Surface Water Quality

Changes related to water level drawdown and changes to surface water flows are not expected to result in impacts to water quality. Impacts related to increases in suspended sediments and the release of process related chemicals are predicted to be low. Mitigation measures implemented during construction, operation and reclamation will protect watercourses and waterbodies in the area.

Baseline analysis indicates that 12 waterbodies in the RSA have the potential to be sensitive to the PAI resulting from approved and existing projects. Changes in water quality from Project aerial emissions are generally not predicted to result in an impact. The Project emission modelling predict additional PAI loading of the 12 potentially sensitive waterbodies; as such these changes are assessed as medium in magnitude, resulting in a moderate impact rating for water quality. For the CEA, one additional waterbody is predicted to experience a critical load exceedance.

7.8 Fish and Fish Habitat

Changes in fish and fish habitat related to riparian and instream fish habitat and combined industrial disturbances are not expected as a result of Project activities. Potential impacts related to increases in suspended sediments and the accidental release of chemicals is predicted to be low. Mitigation measures implemented during construction, operation and reclamation will protect watercourses and waterbodies in the area.

Potential impacts to fish and fish habitat as a result of changing surface water levels are predicted to be low. Surface water levels are predicted to be within natural variation for the life of the Project. The potential impacts on fish and fish habitat as a result of riparian disturbances during construction and operation activities are predicted to be low. The mitigation and restoration measures implemented during construction, operation and reclamation will protect the watercourses and waterbodies in the area.

The potential for a decrease in fish populations resulting from increased access to fish bearing watercourses and waterbodies in the Project was assessed. Potential impacts on fish populations are predicted to be low as the watercourses and waterbodies are regulated under the Province of Alberta's Fishing regulations.

7.9 Soils

The predicted residual impacts to the key parameters of soil moisture, landforms, land capability and acidification potential are low for soils and terrain in the application case. Overall, no single parameter is predicted to affect more than 5% of the soils in the LSA.

The soils and terrain cumulative impact concerns, potentially associated with the Project in the RSA, are soil acidification and loss of Organic soil landforms. The baseline, application and cumulative cases all result in less than <0.1% of the RSA soils at risk of having critical load exceeded by PAI. The surface disturbance of well pads and other facilities of similar size are small relative to the abundance of these landforms in the LSA, and impacts to landforms will be localized and will not impact overall landform diversity. Upland sites will be reclaimed to landforms consistent with pre-disturbance conditions and organic sites to upland subhygric Black spruce-Jack Pine vegetation community (g1- Labrador tea). The Project is anticipated to have a negligible to low effect in the cumulative scenario for acidification and landforms.

7.10 Vegetation

The majority of the Project area is located in the Lower Boreal Highlands Subregion of the Boreal Forest Natural Region, with the remainder located in the Central Mixedwood Subregion. Eighty percent of the LSA is forested. Lowland wetland vegetation comprises 54% of the LSA, with terrestrial vegetation comprising thirty-four percent. Five percent of the LSA was classified as old-growth forest. Ten rare vascular plant species and three rare non-vascular plant species were observed in the LSA.

The Project will have an impact on wetlands. The Project development will result in the removal of 1% of the wetlands in the LSA. The effect of vegetation removal on these habitats is predicted to be low.

Removal of vegetation is expected to have a low impact on rare plant species. Hydrological impacts are anticipated to have no impact (Volume 3, Section 5) and therefore hydrological impacts on rare plant species are judged to be low. One rare community was found in the LSA; however, it was not found within the footprint and therefore there is no environmental impact anticipated.

Five communities with limited distribution occur in the LSA. The environmental impact of vegetation removal on these communities is expected to be low. The impact of vegetation removal on timber resources and old-growth forest is predicted to be low. The impact of development on old-growth stands will be long-term but low in magnitude. The environmental impact for productive forests, merchantable lands and old-growth forests is anticipated to be low.

7.11 Wildlife

Project construction and operations may impact wildlife given habitat loss, the creation of partial barriers to animal movements, or possibly given increased animal mortality. These impacts are anticipated to recover to negligible or low magnitude levels at project closure given a combination of Project mitigation, habitat reclamation, and monitoring programs that have been proposed for wildlife and their habitats by North American.

During the construction and operations phases of the Project, impacts resulting from animal mortality and loss of habitat connectivity are considered as low magnitude impacts given proposed mitigation which includes access management strategies and the construction of wildlife crossing structures for above ground pipelines. Losses in wildlife habitat are predicted to