ATHABASCA
OIL SANDS CORP.

June 2, 2008

Alberta Energy Resources Conservation Board
640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Attention: Mr. Ken Schuldhaus
Section Leader, In Situ Oil Sands Resource Applications

Alberta Environment
Northeast Boreal Region
Environmental Service
111, 4999 – 98 Avenue
Edmonton, Alberta T6B 2X3

Attention: Kem Singh,
Approvals Manager

Alberta Environment
Northeast Boreal Region
Environmental Service
111, 4999 – 98 Avenue
Edmonton, Alberta T6B 2X3

Attention: Mr. Mike Boyd
Regional Environmental Manager

Dear Sirs:

Re: Application for Experimental Scheme Approval of Athabasca Oil Sands Corp. Dover Central Pilot Project

Athabasca Oil Sands Corp. (AOSC) is seeking approval for an experimental scheme to use in-situ thermal technology to produce bitumen up to a rate of 318 m^3/d (2,000 bpd) from Oil sands Lease No. 7406090442. The Project will recover an estimated 477,000 m^3 (3.0 million barrels) of bitumen over its projected 5 year life.

The pilot is being designed to demonstrate a novel recovery process developed by AOSC which will enhance bitumen recovery in areas of low reservoir pressure.

The Central Processing Facility (CPF) for the Pilot will be located in SW¼ 6-94-17 W4M, approximately 90 km northwest of Fort McMurray, Alberta and approximately 60 km west of Fort McKay, Alberta. Additional facilities will include a single well pad with 6 SAGD well pairs, construction/operations camp, and associated infrastructure located within the CPF footprint, and an access corridor to a water source well located outside the CPF footprint.

Suite 2000, 250–6th Avenue SW, Calgary, Alberta T2P 3H7 Phone : 403 237.8227 Fax: 403 264.4640 Email: info@aosc.com

The attached document (Application for Approval of the Dover Central Pilot Project) comprises the Application for Experimental Scheme Approval of the Project and serves to meet requirements under the Alberta *Oil Sands Conservation Act* (AOSCA), ERCB IL OG-78-12 and the Alberta *Environmental Protection and Enhancement Act* (AEPEA). The document is provided as an integrated Application to the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment (AENV) as outlined in the ERCB/AENV Memorandum of Understanding on the Regulation of Oil Sands Developments (IL 96-07).

Specifically, AOSC is seeking approval from:

1. The ERCB to:
   construct and operate an experimental bitumen recovery scheme, in accordance with Section 10 of the AOSCA and ERCB IL OG-78-12; and

2. AENV to:
   a. construct and operate the experimental scheme, including facilities to recover and treat bitumen and produced water, in accordance with Division 2 of Part 2 and Section 63 of the AEPEA; and
   b. develop, operate and reclaim components of the Project in accordance with Division 2 of Part 2 and Part 5 of the AEPEA.

In addition, AOSC is also requesting that all "*operations reports, special studies, laboratory, experimental or cost information*" relating to the Dover Central Pilot Project be kept confidential in accordance with, and for the confidentiality period in, Section 15(2) of the *Oil Sands Conservation Regulation* (Alberta Regulation 76/88). If the Board directs that a lesser confidentiality period apply, AOSC suggests a confidentiality period of 5 years, to coincide with the proposed life of the pilot.

In support of these approval requests, Athabasca Oil Sands Corp. submits the attached document titled Application for Approval of the Dover Central Pilot Project. Please contact the undersigned at (403) 532-7718 if you have any questions.

Sincerely,

Jerry Demchuk
Manager, Regulatory and Stakeholder Affairs

Attachment: Application for Approval of the Dover Central Pilot Project

APPLICATION FOR APPROVAL OF THE DOVER CENTRAL PILOT PROJECT

SUBMITTED TO

ALBERTA ENERGY RESOURCES CONSERVATION BOARD

AND

ALBERTA ENVIRONMENT

SUBMITTED BY

ATHABASCA OIL SANDS CORP.

June 2008

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FIGURES

APPENDICES

1 INTRODUCTION

Athabasca Oil Sands Corp. (AOSC) is a Canadian oil sands company operating in northeastern Alberta. AOSC's corporate philosophy is based around maximizing the value of its oil sands resources while becoming a valued partner in the communities in which it operates. AOSC supports sustainable long term development while building mutually beneficial relationships with its key stakeholders.

This application is seeking approval for the Dover Central Pilot Project (the Pilot) which is an experimental scheme using in-situ thermal technology to produce bitumen up to a rate of 318 m^3/d (2,000 bpd) from Oil Sands Leases No. 7406090442 (the Dover Lease).

The Pilot is being designed to demonstrate a novel recovery process developed by AOSC which will enhance bitumen recovery in areas of depleted top gas.

In addition, AOSC is requesting that all "operations reports, special studies, laboratory, experimental or cost information" relating to the Pilot be kept confidential in accordance with, and for the confidentiality period outlined in Section 15(2) of the *Oil Sands Conservation Regulation* (Alberta Regulation 76/88). If the Energy Resources and Conservation Board directs that a lesser confidentiality period apply, AOSC suggests a confidentiality period of 5 years, to coincide with the proposed life of the Pilot.

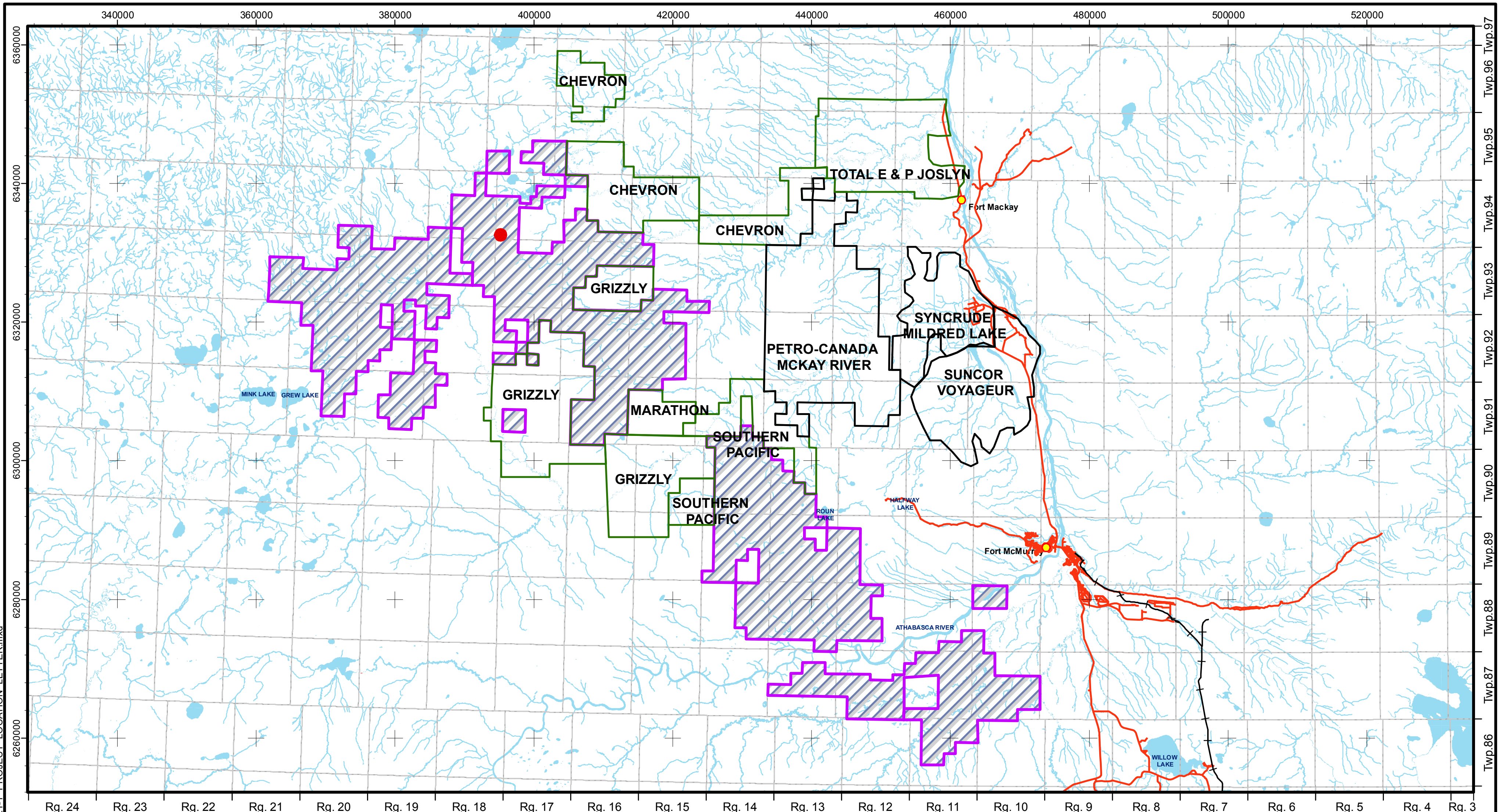
The Pilot is an experimental scheme that will be developed on a portion of AOSC's Dover lease, which spans Townships 91 to 95, Ranges 15 to 20 W4M (Figure 1.1-2). The Dover lease is located within the Regional Municipality of Wood Buffalo (RMWB) and the Municipal District of Opportunity No. 17.

The Central Processing Facility (CPF) for the Pilot will be located in SW¼ 6-94-17 W4M, approximately 90 km northwest of Fort McMurray, Alberta, and approximately 60 km west of Fort McKay, Alberta. The Pilot will use in-situ thermal recovery technology to produce bitumen up to a non-commercial rate of 318 m^3/d (2,000 bpd) on an annual average calendar day basis. The Pilot will recover an estimated 477,000 m^3 (3.0 million barrels) of bitumen over its projected 5 year life. Production from the Pilot will be marketed as a bitumen blend. First steam at the Pilot is anticipated in Q3 2010.

A summary of the anticipated bitumen production and material consumption rates for the Pilot is presented in Table 1.1-1 in metric and imperial units and on a stream and calendar day basis. Unless otherwise noted, all rates presented throughout this application are presented on a calendar day basis.

1.1 Background

AOSC has been conducting seismic and oil sands exploratory (OSE) drilling programs in the Dover area since 2006. To date, AOSC has acquired 100 km of high resolution 2D seismic and drilled 64 wells in the vicinity of the Pilot, with a well density of approximately 16 wells per section.



I:\7349_514\MAPS\FIGURES\001_BASEDATA\FIGURE_1.1-1_PROJECT_LOCATION_LETTER.mxd

LEGEND

AOSC LEASE
EXISTING OPERATION
PROPOSED OPERATION
LAKE
WATERCOURSE
RAILWAY
ROAD
DOVER CENTRAL PILOT PROJECT AREA
CITY

★ Project Location

N
1:800,000
10000 0 10000
Metres
NAD 83 UTM ZONE 12

ATHABASCA OIL SANDS CORP.

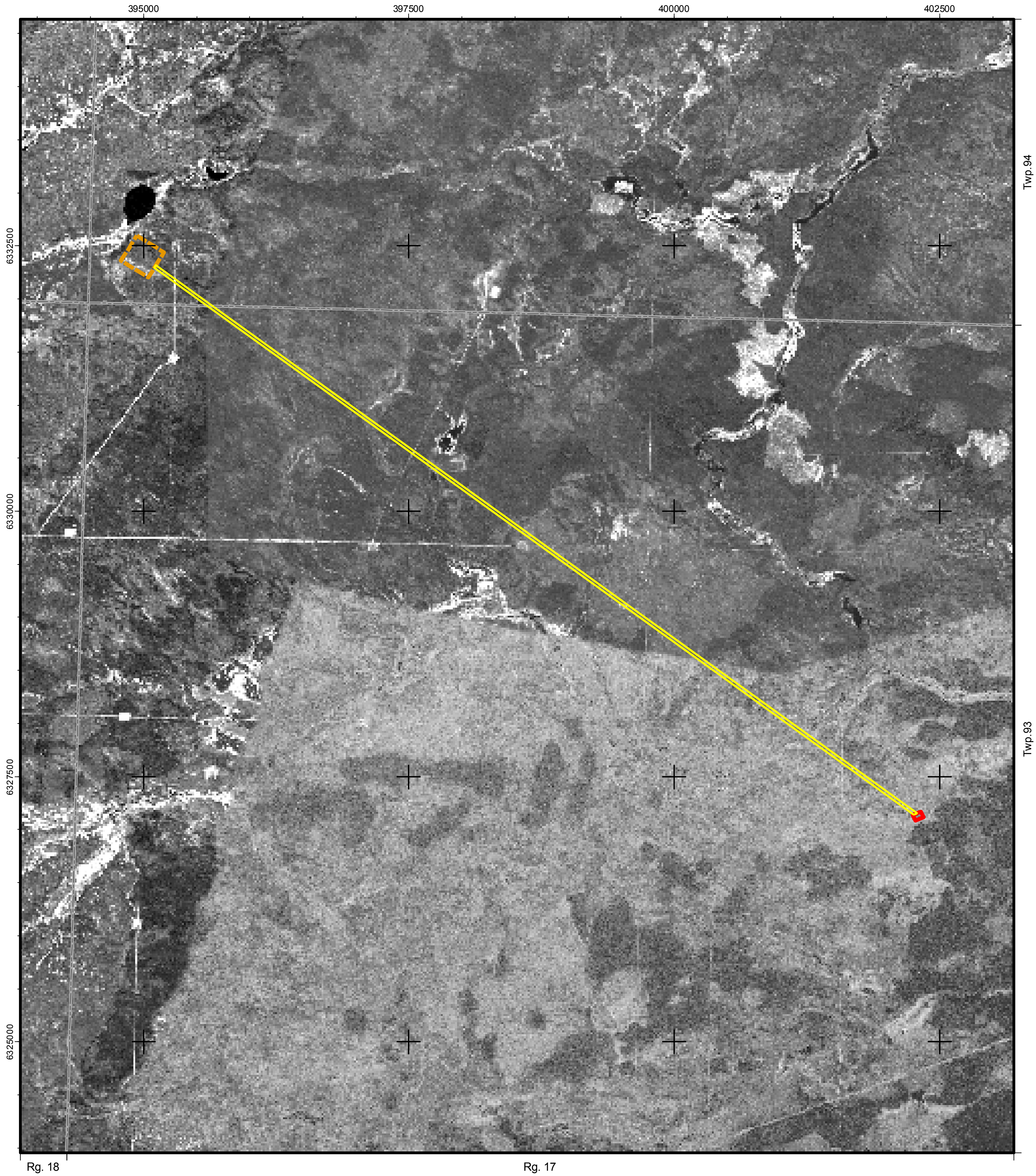
Project Code: 7349-514	Technical: BF	Date: 08/05/09
Senior: RL	Date: 08/05/09	Drawn by: GU	Date: 08/05/09

Reference:
1:50,000 Base Feature obtained from Geobase

Disclaimer:
Prepared solely for the use of AOSC. as specified in the accompanying report.No representation of any kind is made to other parties with which AOSC has not entered into contract.

PILOT LOCATION

FIGURE 1.1-1



LEGEND

- DOVER CENTRAL PILOT CPF
- WATER SOURCE WELL
- ACCESS CORRIDOR

1:50,000

500 0 500

Metres

NAD 83 UTM ZONE 12

Project Code: 7349-514	Technical: BF	Date: 08/05/09
Senior: RL Date: 08/05/09	Drawn by: GU	Date: 08/05/09

Reference:
Orthophoto obtained from AOSC, used under license

Disclaimer:
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ATHABASCA OIL SANDS CORP.

DOVER CENTRAL PILOT PROJECT

FIGURE 1.1-2

I:\7349_514\MAPS\FIGURES\001_BASEDATA\FIGURE_1.1-2_DOVER_DEMONSTRATION_PROJECT.mxd

Table 1.1-1 Bitumen Production and Material Consumption Rates

	Calendar Day Basis		Stream Day Basis	
	bpd	m^3/d	bpd	m^3/d
Bitumen	2,000	318	2,201	350[(a)]
Steam (Cold Water Equivalent)	6,509	1,035	7,233	1,150
Make-up Water to De-Oiling	2,870	456	3,189	507
Produced Water	3,962	630	4,403	700
Liquid Disposal	362	58	403	64
Water Treatment Capacity	7,228	1,149	8,031	1,277

(a) The 350 m^3/d represents the maximum bitumen throughput.

1.2 Purpose

The Pilot is being designed to demonstrate confidential and proprietary experimental in-situ thermal recovery technologies applicable to the Dover lease area. The Pilot as it is planned is uneconomic and has an expected life of 5 years.

1.3 Alternatives

Within the Pilot area, the overburden thickness to the bitumen bearing resource is approximately 233 m with net pay thicknesses of approximately 23 m to 27 m. Due to the depth of the resource, surface mining at this location is not an alternative for the resource recovery. This type of resource is currently only recoverable using in-situ thermal recovery methods.

Not proceeding with the Pilot would sacrifice findings from the experimental scheme, resulting in reduced recovery of the sizeable resource in the Pilot area. Proceeding with the Pilot will provide AOSC with valuable information which will help to maximize resource recovery in AOSC's Dover lease area.

2 OVERVIEW

2.1 Introduction

AOSC will test experimental in-situ thermal recovery methods to recover approximately 318 m^3/d (2,000 bpd) of bitumen at the Pilot. The Pilot will consist of five horizontal production wells and associated injection wells that will be connected to a CPF where the steam generation and production processing will occur. The wells will be located on a single well pad which will be part of the CPF footprint located on a portion of the Dover lease in SW¼ 6-94-17 W4M. No additional production well pads are proposed as part of the Pilot.

Surface facilities will be required for the Pilot to produce bitumen, generate and distribute steam, gather produced fluids, process oil and emulsions, and treat and recycle water. These facilities can be broken down into three components: wells, the CPF, and offsite services and utilities, which are described further below.

Wells:

- production wells;
- injection wells;
- observation wells; and
- associated facilities.

CPF:

- steam generation facilities;
- production (bitumen, gas and water) handling and treatment facilities;
- tankage;
- water treatment and recycle facilities;
- utility systems; and
- support buildings.

Offsite Services and Utilities:

- construction/operations camp;
- fuel gas pipeline (Section 5.3.3.3); and
- all-weather source water well access corridor that includes:
  - an access corridor;
  - aboveground electrical lines; and
  - an underground source water pipeline.

2.2 Proponent

AOSC is a Canadian oil sands company operating in northeastern Alberta. AOSC's corporate philosophy is based around maximizing the value of its oil sands resources while becoming a valued partner in the communities in which it operates. AOSC supports sustainable long term development while building mutually beneficial relationships with its key stakeholders. AOSC is currently the working interest owner and operator of greater than 263,000 ha (650,000 acres) of oil sands leases in the Fort McMurray area.

2.3 Location

AOSC will develop the Pilot on a portion of oil sands lease No. 7406090422 (the Dover lease) in the Fort McMurray, Alberta area. The CPF for the Pilot will be located in SW¼ 6-94-17 W4M, approximately 90 km northwest of Fort McMurray, Alberta and approximately 60 km west of Fort McKay, Alberta. The wells will be drilled from a common well pad within the CPF footprint (located in SW¼ 6-94-17 W4M). Development of the Pilot will also include drilling and operation of a water source well which will be located approximately 9 km southeast of the CPF and within AOSC's Dover lease, in 1-23-93-17 W4M.

2.4 Schedule

The Pilot schedule (Table 2.4-1) is based on AOSC's current estimate of the time required to complete key Pilot components. First steam at the Pilot is planned in Q3 2010, but is contingent on a timely regulatory approval process and community and stakeholder engagement efforts.

Life of the Pilot is planned to be 5 years at the expected production rate of 2,000 bpd. It is anticipated that the ramp up phase for the Pilot from first steam to full production will take approximately 1 year.

Table 2.4-1 Schedule

Dover Central Pilot Facility	**2008**			**2009**				**2010**				**2011**			
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Regulatory Review															
Engineering															
Construction															
Drilling															
Commissioning and Startup															
First Steam / Production															
Community and Stakeholder Engagement															

2.5 Economics

The Pilot is currently uneconomic. The Pilot is being designed to demonstrate experimental in-situ thermal recovery technologies. It will provide critical reservoir and technical information which will improve overall resource recovery and enhance the economic value of future commercial operations.

2.6 Financing

AOSC intends on financing the Pilot utilizing equity and corporate debt.

2.7 Marketing Arrangements

The Pilot will produce small volumes of bitumen that will be blended with condensate and sold at plant gate to local upgraders or transported and sold at Edmonton or Hardisty.

2.8 Effects

2.8.1 Employment

Current estimates indicate that a 60-person labour force will be required for construction and drilling of the Pilot, which will be comprised of:

- management staff;
- welders;
- pipefitters;
- labourers;
- drilling personnel;
- equipment operators; and
- camp staff.

AOSC will award the construction contract to a prime subcontractor who will be responsible for providing all the skilled labour to complete the Pilot. Construction personnel will be housed in an onsite camp for the duration of the construction period. Opportunities to use local skilled workers and contractors will be dependent on the number and type available in the region at the time of construction. The hiring process will follow the principles outlined in AOSC's procurement strategy, described in Section 2.8.2.

Operation of the Pilot will require approximately 10 full time staff positions. Current plans have included onsite camp accommodations for all operations staff.

2.8.2 Procurement

The Pilot is AOSC's first project development. AOSC understands that the Pilot, as well as any subsequent AOSC developments, will provide some opportunities and economic benefits for the local residents, the RMWB, the Municipal District of Opportunity No. 17 and the Province of Alberta.

Potential opportunities and benefits include:

- business and employment opportunities related to the fabrication, drilling and construction of the Pilot facilities; and
- business and employment opportunities related to the ongoing operations of the Pilot.

AOSC's approach to employment and procurement will be based on engaging qualified potential employees and contract services for all Pilot activities. AOSC will have a well defined contractor qualification and bid process in place for all contract services.

AOSC will endeavour to provide economic benefits to local residents. If AOSC is unable to find qualified and competitive personnel or contract services locally, regional and provincial personnel and contractors will be hired. As part of ongoing community and stakeholder engagement initiatives AOSC will work with key stakeholders and communities, including Métis and First Nations communities, to identify potential employment opportunities.

2.8.3 Traffic

AOSC is in the process of evaluating options for accessing the Pilot and is currently in discussions with Alberta Sustainable Resource Development (ASRD) and the RMWB, as well as other industry partners regarding access road options and any potential synergies. Application for approval of an access road to support the Pilot will be submitted under separate cover.

Estimated traffic volumes expected during the construction and operations phases of the Pilot are presented in Table 2.8-1.

Table 2.8-1 Estimated Traffic Volumes

Phase	**Traffic Volume (vehicles/day)**	
	Light Vehicles	Heavy Vehicles [(a)]
Construction	15-20	10-15
Operations	15-20	20-25

(a) Includes hauling CPF modules to site, supply delivery, and product transport

2.8.4 Integration with Other Land Use Activities

The Pilot is located within AOSC oil sands lease No. 7406090442, in an area surrounded by adjoining AOSC oil sands leases. The Pilot is located entirely within the RMWB, but outside of the boundaries of the existing sub-regional integrated resource plan (IRP). The Pilot area also falls within the Wabasca-Dunkirk caribou zone, which is managed by ASRD. Surface access within the caribou zone is subject to specific timing restrictions.

Resource and land uses in the Pilot area include both renewable (forestry, trapping, recreation, and berry picking) and non-renewable (in-situ oil sands operations and conventional oil and gas operations) resources. No metallic or industrial mineral leases or sand and gravel dispositions have been identified within the Pilot area.

Various land uses within the region are presented in Figure 2.8-1.

2.8.4.1 Forestry

The entire Pilot area is located within Alberta-Pacific Forest Industries Inc. (Al-Pac) forestry management area (FMA). AOSC has engaged in discussions with Al-Pac regarding timber harvesting plans for the Pilot area. Al-Pac has advised AOSC that there are no current plans for timber harvesting in this area.

2.8.4.2 Trapping

The Pilot is located in Registered Fur Management Area (RFMA) 771. There are several other RFMAs located in close proximity to the Pilot area, including the following:

- RFMA 879;
- RFMA 21;
- RFMA 2885; and
- RFMA 2900.

RFMA 771 is located in the Pilot area and may be affected by the development. AOSC will discuss a compensation program with RFMA 771 to minimize the effect of the Pilot. AOSC has also been working with other trappers in the Pilot area during the winter exploration programs. AOSC will continue to work with the trappers to ensure their continued access onto lands not part of the Pilot area.

2.8.4.3 Recreation

Recreation use within the Pilot area is restricted due to the lack of all season access. Seasonal recreation activities include:

- non-Aboriginal hunting;
- off-road vehicle use;
- snowmobiling; and
- camping.

For safety considerations, AOSC will control access on the CPF footprint and will also restrict recreation activities on the Pilot site. The remainder of the area will be available for hunting and other recreational activities.

The development of a new all-season access road into the area to support the Pilot will increase recreational opportunities. It is anticipated that hunting pressure and overall recreation usage will increase within the Pilot area due to the creation of the new access road.

2.8.4.4 Oil Sands

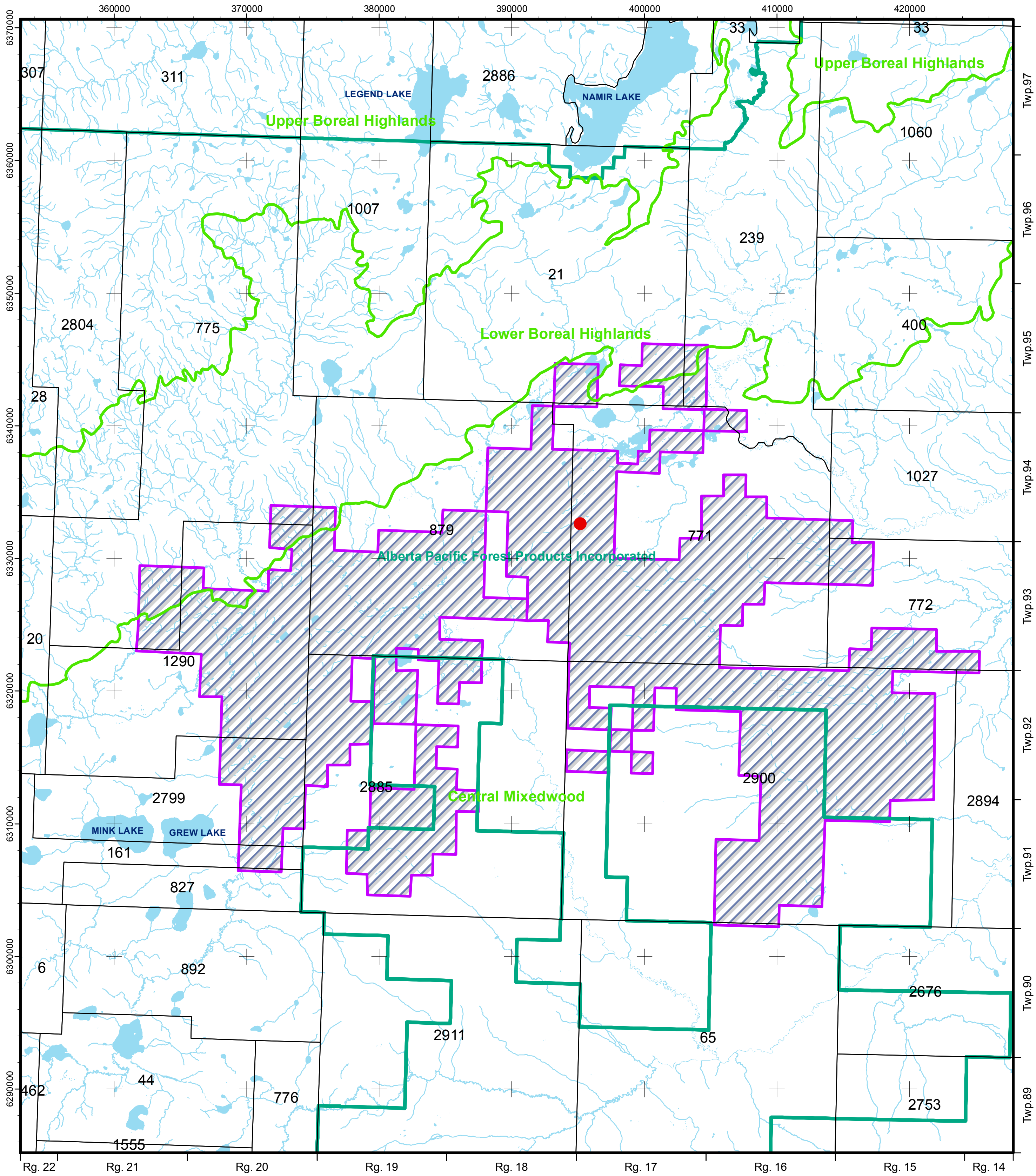
Other oil sands leaseholders in the region include the following:

- Chevron;
- Sunshine Oil Sands;
- Petro-Canada;
- Grizzly Holdings;
- Total E&P;
- Southern Pacific; and
- Marathon.

None of these oil sands leaseholders are located in the immediate vicinity of the Pilot. AOSC is working with the other oil sands leaseholders in the area to explore potential synergies with respect to area access, infrastructure and data sharing.

2.8.4.5 Petroleum and Natural Gas, Mineral Surface Lease and Other Public Dispositions

Canadian Natural Resources Ltd., Petro-Canada and Paramount Energy Trust Inc. each hold numerous petroleum and natural gas (P&NG) licenses, mineral surface leases (MSL) and pipeline agreements within the Pilot area. These licenses are managed by the Alberta Department of Energy, Mineral Development and Strategic Resources and ASRD.



I:\7349_514\MAPS\FIGURES\001_BASEDATA\FIGURE_2.8-1_PROJECT_AREA_LAND_USES.mxd

LEGEND

- AOSC DOVER LEASE
- FORESTRY MANAGEMENT AREA
- REGISTERED FUR MANAGEMENT AREA
- NATURAL SUB-REGION
- LAKE
- WATERCOURSE
- DOVER CENTRAL PILOT PROJECT AREA

N

1:400,000

4000 0 4000

Metres

NAD 83 UTM ZONE 12

ATHABASCA OIL SANDS CORP.

Project Code: 7349-514		Technical: BF	Date: 08/05/09
Senior: RL	Date: 08/05/09	Drawn by: GU	Date: 08/05/09

Reference:
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PILOT AREA LAND USES

FIGURE 2.8-1

2.9 Regional Initiatives

AOSC recognizes the value of the various multi-stakeholder groups in place to ensure sustainable growth within the oil sands. Based on this, AOSC is currently evaluating its potential participation level in the key multi-stakeholder groups such as the Cumulative Environmental Management Association (CEMA), the Regional Issues Working Group (RIWG), the Wood Buffalo Environmental Association (WBEA), the Regional Aquatics Monitoring Program (RAMP) and the Athabasca Tribal Council (ATC) All Parties Core Agreement.

3 APPLICATION FOR APPROVAL

3.1 Existing Approvals

To date, AOSC has received ASRD approval for several OSE programs in Townships 91 to 95, Ranges 15 to 20 W4M, which includes the Pilot area.

AOSC conducted OSE programs during the winter of 2006/2007 under ASRD Approval No. 0600063, consisting of 10 core holes. An additional 34 core holes were drilled during the winter of 2007/2008 under ASRD Approval Nos. 070048 and 070033. AOSC received ERCB licences for all the wells drilled during the OSE programs.

In addition, AOSC received AENV Approval No. 00245800-00-00 to temporarily divert water from the Horse River, the McKay River, and the Dunkirk River for the purposes of drilling and winter access during the 2007/2008 OSE program.

3.2 Request for Approval

With this application, AOSC is requesting experimental scheme approval to construct, operate and reclaim the Pilot on a portion of its Dover lease located in Townships 91 to 95, Ranges 15 to 20 W4M. The CPF for the Pilot will be located in SW¼ 6-94-17 W4M, approximately 90 km northwest of Fort McMurray, Alberta and 60 km west of Fort McKay, Alberta.

The Pilot will use experimental in-situ thermal recovery methods to produce bitumen at a rate of 318 m^3/d (2,000 bpd) on an annual average calendar day basis. The Pilot will recover an estimated 477,000 m^3 (3.0 million barrels) of bitumen over the estimated 5 year life. First steam at the Pilot is anticipated in Q3 2010.

This document (Application for Approval of the Dover Central Pilot Project) comprises the Application for Experimental Scheme Approval of the Pilot and serves to meet requirements under the Alberta *Oil Sands Conservation Act* (AOSCA), ERCB Information Letter (IL) OG-78-12 (ERCB 1978) and the Alberta *Environmental Protection and Enhancement Act* (AEPEA). The document is provided as an integrated Application to the ERCB and AENV as outlined in IL 96-07, the ERCB/AENV Memorandum of Understanding on the Regulation of Oil Sands Developments (ERCB/AENV 1996).

Specifically, AOSC is seeking approval from:

1. The ERCB to:

    construct and operate an experimental bitumen recovery scheme, in accordance with Section 10 of the AOSCA and ERCB IL OG-78-12; and

2. AENV to:

    a. construct and operate the experimental scheme, including facilities to recover and treat bitumen and produced water, in accordance with Division 2 of Part 2 and Section 63 of the AEPEA; and

    b. develop, operate and reclaim components of the Pilot in accordance with Division 2 of Part 2 and Part 5 of the AEPEA.

In addition, AOSC is requesting that all "operations reports, special studies, laboratory, experimental or cost information" relating to the Pilot be kept confidential in accordance with, and for the confidentiality period outlined in Section 15(2) of the *Oil Sands Conservation Regulation* (Alberta Regulation 76/88). If the Energy Resources and Conservation Board directs that a lesser confidentiality period apply, AOSC suggests a confidentiality period of 5 years, to coincide with the proposed life of the Pilot.

Under Alberta Regulation 276/2003, Activities Designation Regulation, the Pilot is listed in Schedule 1 and is, therefore, designated as an activity requiring an approval. The information needed to satisfy the requirements for joint ERCB and AENV approval is contained herein. AENV has corresponded with AOSC, stating that an environmental impact assessment is not required for the Pilot.

Head Office:
Athabasca Oil Sands Corp.
Suite 2000, 250 - 6 Avenue SW
Calgary, Alberta T2P 3H7
www.aosc.com

Original Signed by

____
Jerry Demchuk
Manager, Regulatory and
Stakeholder Affairs
Phone: [403] 237-8227
Fax: [403] 264-4640

3.3 Associated Applications

AOSC will also file applications for different aspects of the Pilot under various other statutes. The provincial application and approval requirements applicable to the Pilot 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;
- *Pipelines Act* and AEPEA, for the construction and operation of pipelines between the CPF and the water source well and the CPF and the fuel gas pipeline tie-in;
- *Water Act*, for groundwater diversion licenses;
- *Oil and Gas Conservation Act*, for well licenses; and
- *Municipal Government Act*, Part 17, for a development permit from the RMWB for the construction and operation of the Pilot and related infrastructure.

4 GEOLOGY AND RESERVOIR

4.1 Lease Area

AOSC has a 100% working interest in oil sands lease No. 7406090442 (the Dover Lease), covering an area of 1,536 hectares. In the Pilot area, AOSC's oil sands leases cover a stratigraphic interval spanning the top Cretaceous Viking to the base Devonian Woodbend. The target oil sands reservoir is the McMurray/Wabiskaw interval.

4.2 Geological Study Area

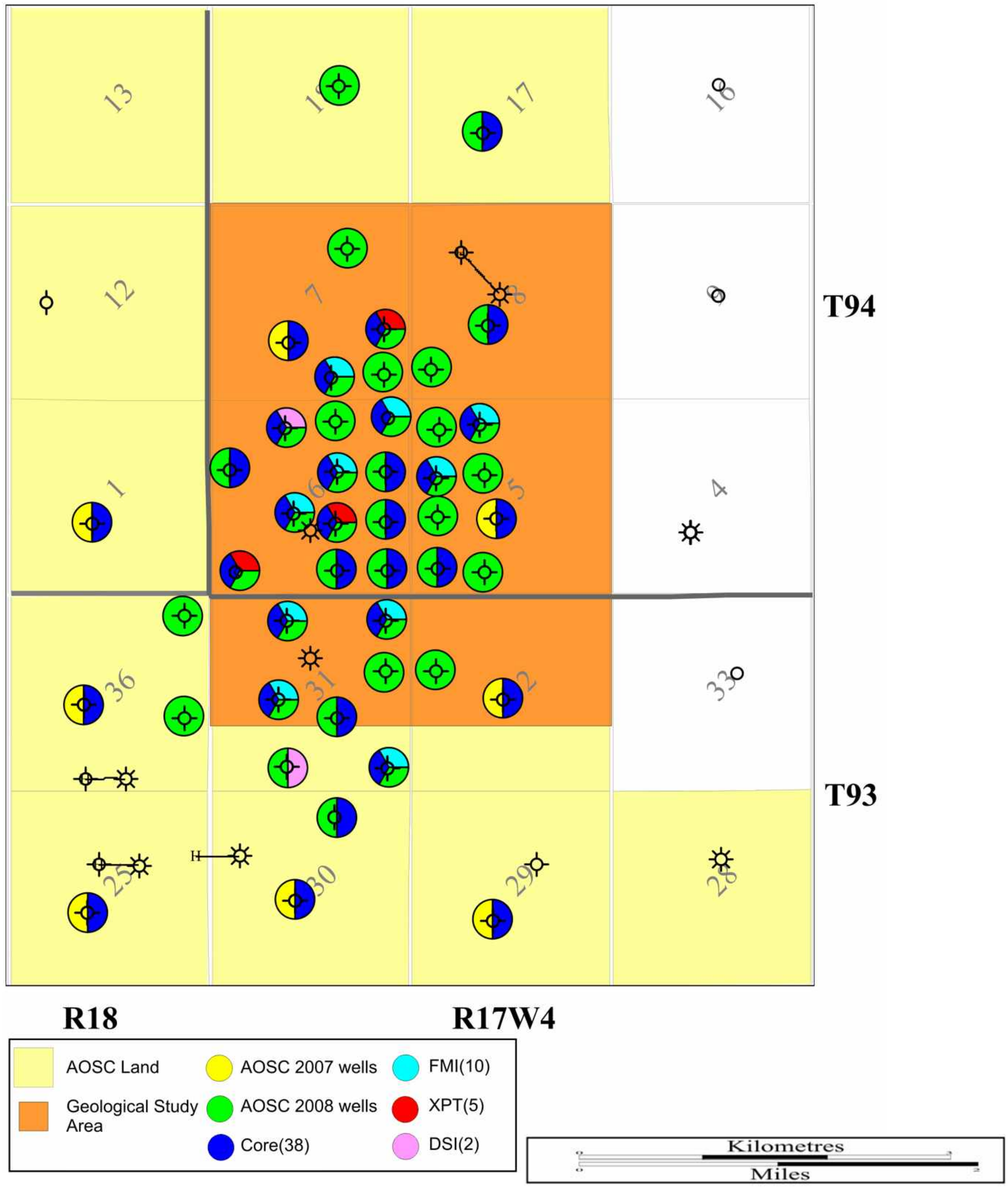
The geological study area (GSA) for the Pilot (sections 5, 6, 7 and 8 of 94-17 W4M and sections N½ 31 and N½ 32 of 93-17 W4M) covers 160 ha (Figure 4.2-1). The GSA contains 13 delineation wells penetrating the McMurray/Wabiskaw interval (Figure 4.2-1). Three delineation wells existed in the GSA prior to 2006 (Figure 4.2-1) and ten wells were drilled and cored in the GSA by AOSC in 2007. AOSC drilled 34 wells in 2008, of which 24 (71%) were cored in the McMurray/Wabiskaw interval, resulting in an increased well density from 1 well per section to 16 wells per section. In the GSA, nine formation micro imager logs (FMI), three pressure logs and one dipole sonic imager (DSI) log were acquired (Figure 4.2-1). AOSC's well distribution in 6-94-17 W4M is presented in Table 4.2-1.

Table 4.2-1 Summary of Well Data within 6-94-17 W4M

Drilling Season	Standard Logs	FMI	Cores	DSI	Pressure Tests
Prior to 2006	1	0	0	0	0
Winter 2006/07	0	0	0	0	0
Winter 2007/08	12	3	11	1	2

4.3 Methods

A series of wire-line logs and cores has been obtained in the GSA. High resolution wire-line log data were acquired over the reservoir interval in order to capture a higher level of reservoir quality detail. Cores were obtained to provide information on reservoir facies, determine environments of deposition and establish vertical reservoir characterization details. Core analyses are being conducted to characterize the porosity, bitumen saturation, grain density and permeability of the McMurray/Wabiskaw interval. Core-derived bitumen saturation from Dean-Stark core analyses was used to calibrate log-derived bitumen saturation calculations from neighbouring wells (1AA/6-5-94-17W4 and 1AA/6-7-094-17W4). This information will be used to validate the wire-line log interpretations. Clay volume has been determined from log analysis that has been calibrated to petrographic and x-ray diffraction (XRD) data. Pairs of overburden plugs are being obtained to determine horizontal and vertical permeabilities within various reservoir lithofacies. The well-log, core analysis and facies information is being integrated into a geological model for both volumetric determination as well as for future planning and development purposes.



ATHABASCA OIL SANDS CORP.

Project Code: 7349-514		Technical: ##	Date: 13/05/08
Senior: ##	Date: 13/05/08	Drawn by: GDE	Date: 13/05/08

Reference:

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GEOLOGICAL STUDY AREA WELL DISTRIBUTION

FIGURE 4.2-1

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4.4 Regional Geology

The stratigraphy of the GSA covers the Quaternary to Pre-Cambrian basement. Much of the geological description (excluding target interval) comes from hydrogeological studies conducted in the area. The general stratigraphy of the GSA is depicted in Figures 4.4-1 and 4.4-2.

The stratigraphy can be broadly divided into four systems: Pre-Cambrian, Devonian, Cretaceous and Quaternary. The Pre-Cambrian forms a crystalline basement at about 420 to 450 metres below sea level (mbsl). It is erosionally overlain by Devonian strata which are dominated by carbonates. These strata comprise the Elk Point, Beaverhill Lake and the Woodbend groups. The Devonian strata are separated from the overlying Cretaceous sediments by an angular unconformity. The unconformity surface varies from 262 to 291 metres above sea level (masl) across the GSA. The Cretaceous sediments are siliciclastics, and comprise the Mannville Group sands overlain by more argillaceous Upper Cretaceous Colorado Group, consisting of the Joli Fou, Viking and La Biche formations. These strata are unconformably overlain by Quaternary sands, gravels and clays reflecting glacial channel fills and tills.

4.4.1 Devonian Strata

Description of the Devonian strata in the area is based on complete Devonian penetration of neighbouring wells as well as CanStrat lithological logs close to the Pilot (Figure 4.4-2).

4.4.1.1 Elk Point Group

In the GSA, the Elk Point Group is composed of a series of argillaceous dolostones, carbonate reefs, halite and anhydrite, clastics, carbonates and evaporates that make up the Contact Rapids, Keg River, Muskeg-Prairie and Watt Mountain formations in ascending stratigraphic order. The Contact Rapids Formation is approximately 25 m thick and ranges from 369 to 392 mbsl. It consists of argillaceous dolostone and shale. It is overlain by the Keg River Formation, consisting of carbonate reefal build-ups. The build-ups can attain a thickness of 58 to 64 m and have produced gas. The Muskeg-Prairie Formation overlies the Keg River. It consists of a series of interbedded anhyrites and halites and reaches a thickness of 269 m. The Watt Mountain Formation is a thin (13 m) dolomitic shale that varies from 228 to 308 mbsl.

The overlying Beaverhill Lake Group consists of carbonates and evaporates of the Fort Vermillion, Slave Point and Waterways formations, in ascending stratigraphic order. The Fort Vermillion Formation is a 10 m thick anhydrite, the top of which varies structurally from 58 to 82 mbsl. It is overlain by a 10 m thick limestone of the Slave Point Formation, the top of which varies from 49 to 75 mbsl. The Waterways Formation can be divided into the Firebag, Calumet, Christina, Moberly and Mildred Lake members. They consist of alternating calcareous mudstones and carbonates. The top of the formation varies from 124 to 152 masl and in thickness from 49 to 103 m.

The Woodbend Group consists of the Cooking Lake, Ireton, Leduc and Grosmont formations. The Ireton is penecontemporaneous with the Cooking Lake and Leduc formations. It consists of calcareous mudstone. The Leduc is a carbonate reef build-up situated above the Cooking Lake carbonate platform. The Grosmont is poorly preserved in the GSA and difficult to identify and so has not been described.

4.4.2 Cretaceous Sediments

The Cretaceous is composed of the Mannville and Colorado groups in the GSA (Figures 4.4-1 and 4.4-3).

4.4.2.1 Mannville Group

The Mannville Group exhibits a regional structural dip to the southwest and comprises the McMurray, Clearwater and Grand Rapids formations in ascending stratigraphic order.

McMurray Formation

The McMurray Formation varies in depth from 294 to 299 masl across the GSA (Figure 4.4-4), and ranges in thickness from 37 to 46 m (Figure 4.4-5), averaging 42.5 m. Stratigraphic thickness reflects structural variations of the underlying Devonian unconformity surface. The McMurray Formation consists of widespread sandy, delta plain, delta front and tidal flat sands that are laterally continuous across the GSA. There is no evidence supporting estuarine channel deposition in the GSA. The basal part of the McMurray Formation, which lies directly on the Devonian carbonates, corresponds to the informal middle McMurray member which has no reservoir prospectivity in the GSA. It consists of argillaceous muds and silts, with minor organic-rich muds and thin (1 to 2 m), cleaning-upward, very-fine lower to very-fine upper sands. These sediments were deposited in an interdistributary bay environment of a lower delta plain. The bay was partially infilled with crevasse splay sand lobes. Palaeosols are typically developed at the top of each cleaning-upward sandy cycle indicating frequent subaerial exposure. Trace fossils are not common, but when they are present, they are abundant, of low diversity and are mainly diminutive *Teichichnus* and *Planolites* traces and occur toward the base of each cleaning-upward cycle.

The informal upper McMurray member erosively overlies argillaceous deposits of the middle McMurray member. It makes up the main reservoir interval. The basal reservoir and clean sands can be up to 10 m in thickness. These clean sands grade upward into an interval of up to 6 m of flaser-bedded sand, which passes up into another clean sand. The sands are fine-lower to fine-upper and are sublitharenites, consisting dominantly of chert rock fragments. Sands contain clay mostly as a disseminated matrix kaolinitic clay, although continuous and discontinuous mud laminae across the width of a 3 inch core are also present in certain intervals. These laminated muds are typically 1 to 10 mm in thickness. They drape current-ripple bedforms of an underlying thin sand bed. These flaser-bedded intervals may be abundantly bioturbated with robust, horizontal, deposit feedng forms of *Thalassinoides, Planolites and Teichichnus*. In many instances the mud laminae occur in pairs forming double mud drapes, indicating the possibility of tidal processes affecting sediment deposition. These cleaning-upward cycles have been interpreted as proximal delta front successions that were deposited in a brackish bay/estuarine setting as a series of prograding, tidally-influenced, deltaic sand lobes.

Above this sandy facies are additional bioturbated, coarsening- and cleaning-upward sand packages, ranging from 5 to 8 m in thickness. These sands appear clean and contain a wider diversity and abundance of trace fossils including *Thalassinoides, Rosselia* and *Asterosoma*, indicating deposition in an environment exposed to more frequent higher-salinity water conditions. These sandy cycles correspond to progradation of deltaic lobes into a restricted, but open, marine embayment setting.

Clearwater Formation

The McMurray Formation is disconformably overlain by a 95 to 100 m thick argillaceous interval of silts, muds and thin sands that comprise the Clearwater Formation. These deposits form a series of cleaning-upward, distal marine cycles. A basal thin sandy interval, referred to as the Wabiskaw Member, varies from 297 to 301 masl (Figure 4.4-6), and ranges from 1 to 3 m in thickness (Figure 4.4-7). The laterally extensive thick argillaceous sediments of the Clearwater Formation make this stratigraphic interval ideal as a good caprock in the GSA. The remainder of the Clearwater Formation consists of several distal cleaning-upward mud to silt packages. The top Clearwater Formation varies from 392 to 396 masl (Figure 4.4-8) and the argillaceous

Clearwater Formation, excluding the Wabiskaw Member, varies in thickness from 94 to 97 m (Figure 4.4-9).

The Wabiskaw Member is thin, averaging 2 m (ranging in thickness from 1 to 3 m), and exhibits poor reservoir quality. The basal Wabiskaw is a sharp-based glauconite-rich, abundantly bioturbated, muddy-sand. A *Glossifungities* surface is developed at the base of the Wabiskaw Member and cuts into the underlying McMurray sands. This surface acts as a conduit for glauconite to be filtered down into the McMurray sands below. The *Glossifungites* surface was formed by wave ravinement during a marine transgression of the Boreal Sea.

The glauconitic sands of the Wabiskaw Member are gradationally overlain by mudshales and mudstones of the Clearwater Formation. These argillaceous sediments are typically bioturbated by organisms reflecting open marine, grazing and deposit feeding behavioural patterns, such as *Anchonichnus/Phycosiphon, Cosmoraphe*, *Planolites, Chondrites*, and rarer *Zoophycus, Diplocraterion* and *Rosselia*. The shaly cycles grade laterally into 5 m thick mud-silt packages to the southwest of the GSA. The thickness between the top Wabiskaw and top Clearwater stratigraphic picks is quite uniform throughout the area, varying from 94 to 97 m.

Grand Rapids Formation

The Clearwater argillaceous deposits are overlain by a regressive series of at least two cleaning-upward cycles which form the Grand Rapids Formation. These sands thicken to the southeast, ranging in thickness from 38 to 44 m, and range from 433 to 439 masl. The Grand Rapids comprises two sand packages which have been interpreted as shoreface to deltaic shallow marine depositional environments. Both sand packages contain low salinity formation water (Section 4.9, Hydrogeology).

4.4.2.2 Colorado Group

The Colorado Group consists of a series of transgressive marine sediments, and includes the Jolie Fou, Viking and Second White Specks (La Biche) formations in ascending stratigraphic succession. Thickness of the Colorado Group is controlled, in part, by the degree of Quaternary incision; however, incision is minor in the GSA. The Colorado Group deposits usually occur behind the surface casing, and so only a limited log suite is available for study.

Joli Fou Formation

The Grand Rapids Formation is overlain by a widespread, but thin, shale interval, referred to as the Joli Fou Formation. It varies in thickness from 16 to 25 m and ranges in structural elevation from 445 to 448 masl.

Viking Formation

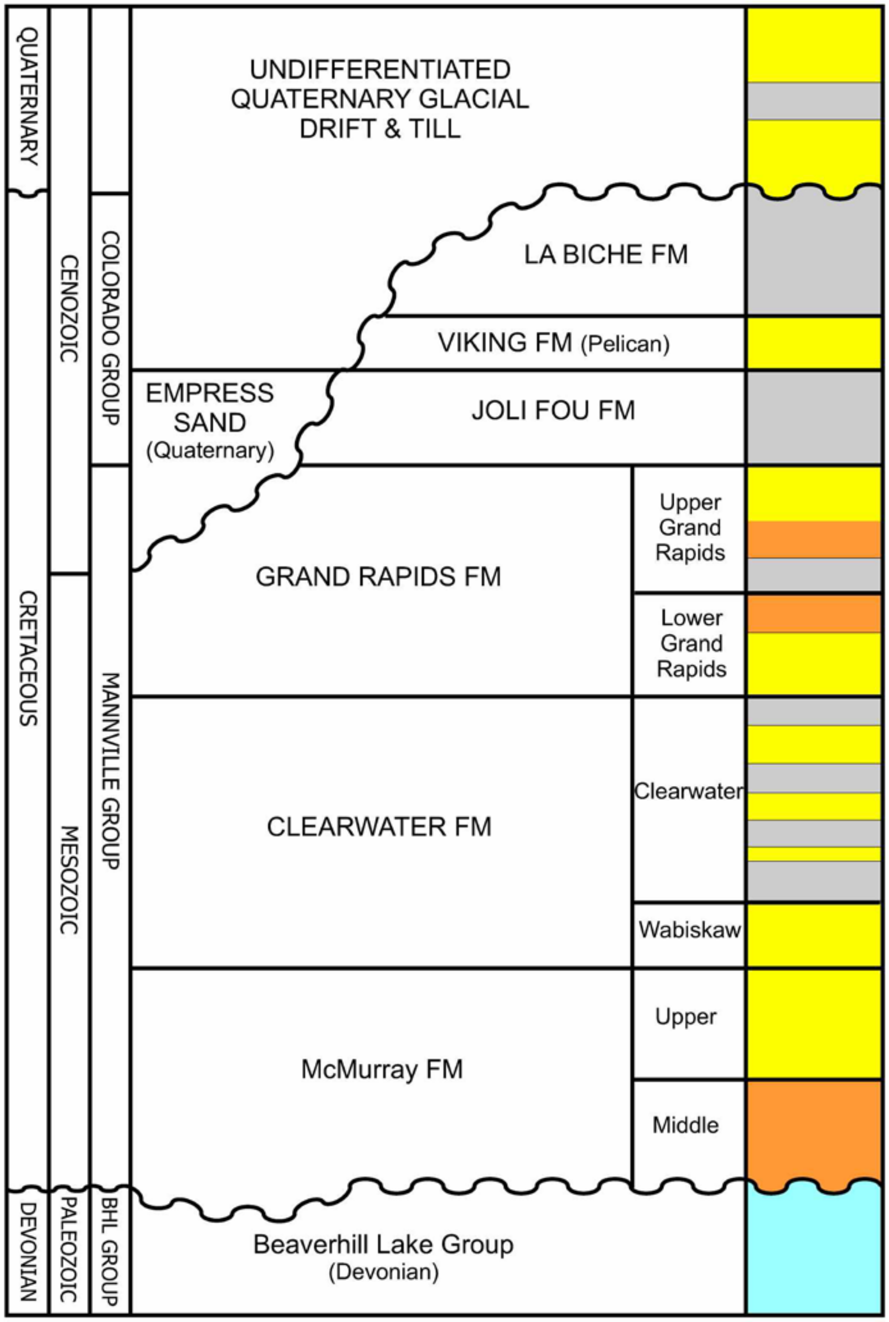
The Viking (Pelican) Formation consists of prograding deltaic to estuarine sands that sharply overly the Joli Fou shales. These sands can reach thicknesses in excess of 40 m. This stratigraphic interval is behind casing and so less geological information can be obtained.

La Biche Formation

This formation consists mostly of shales, assigned to the base of Fish Scales Zone, Second White Speckled Shale and First White Speckled Shale marker zones. This interval is only partially preserved, due to the erosive nature of the Quaternary incision events outside of the GSA. This stratigraphic interval is behind casing and so less geological information is available for examination.

4.4.3 Quaternary Deposits

The Quaternary deposits are described in more detail in Section 4.9 (Hydrogeology). They consist of a mixture of unconsolidated sands, muds and conglomerates that were formed in glaciofluvial environments. Glacial channels have been reported to incise the Mannville Group deposits, but have not been identified in the GSA.



LEGEND

- SAND
- SILT
- CARBONATE
- MUD

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CRETACEOUS TO QUATERNARY STRATIGRAPHIC COLUMN

FIGURE 4.4-1

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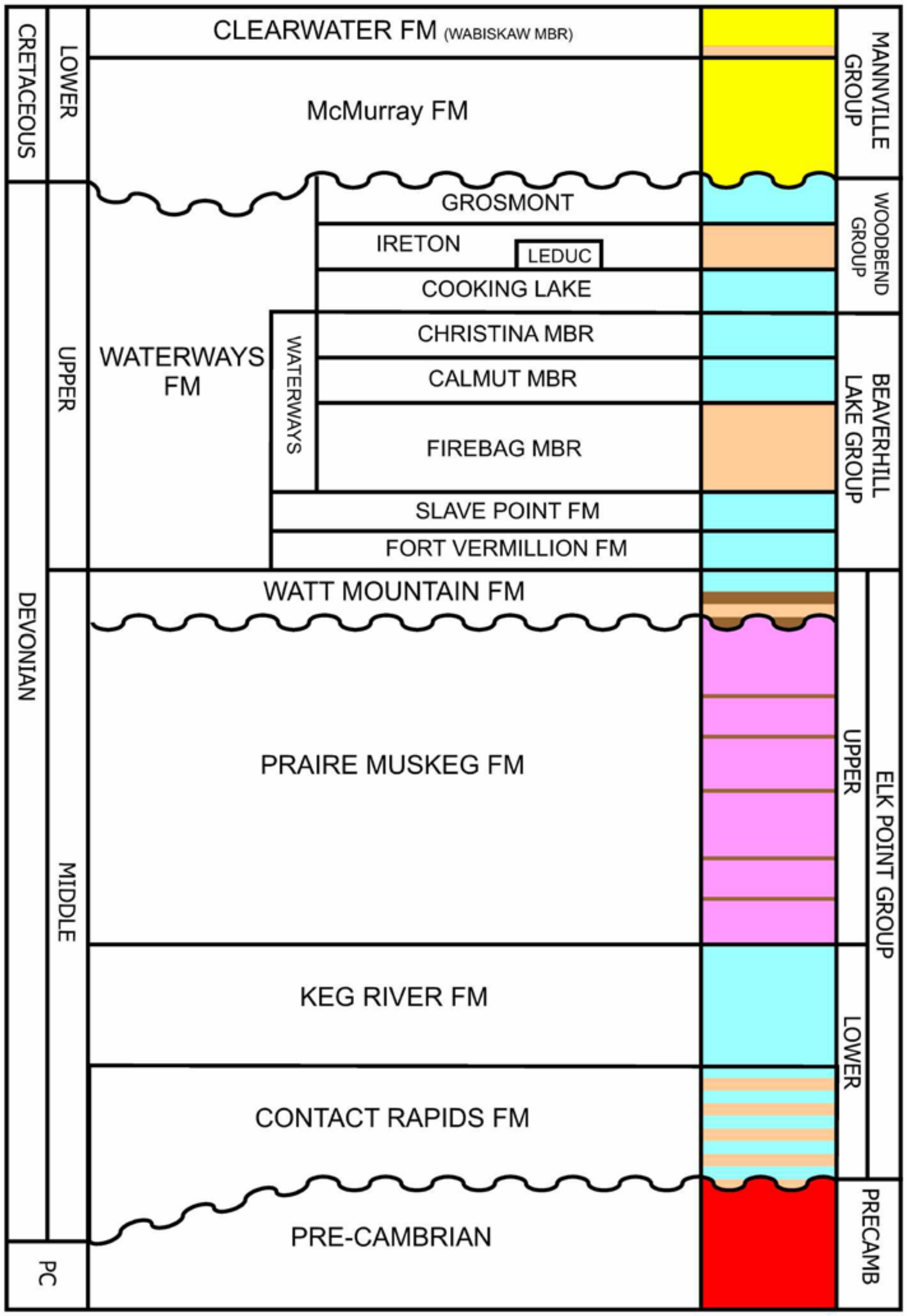

LEGEND

- SAND
- SHALE & CARBONATES
- SALT
- CARBONATE
- ANHYDRITE
- GRANITE

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PRE-CAMBRIAN TO DEVONIAN STRATIGRAPHIC COLUMN

FIGURE 4.4-2

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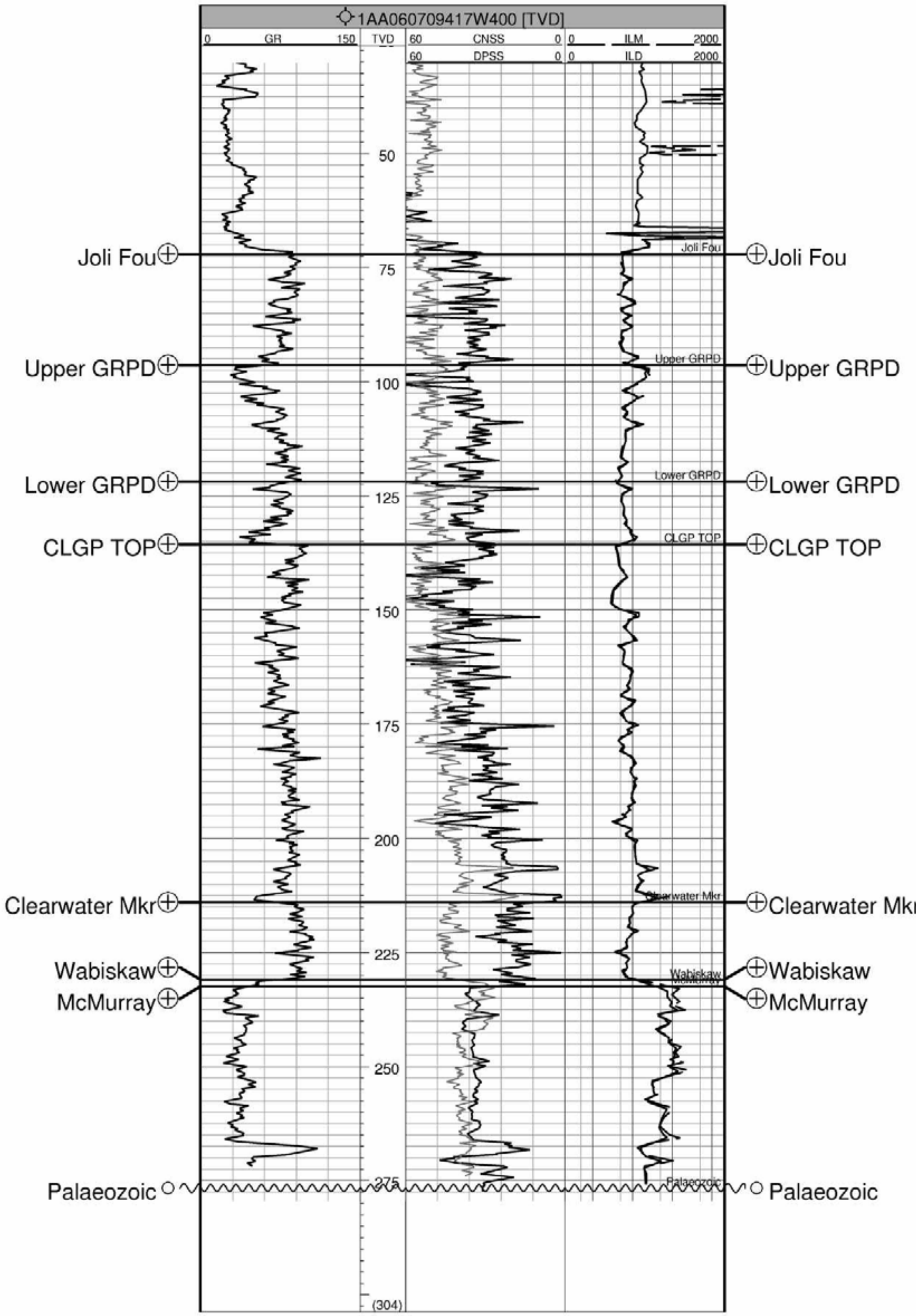

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TYPE WELL FOR GSA

FIGURE 4.4-3

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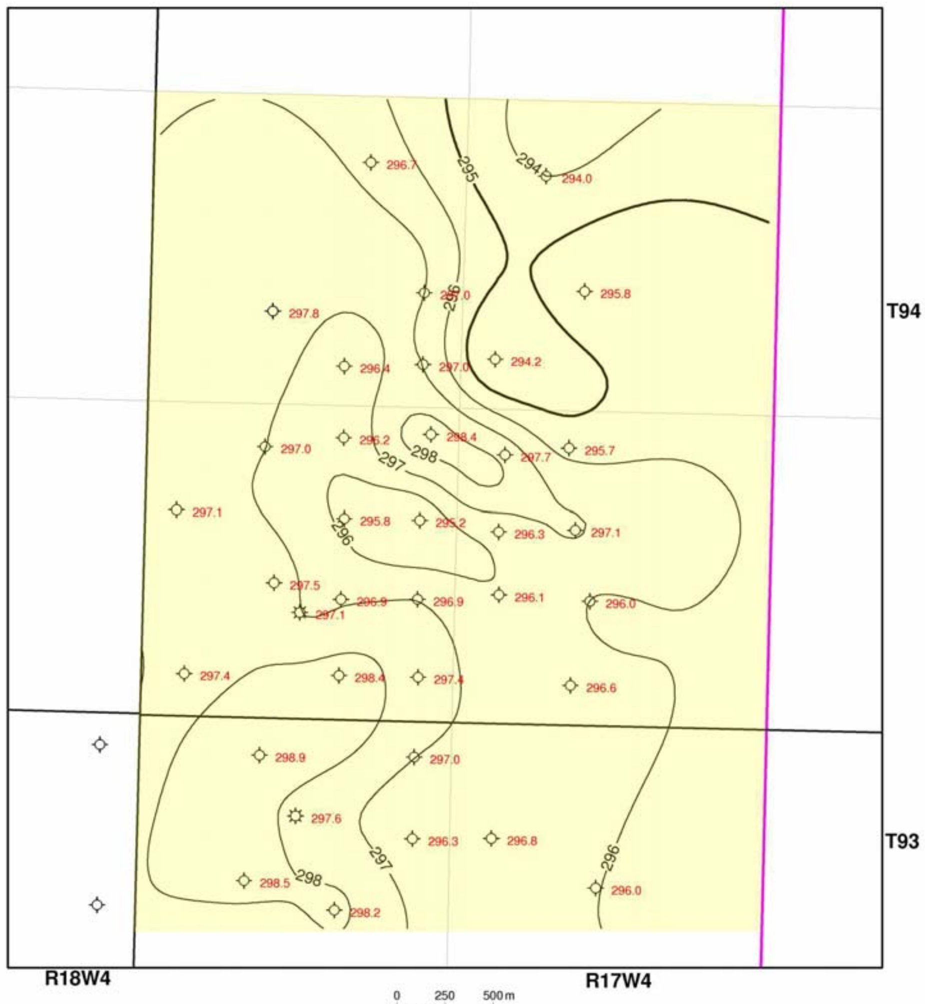

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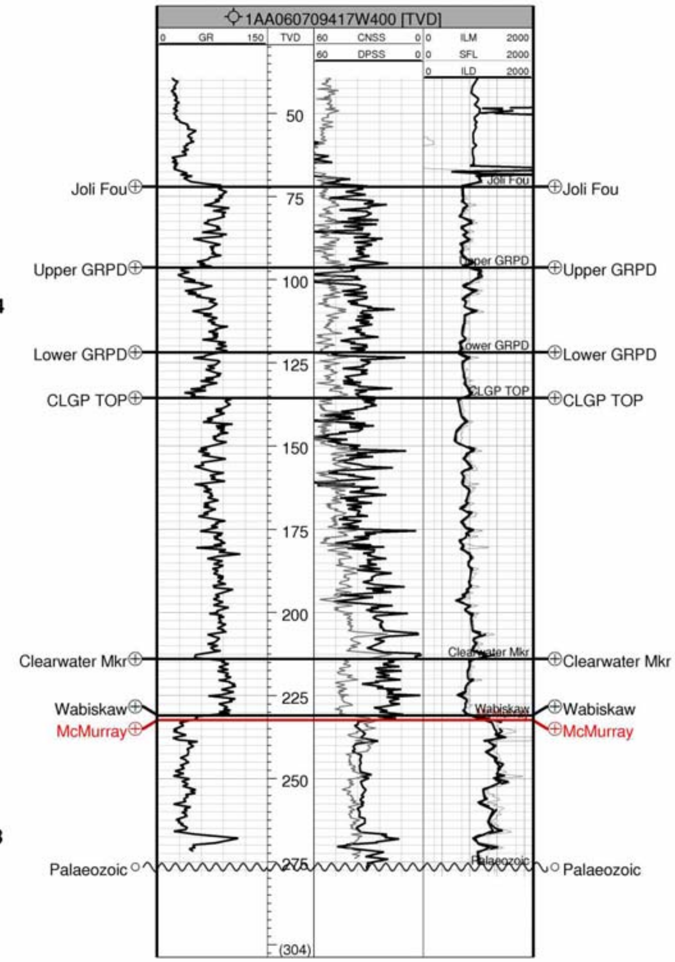
Structure elevation is MASL



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TOP McMURRAY FORMATION STRUCTURE MAP

FIGURE 4.4-4

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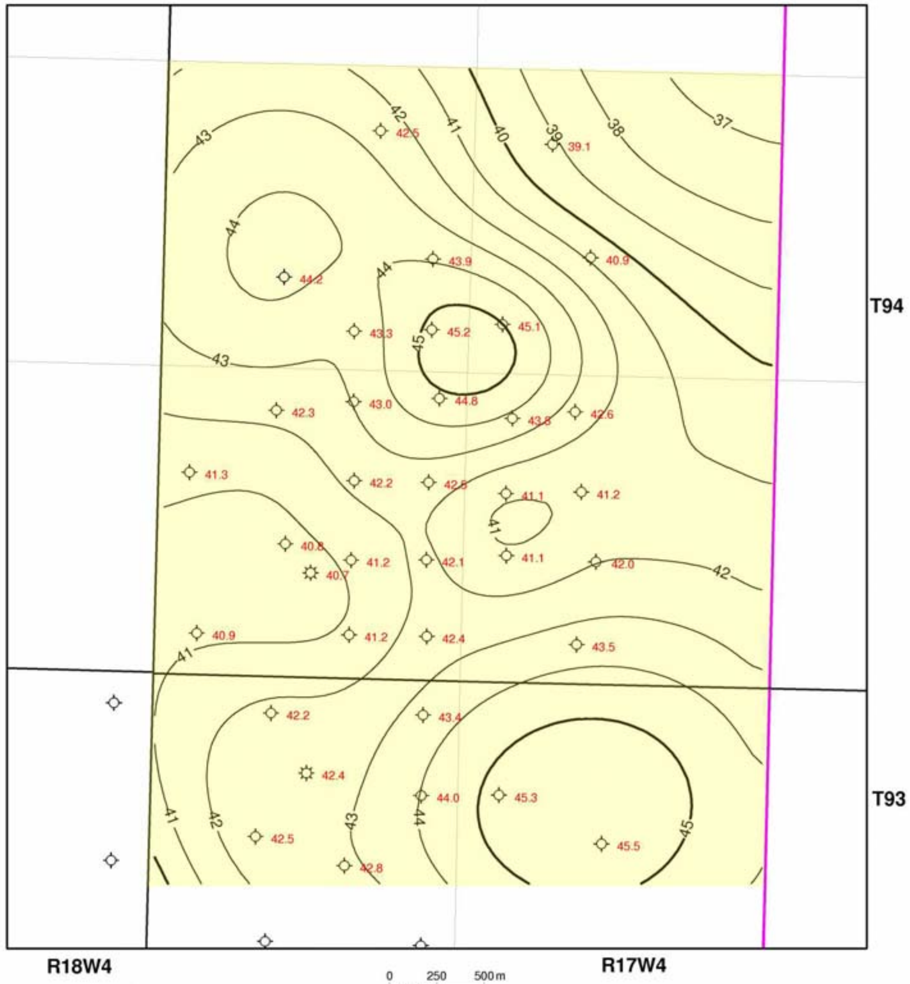

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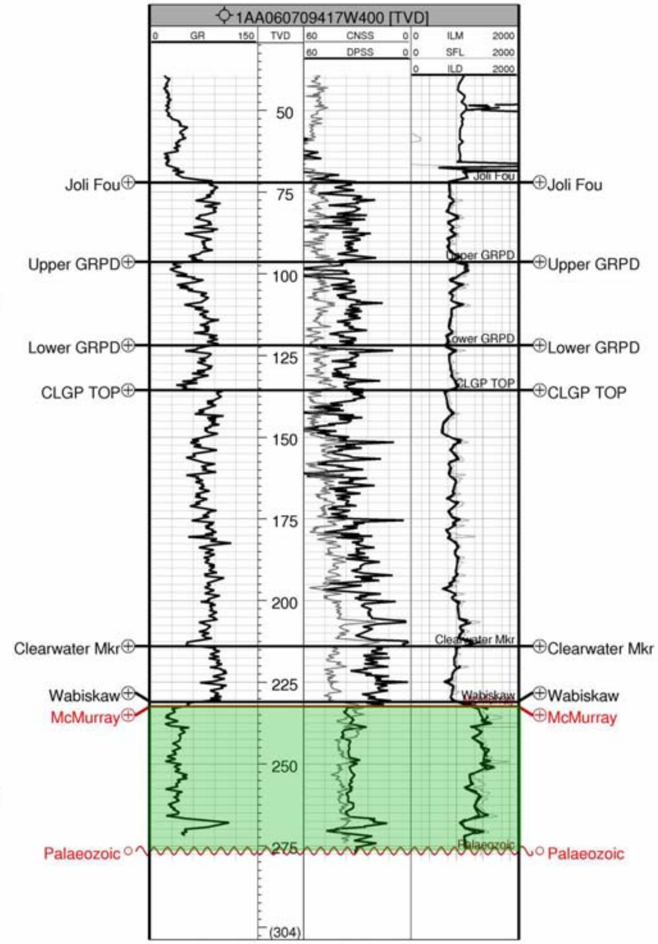

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McMURRAY FORMATION ISOPACH MAP

FIGURE 4.4-5

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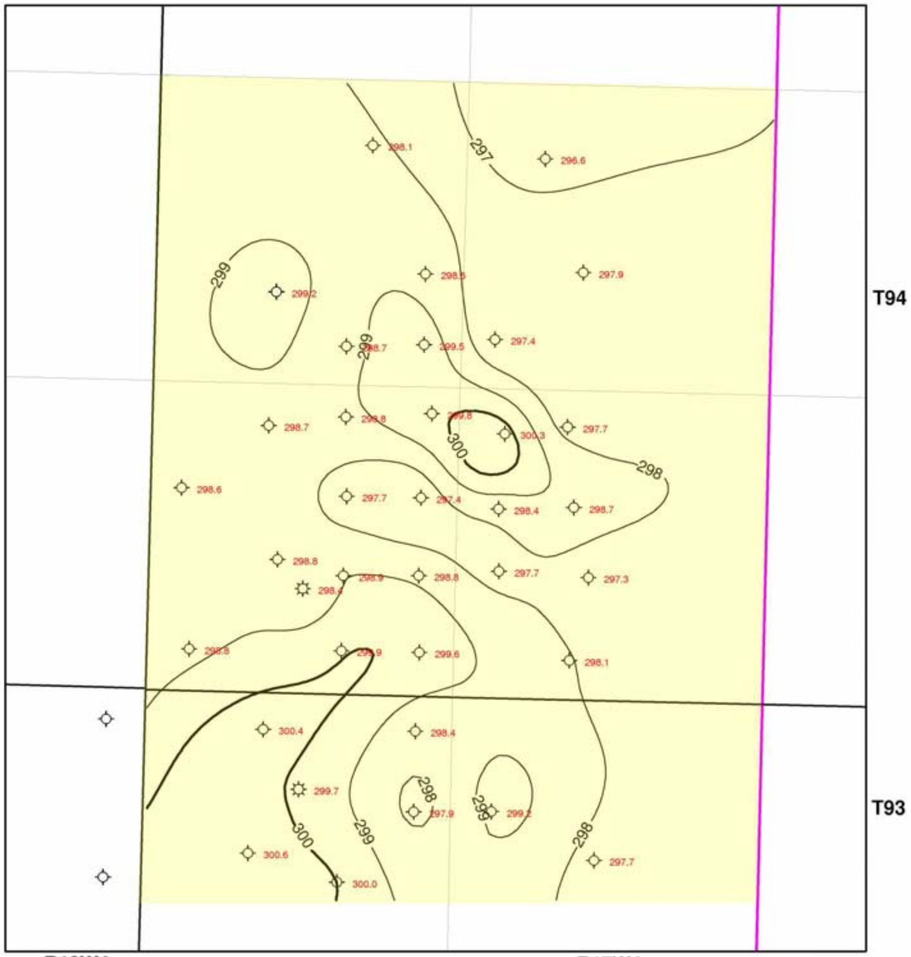
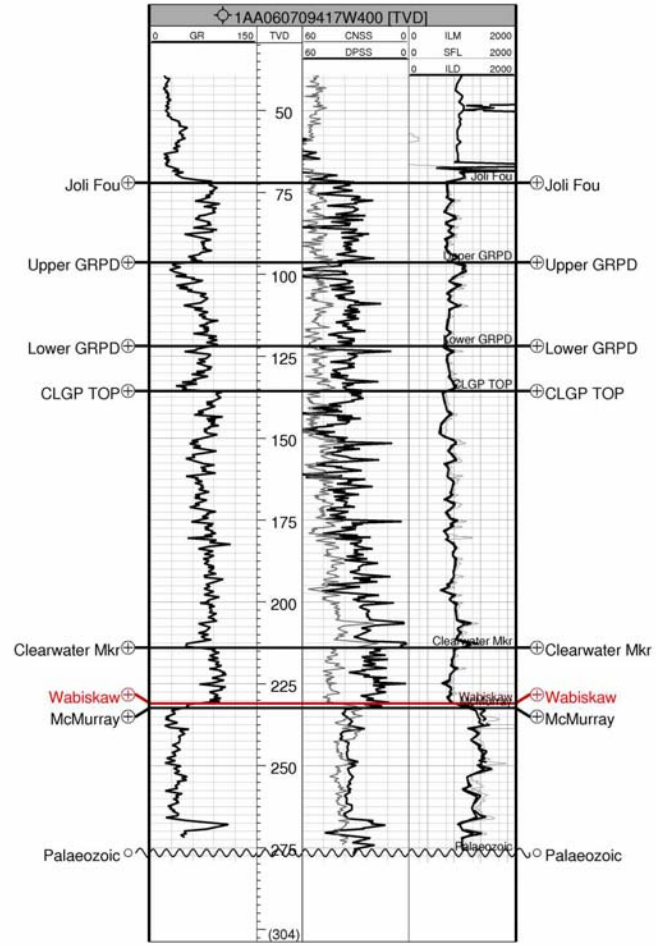


Contour interval: 1m
Structure elevation is MASL



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TOP WABISKAW MEMBER STRUCTURE MAP

FIGURE 4.4-6

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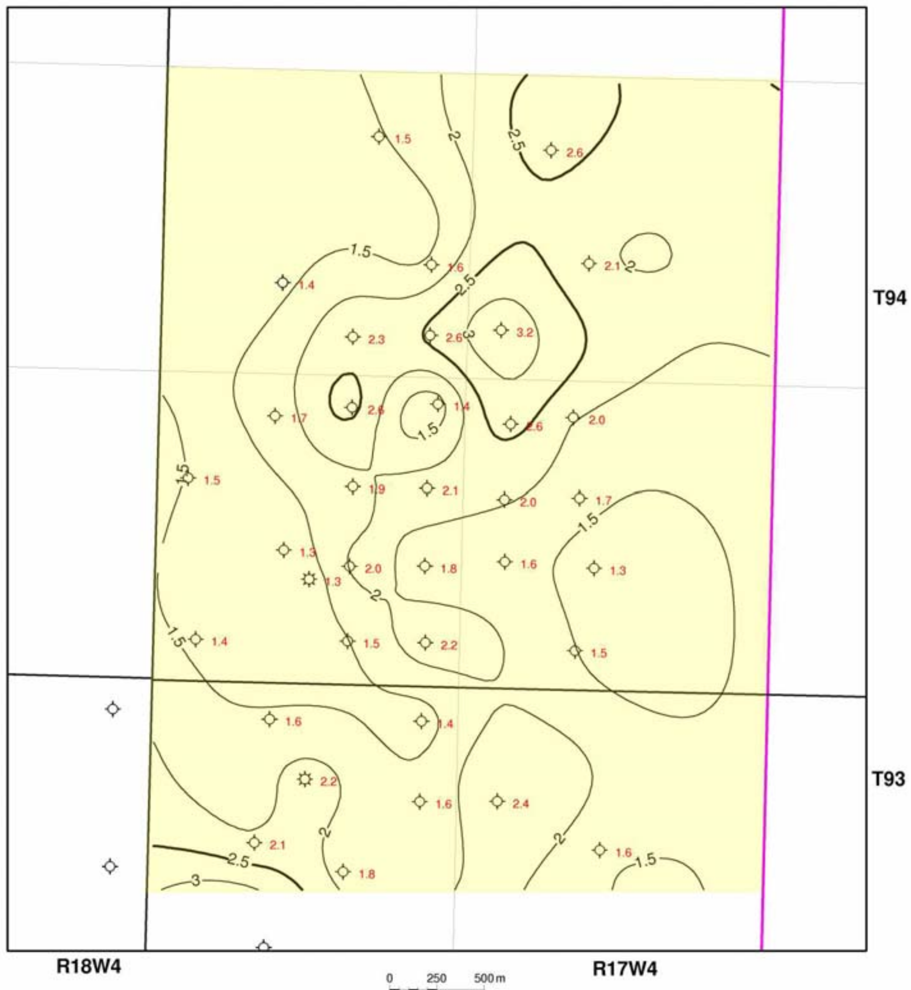

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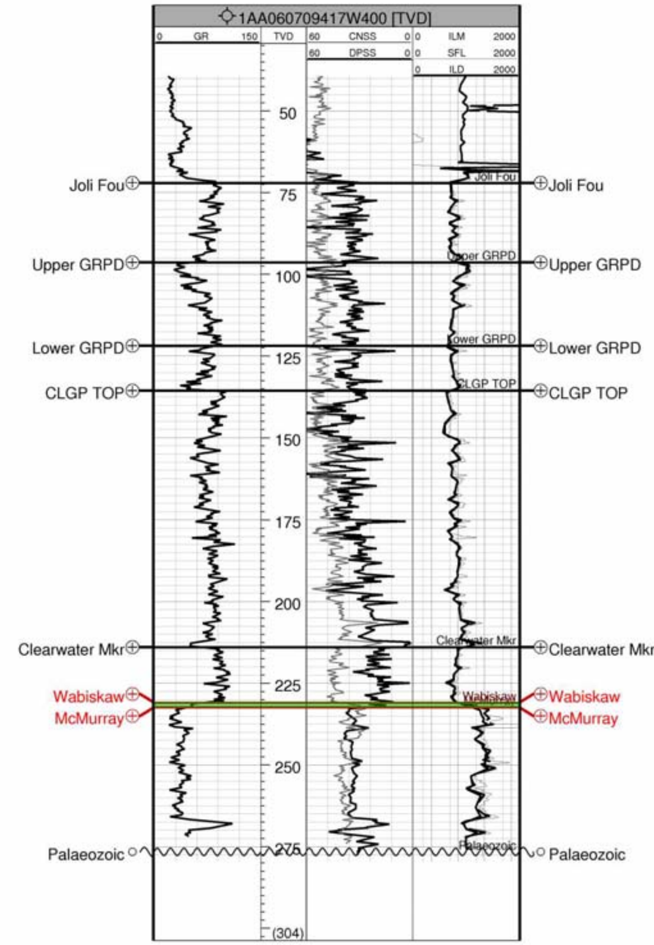

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WABISKAW MEMBER ISOPACH MAP

FIGURE 4.4-7

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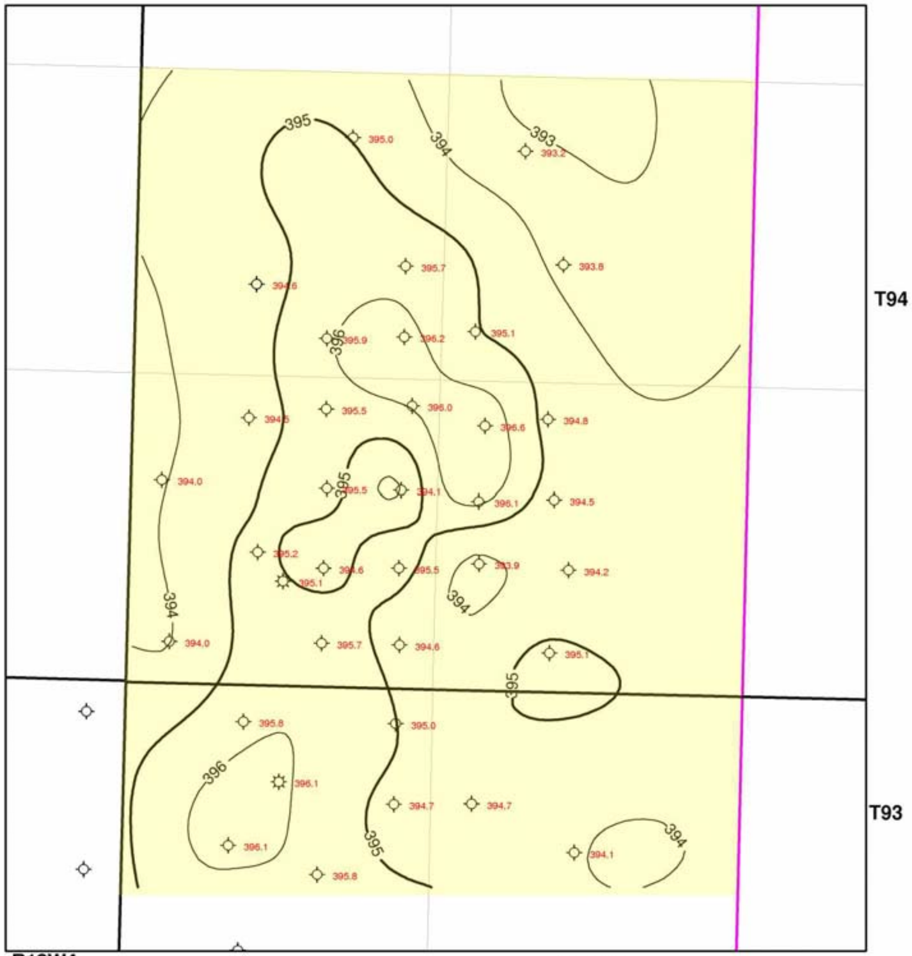

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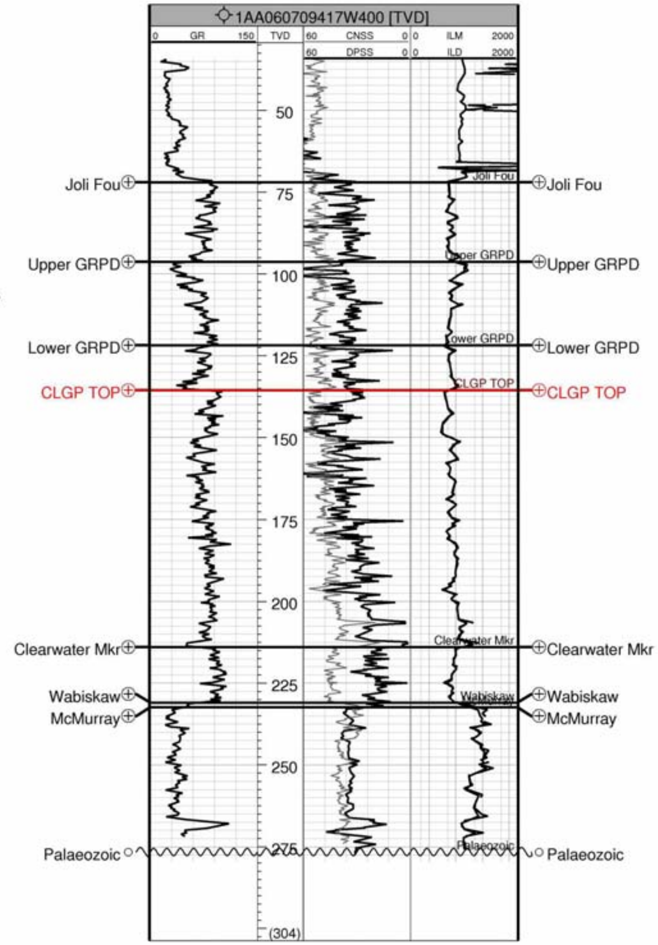

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TOP CLEARWATER FORMATION STRUCTURE MAP

FIGURE 4.4-8

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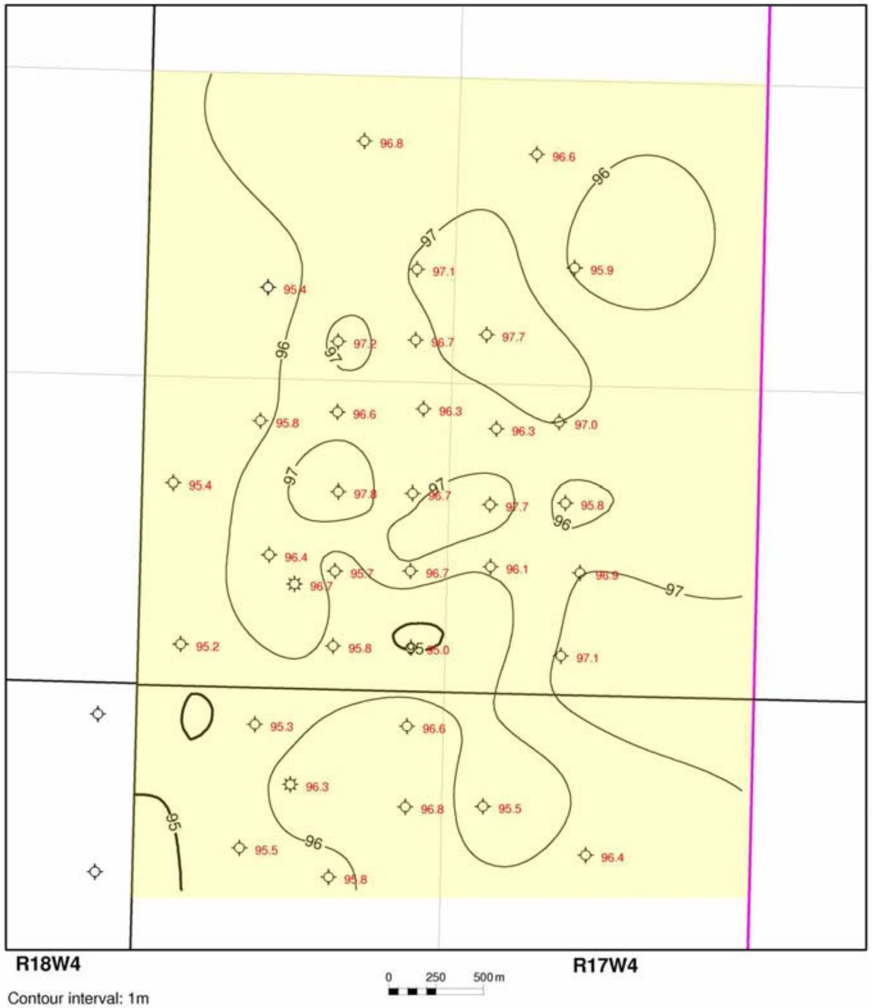

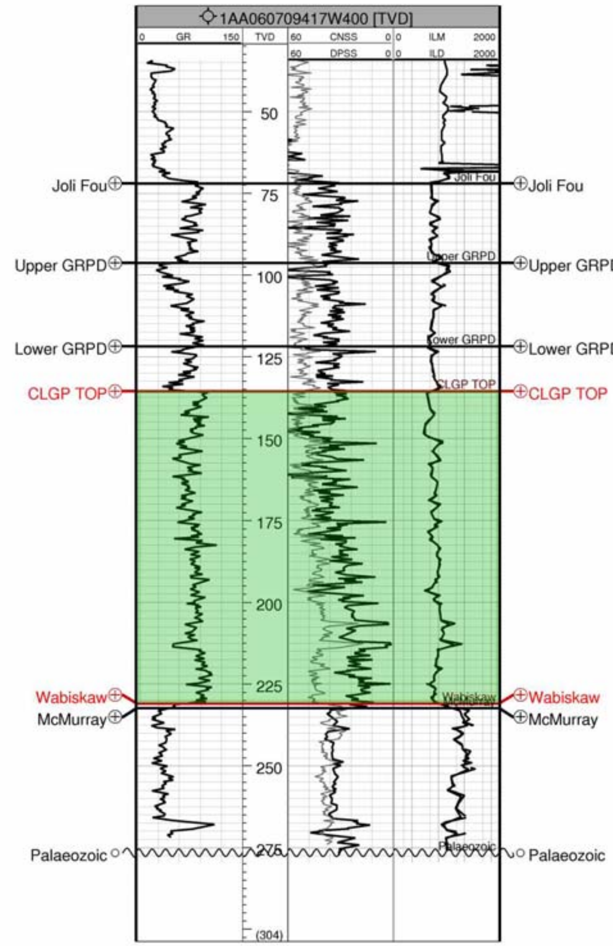

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CLEARWATER FORMATION ISOPACH MAP

FIGURE 4.4-9

4.5 Reservoir Description

All structural and thickness maps presented in this section include information derived from winter 2007/2008 delineation wells. Structural variations for the top Wabiskaw sand interval in the GSA are shown in Figure 4.4-6. It is evident from well control that structural elevation over this area does not vary. As seen in Figure 4.4-6, the top Wabiskaw structural elevation varies from 297 to 301 masl over the GSA, with a range of only 4 m. Similar observations occur for the top of the McMurray Formation, with structural elevation varying from 294 to 299 masl across the GSA (Figure 4.4-4). The Devonian structural elevation exhibits greater relief of 7 m from 251 to 259 masl, with a structural low centred under the GSA (Figure 4.5-1). The structural lows are due to the erosive nature and development of this angular unconformity surface. The McMurray isopach map for the GSA shows a thickness variation from 37 to 46 m, with an average of 42.5 m (Figure 4.4-5). This thickness variation is impacted mostly by palaeotopographical variability of the top Devonian surface, where thick intervals in the McMurray are attributed to deposition within structural lows on the Devonian surface. The Wabiskaw sands are very thin in the GSA, comprising the Wabiskaw A stratigraphic interval. It consists of abundantly bioturbated, glauconitic, muddy sands. The isopach map of Wabiskaw A shows a thickness variation from 1 to 3 m across the GSA (Figure 4.4-7).

The Top McMurray bitumen pay interval displays little structural variation (Figure 4.5-2; Section 4.6.1 provides more detailed definition of the top and base of the pay zone). This map exhibits structural elevation varying from 285 to 296 masl (Figure 4.5-2). The structural variability is mostly attributed to the presence and elevation of gas accumulations in specific wells. The base of bitumen net pay zone structure map illustrates as much structural variation as the top pay zone map (Figure 4.5-3). The structural elevation varies 10 m, from 261 to 271 masl across the GSA. There is a clear north-south trending structural low centred on the GSA. The McMurray net pay zone varies in thickness from 17 to 27 m and exhibits a north-south trending thick reservoir interval (Figure 4.5-4). In the area where the wells will be placed, net pay thickness ranges from 23 to 27 m. Representative cross-sections illustrate the lithological continuity and persistence in reservoir quality of the McMurray reservoir interval over the GSA (Figures 4.5-5 and 4.5-6).

Initial sedimentation style of the McMurray in the GSA consists of a series of interstratified muds, silts and sands which comprise the middle McMurray member. This interval is not prospective for bitumen exploitation. Initial deposition of the McMurray occurred as a series of thin, 1 to 3 m cleaning- and coarsening-upward sandy cycles that are encased in grey, laminated to bioturbated shale. Each cycle exhibits an upward decrease in bioturbation abundance. Trace diversity is low, being mostly *Teichichnus*. As trace fossil abundance decreases upward in each cycle, it results in increased preservation of physical sedimentary structures such as current ripple cross-stratification and parallel-lamination. The top of each sandy cycle is capped by a grey to cream-coloured clay-rich palaeosol with carbonaceous, pyritised root traces. This interval is interpreted as crevasse splay sandy lobes which prograded into a very shallow body of low-energy water, likely an interdistributary bay in a lower delta plain environment. The sands were likely intermittently subaerially exposed reflecting their aggradational nature to the water surface.

The upper McMurray member is the principal reservoir zone. It has been subdivided into three intervals; referred to as McMurray 1, McMurray 2 and McMurray 3 from stratigraphic top to base. The upper McMurray member erosively overlies the middle McMurray member. It contains at least three stratigraphic cycles that can be correlated across the GSA. Each cycle consists of a 5 to 8 m thick, cleaning- and coarsening-upward succession. Generally, each cycle except for the lower most or initial cycle commences with flaser-bedded, current-ripple cross-laminated, fine to very-fine-grained sands. The lower or initial cycle, which contains both the injector and the producer, typically consists of a series of fining upward cycles. Mud laminae are less than 1 cm in thickness and are discontinuous across the width of the core due to disruption by bioturbation, contributed by *Teichichnus, Planolites* and *Thalassinoides*. The size of trace fossils increases upward and diversity decreases within each cycle. As the reservoir cleans upward, the traces grade into mostly *Asterosoma* and *Rosselia*, some of which have been reworked and locally transported. This facies is clean fine-lower to medium-grained sand and appears to be completely bioturbated. These sands grade up into a fine-upper to medium-lower facies of sharp-based, parallel-laminated to hummocky cross stratified (HCS) sands overlain by flaser bedding. These cleaning-upward cycles reflect the progradational nature of several vertically-stacked sand lobes that prograded into a tidally-influenced, marine embayment. The salinity-stressed ichnosuites indicate that conditions were never fully marine, probably due to fresh water influx into the bay sourced from a delta. The cleaning-upward cycles reflect distal to proximal vertical transition of a delta front environment. The base of each cycle is clean, indicating its proximity to a sediment source.

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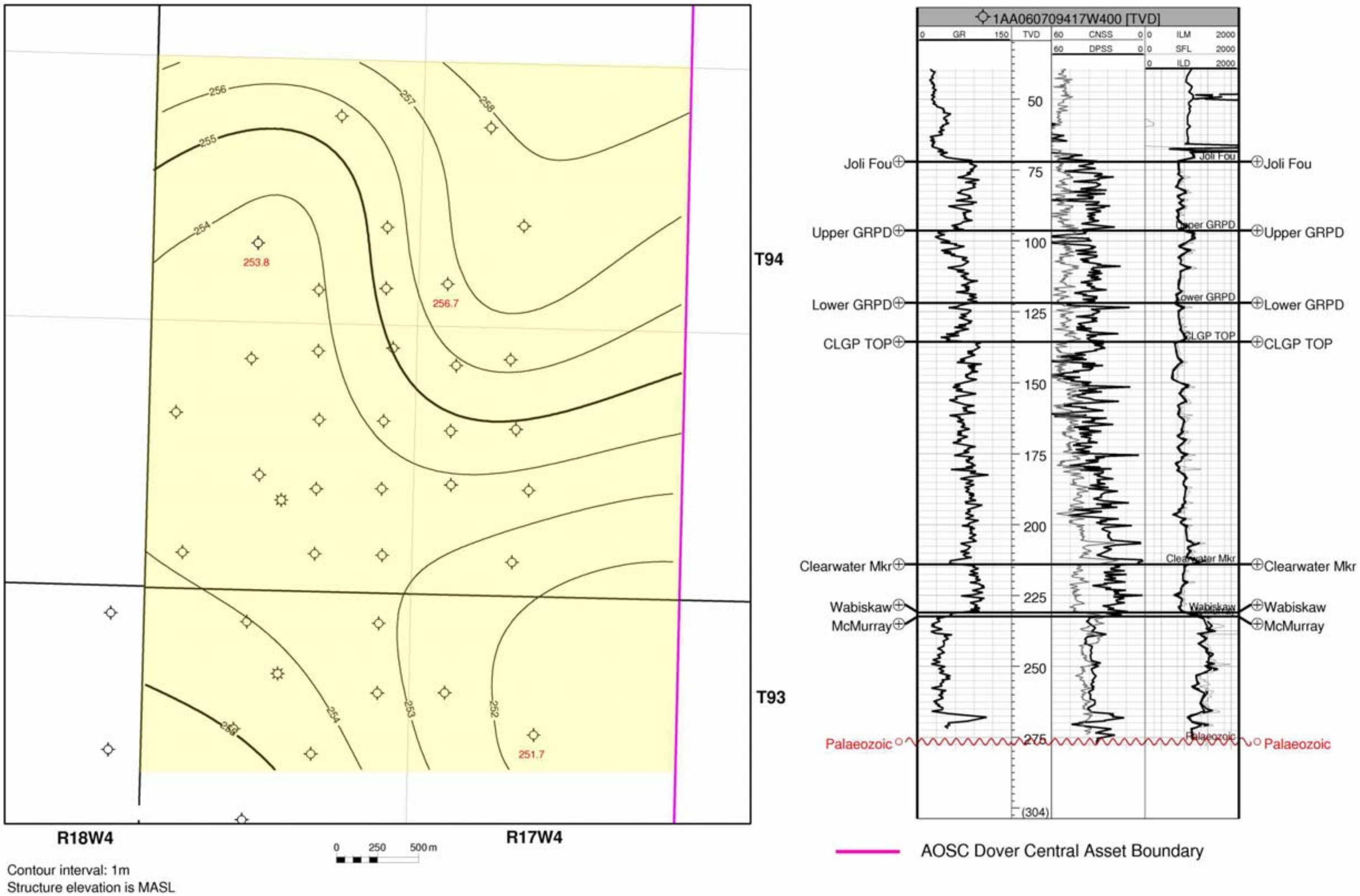

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TOP DEVONIAN SYSTEM STRUCTURE MAP

FIGURE 4.5-1

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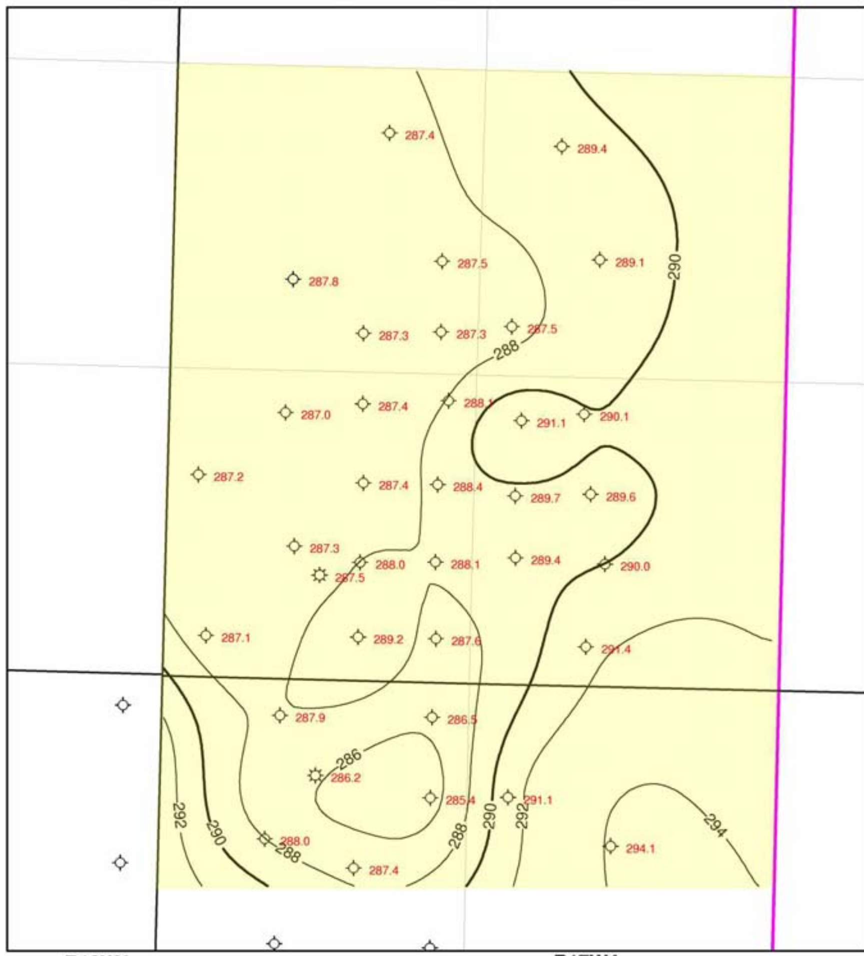

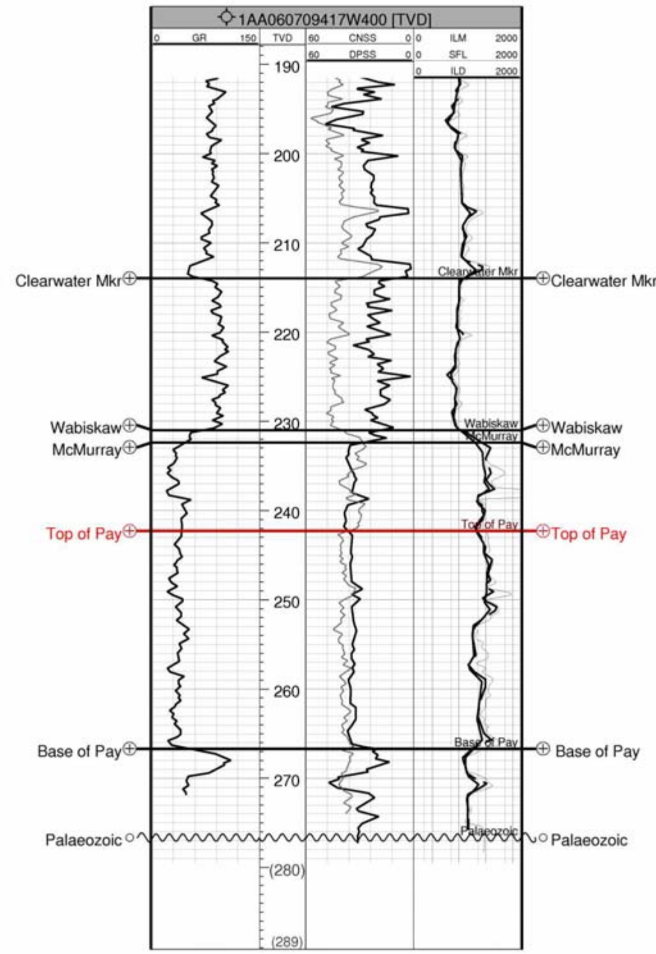

Contour interval:2m
Structure elevation is MASL

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MCMURRAY FORMATION TOP NET PAY ZONE STRUCTURE MAP

FIGURE 4.5-2

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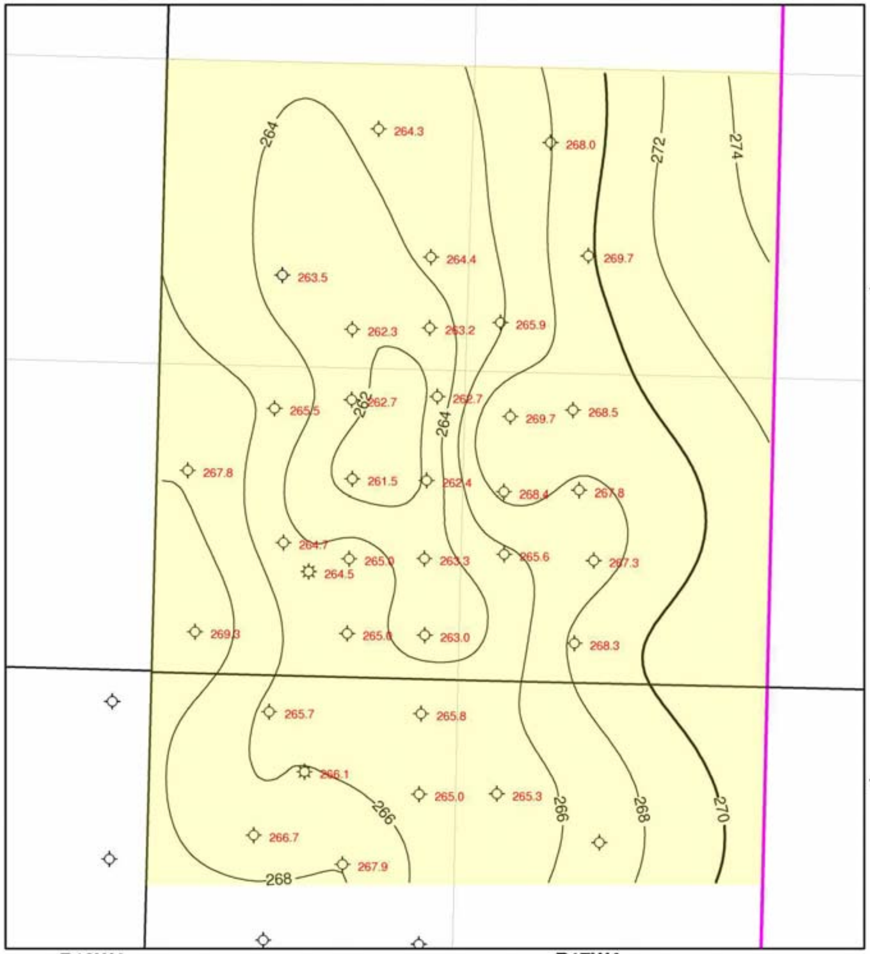
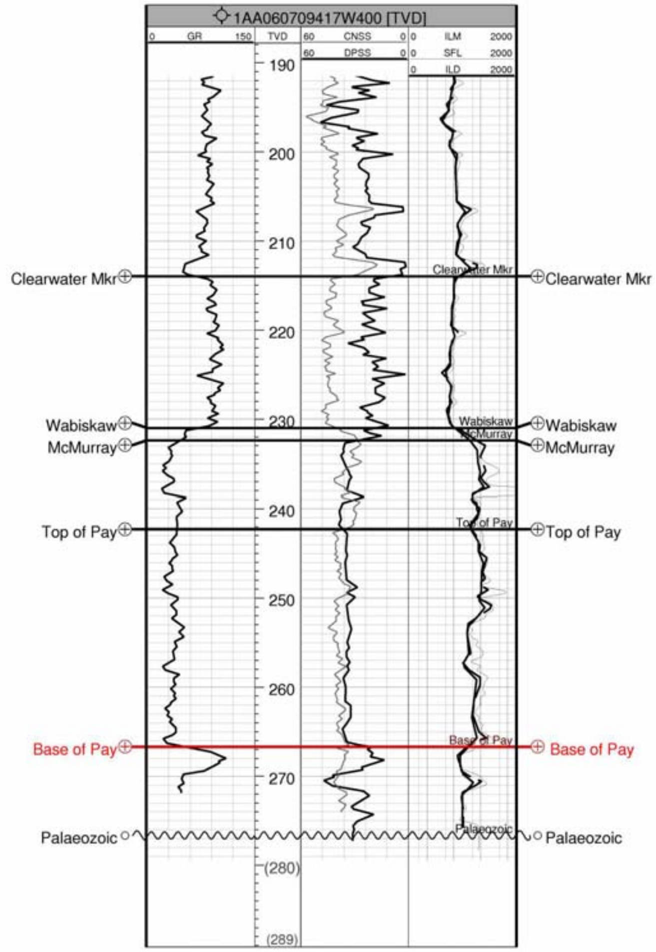


Contour interval: 2m
Structure elevation is MASL



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McMURRAY FORMATION BASE NET PAY ZONE STRUCTURE MAP

FIGURE 4.5-3

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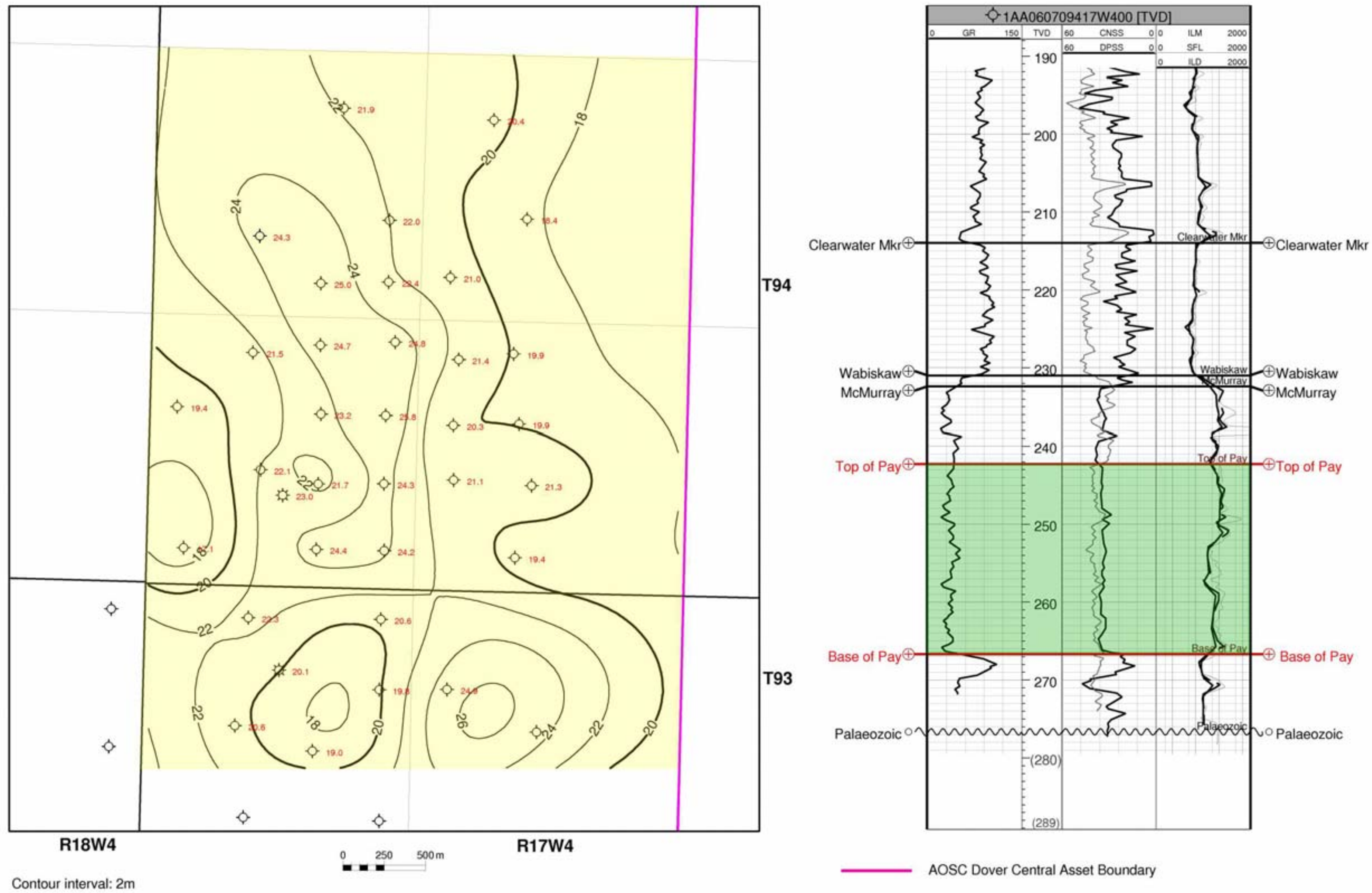

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McMURRAY FORMATION NET PAY ISOPACH MAP

FIGURE 4.5-4

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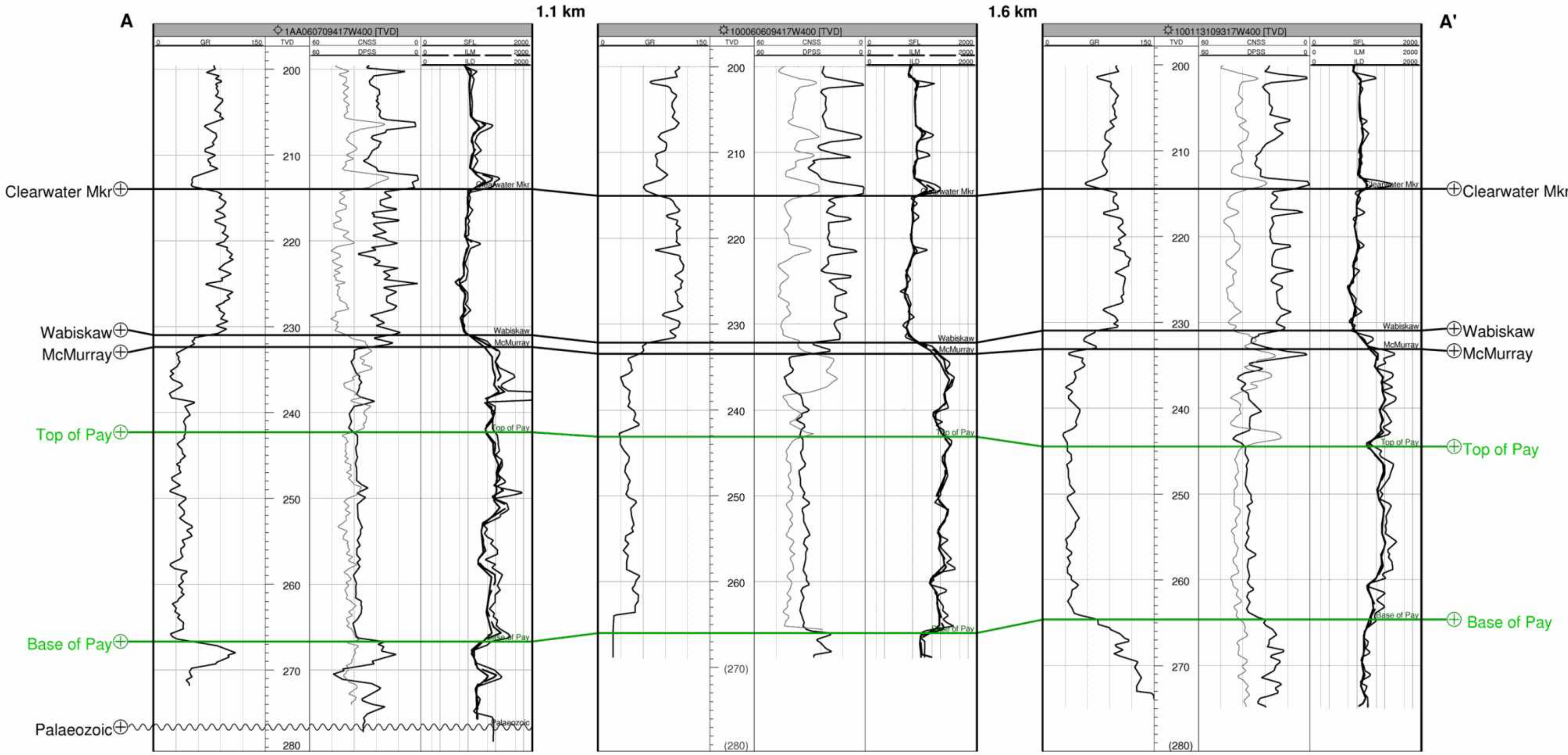

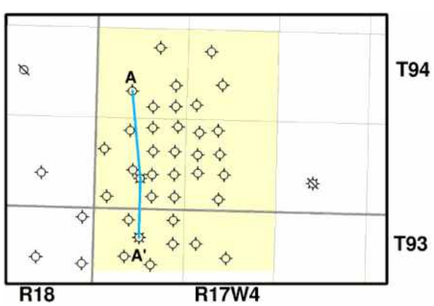

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NORTH - SOUTH STRUCTURAL CROSS-SECTION A-A'

FIGURE 4.5-5

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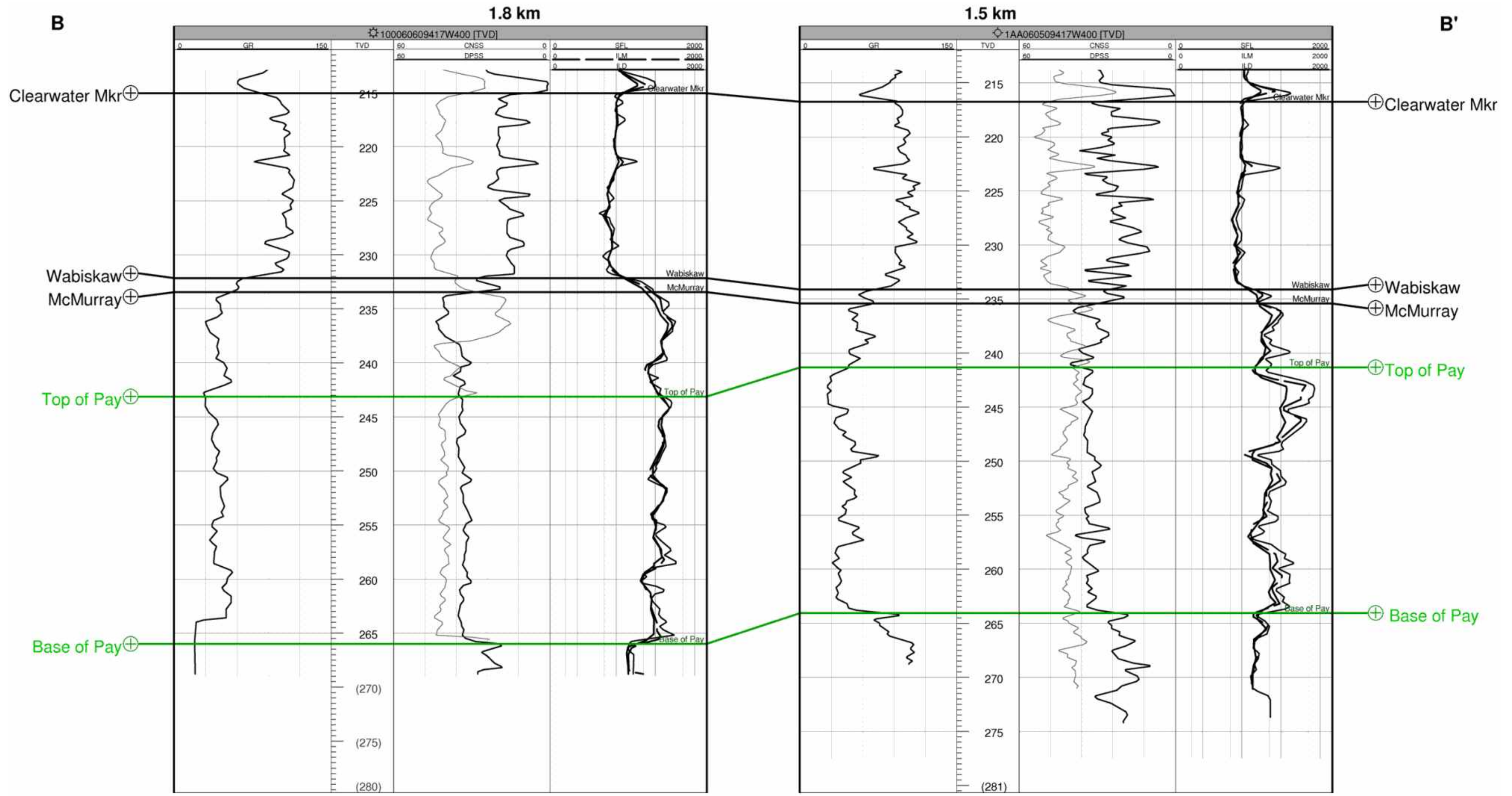

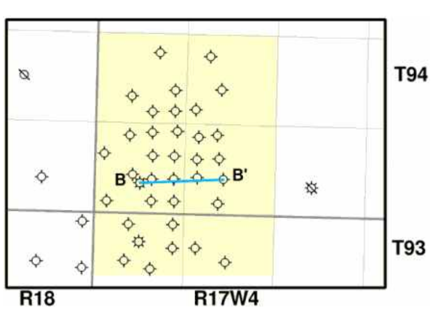

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EAST - WEST STRUCTURAL CROSS-SECTION B-B'

FIGURE 4.5-6

4.6 Reservoir Parameters

The bitumen pay zone is located within the upper member of the McMurray Formation. Top and base of the pay zone are determined from well-log, core description, FMI and core analysis information. The base pay zone is determined by the first appearance of fine-grained, black, bituminous, clean sand overlying argillaceous deposits, and is characterized by elevated deep resistivity values, high bitumen saturations, a low gamma-ray API response and high, persistent porosities. The top of the pay zone is determined by the first occurrence of a gas zone, more than 1 m in thickness which can be correlated for more than one legal subdivision (LSD). Net pay is defined from various reservoir parameter cut-offs (Table 4.6-1). These net pay cut-offs were determined from cross-plotting various wire-line log and core analysis parameters as well as examining core photos and core descriptions.

The type well for this area (1AA/06-07-094-17W4; Figure 4.6-1) was chosen since AOSC collected core analysis data from it in 2007. Core analysis samples were taken throughout the McMurray interval to determine porosity and oil saturation. A good agreement exists between core analysis and wire-line log analysis for both porosity and bitumen saturations, thus indicating high confidence for interpreted porosity and bitumen saturation curves in uncored wells.

The deep resistivity, gamma-ray and density porosity curves were used to define reservoir parameters and pay intervals. There was good correlation between the bitumen saturation derived from log interpretation and bitumen saturation derived from core analysis, and also between density porosity and core porosity for wells located throughout the GSA.

A 50% bitumen saturation, greater than 70 API gamma-ray and a density porosity cut-off of 27% were used to define net pay intervals (Table 4.6-1). Table 4.6-2 illustrates the average reservoir properties for the McMurray net pay zone in the GSA.

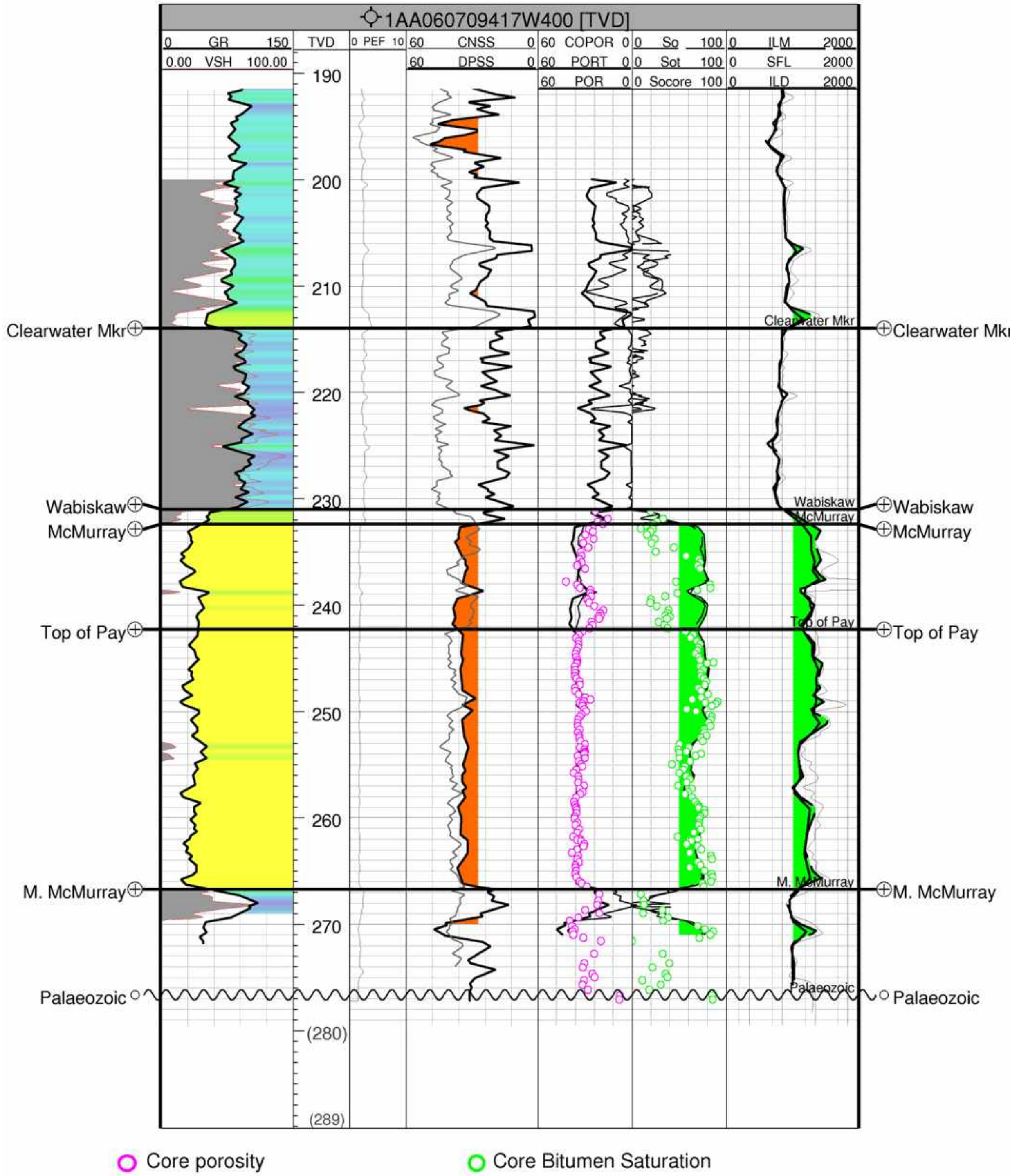
Table 4.6-1 Net Pay Cut-Offs Used to Define the Upper McMurray Bitumen Pay Zone

Net Pay Parameter	Cut-Off Value
Porosity (from density log) (%)	>27
Bitumen Saturation (%)	>50
Deep Resistivity (ohm-m)	>22
Net Pay Thickness (m)	>13
Shale Volume (V_{sh}) (%)	<35
Gamma-Ray (API)	<70
Shale Thickness (m)	<0.5

Table 4.6-2 Reservoir Parameter Characteristics for the Upper McMurray Bitumen Pay Zone

Average Reservoir Parameters	Value
Reservoir Depth (m)	233
Net Pay (m)	23 to 27
Net to Gross (NTG) (frac)	0.98
Log PHI (%)	33
Log So (%)	75
Shale Volume (V_{sh}) (%)	3
Horizontal Permeability (K_h) (D)	3.4
Vertical Permeability (K_v) (D)	1.8

Bitumen saturation varies from 68 to 82%, averaging 75% across the GSA and porosity varies from 30 to 35%, averaging 33%.



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COMPARISON OF CORE ANALYSIS TO INTERPRETED LOG DATA FOR TYPE WELL

FIGURE 4.6-1

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4.7 Original Bitumen In Place Volumetrics

The original bitumen in-place (OBIP) volumes were calculated for the drainage area of the well pad (Table 4.7-1). Since the pay was greater than 20 m, no net pay thickness cut-off was used. An average of 33% porosity and 75% bitumen saturation were used to calculate volumes from the net bitumen pay zone of the upper McMurray within the GSA.

Table 4.7-1 OBIP Volumes and Reserves

OBIP		Reserves	
10^6 m^3	10^6 bbls	10^6 m^3	10^6 bbls
1.0	6.0	0.5	3.0

4.8 Reservoir Recovery Process

AOSC will be implementing an experimental process at the Pilot to evaluate a novel method of in-situ thermal recovery in low pressure reservoirs. The process, called the “SAGD Triplet Process”, will involve a high temperature startup, the co-injection of non-condensable gas (NCG), followed by low pressure SAGD production with a well configuration and operating strategy.

The successful piloting of this experimental process will provide a significant improvement in the recovery of the bitumen resource located in parts of AOSC’s Dover lease area.

4.8.1 Recovery Process Selection

The bitumen resource located in AOSC’s Dover lease area is sizeable; however the initial reservoir pressure is low in some areas due to depleted top gas. The massive bitumen resource and low reservoir pressure raised several considerations in the design of a recovery process.

AOSC has developed an experimental process to test at the Pilot that will address these considerations and provide a viable method of bitumen recovery. The process will demonstrate significant improvement in recovery factor.

4.8.2 Recovery Process Description

The proposed SAGD Triplet Process is depicted in Figure 4.8-1. SAGD well pairs will be drilled with an additional horizontal well in between. This additional well is called the Lateral Drainage (LD) well. A triplet is comprised of one SAGD well pair and one LD well. The Pilot will consist of three SAGD well pairs and two LD wells.

The LD well will alternate between injection and production cycles to promote lateral communication between the SAGD well pairs. Low volumes of NCG, consisting of flue gas and/or methane, will be co-injected into the SAGD injection wells and LD wells at intermittent time intervals to optimize the growth of the steam chambers. The operating pressure in both SAGD wells and the LD wells will be reduced as the steam chambers rise.

4.8.2.1 Artificial Lift Methodology

AOSC will be utilizing metal to metal progressive cavity pumps (PCP) at low pressure SAGD conditions.

4.8.2.2 Non-Condensable Gas Co-Injection

AOSC is proposing to co-inject flue gas and/or methane with steam at a CPF rate of 500 to 25,000 m^3/d at the Pilot.

4.8.2.3 Well Configuration and Operating Strategy

The SAGD well pairs will initially be started up at an operating pressure of approximately 3,500 kpa. This pressure is within a safe operating range, and will provide higher initial production rates.

4.8.2.4 Caprock Integrity

The caprock in the GSA occurs within the Clearwater Formation. The Clearwater consists of mudrocks. The high clay content and a thickness varying from 94 to 97 m make this interval suitable as a competent caprock for in-situ thermal operations.

In the winter of 2007-2008, AOSC carried out an injection test (mini-fracture) program in the GSA to determine the in-situ stress state for the McMurray Formation pay zone and the Clearwater Formation caprock. The test results determined that the fracture gradient in the McMurray and Clearwater formations are 17.7 and 22 kPa/m, respectively. These measured fracture gradients are consistent with public data for the Athabasca Oil Sands area.

The base depth of the Clearwater caprock in the GSA is around 230 m, giving a fracture pressure at the base of the caprock of 5,060 kPa. While the injection wells will be placed at a depth of approximately 260 m, AOSC has applied the McMurray fracture gradient of 17.7 kPa/m at the depth of the base of the caprock (230 m) in calculating safe operating pressures. As such, AOSC is proposing to operate at approximately 3,500 kPa, representing a factor of safety of 20 to 30% with respect to the Clearwater Formation fracture pressure at the base of the caprock.

4.8.3 Simulation Model and Results

AOSC used Computer Modelling Group's (CMG's) Steam, Thermal and Advanced Processes Reservoir Simulator (STARS) thermal software to evaluate the performance of the SAGD Triplet Process. STARS is a three phase, multi-component model that has the ability to simulate advanced thermal recovery processes in oil sands reservoirs.

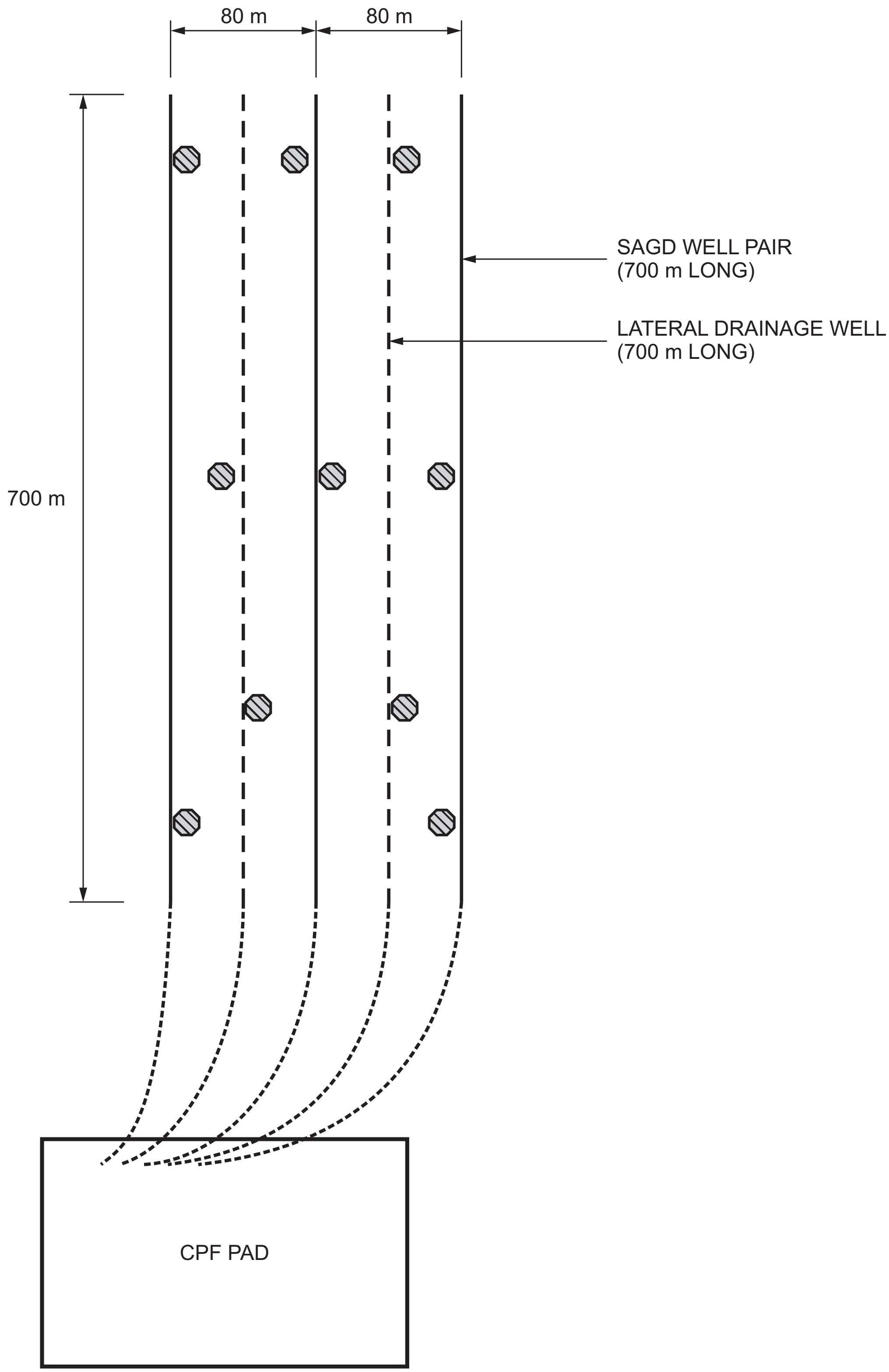
The simulations have confirmed that the co-injected NCG will increase the sweep efficiency of the process and bitumen recovery.

4.8.4 Reservoir Performance Monitoring

AOSC will drill 8 to 12 observation wells to monitor reservoir performance. These wells will typically be cased and cemented in place. Conceptual observation well locations are presented in Figure 4.8-1.

The observation wells will be equipped with thermocouples placed in the bitumen zone to monitor the temperature progress of the steam chamber. Piezometers will be used for pressure monitoring. They will be attached to the outside of the casing, positioned both in and above the bitumen zone and cemented in place.

Performance monitoring results of the Pilot are highly confidential and proprietary to AOSC.



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CONCEPTUAL OBSERVATION WELL LAYOUT

FIGURE 4.8-1

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4.9 Hydrogeology

A report outlining baseline hydrogeologic conditions and a detailed hydrogeologic assessment for the Pilot is presented in Appendix A. The hydrogeology assessment is based on a conservative 7 year life. Key findings of the baseline and assessment are summarized below.

4.9.1 Methodology

The following work was completed in order to assess the potential impacts of the Pilot on groundwater resources:

- Definition of a study area of adequate areal extent to facilitate the discussion of impacts of the Pilot on groundwater resources (Appendix A, Figure 1);
- Documenting of baseline geologic and hydrogeologic conditions within the study area;
- Drilling and field testing of one Lower Grand Rapids Aquifer well in 2008 (1-23-93-17 W4M);
- Compilation of local water users in the study area; and
- Evaluation and discussion of the potential impacts of the Pilot on groundwater resources in terms of water quality and water levels.

4.9.2 Geology

Underlying the hydrogeologic study area at approximately 420 to 450 mbsl is Precambrian crystalline basement which is erosionally overlain by Devonian, Cretaceous and Quaternary Period sediments. The Devonian is separated into the Elk Point, Beaverhill Lake and Woodbend groups. The sub Cretaceous unconformity separates the Devonian deposits from the Cretaceous Period clastic sediments. The Cretaceous sediments consist of the Mannville and the Colorado Groups. Unconsolidated Quaternary sediments are deposited on Cretaceous bedrock. A Quaternary Channel, named the Birch Channel, has incised into the Cretaceous bedrock and is a prominent Quaternary and top of bedrock feature in the region.

Regionally, the Precambrian basement and the Devonian sediments dip to the southwest at slopes of 3 to 5 m/km and 1 to 5 m/km, respectively (Bachu et al., 1993). The Cretaceous sediments regionally dip to the southwest at approximately 2 m/km (Bachu et al., 1993).

Based on detailed correlation the uppermost bedrock units in the region include the La Biche Formation, the Viking Formation, the Joli Fou Formation, the Grand Rapids Formation and the Clearwater Formation. East of the study area, the McMurray and Waterways formations subcrop below the Quaternary sediments in the Athabasca River Valley (AGS, 1999).

4.9.3 Hydrogeology

The geologic units were divided into 19 hydrostratigraphic units based on the interpreted relative permeability, thickness and mapped/expected continuity. Within the study area, key candidate aquifers for the Pilot steam generation make-up water include the Empress Channel, Upper Grand Rapids and Lower Grand Rapids aquifers. The Lower Grand Rapids Aquifer is the proposed source for Pilot steam generation make-up water withdrawal.

4.9.3.1 Empress Channel Aquifer

Within the Birch Channel, up to 50 m of sand and gravel of the Empress Formation is present and referred to as the Empress Channel Aquifer. Based on pumping tests and production rates from wells completed in similar aquifers throughout the Athabasca Oil Sands region, the per well deliverability within the Empress Channel Aquifer can exceed 1,000 m^3/day. Groundwater chemistry results are not available within the study area. However, Petro-Canada (2005) has estimated the TDS concentration in the Empress Channel Aquifer (Birch Channel) to range from 100 to 1,000 mg/L based on results at their Mackay River SAGD Project east of the study area.

4.9.3.2 Grand Rapids

The Grand Rapids Formation of the Mannville Group is interpreted to represent a regional regressional sequence as the Clearwater Sea withdrew to the north and northwest (Bachu et al., 1993). The Grand Rapids Formation was divided into three hydrostratigraphic units. The two coarsening upwards sand successions of the Grand Rapids are referred to as the Upper Grand Rapids Aquifer and the Lower Grand Rapids Aquifer. Both aquifers are completely eroded within the Birch Channel. Shale and/or silt deposits that occur above and below the Upper and Lower Grand Rapids aquifers are referred to as the Grand Rapids Aquifer/Aquitard.

In the study area, the Upper Grand Rapids Aquifer ranges in thickness from 0 to 18 m. There are no chemistry or hydraulic head data available for the Upper Grand Rapids Aquifer within the study area.

The Lower Grand Rapids Aquifer is up to 27 m thick in the study area and is the proposed steam generation make-up water source for the Pilot. Available Lower Grand Rapids Aquifer hydraulic head values indicate that horizontal groundwater flow is directed east and southeast towards the Athabasca River where the Lower Grand Rapids Aquifer outcrops and discharges within the Athabasca River valley. Lower Grand Rapids Aquifer groundwater chemistry samples collected at 1-23-093-17 W4M indicate that the groundwater is a sodium-bicarbonate type with a TDS concentration of approximately 1,320 mg/L. Additional groundwater quality data collected at 1-23-093-17 W4M is presented in Appendix A.

Based on available pumping test data at 10-29-092-17 W4M and 1-23-093-17 W4M, the hydraulic conductivity of the aquifer was estimated to range from 6.7×10^{-6} to 1×10^{-5} m/s.

4.9.4 Impact Evaluation

Through the construction, operations and reclamation phases of the Pilot, components which have the potential to affect groundwater resources include the operation of surface facilities, groundwater withdrawal and steam injection. The following conclusions are presented regarding the hydrogeology impact evaluation:

- Given the low hydraulic conductivity of the Undifferentiated Overburden Aquifer/Aquitard and the relatively large distance to the closest domestic water well (11 km), an accidental surface release would pose little threat to existing local groundwater users.
- A decrease in aquifer productivity of 10% is predicted to extend up to 4.1 km from the pumping center. The closest existing well completed in the Lower Grand Rapids Aquifer is located 9 km from the pumping center. There are no licensed users of the Lower Grand Rapids Aquifer in the study area and the magnitude of impact is ultimately considered low.
- Groundwater removal from the Lower Grand Rapids Aquifer is predicted to have a non-detectable impact on water levels in shallow overburden aquifers and surface water bodies.
- Impacts to groundwater quality as a result of heating are limited to the potential mobilization of metals in the study area. These impacts, if any, are anticipated to be localized and limited to within 100 m of the injection wells. These impacts do not

represent a threat to existing groundwater users because the nearest groundwater user is 11 km away.

- If, through groundwater monitoring, it is established that groundwater quality has been impacted by ongoing operations or an accidental release, a groundwater response plan will be initiated in consultation with the appropriate regulatory agencies.

Based on the conclusions presented above, the Pilot is anticipated to have low to negligible effects on existing groundwater resources.

5 PROCESS DESCRIPTION

Facilities associated with the Pilot can be broken down into three components: wells, the CPF, and offsite services and utilities, which are described further in the subsections below.

5.1 Wells

5.1.1 Well Layout

Both the SAGD well pairs and the LD wells will be drilled from a common multi-well pad. The SAGD production wells and the LD wells will be drilled to a vertical well depth of about 265 m, placed 1 m above the base of pay. The injection wells will be drilled approximately 5 m above the production wells. The horizontal well length will be approximately 700 m. The inter-well spacing between the SAGD well pairs and the LD well will be about 40 m. The conceptual well placement is presented in Figure 5.1-1.

5.1.2 Drilling and Completions

All of the proposed horizontal wells for the Pilot will be started approximately 20° to 30° from vertical and then drilled to target following a build rate of approximately 8° per 30 m. The horizontal wells will encounter the bitumen pay zone at 90° from vertical. The total measured depth of the wells will be around 1,200 m, depending on the well trajectory.

The surface casing interval will be cemented in place using thermal cement. The surface casing selected will comply with the requirements of ERCB Directive 008 (1997). The intermediate section of the well will remain approximately 20° to 30° from vertical until the kickoff depth is reached, at which point directional drilling will begin. The directional drilling assembly will consist of a mud motor system and a measurement while drilling (MWD) system. The intermediate sections of all wells will be cased with casing designed for thermal conditions, utilizing high strength connections and cemented in place using thermal cement.

The horizontal sections of all wells will be drilled using the same MWD system. In addition, a gamma ray logging tool will be run to identify reservoir quality. A resistivity tool may also be run to gather saturation information. The horizontal length will be completed using a slotted liner for sand control and secured using a thermal liner hanger.

5.1.2.1 Injection Well Completion

The injection wells will be completed using dual tubing strings, a long string landed at the toe and a short string landed at the heel. High quality steam will be injected down both strings, into the slotted liner and into the reservoir. An instrumentation string may also be placed in the horizontal section to monitor pressure and/or temperature. The typical injection well schematic is presented in Figure 5.1-2. Additional research is being conducted by AOSC to further optimize tubular dimensions of the injection wells in an effort to enhance steam placement accuracy.

Before thermal recovery can begin, steam must be circulated in both the injection and production wells for several months in order to conductively warm the near well region. This heat reduces the viscosity of the bitumen and mobilizes the reservoir fluids. Once communication between the injection and production wells is established, the wells are converted to recovery mode.

5.1.2.2 Production Well Completion

The production wells will use a single production string landed at the heel and completed with a rod driven positive displacement progressive cavity pump (PCP). A utility string will be landed at the toe of the well. This utility string will act as a guide string for any instrumentation requirements as well as a start up steam circulation string. The typical production well schematic is presented in Figure 5.1-3. Additional research is being conducted by AOSC to further optimize tubular dimensions of the production wells in an effort to enhance production performance.

5.1.2.3 Lateral Drainage Well Completion

The LD well completion is comparable to the SAGD production well completion, described in Section 5.1.2.2. The LD well will have a steam circulation period to mobilize the bitumen in the near well region. During the injection interval, steam is injected down the production tubing past the pump and down the utility string. Details regarding the LD well completion are presented in Figure 5.1-3.

5.1.2.4 Observation Well Completion

Vertical observation wells will be drilled to the base of the McMurray formation and cemented in place using thermal cement. Thermocouples and/or piezometers will be installed to monitor pressure and temperature. Some of the observation wells may use an abandonment completion in which case the instrumentation is cemented in place and is irretrievable. Other observation wells may use 4.5 inch casing so that the instrumentation is retrievable and so that cased hole logging tools can be run.

5.1.2.5 Source Water Well Completion

The proposed steam generation make-up water source for the Pilot will be the Lower Grand Rapids aquifer. The source water well will be cased to the top of the aquifer and will be completed through the zone using a wire-wrapped screen and sand pack. The water will be brought to surface using an electrical submersible pump (ESP) connected to tubing. The pump suction will be landed above the top of the Lower Grand Rapids aquifer. The water well will not penetrate the bitumen bearing formation; therefore, a thermal wellbore design specification is not required. The well will be drilled by a licensed groundwater drilling contractor.

The Lower Grand Rapids source well will be supported by a nearby observation well. Real time measurements will be obtained to understand the performance of the aquifer.

5.1.3 Well Performance Monitoring

The daily injected steam volume to each well will be measured using standard steam flow meters. The production wells will be flow tested at least twice a month. Daily produced oil, water and gas volumes will be allocated accordingly using CPF prorations and well tests.

5.1.4 Casing Failure Monitoring Program

Hydraulic isolation between the well bore and surrounding formations will be provided by using casing designed to meet thermal conditions, high strength connections and thermal cement. In addition, surface casing will be set below any Quaternary formations to provide additional isolation between the well and associated groundwater.

Processes will be in place to ensure that Pilot operations staff have the ability to observe any unexpected changes in well pressures, temperatures or fluid rates. Any such changes will be acted upon immediately to ensure that casing integrity is maintained.

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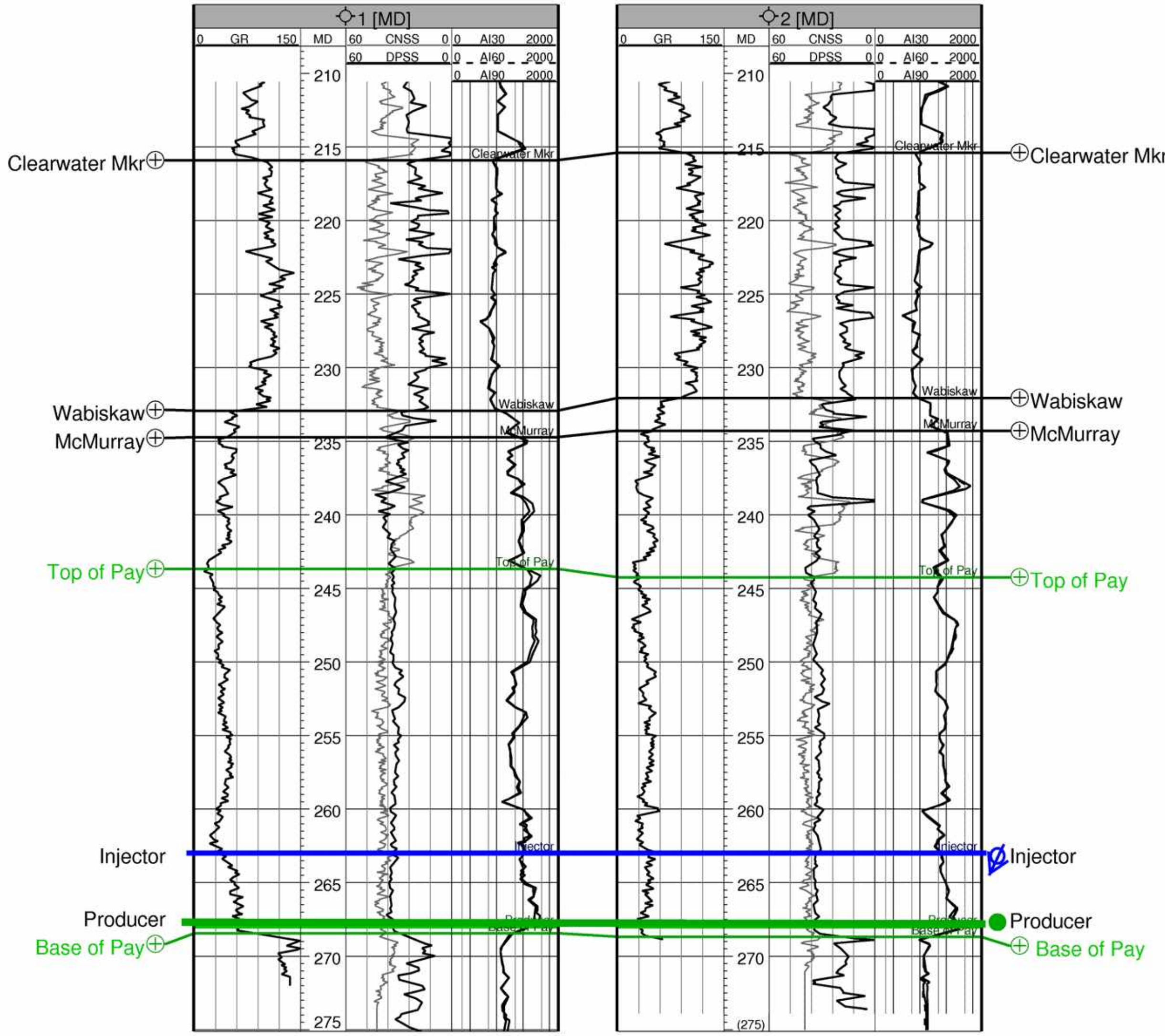

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WELL PLACEMENT

FIGURE 5.1-1

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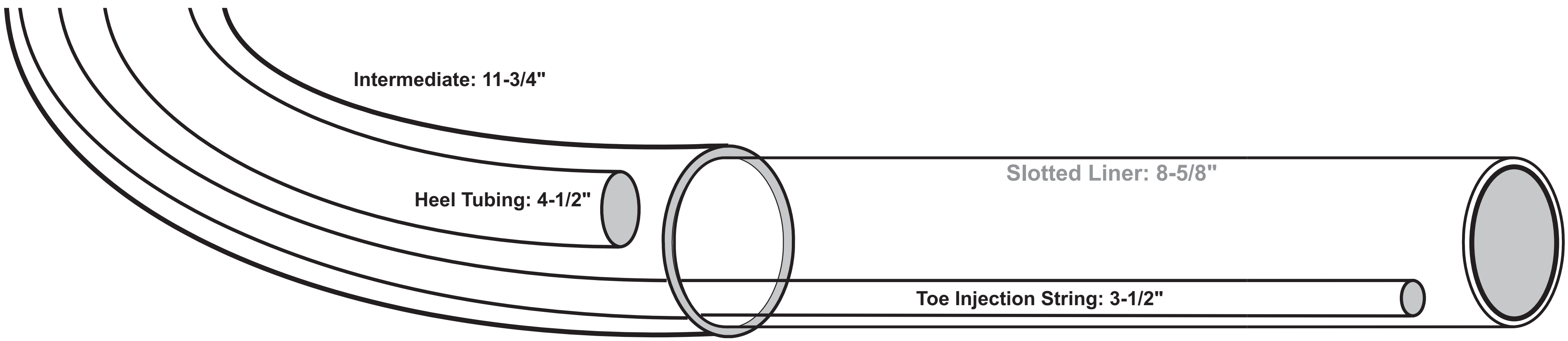

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INJECTION WELL COMPLETION

FIGURE 5.1-2

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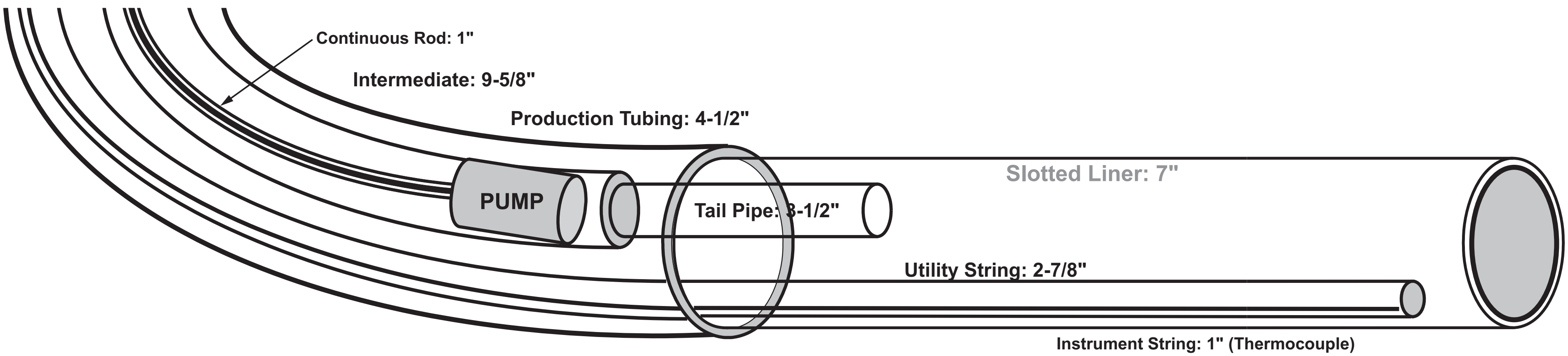

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LATERAL DRAINAGE AND PRODUCTION WELL COMPLETION

FIGURE 5.1-3

5.2 Central Processing Facility (CPF)

5.2.1 CPF Overview

The CPF for the Pilot consists of a modularized transportable plant located on the same site as the production well pad. The CPF footprint measures 300 by 280 m and occupies an area of approximately 8.4 ha in SW¼ 6-94-17 W4M. Activities conducted at the CPF will include:

- steam generation;
- handling and treatment of produced bitumen, produced gas, and produced water;
- heating and cooling;
- storage of process materials;
- soil stockpile storage; and
- construction/operations camp operations.

The CPF plot plan is presented in Figure 5.2-1. A block flow diagram representing the process conducted at the CPF is presented in Figure 5.2-2. Values presented on the block flow diagram are presented in stream day rates. Production and consumption rates of materials at the CPF are presented in Table 1.1-1.

5.2.2 Steam Generation

Approximately 1,035 m^3/d of cold water equivalent (15°C) steam is required for the Pilot. Steam is generated using a combination of de-oiled produced water and make-up water from the water source wells. Water from these sources is treated to meet boiler feedwater (BFW) specifications prior to steam generation.

The BFW pre-treatment process uses an evaporator system which is designed to remove 99% of the total dissolved solids (TDS) in the inlet stream and produce distillate quality water. De-oiled produced water and make-up water are fed to the evaporator feed tank, where caustic is introduced to control pH. The water is then pumped from the evaporator feed tank, through a heat exchanger, to the de-aerator. The water is cross-exchanged with hot distillate product in the heat exchanger and heated to near boiling point to reduce fuel costs. The water is degassed in the de-aerator prior to entering the evaporator.

The heated and de-aerated water stream is combined with brine slurry in the evaporator sump. The brine slurry is constantly circulated from the sump to the falling film tubes. Some of the brine evaporates as it flows through the heat transfer tubes before returning back to the evaporator sump. The vapour that is formed in the heat transfer area of the evaporator passes through mist eliminators, and is then compressed. Heat from the compressed vapour is transferred to the colder brine, causing some of the brine to evaporate. As the compressed vapour loses heat, it condenses as distillate. The distillate is pumped back through the heat exchanger, where it exchanges heat with the incoming water stream. The distillate finally flows to one of the two BFW tanks.

Approximately 58 m^3/d of waste brine is blown down from the sump of the evaporator to control the brine density. This concentrated waste will be disposed of by periodic truck out.

Process flow diagrams depicting the BFW pre-treatment process are presented in Figures 5.2-3 and 5.2-4.

Steam is generated by one 38.4 MW drum-type boiler, to produce 99.5% quality steam for injection into the reservoir. The steam boiler is designed to use low NO_x burners. The primary fuel source for the steam boiler is purchased dry natural gas, which is supplemented by treated produced gas to satisfy fuel requirements. Purchased fuel gas will be preheated in a glycol heat exchanger to minimize the formation of hydrates in the pressure letdown stations. Preheating of the fuel gas also reduces the amount of fuel required.

BFW at approximately 90°C is pumped from the BFW tank and supplied to the steam boiler. The produced steam is supplied to the steam header at a pressure of 5,000 kPag. This pressure is subsequently reduced by line losses and finally by flow control valves until the desired injection pressure and rate is obtained. The steam drum of the boiler requires a small blowdown, approximately 2 to 3% of the inlet BFW flow rate, which will be disposed of at a licensed third party facility.

A process flow diagram depicting the steam generation process is presented in Figure 5.2-5.

5.2.3 Produced Bitumen Handling and Treatment

The bitumen processing facilities use the density difference between the bitumen and water at vessel operating temperatures to allow the oil to separate from the water. Diluent is applied to enhance the density differential.

The oil separation unit consists of a combination of vessels that includes a degasser, a free water knockout (FWKO) unit and a treater unit, as well as associated utility components. Emulsion from the wells passes through a degasser to separate gas from the incoming emulsion. The emulsion is cooled in the emulsion/BFW heat exchanger, followed by the emulsion/glycol heat exchanger. Diluent is blended with the emulsion during cooling to enhance oil/water separation. The multi-phase emulsion is then fed through the FWKO/treater vessel to separate any remaining vapours and water from the sales oil. The FWKO/treater vessel operates as a three-phase vessel where separation of water, diluted bitumen (sales oil) and gas occurs. The separated sales oil, with a basic sediment and water (BS&W) content of approximately 0.5% and API gravity of approximately 12°, is transferred to one of two sales oil storage tanks. Sales oil is trucked offsite to the sales transfer point where it is blended to pipeline quality specifications and sold.

A process flow diagram depicting the bitumen treating process is presented in Figure 5.2-6.

5.2.4 Produced Gas Handling and Treatment

Produced gas separated from the emulsion will exit the top of the degasser and the FWKO/treater vessel and be cooled, which allows steam and hydrocarbon liquids contained in the produced gas to be removed in the produced gas separator. Liquids recovered from the produced gas separator are sent to the backwash tank, while the separated produced gas is sent to the mixed gas scrubber where it is blended with purchased natural gas for use as fuel gas in the steam generator. The H_2S concentration in the produced gas is estimated at a molar fraction of 0.01 (or 1%). Inlet sulphur for the Pilot will be less than 1 t/d; therefore, sulphur recovery is not required, as per ERCB Directive 060 (2006b). Sulphur production will be monitored to ensure compliance with ERCB Interim Directive 2001-3 (2001).

A process flow diagram depicting the produced gas treating process is presented in Figure 5.2-7.

Gas blanketing is used on all hydrocarbon tanks to eliminate emissions of volatile organic compounds (VOCs). A vapour recovery unit (VRU) is used to recover vapours that may contain hydrocarbons. Captured gases are sent to the mixed gas scrubber, where condensed hydrocarbons are diverted to the skim tank (via either the backwash tank or the diluent tank).

A process flow diagram depicting the VRU and fuel gas system is presented in Figure 5.2-8.

5.2.4.1 Flare System

The CPF will include one high pressure flare stack. All vapour relief vents and manual vents are directed to the high pressure flare header. The flare header is routed to the aboveground flare knockout drum and then to the flare stack. The flare stack is provided with an electric ignition system and wind guard.

Fluids collected in the flare knockout drum are pumped to the slop oil tank.

A process flow diagram depicting the flare system is presented in Figure 5.2-9.

5.2.4.2 Non-Condensable Gas Injection Facilities

Low volumes of NCG, consisting of flue gas and/or methane, will be co-injected into the SAGD injection wells and LD wells at strategic time intervals to optimize the growth of the steam chambers. The compressed NCG is directed via a header to the wells. NCG injection is controlled individually in each well using a flow meter and manual control valves.

5.2.5 Produced Water Handling and Treatment

Produced water that is separated from the emulsion is removed from the bottom of the FWKO/treater vessel, cooled with a glycol heat exchanger and sent to the skim tank. The produced water may contain up to 5,000 ppm of oil, depending on the efficiency of the bitumen treating process. The oil content in the produced water will be reduced to less than 500 ppm in the skim tank through gravity separation. Recovered oil from the skim tank is sent to the slop oil tank and returned to the FWKO/treater vessel for re-processing.

The remaining produced water in the skim tank gravity feeds to the induced gas flotation (IGF) vessel where the oil content is reduced to 50 ppm. The produced water is pumped from the IGF vessel through the oil removal filter (ORF) package, that will reduce the oil content of the produced water from 50 to 5 ppm. The de-oiled water is stored in the de-oiled water tank and then fed to the evaporator feed tank for use as BFW. The Pilot has been designed to comply with the ERCB's minimum water recycle rate of 90%.

A process flow diagram depicting the de-oiling process is presented in Figure 5.2-10.

5.2.6 Storage Tanks

Tankage will be required at the CPF to store fluids. All tanks will meet the requirements of ERCB Directive 055 (2001). As described in Section 5.2.4, gas blanketing is used on all tanks that may contain hydrocarbons to eliminate emissions of VOCs. A VRU is used to recover gases released from fluids stored in the hydrocarbon tanks. Details of each tank to be used at the CPF are presented in Table 5.2-1.

Table 5.2-1 Storage Tanks

Tank	Capacity	Secondary Containment	Venting
Skim Tank	318 m^3 (2,000 bbl)	Yes	VRU
Backwash Tank	159 m^3 (1,000 bbl)	Yes	VRU
Slop Oil Tank	80 m^3 (500 bbl)	Yes	VRU
De-Oiled Water Tank	477 m^3 (3,000 bbl)	Yes	VRU
Disposal Tank	159 m^3 (1,000 bbl)	Yes	Atmosphere
Excess Water Disposal Tank	477 m^3 (3,000 bbl)	Yes	Atmosphere
BFW Tank (2 tanks)	477 m^3 (3,000 bbl)	No	Atmosphere
Sales Oil Tank (2 tanks)	477 m^3 (3,000 bbl)	Yes	VRU
Diluent Tank	239 m^3 (1,500 bbl)	Yes	VRU

5.2.7 Heating and Cooling System

A single glycol system located at the CPF services both process and utility glycol users. Glycol at a maximum temperature of 45°C is pumped from the glycol surge drum to the process coolers and the utility users. The warm glycol return from the process coolers, with a temperature not exceeding 120°C, is distributed to the hot glycol process and utility users. Glycol return from the various users is collected and routed to the glycol cooler. The glycol cooler is an aerial cooler that cools the glycol to approximately 45°C. The cold glycol is returned to the glycol surge drum to complete a closed loop.

A pop tank will be provided for collecting the discharges from pressure safety valves (PSVs) in the glycol service.

A process flow diagram depicting the glycol system is presented in Figure 5.2-11.

5.2.8 Chemical Consumption

A variety of chemicals will be required for operation of the Pilot. Chemical consumption estimates are presented in Table 5.2-2.

Table 5.2-2 Chemical Consumption

Chemical	Estimated Consumption Rate (m^3/d)
Demulsifier	0.15
Reverse Demulsifier	0.07
De-Oiling Polymer	0.02
Caustic (50% NaOH)	1.16
Dispersant	0.06
Anti-foam	0.04
Oxygen Scavenger	0.06
Phosphate	0.04
Neutralizing Amine	0.02
Methanol Package	0.17

In addition, acid wash (35% HCl) and caustic wash (50% NaOH) will be used for an approximately 8 to 12 hour period to clean the water treatment facility once every 3 to 6 months.

Estimated consumption rates for the acid wash and the caustic wash during these periods are 15.56 and 7.02 m^3/d, respectively.

5.2.9 Material and Heat Balances

Material and heat balances for the Pilot are presented in Tables 5.2-3 and 5.2-4, respectively. Values shown on the material and heat balances are presented in stream day rates.

5.2.10 Produced Fluids Measurement

Metering of the produced emulsion from the wells is conducted using a two-phase test separator at the well pad. At steady state operations, production wells will be tested in accordance with ERCB Directive 017 (2007b) and ERCB Interim Directive 91-03 (1991b). Daily oil, gas and water production will be pro-rated to the wells based on the plant volumes and well test data. The volume and pressure of steam injected into each injection well will be continuously measured and recorded.

Production accounting reports will be submitted to the Petroleum Registry in accordance with ERCB Directive 007 (2007a). A Measurement, Accounting and Reporting Plan (MARP) will be prepared and submitted in accordance with ERCB Directive 042 (2006a).

5.2.11 Industrial Runoff Drainage System

The CPF area is located near a wetland area that drains generally to the west-northwest and enters an unnamed creek in the headwaters of the Dunkirk River. The Dunkirk River is a tributary of the McKay River, which flows into the Athabasca River at Fort McKay approximately 60 km to the east of the Pilot site. The local natural drainage pattern in the Pilot area is shown in Figure 5.2-12.

The principal components of the industrial runoff drainage system in the CPF area consist of: a perimeter ditch and a pond to collect and control runoff from the CPF area; a pond overflow and outlet drain; and, culverts through the access roads on the CPF site. The conceptual site drainage plan is shown in Figure 5.2-13.

5.2.11.1 General Concepts

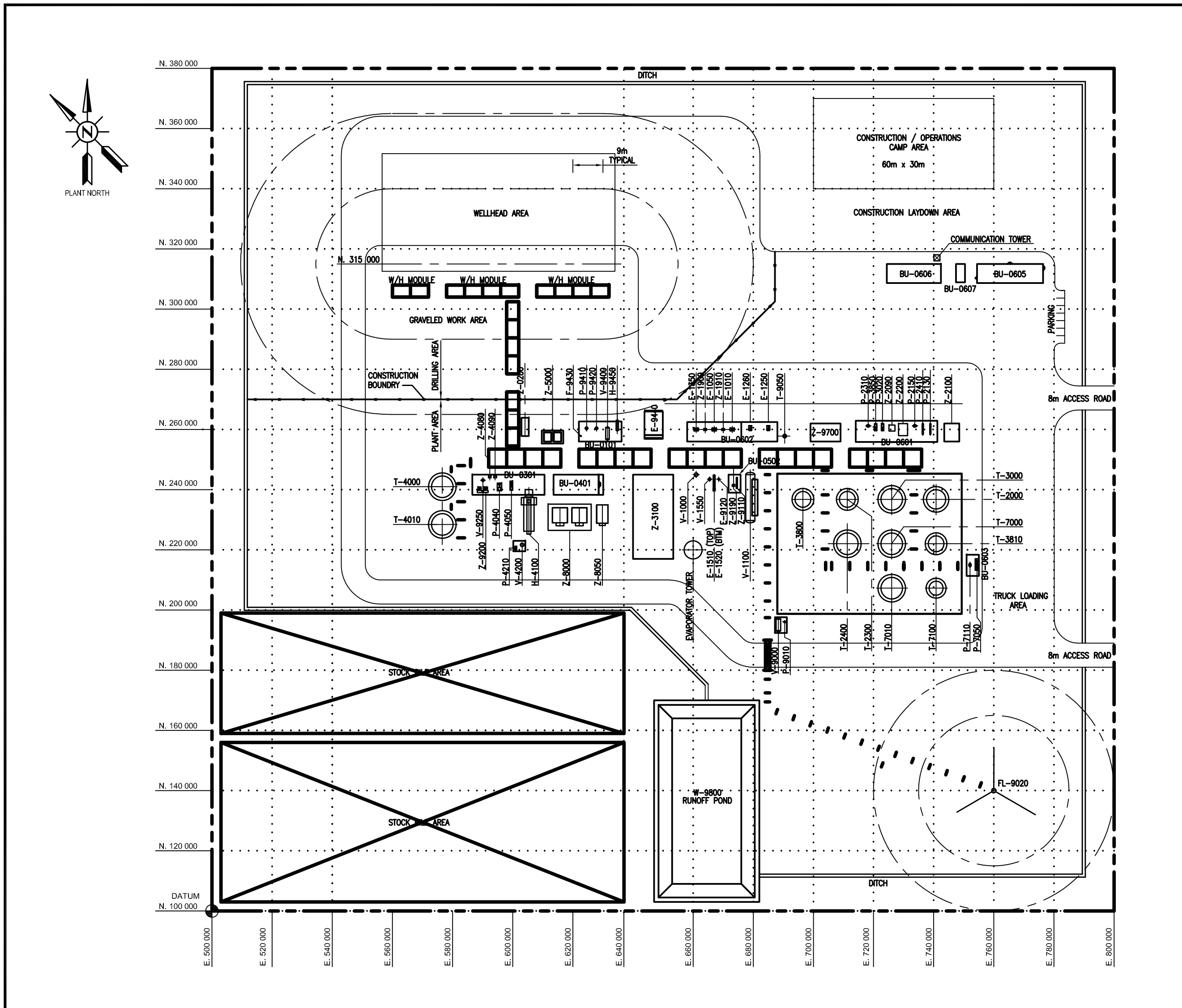
The design of the surface water drainage and management system for the proposed development was based on the following general concepts:

- The CPF area will be graded, with a minimum slope of approximately 1%, towards the runoff pond. A perimeter ditch (or ditches) will be provided to direct surface runoff to the pond culverts placed through the access roads.
- Surface runoff from the CPF site will be contained in a runoff pond and released to the surrounding natural area after testing to ensure that the water quality meets required standards. The runoff pond will be provided with an overflow section that will also discharge to the natural area. The point of discharge from the pond and the overflow will be more than 100 m from the unnamed tributary to the Dunkirk River.
- No surface runoff drainage control will be provided for the soil stockpile area. Rainfall from the stockpiles will drain offsite into the natural drainage system, but they will be grassed to prevent erosion.

5.2.11.2 Storm Runoff Controls

The industrial runoff pond size, peak runoff discharge rates and runoff volume has been calculated based on the "Rational Formula" (AENV 1999a). The following design parameters have been incorporated in the design:

- The industrial runoff pond will have sufficient volume to retain a 1 in 25 year, 24 hour rainfall of 76.9 mm at the Pilot site. The rainfall intensity is based on the rainfall intensity-duration frequency values available from Atmospheric Environment Service of Environment Canada for the Fort McMurray Airport climate station.
- The volume of runoff from the design storm is based on the Rational Formula as described in regulatory guidelines. An average composite runoff coefficient of 0.6 has been estimated for the CPF site. This runoff coefficient is based on a moderately sloped site and a graveled surface with moderate surface depression storage. The runoff pond will collect runoff only from the CPF site (excluding the tankage area). The tankage area will be enclosed by a berm and will not contribute to surface runoff or be pumped to the pond. There will be no run-on to the site as the perimeter ditch will have a low berm on the outside.
- A minimum of 0.3 m freeboard on the industrial runoff pond will be provided to accommodate a greater-than-design storm event.
- For extreme events, well in excess of the 25 year storm, runoff into the industrial runoff pond will be limited by the volume of the pond and backup into the drainage ditches. An emergency overflow outlet will be provided to ensure any release is appropriately controlled and erosion damage does not occur. The controlled overflow will consist of a cobble-armoured weir and a downstream swale. The overflow will be directed into the natural wetland areas to the south of the CPF site and will be approximately 350 m from the nearest defined watercourse.
- A small diameter outlet pipe and outlet control valve will be provided to drain the water from the runoff pond. The pond water will be released after water quality sampling and testing confirms the water is suitable for release. Water release points will be located in stable areas where the flow will disperse.
- The industrial runoff pond will be lined with an impermeable clay or synthetic membrane having a hydraulic conductivity no greater than 1×10^{-7} cm/s to contain contaminants in the event of a spill.
- The CPF site, with a surface area of 70,000 m^2 (7.0 ha), will require a runoff storage volume of 3,230 m^3 (i.e., 0.6×0.0769 m $\times$ 70,000 m^2 = 3,230 m^3). A peak runoff for the 10 year, 1 hour storm event has been calculated as 0.12 m^3/s.



MAJOR EQUIPMENT LIST

E-1010	EMULSION / BFW EXCHANGER
E-1050	EMULSION / GLYCOL EXCHANGER
E-1250	SALES OIL COOLER
E-1260	SALES OIL COOLER
E-1350	PRODUCED WATER COOLER
E-1510	PRODUCED GAS BFW EXCHANGER
E-1520	PRODUCED GAS COOLER
E-9110	FUEL GAS HEATER
E-9440	GLYCOL COOLER
F-9430	GLYCOL FILTER
FL-9020	HP FLARE STACK
H-4100	HP STEAM BOILER
H-9450	GLYCOL HEATER
P-2150	OIL REMOVAL FILTER CHARGE PUMP
P-2310	BACKWASH RECYCLE PUMP
P-2410	SLOP OIL PUMP
P-3020	DE-OILED WATER PUMP
P-3850	EXCESS WATER DISPOSAL PUMP
P-4040	LP BFW PUMP
P-4050	HP BFW PUMP
P-4210	BLOWDOWN RECYCLE PUMP
P-7050	SALE OIL RECYCLE PUMP
P-7110	DILUENT PUMP
P-9010	FKOD PUMP
P-9410	GLYCOL CIRCULATION PUMP
P-9420	GLYCOL CIRCULATION PUMP
T-9050	POP TANK (200 bbl)
T-2000	SKIM TANK (2000 bbl)
T-2300	BACKWASH TANK (1000 bbl)
T-2400	SLOP OIL TANK (500 bbl)
T-3000	DE-OILED WATER TANK (3000 bbl)
T-3800	DISPOSAL TANK (1000 bbl)
T-3810	EXCESS WATER DISPOSAL TANK (3000 bbl)
T-4000	BFW TANK (3000 bbl)
T-4010	BFW TANK (3000 bbl)
T-7000	SALES OIL TANK (3000 bbl)
T-7010	SALES OIL TANK (3000 bbl)
T-7100	DILUENT TANK (1500 bbl)
V-1100	FWKO/TREATER
V-1550	PRODUCED GAS SEPARATOR
V-4200	MUD DRUM BLOWDOWN TANK
V-9000	FLARE KNOCK OUT DRUM
V-9120	MIXED GAS SCRUBBER
V-9250	INSTRUMENT AIR RECEIVER
V-9400	GLYCOL SURGE DRUM
W-9800	RUNOFF POND
Z-0200	TEST SEPARATOR PACKAGE
Z-1900	DEMULSIFIER PACKAGE
Z-1910	REVERSE DEMULSIFIER PACKAGE
Z-2090	DE-OILING POLYMER INJECTION PACKAGE
Z-2100	INDUCED GAS FLOTATION PACKAGE
Z-2200	OIL REMOVAL FILTER PACKAGE (ORF)
Z-3100	EVAPORATOR PACKAGE
Z-5000	COMPRESSOR PACKAGE
Z-8000	POWER GENERATION PACKAGE (GAS)
Z-8050	POWER GENERATION PACKAGE (DIESEL)
Z-9200	INSTRUMENT AIR PACKAGE
Z-9700	VRU PACKAGE
I-0502	GAS BUILDING
BU-0601	TANK FARM PUMP BUILDING
BU-0602	EXCHANGER BUILDING
BU-0603	SALES OIL PUMP BUILDING

PACKAGED BUILDING LIST

BU-0401	MCC BUILDING
BU-0605	CONTROL ROOM/OFFICE
BU-0606	STORAGE BUILDING
BU-0607	PORTABLE WASHROOMS

PLANT COOr

★ Project Location

SCALE 1:2250 metres

22.5 0 22.5 45

ATHABASCA OIL SANDS CORP.

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Senior: ##	Date: 09/05/08	Drawn by: GDE	Date: 09/05/08

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PLOT PLAN

FIGURE 5.2-1

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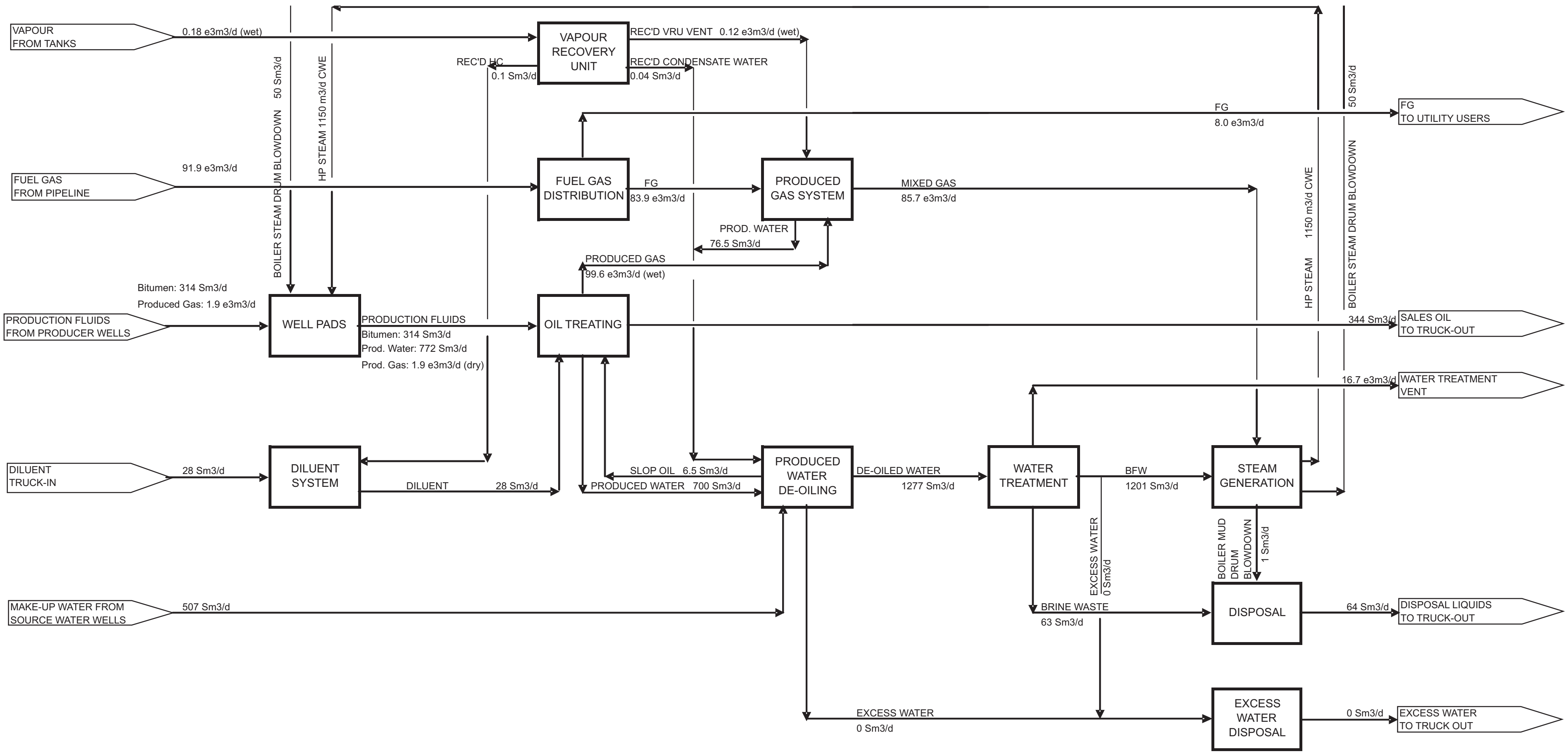

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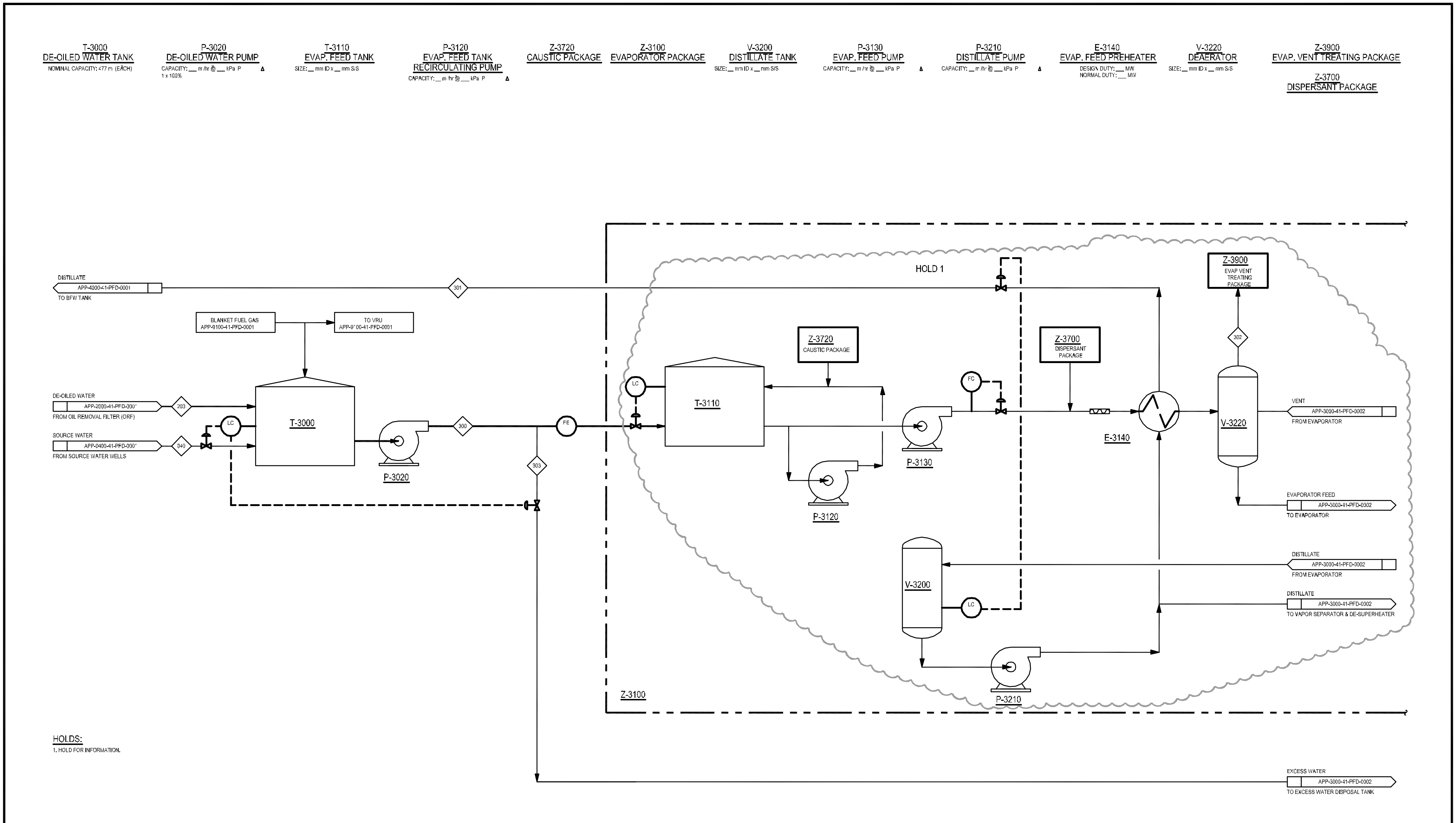
BLOCK FLOW DIAGRAM

FIGURE 5.2-2



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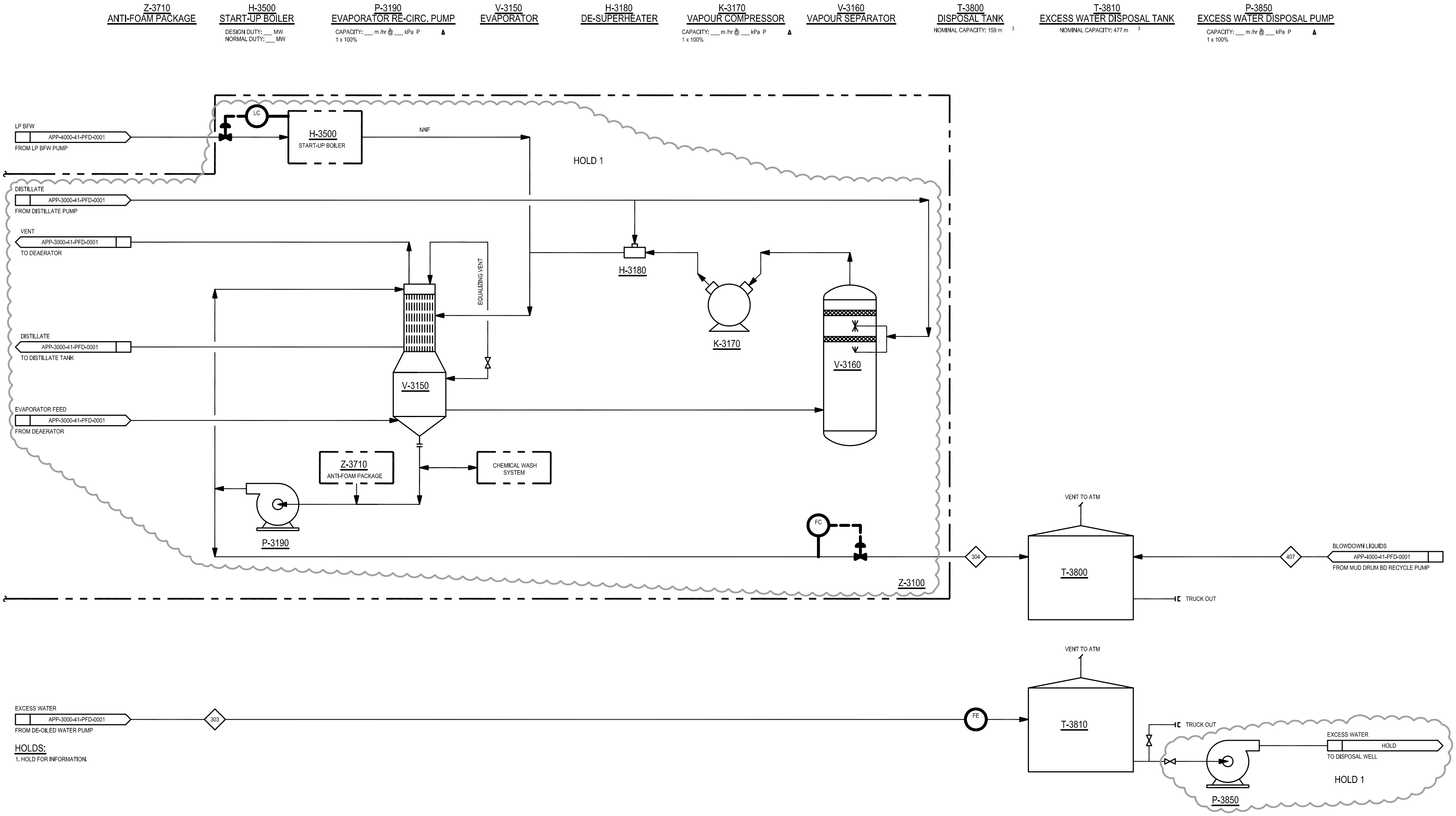
INITIAL BFW PRE-TREATMENT

FIGURE 5.2-3

F:\7349 AOSC\Drafting\2008\7349-MS-08.dwg - IntBFW - 5/22/2008 12:02 PM - gstein



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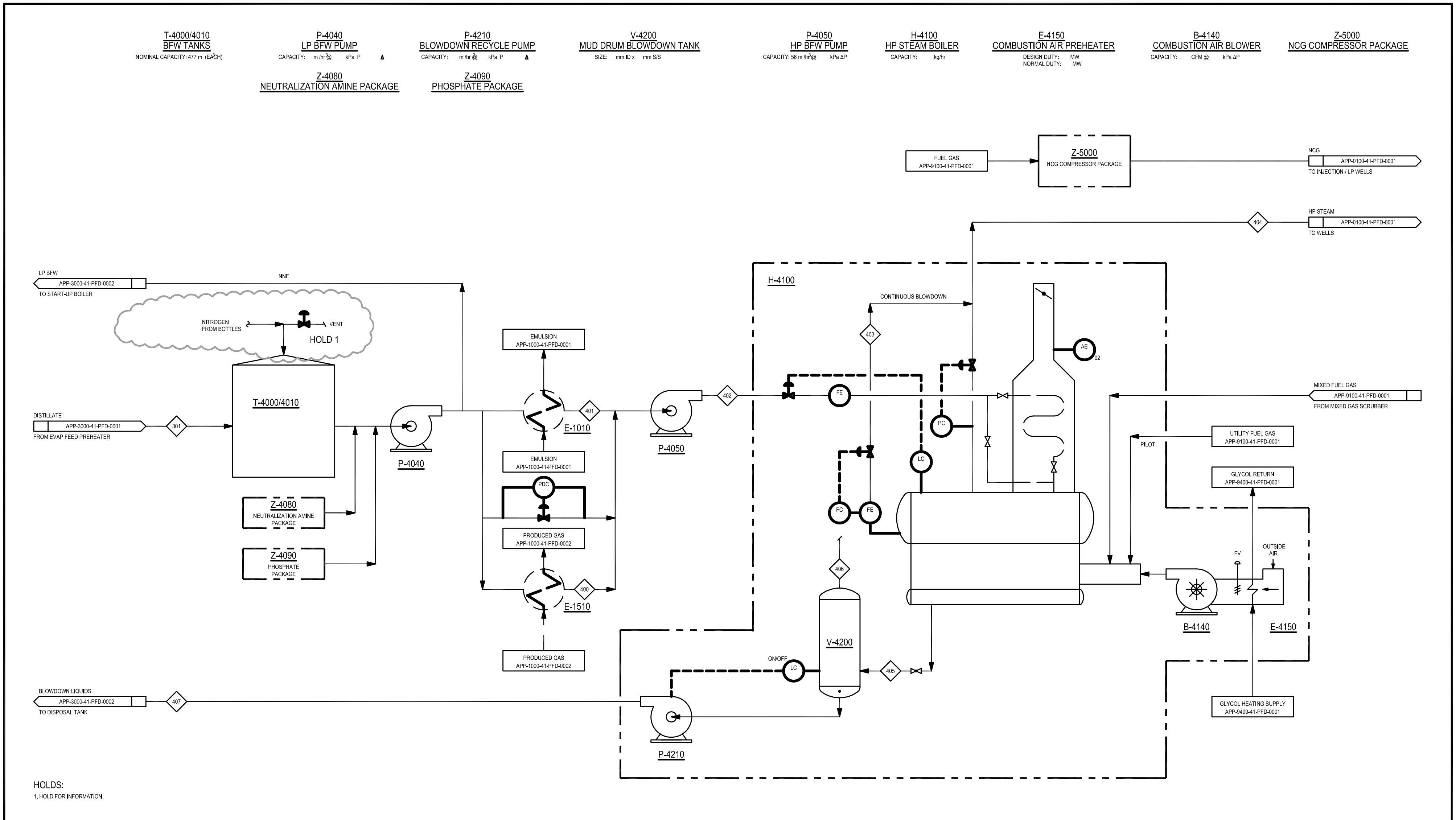
ADDITIONAL BFW PRE-TREATMENT

FIGURE 5.2-4

F:\7349 AOSC\Drafting\2008\7349-MS-08.dwg - AddBFW - 5/22/2008 10:19 AM - gstein



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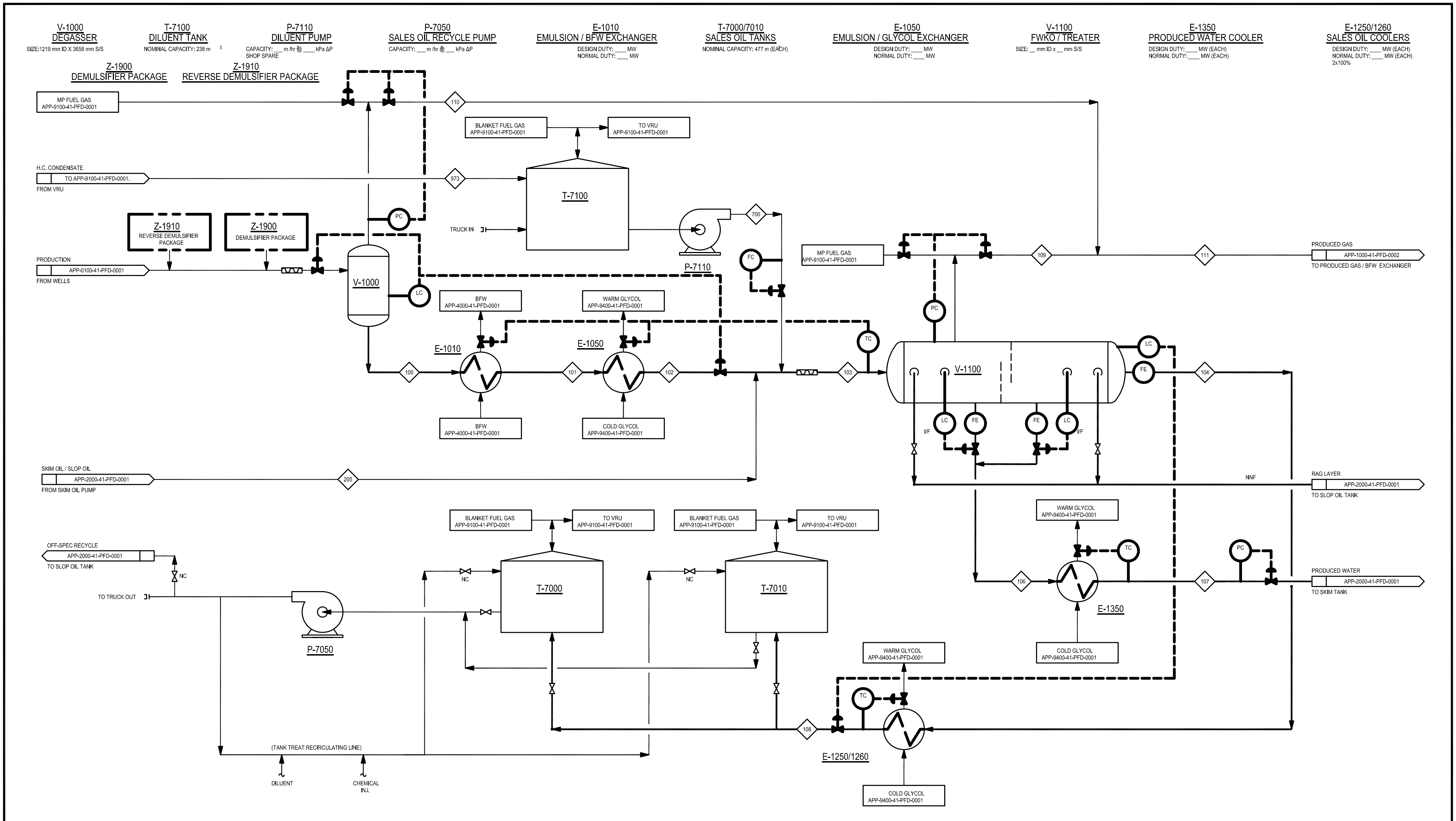
STEAM GENERATION

FIGURE 5.2-5



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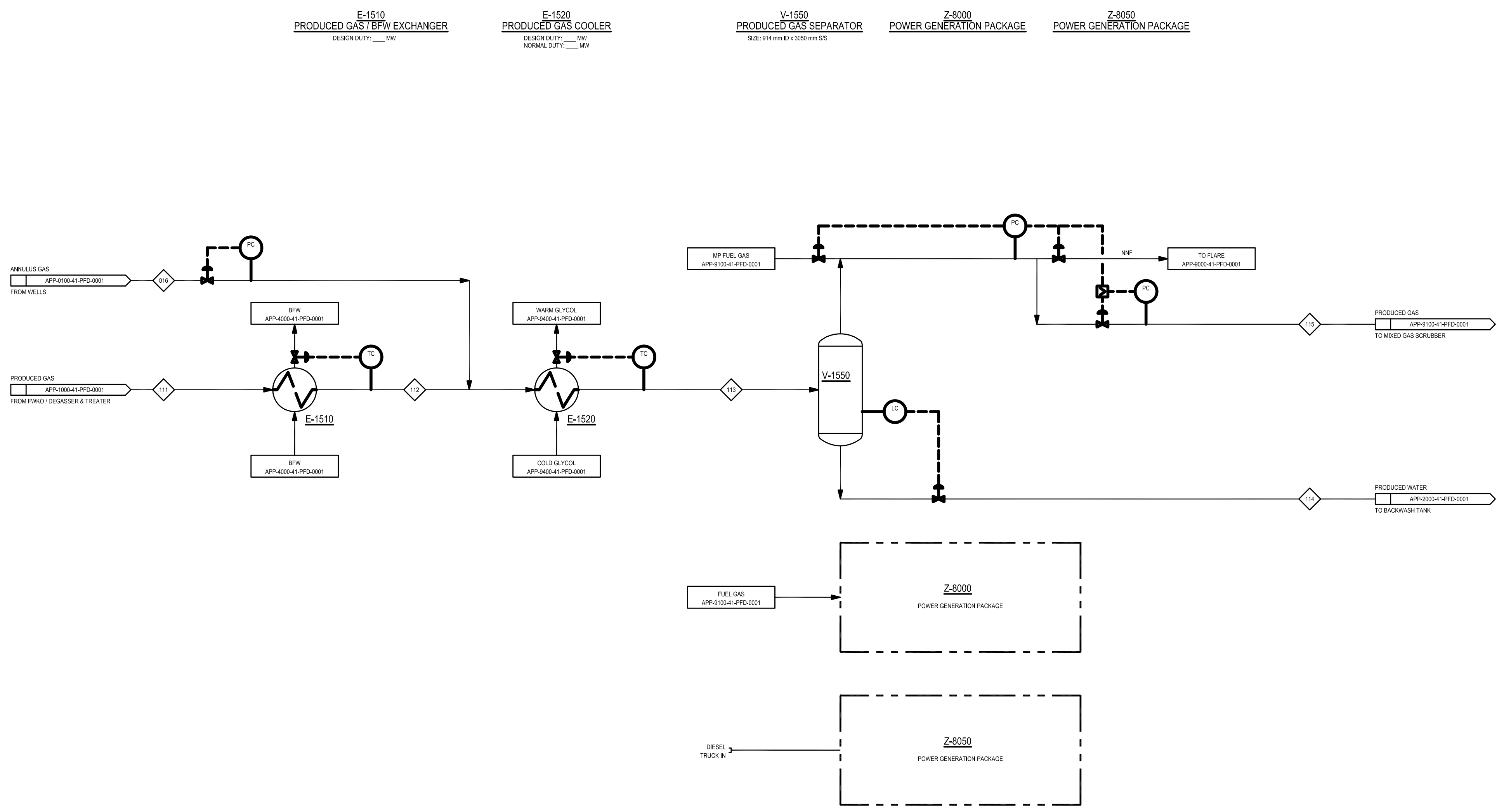
BITUMEN TREATING

FIGURE 5.2-6

F:\7349 AOSC\Drafting\2008\7349-MS-08.dwg - BitTreat - 5/22/2008 10:19 AM - gstein



F:\7349 AOSC\Drafting\2008\7349-MS-08.dwg - ProGasTreat - 5/22/2008 10:19 AM - gstein

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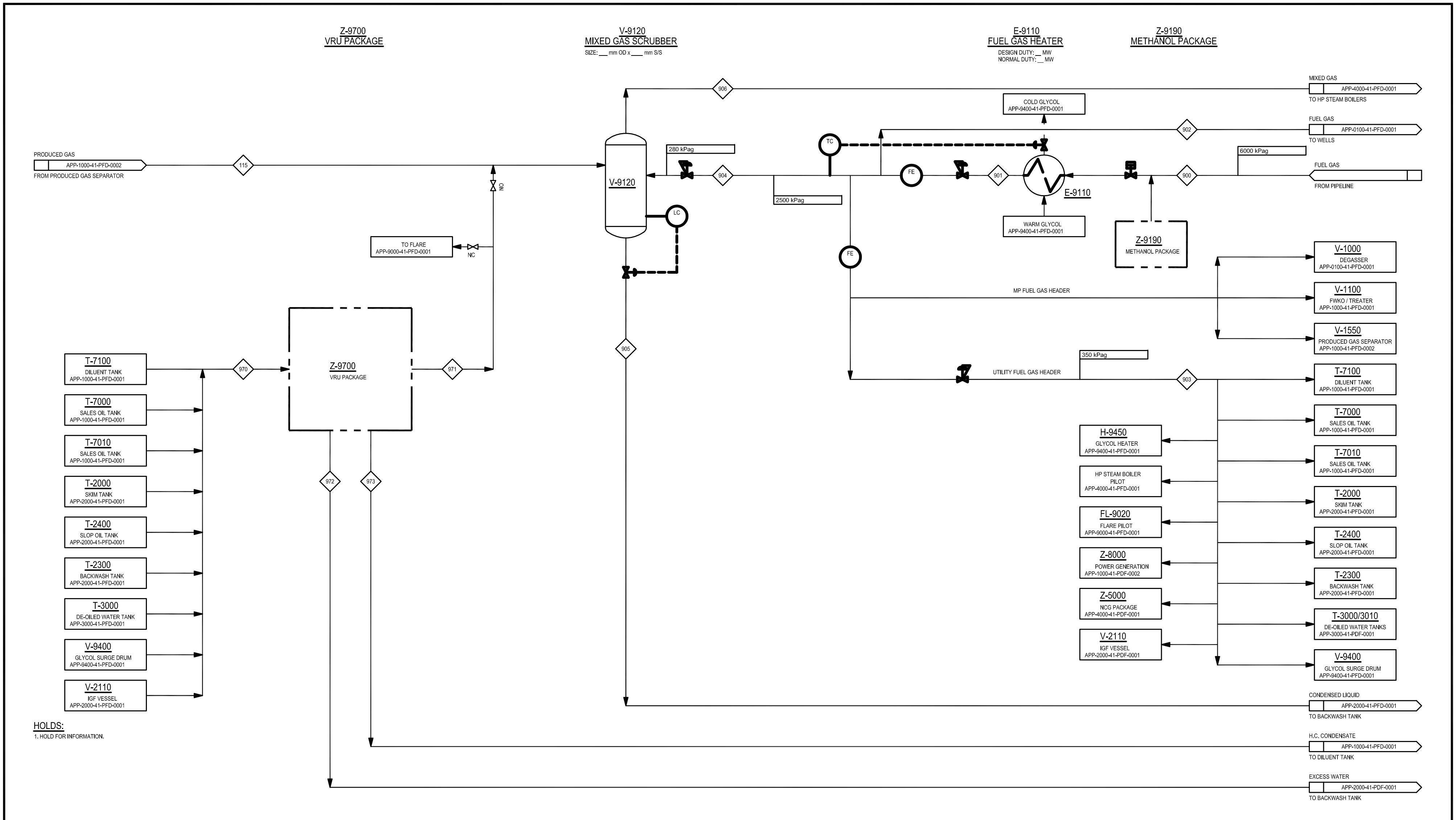
PRODUCED GAS TREATING

FIGURE 5.2-7



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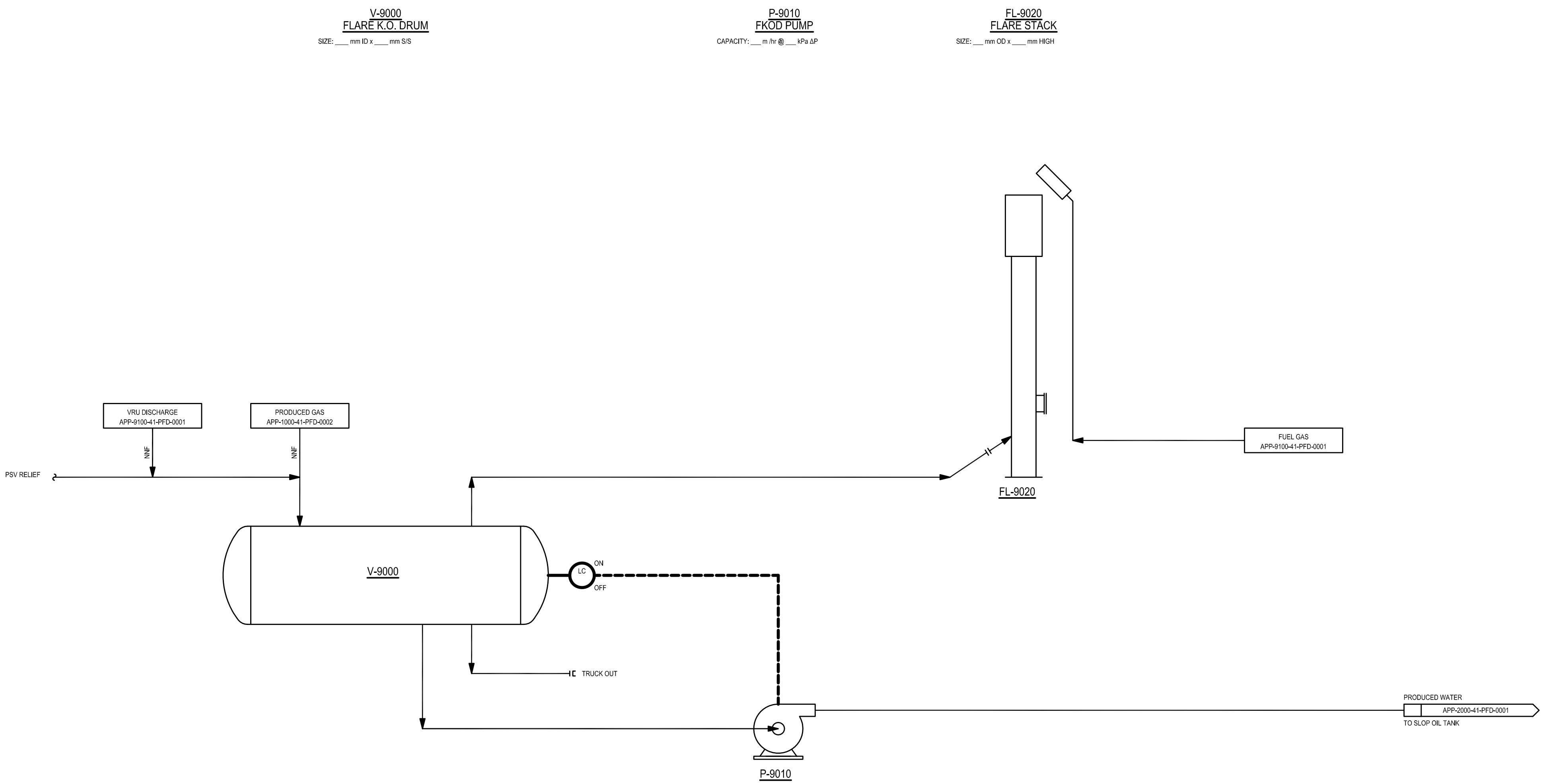
VRU AND FUEL GAS SYSTEM

FIGURE 5.2-8

F:\7349 AOSC\Drafting\2008\7349-MS-08.dwg - VRU - 5/22/2008 10:19 AM - gstein



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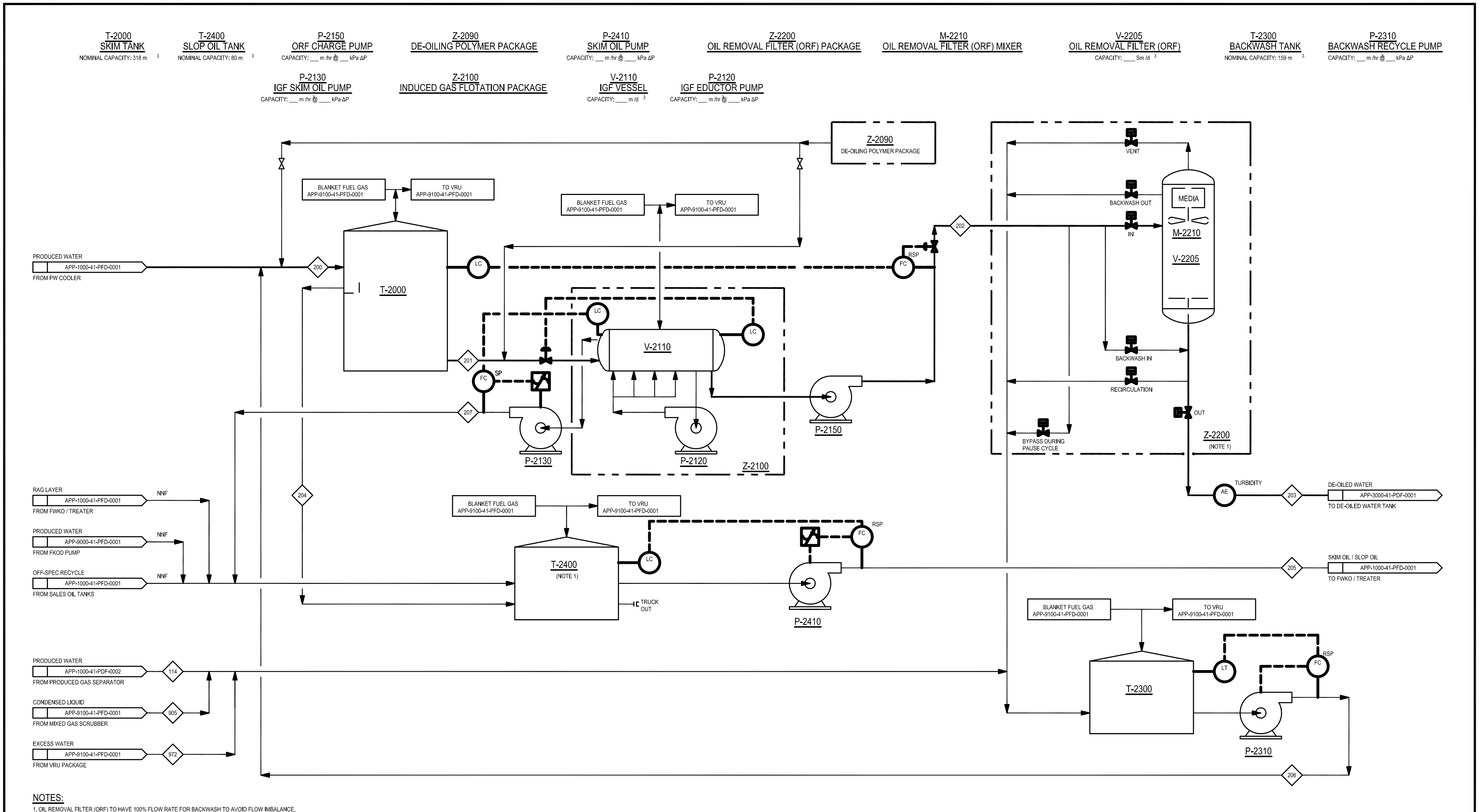
FLARE SYSTEM

FIGURE 5.2-9



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DE-OILING

FIGURE 5.2-10

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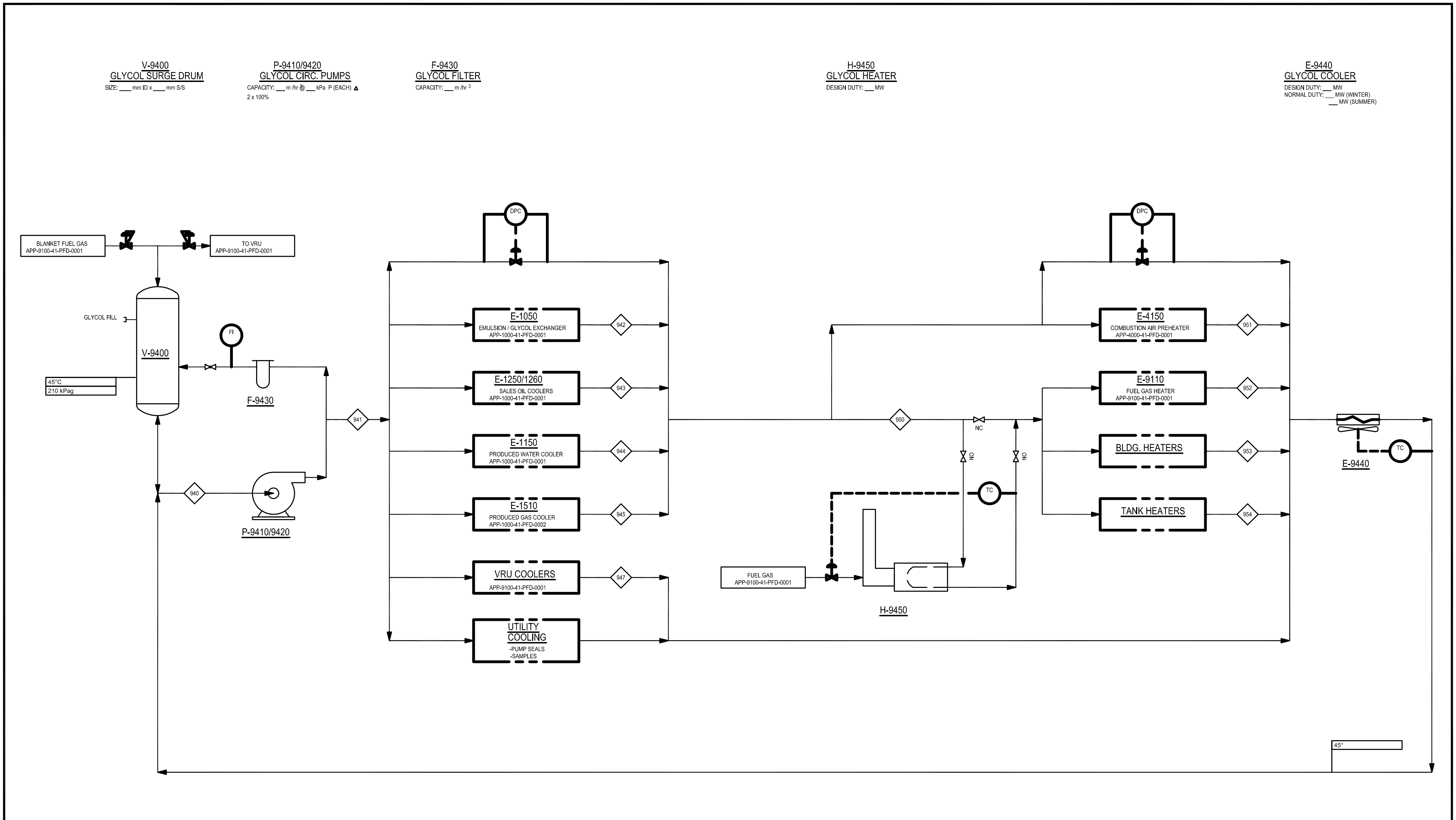

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ATHABASCA OIL SANDS CORP.

GLYCOL SYSTEM

FIGURE 5.2-11

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Table 5.2-3 Material Balance (Page 1 of 3)

Stream Number	100	101	102	103	104	106	107	108	109	110	111	112	113	114	115	200
Stream Name	Emulsion from Degasser	Emulsion from Emulsion / BFW Exchanger	Emulsion from Emulsion / Glycol Exchanger	Emulsion to FWKO / Treater	Oil from Treater	Produced Water from FWKO / Treater	Produced Water from Produced Water Cooler	Oil to Sales Oil Tanks	Produced Gas from FWKO / Treater	Produced Gas from Degasser	Produced Gas to Produced Gas/BFW Exchanger	Produced Gas from PG / BFW Exchanger	Produced Gas to Produced Gas Separator	Produced Water from Produced Gas Separator	Produced Gas to Mixed Gas Scrubber	Produced Water to Skim Tank
PFD No.	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0001	1000-41-PFD-0002	1000-41-PFD-0002	1000-41-PFD-0002	1000-41-PFD-0002	2000-41-PFD-0001
TOTAL STREAM																
Phase	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Mixed	Vapour	Vapour	Vapour	Mixed	Mixed	Mixed	Vapour	Mixed
Temperature, ºC	175	123	122	120	120	120	90	65	120	169	169	100	55	55	55	87
Pressure, kPag	822	722	622	507	500	400	330	0	420	420	420	350	315	0	280	0
Mass Flow, kg/hr	42268	42268	42268	43326	14133	29193	29193	14133	0	3263	3263	3263	3263	3170	97	32815
Standard Volume, sm3/day	1011	1011	1011	1045	344	701	701	n.a.	0	99633	99633	N/A	N/A	N/A	1737	N/A
Actual Volume, m3/day	1127	1076	1075	1110	367	743	726	n.a.	0	29265	29265	N/A	N/A	N/A	528	N/A
HYDROCARBON LIQUIDS																
Mass Flow, kg/hr	13227	13210	13210	14126	14069	58	58	14052				65	66	66		124
Standard Volume, sm3/day	314	314	314	344	342	1.4	1.4	342				2.0	2.1	2.1		3.0
Standard Density, kg/m3	1011	1011	1011	986	986	986	986	986				768	767	768		986
Actual Density, kg/m3	918	949	949	925	925	925	942	956				708	742	741		944
Gravity, ºAPI	8.5	8.5	8.5	12.0	12.0	12.0	12.0	12.0				52.8	52.9	52.8		12.0
WATER																
Mass Flow, kg/hr	29041	29058	29058	29200	65	29135	29135	71				3088	3104	3101		32689
Standard Volume, sm3/day	697	697	697	701	1.5	699	699	1.7				74.1	74.5	74.4		785
Actual Density, kg/m3	892	941	942	943	943	943	965	980				958	986	986		967
VAPOR																
Mass Flow, kg/hr								10		3263	3263	110	93	3.2	93	1.6
Standard Volume, sm3/day								108		99633	99633	2217	1737	48	1737	28
Molecular Weight								55.07		18.59	18.59	28.15	30.25	38.56	30.25	33.11
Actual Density, kg/m3								1.89		2.68	2.68	4.09	4.60	1.35	4.21	1.06
Composition mole%																
H2O								26.20		98.08	98.08	23.34	3.95	16.66	3.95	65.14
N2								0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2								3.00		0.92	0.92	40.11	49.70	77.00	49.70	14.53
H2S								0.09		0.02	0.02	0.99	1.16	3.23	1.16	0.57
C1								1.94		0.79	0.79	35.41	45.17	0.00	45.17	0.21
C2								0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00
C3								2.78		0.00	0.00	0.00	0.00	0.00	0.00	0.27
n-C4								10.91		0.00	0.00	0.00	0.00	0.00	0.00	2.03
i-C4								2.97		0.00	0.00	0.00	0.00	0.00	0.00	0.48
C5+								52.11		0.18	0.18	0.15	0.02	3.11	0.02	16.78
Total								100.00		100.00	100.00	100.00	100.00	100.00	100.00	100.00

NOTES: 1. TOTAL STREAM VOLUME FLOW RATES NOT SHOWN FOR MULTIPHASE STREAMS (N/A = NOT APPLICABLE)

Table 5.2-3 Material Balance (page 2 of 3)

Stream Number	201	202	203	204	205	206	207	300	301	302	303	304	400	401	402	403
Stream Name	Produced Water from Skim Tank	Produced Water to Oil Removal Filter	De-Oiled Water from Oil Removal Filter	Skim Oil from Skim Tank	Skim Oil / Slop Oil to FWKO / Treater	Backwash Recycle Water (Daily Average)	Skim Oil from IGF Skim Oil Pump	De-Oiled Water from De-Oiled Water Pump	Distillate Water to BFW Tank	Vent from Evap. Package Deaerator	Excess Water from De-Oiled Water Pump	Disposal Water from Evaporator	BFW from PG/BFW Exchanger	BFW from Emulsion / BFW Exchanger	BFW to HP Steam Boiler	HP Steam Continous Blowdown
PFD No.	2000-41-PFD-0001	2000-41-PFD-0001	2000-41-PFD-0001	2000-41-PFD-0001	2000-41-PFD-0001	2000-41-PFD-0001	2000-41-PFD-0001	3000-41-PFD-0001	3000-41-PFD-0001	3000-41-PFD-0001	3000-41-PFD-0001	3000-41-PFD-0002	4000-41-PFD-0001	4000-41-PFD-0001	4000-41-PFD-0001	4000-41-PFD-0001
TOTAL STREAM																
Phase	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Vapour	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Temperature, ºC	87	87	87	87	87	59	87	57	62	98	65	98	159	126	139	265
Pressure, kPag	0	537	100	0	850	320	200	410	0	0	410	0	1150	1150	6000	5000
Mass Flow, kg/hr	32548	32546	32095	266	267	3622	1.4	53206	50042	531	0	2634	18114	31928	50042	2083
Standard Volume, sm3/day	781	781	770	6.4	6.5	87	0	1277	1201	16675	0	63	435	766	1201	50
Actual Volume, m3/day	808	808	797	6.7	6.7	89	0	1314	1223	22656	0	66	479	816	1292	64
HYDROCARBON LIQUIDS																
Mass Flow, kg/hr	1.4	0.7	0.16	123	123	67	0.7	0.16								
Standard Volume, sm3/day	0.0	0.0	0.0	3.0	3.0	2.1	0.0	0.0								
Standard Density, kg/m3	986	986	986	986	986	769	986	986								
Actual Density, kg/m3	944	944	944	944	942	740	944	961								
Gravity, ºAPI	12.0	12.0	12.0	12.0	12.0	52.4	12.0	12.0								
WATER																
Mass Flow, kg/hr	32546	32546	32095	143	144	3555	0.7	53206	50042			2634	18114	31928	50042	2083
Standard Volume, sm3/day	781	781	770	3.4	3.4	85	0.0	1277	1201			63	435	766	1201	50
Actual Density, kg/m3	967	967	967	967	967	983	967	972	982			959	908	939	930	775
VAPOR																
Mass Flow, kg/hr										531						
Standard Volume, sm3/day										16675						
Molecular Weight										18.08						
Actual Density, kg/m3										0.56						
Composition mole%																
H2O										99.74						
N2										0.00						
CO2										0.22						
H2S										0.03						
C1										0.00						
C2										0.00						
C3										0.00						
n-C4										0.00						
i-C4										0.00						
C5+										0.01						
Total										100.00						

NOTES: 1. TOTAL STREAM VOLUME FLOW RATES NOT SHOWN FOR MULTIPHASE STREAMS (N/A = NOT APPLICABLE)

Table 5.2-3 Material Balance (page 3 of 3)

Stream Number	404	405	406	407	700	900	901	902	903	904	905	906	970	971	972	973
Stream Name	HP Steam from HP Steam Boiler	HP Steam Boiler Mud Drum Blowdown (Daily Average)	Mud Drum Blowdown Tank Vent	Mud Drum Blowdown Recycle Pump Discharge	Diluent from Diluent Pump	Fuel Gas from P/L	Fuel Gas from Fuel Gas Heater	Fuel Gas to Well Pad	Fuel Gas to Utility FG Header	Fuel Gas to Mixed Gas Scrubber	Condensed Liquid from Mixed Gas Scrubber	Mixed Gas from Mixed Gas Scrubber	Tanks Vent to VRU	Recovered Vent from VRU	VRU Excess Water to Backwash Tank	VRU HC Condensate to Diluent Tank
PFD No.	4000-41-PFD-0001	4000-41-PFD-0001	4000-41-PFD-0001	4000-41-PFD-0001	1000-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001	9100-41-PFD-0001
TOTAL STREAM																
Phase	Vapour	Mixed	Vapour	Liquid	Liquid	Vapour	Vapour	Vapour	Vapour	Vapour	Liquid	Vapour	Mixed	Vapour	Mixed	Mixed
Temperature, ºC	265	98	98	98	11	4	80	68	60	68	60	60	68	60	60	35
Pressure, kPag	5000	0	0	276	896	6000	2685	2500	350	2500	280	280	0	300	0	0
Mass Flow, kg/hr	47917	42	14	28	791	2654	2685	51	181	2423	0	2527	15	12	1.6	2.0
Standard Volume, sm3/day	1150 CWE	N/A	435	0.7	28	91861	91861	1750	6250	83861	0	85718	N/A	120	N/A	N/A
Actual Volume, m3/day	N/A	N/A	592	0.7	28	1239	1795	78	1636	3752	0	26623	N/A	34	N/A	N/A
HYDROCARBON LIQUIDS																
Mass Flow, kg/hr					791											1.7
Standard Volume, sm3/day					28											0.1
Standard Density, kg/m3					677											662
Actual Density, kg/m3					688											647
Gravity, ºAPI					77.5											82.4
WATER																
Mass Flow, kg/hr		28		28									0.02		1.6	
Standard Volume, sm3/day		0.7		0.7									0.0		0.0	
Actual Density, kg/m3		959		959									979		979	
VAPOR																
Mass Flow, kg/hr	47917	14	14			2654	2685	51	181	2423		2527	15	12	0.00	0.3
Standard Volume, sm3/day	1509347	435	435			91861	91861	1750	6250	83861		85718	184	120	0.01	3
Molecular Weight	18.02	18.02	18.02			16.40	16.40	16.40	16.40	16.40		16.73	47.25	55.55	38.09	67.79
Actual Density, kg/m3	25.84	0.56	0.56			51.39	35.89	15.50	2.65	15.50		2.28	1.60	8.38	1.31	2.59
Composition mole%																
H_2O	100.00	100.00	100.00			0.00	0.00	0.00	0.00	0.00		0.09	30.17	5.05	21.02	1.11
N_2	0.00	0.00	0.00			0.81	0.81	0.81	0.81	0.81		0.79	0.00	0.00	0.00	0.00
CO_2	0.00	0.00	0.00			0.60	0.60	0.60	0.60	0.60		1.65	23.72	36.24	74.37	6.91
H_2S	0.00	0.00	0.00			0.00	0.00	0.00	0.00	0.00		0.03	0.96	1.46	4.60	0.63
C1	0.00	0.00	0.00			98.01	98.01	98.01	98.01	98.01		96.81	1.96	3.00	0.00	0.29
C2	0.00	0.00	0.00			0.51	0.51	0.51	0.51	0.51		0.50	0.00	0.00	0.00	0.00
C3	0.00	0.00	0.00			0.05	0.05	0.05	0.05	0.05		0.05	1.67	2.49	0.00	2.15
n-C4	0.00	0.00	0.00			0.01	0.01	0.01	0.01	0.01		0.02	6.69	9.51	0.00	14.24
i-C4	0.00	0.00	0.00			0.01	0.01	0.01	0.01	0.01		0.01	1.81	2.62	0.00	3.53
C5+	0.00	0.00	0.00			0.00	0.00	0.00	0.00	0.00		0.06	33.02	39.63	0.01	71.14
Total	100.00	100.00	100.00			100.00	100.00	100.00	100.00	100.00		100.00	100.00	100.00	100.00	100.00

NOTES: 1. TOTAL STREAM VOLUME FLOW RATES NOT SHOWN FOR MULTIPHASE STREAMS (N/A = NOT APPLICABLE)

Table 5.2-4 Glycol System Heat and Material Balance

Stream Number	940	941	942	943	944	945	947	950	951	952	953	954
Stream Name	50 wt% Glycol to Glycol Circ. Pump	50 wt% Glycol from Glycol Circ. Pump	50 wt% Glycol from Emulsion / Glycol Exchanger	50 wt% Glycol from Sales Oil Coolers	50 wt% Glycol from Produced Water Cooler	50 wt% Glycol from Produced Gas Cooler	50 wt% Glycol from VRU Coolers	50 wt% Glycol to Glycol HeaTer	50 wt% Glycol from Combustion Air Preheater	50 wt% Glycol from Fuel Gas Heater	50 wt% Glycol from Bldg. Heaters	50 wt% Glycol from Tank Heaters
PFD No.	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001	9400-41-PFD-0001
Phase	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid	Liquid
Temperature, ºC	45	45	100	100	100	100	60	100	86	65	65	65
Pressure, kPag	210	777	707	707	707	707	707	527	357	357	357	357
Mass Flow, kg/hr	99709	99709	26690	8974	23205	37360	3480	21632	74597	3361	14802	3469

Equipment Number	**E-1050**	**E-1250/60**	**E-1350**	**E-1520**	**E-9710/9760**	**E-9110**	**E-4150**			**E-9440**	**H-9450**
Equipment Description	Emulsion / Glycol Exchanger	Sales Oil Coolers	Produced Water Cooler	Produced Gas Cooler	VRU Coolers	Fuel Gas Heater	Combustion Air Preheater	Bldg. Heaters	Tank Heaters	Glycol Cooler	Glycol Heater
Duty, kW	65 1,436 (max)	435 483 (max)	1,074 1,765 (max)	182 2,010 (max)	50	147	530	512	120	3,457 kW (winter max) 4,781 kW (summer max)	0 kW (normal) 1,906 kW (plant winter start-up)

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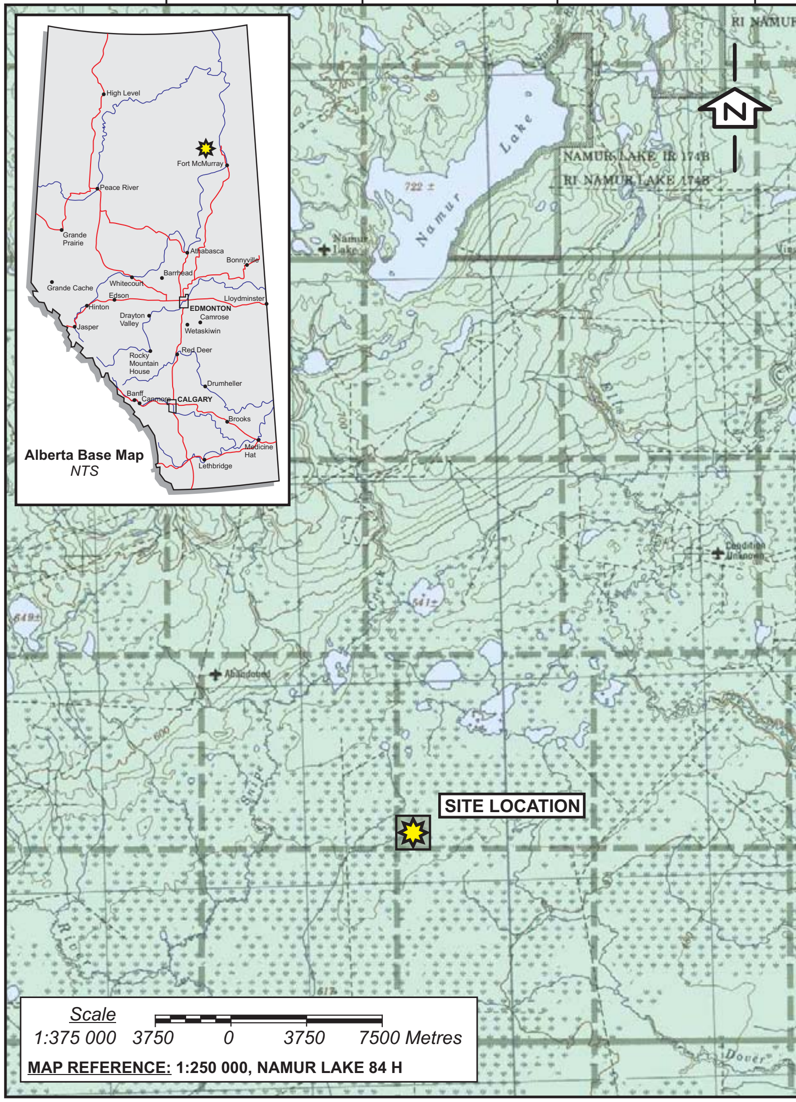

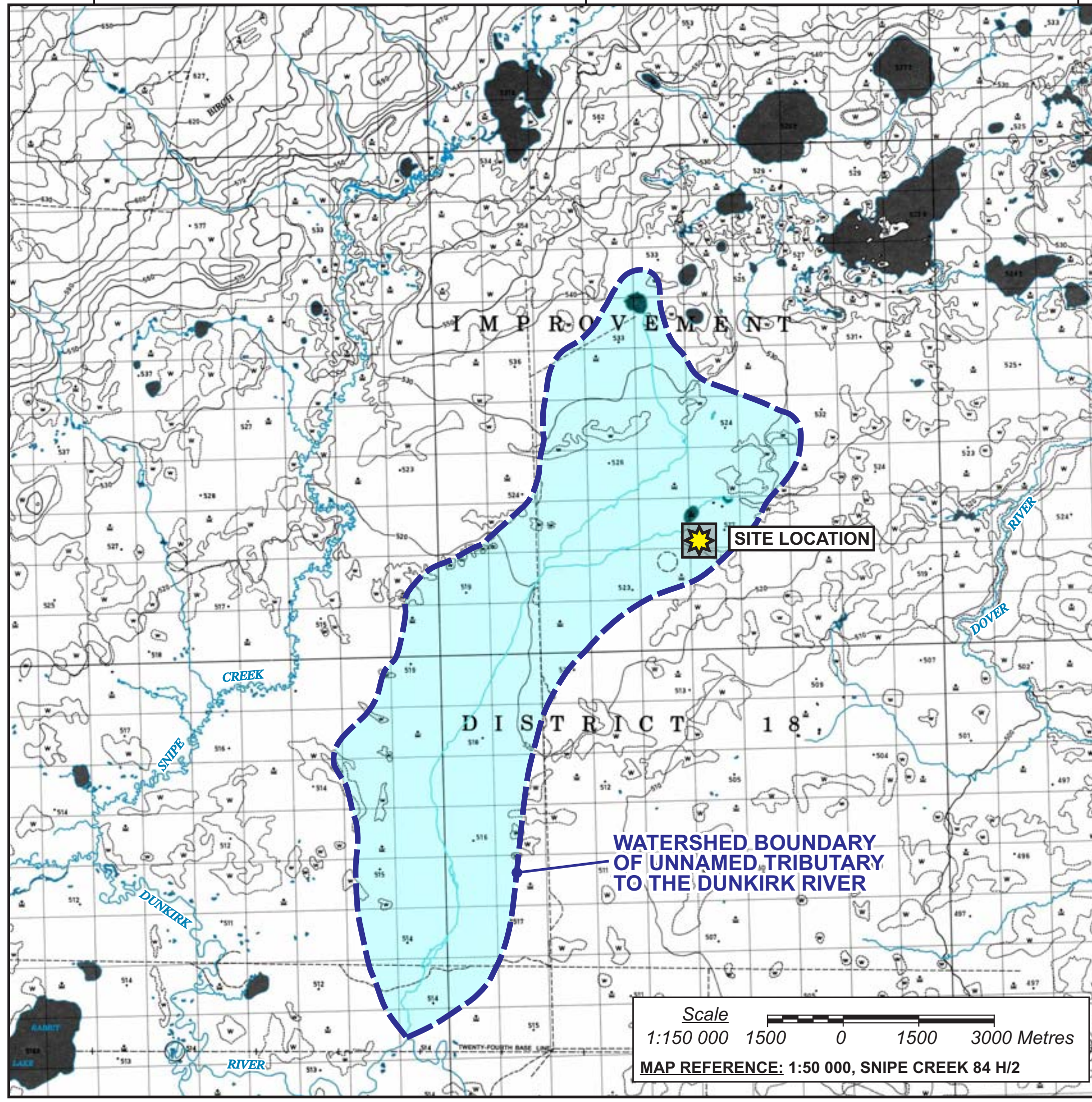

Project Code: 7349-514		Technical: ##	Date: 13/05/08
Senior: ##	Date: 13/05/08	Drawn by: GDE	Date: 13/05/08

Reference:

Disclaimer:
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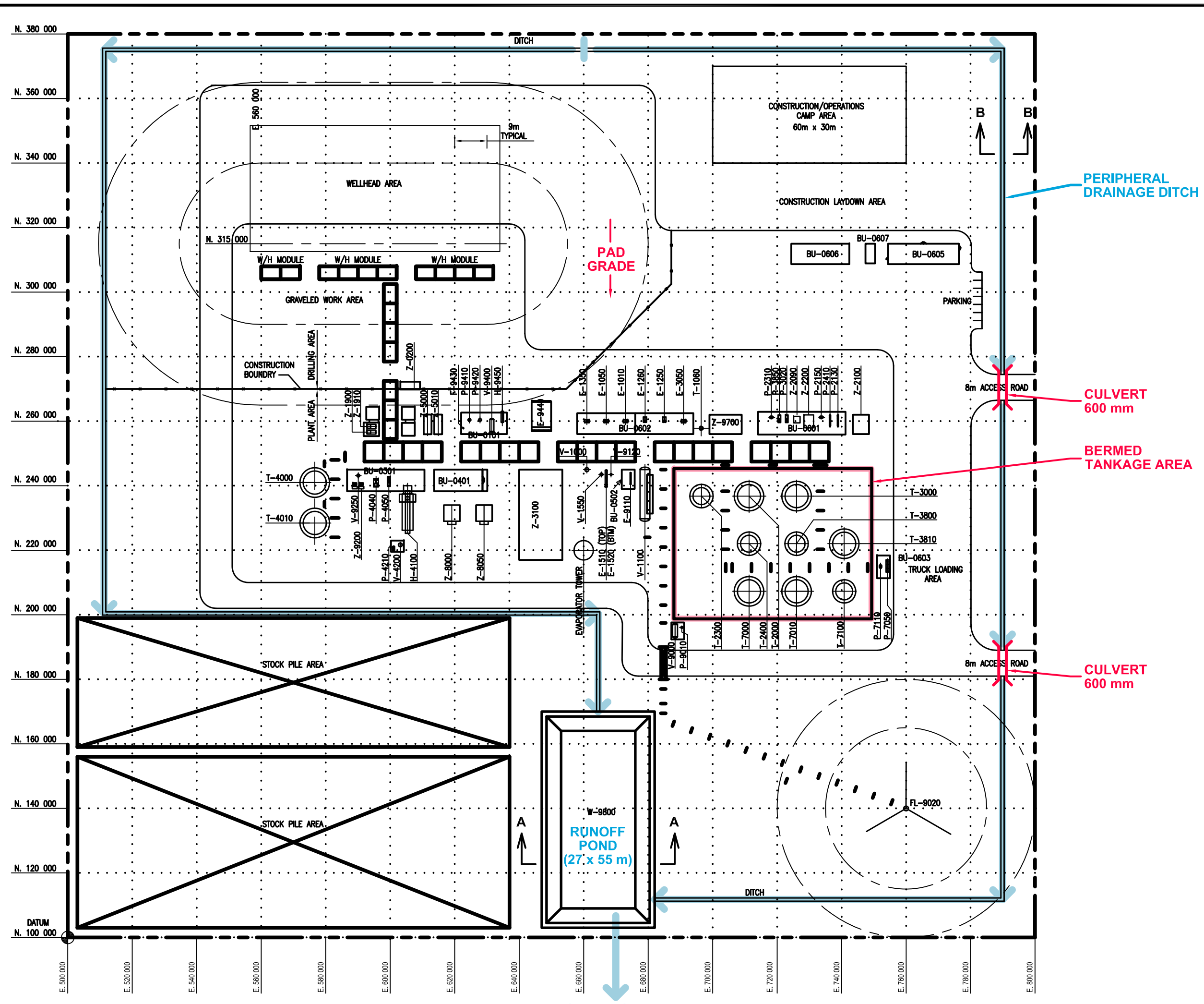
ATHABASCA OIL SANDS CORP.

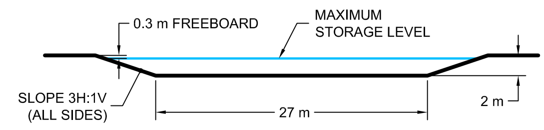
LOCAL NATURAL DRAINAGE PATTERN

FIGURE 5.2-12



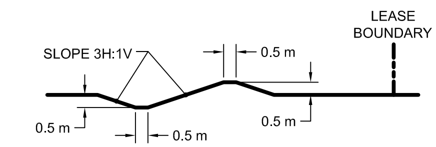
PLAN

Scale 1:1500



SECTION A-A - RUNOFF POND

Scale 1:750



SECTION B-B - DRAINAGE DITCH

Scale 1:300

SCALE 1:2250 metres

22.5 0 22.5 45

Project Code: 7349-514		Technical: ##	Date: 09/05/08
Senior: ##	Date: 09/05/08	Drawn by: GDE	Date: 09/05/08
Reference:			

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ATHABASCA OIL SANDS CORP.

CONCEPTUAL DRAINAGE PLAN

FIGURE 5.2-13

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5.3 Offsite Services and Utilities

5.3.1 Camps

5.3.1.1 Temporary Construction Camp

Construction of the Pilot will require a 60 person labour force. Construction personnel will be housed in an onsite camp for the duration of the construction period to be located within the CPF footprint (Figure 5.2-1).

5.3.1.2 Operations Camp

Operation of the Pilot will require 10 full time staff positions. Current plans include onsite camp accommodations for all operations staff located within the CPF footprint (Figure 5.2-1).

5.3.2 Access Roads

A main access road will be constructed to connect the CPF to the Fort McMurray area. AOSC has been in consultation with ASRD regarding the proposed routing for this access road. Details regarding the final access road will be submitted in a separate application.

An access road will also be constructed to connect the CPF to the source water well pad located in 1-23-93-17 W4M. The access road will follow the corridor for the underground pipeline connecting the water source well to the CPF. It is anticipated that this corridor will be approximately 30 m wide.

5.3.3 Utilities

5.3.3.1 Water

Steam generation make-up water will be provided by the source water well located in 1-23-93-17 W4M, which will target the Lower Grand Rapids Aquifer. The steam generation make-up water usage rate is anticipated to fluctuate throughout the life of the Pilot, as presented in Figure 2, Appendix A. Make-up water will be supplied to the CPF through an underground pipeline.

Domestic water for use at the CPF will be provided from a quaternary water well to be located in close proximity to the CPF. Additional information regarding this well will be determined during detailed engineering, and will be the subject of a separate *Water Act* license application.

Potable water (for human consumption) during both the construction and operations phases will be purchased from a commercial supplier and delivered to the CPF by truck.

5.3.3.2 Electricity

Electrical power will be generated by two 1.5 MW stand alone fuel gas generator sets (gensets) located at the CPF. Electrical production will be monitored as required to match demand. Backup power will be supplied by an emergency diesel genset located at the CPF.

Electricity will be supplied to the source water well pad through pole-mounted electrical lines within the access corridor.

5.3.3.3 Pipelines

Steam generation make-up water will be supplied to the CPF through an underground pipeline from the source water well in 1-23-93-17 W4M.

Dry natural gas will be used as fuel gas for the CPF. Details regarding fuel gas supply has not been finalized to date and will be included in a separate submission to the ERCB.

5.4 Environmental and Management Controls

AOSC will implement its corporate Health and Safety (H&S) Management System as part of the development of the Pilot. The H&S Management System reflects AOSC's high priority to minimize the impact of the Pilot, to ensure the health and safety of all affected individuals and communities. The existing H&S Management System will be expanded to include environmental management.

The H&S Management System is applied equally to employees, and all affiliates, contractors and agents, and will cover construction, operations, decommissioning and reclamation of the Pilot. Upgrades to the H&S Management System will include the creation of an incident reporting system, an environmental management module and development of metrics and performance measures.

Programs that have been developed within the H&S Management System ensure continued compliance with regulations by identifying the regulatory requirements, ensuring required approvals are in place prior to commencement of work, and providing appropriate training and equipment for employees and contractors.

5.4.1 Contingency Planning

AOSC has developed a corporate approach to contingency planning based on operations-specific hazard and risk analysis. In conjunction with the existing H&S Management System, contingency planning will include the implementation of standard operating procedures for all tasks and the implementation of a facility emergency response plan (ERP). All contingency planning materials will be in place prior to the commencement of operations at the Pilot. Full compliance with all applicable regulations will be required at all times.

Prior to initiating construction, AOSC's existing corporate ERP will be updated to address potential site-specific emergencies. Contingency planning efforts that will be implemented include the establishment of communications with protective and emergency service providers, the presence of additional medical and security personnel for the construction camp and CPF, and the implementation of measures to mitigate the impact of increased traffic on area roads.

5.4.1.1 Facility Emergency Response Plan

AOSC's existing ERP will be updated and used to facilitate an effective response by AOSC's operations, management and support personnel to an emergency occurrence at the Pilot. To ensure a state of emergency preparedness throughout the company, AOSC has developed emergency procedures to protect the public, employees, contractors, property and the environment.

Implementation of the ERP will provide solutions to:

- promote the safety of workers, responders, and the public;
- promote the protection of the environment and reduce the magnitude of environmental impacts;

- reduce the potential for the destruction of goods and other property;
- help responders quickly determine and initiate proper remedial actions;
- reduce recovery times and costs; and
- make responders, industry and the public more confident that emergencies will be properly managed.

A copy of the table of contents from AOSC's corporate ERP is presented in Appendix B.

5.4.2 Fire Control Management

Response procedures for handling potential minor and major fire risks are detailed in the AOSC corporate ERP. AOSC will work with local industry operators and the RMWB to develop a fire response strategy.

AOSC has identified two major fire risks associated with the Pilot: the Pilot as a source of fire (based on the operation of electrical and natural gas fired equipment and presence of steam, diluent, natural gas and sales oil) and impact on the Pilot from a wildfire.

AOSC will incorporate fire reduction strategies into the Pilot design, including the following:

- use of combustible gas and smoke detection equipment throughout the Pilot;
- removal of identified combustible ground cover, and regular housekeeping to prevent buildup of combustible vegetation;
- setback of all facilities from any natural combustible materials; and
- design measures including adequate building separation, tank farm placement, and combustible equipment setbacks.

Fire suppression measures to be implemented during operation of the Pilot will include a combination of wall-mounted and wheeled fire extinguishers located throughout the Pilot site, including the CPF and well locations. In addition, operators' trucks will be outfitted with portable fire extinguishers and fire blankets will be located strategically throughout the Pilot.

The AOSC facility ERP will include a shutdown and evacuation plan to be implemented in the event of a forest fire, as well as housekeeping measures to prevent a forest fire from entering the Pilot facilities.

The design of the flare system at the CPF incorporates 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. The liquid level in the flare knockout will be monitored and accumulated liquids will be 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.

These strategies address the risk of fire in the plant process, and minimize the chances of the Pilot causing a forest fire in the surrounding areas. AOSC will also ensure continuous assessment of fire risks during construction, operation, and decommissioning of the Pilot, both within and outside the Pilot footprint.

5.4.3 Water Management

AOSC recognizes water management as an important part of the operations. AOSC's water management plan focuses on produced water reuse, water supply management and groundwater and surface water protection.

Produced water recycling and reuse is a major component of the Pilot. AOSC is committed to meeting the ERCB's target of 90% water recycling. The efficient recycling of produced water will reduce the Pilot's make-up water demands. Additional details regarding AOSC's water usage is presented in Appendix A.

Surface runoff from the CPF will be collected, tested and, if deemed suitable, released into the surrounding watershed as per AENV guidelines. Runoff that is deemed not suitable for release will be recycled to the process or sent for proper disposal. No underground closed drains will be present at the CPF.

A network of groundwater monitoring wells will be installed to determine the direction and average groundwater flow velocity and quality of the groundwater. This will ensure an understanding of the hydrogeology of the area and, in the unlikely event of a spill or plant upset, help to effectively conduct remediation efforts. The locations of the monitoring wells will be finalized during detailed engineering.

The Pilot includes a temporary alteration of surface runoff through the incorporation of ditches and surface runoff impoundments. Ditches are designed to ensure that the natural drainage patterns are maintained and avoid ponding of water along roads. Natural runoff will be diverted from the CPF to the industrial runoff pond.

5.4.4 Air Emissions Management

The largest air emissions source for the Pilot will be the steam generation equipment. As part of the detailed engineering phase, AOSC will select a steam boiler manufacturer who can supply an energy efficient unit with a low NO_x burner.

Combustion efficiencies for a properly controlled flare, under steady operation, are 98%. During an upset condition, emissions will result from the combustion of produced gas that will contain a small amount of H_2S, therefore, the emitted gas may contain SO_2 and a small amount of uncombusted H_2S.

Vapours from storage tanks containing hydrocarbons will be controlled with a natural gas pressure blanket in conjunction with a vapour recovery system. The vapour recovery system will allow for collection of any liberated gas to supplement the fuel gas supply to the steam generation equipment.

5.4.5 Waste Management

Effective waste management will be a priority for AOSC through construction, operation and decommissioning of the Pilot in order to reduce waste and prevent soil and groundwater contamination. Waste minimization procedures will include:

- reusing, recycling, reducing, and recovering waste, where practical;
- monitoring of primary and secondary containment equipment, as well as plant piping, valves, fittings, pumps, and other associated equipment;
- providing adequate secondary containment, leak detection and weather protection for storage facilities; and
- using operating procedures, maintenance practices and inspection programs to maintain materials handling and storage facilities.

Waste materials that cannot be reused will be generated during the various stages of the Pilot. These waste streams include:

- sanitary sewage;
- solid and liquid waste from construction, utilities and services;
- drilling waste; and
- BFW pre-treatment brine waste.

AOSC will dispose of these waste streams in accordance with the practices and procedures identified in ERCB Directive 058 (1996b). The guidelines apply to all solid and liquid waste that is generated, handled, stored and disposed of through activities resulting from the Pilot. Activities will be closely monitored to ensure compliance with environmental regulations and to encourage the most effective and efficient use of resources. Additional information on drilling waste management is presented in Section 5.4.5.1.

5.4.5.1 Drilling Waste Management

The drilling mud system that will be used to drill the Pilot wells will generate wastes comprised largely of drill cuttings and hydrocarbon contamination from the bitumen bearing formation. The production, injection and observation wells will be drilled with a water-based mud system.

Wastes generated during drilling of the surface hole will be contained in a remote sump located near the Pilot location and will be disposed of using a mix-bury-cover method in compliance with ERCB Directive 050 (1996a). Recycled fluids will not be used during this stage in order to prevent contamination of useable groundwater.

The solid waste from the intermediate and main hole will also be sampled and analyzed. Should the solid waste meet requirements of Directive 050, it will be disposed of using the mix-bury-cover method. If the wastes do not meet Directive 050 criteria and the wastes can not be bioremediated, the waste will be disposed of at a licensed third party facility.

The location of the remote drilling sump has not been identified. It will be located close to the drilling operation in soils that meet permeability requirements. The sump will be constructed with various compartments to isolate fluid and material generated in the different drilling stages.

5.5 Alternative Technologies

The Pilot is being designed to demonstrate experimental in-situ thermal recovery technologies applicable to the Dover lease area. AOSC has committed considerable resources to the study of alternative technologies in the design and operation of Pilot facilities.

6 ENVIRONMENTAL SETTING

6.1 Climate

The Pilot is located in the Central Mixedwood Subregion of the Boreal Forest Natural Region (AEP, 1998). The climate is considered sub-humid and is typically cool and moist; favourable for the development of muskegs (fen and bogs) and aspen-spruce forests. Summers tend to be short and cool with considerable rainfall in June and July. Annual mean precipitation is about 380 mm of which 70% is rainfall. Summer typically lasts from May through September with mild temperatures and about 85 frost free days. Winters are long, cold and typically dry (Natural Regions Committee, 2006).

6.2 Terrain and Soil

A preliminary soils and terrain reconnaissance survey was conducted October 20, 2007. All inspection sites were located using a hand-held GPS. The soil profile was described in detail to a depth of 120 cm. The area was accessed by helicopter exclusively. The inspections were conducted using a shovel and hand-held Dutch auger.

Inspections were conducted at six locations north of the Pilot location. Soils were described according to the criteria established by the Expert Committee on Soil Survey (Agriculture Canada, 1987). At each inspection site the soil profile was described. The following parameters were measured and recorded for each soil horizon:

- depth and horizon morphology;
- colour;
- texture;
- structure;
- consistency;
- coarse fragments within the profile and surface stoniness;
- presence/absence of carbonate and visible salts;
- presence/absence of mottles or gleying; and
- profile drainage.

Landform, surficial materials, slope, aspect and vegetation were also described at each inspection site.

For portions of the proposed footprint that could not be accessed due to wet conditions or impassable vegetation, soil information was extrapolated using stereo pairs of aerial photographs, principles of geomorphology and surficial geology, and available Alberta Vegetation Index (AVI) information. Site specific soil surveys are planned for the summer of 2008 to facilitate the development of detailed soil handling plans.

Quaternary deposits of glaciofluvial materials, as well as recent organic (peat) deposits, dominate the Pilot area. The glaciofluvial Livock and Bitumont series are a medium to very coarse (loamy sand) textured with some coarse fragments and typically occur as veneers (i.e., depths of less than 1 m) overlying silty clay to silty clay loam glaciolacustrine deposits. Organic deposits (Hartley) have derived from accumulations of moss species, predominantly sphagnum.

Surface expression is variable in the study area, ranging from level in areas of peat accumulation to undulating. Slopes on the proposed Pilot area range from 0.5 to 5%.

The three soil series identified in the CPF area during the preliminary soils and terrain reconnaissance are summarized in Table 6.2-1.

Table 6.2-1 Soil Series Classification

Soil Series Name	Soil Series Code	Classification	Parent Material
Bitumont	BMT	Eluviated Eutric Brunisol	Sandy loam textured glaciofluvial
Hartley	HLY	Terric Fibrisol	Organic (peat) materials
Livock	LVK	Orthic Gleysol	Sandy loam textured glaciofluvial

The Pilot area is located predominantly on Bitumont and Livock soils, both of which have developed on glaciofluvial deposits overlying glaciolacustrine deposits.

Additional soil information is presented in the Pilot C&R Plan in Section 8.

6.2.1 Potential Impacts to Soils

The Pilot will disturb approximately 35.4 ha of soils as detailed in Table 6.2-2. Appropriate mitigation, reclamation and revegetation measures will reduce long term effects of the Pilot. AOSC is committed to reducing footprint by using existing disturbances wherever practicable.

Table 6.2-2 Area of Disturbance

Facility / Infrastructure	Area (ha)
CPF	8.40
Water Source Well Pad	0.48
Water Source Well Access Corridor	26.52
Total	**35.40**

6.3 Vegetation

6.3.1 Methodology

The vegetation study area was defined as the CPF with a 500 m buffer, the water source well pad with a 250 m buffer, and the water source well access corridor with a 110 m buffer on either side. The study area incorporates all areas of direct disturbance from the Pilot.

Vegetation communities were mapped using Ecological Land Classification (ELC) methods and according to the classification system in Beckingham and Archibald (1996). Where land was not vegetated or could not be assigned an ecosite phase, four natural land cover classes were used, including burned, burned regenerating, flooded, and lake areas. Anthropogenically disturbed lands were classified as either cutlines, ROWs, transportation or wellsites.

Wetlands and peatlands were described using the Alberta Wetlands Inventory (AWI) (Halsey et al., 2003). Wetlands were defined as ecosite phases with soils that are saturated for at least a portion of the year. This can include ecosites h, i, j, k and l. Ecosite h is a transition community, and can therefore be either a wetland or upland, depending on moisture conditions. Peatlands were defined by the AWI system as those areas having greater than 40 cm of accumulated organic material and include ecosites i, j and k.

Baseline ecosite phases within the vegetation study area are presented in Figure 6.3-1.

Presently, no vegetation ELC field studies or rare plant surveys have been completed for the study area. An Alberta Natural Heritage Information Centre (ANHIC) database search returned no rare plants or rare plant communities for the Pilot area (ANHIC 2008, pers. comm.). However, this is most likely due to a lack of surveys, rather than a lack of rare plants in the study area. Site-specific vegetation surveys are planned for the summer of 2008 to identify any rare plants in the study area.

6.3.2 Vegetation Assessment Results

6.3.2.1 Vegetation Communities

Upland forests in the Central Mixedwood Natural Subregion include aspen (*Populus tremuloides*) dominated stands, mixedwood aspen and white spruce (*Picea glauca*) forests and hybrid lodgepole pine and jack pine (*Pinus contorta* and *Pinus banksiana*) stands (Natural Regions Committee 2006). Upland understory species typically include low bush cranberry (*Viburnum edule*), rose (*Rosa acicularis*), green alder (*Alnus viridis*), Canada buffaloberry (*Shepherdia canadensis*), hairy wild rye (*Elymus innovatus*), bunchberry (*Cornus canadensis*) and feathermosses. However, upland understory composition is diverse and varied between the different ecosite phases. Wetlands including bogs and fens are common and are comprised in various combinations of black spruce (*Picea mariana*), tamarack (*Larix laricina*), Labrador tea (*Ledum groenlandicum*), willows (*Salix* species), dwarf birch (*Betula pumila*), golden moss (*Tomenthypnum nitens*), sedges (*Carex* species) and peat mosses (*Sphagnum* species) (Natural Regions Committee, 2006).

Vegetation communities in the study area consist mainly of the d1, i1, i2 and k2 ecosite phases (Figure 6.3-1, Table 6.3-1). There is also a burned area just to the west of the CPF and some smaller areas of ecosite phases d2, h1, j1 and j2. In total, fourteen ecosite phases, four natural cover classes and four anthropogenic disturbance types are present in the study area.

The Pilot footprint, which includes the CPF, the access corridor and the water source well pad, will disturb approximately 35.4 ha of land or 8.4% of the vegetation study area (Table 6.3-1). This includes disturbance to approximately 15% of the upland ecosite phases, 8% of the lowland ecosite phases, 3% of the natural cover classes and 5% of the disturbed lands.

The Pilot CPF is located mainly on the upland low-bush cranberry Aw (d1) plant community, with some smaller areas of treed bog (i1), treed poor fen (j1) and burned area (Figure 6.3-1). The source water access corridor is located largely on wetland areas. This includes treed and shrubby bogs (i1 and i2) as well as some Labrador tea/horsetail Sw-Sb (h1) areas, shrubby poor fens (j2) and shrubby rich fens (k2). The steam generation make-up water source well is located on treed bog (i1) and shrubby rich fen (k2).

Table 6.3-1 Ecosite Phases in the Vegetation Study Area

Ecosite Phase or Cover Class	Study Area (ha)	Percentage of Study Area (%)	Area Disturbed by Pilot (ha)	Percentage Disturbed (%)
Upland				
b1 – blueberry Pj-Aw	1.4	0.3	0.0	0.0
c1 – Labrador tea-mesic Pj-Sb	0.1	< 0.1	0.0	0.0
d1 – low-bush cranberry Aw	35.7	8.5	7.2	20.2
d2 – low-bush cranberry Aw-Sw	15.5	3.7	1.3	8.4
d3 – low-bush cranberry Sw	1.3	0.3	< 0.1	6.0
h1 – Labrador tea/horsetail Sw-Sb	13.6	3.2	1.6	11.8
Total Upland	*67.6*	*16.1*	*10.2*	*15.1*
Lowland				
h1 – Labrador tea/horsetail Sw-Sb (swamps)	5.2	1.2	0.4	7.7
i1 – treed bog	148.0	35.2	8.2	5.5
i2 – shrubby bog	76.5	18.2	8.7	11.4
j1 – treed poor fen	13.8	3.3	1.5	10.9
j2 – shrubby poor fen	16.3	3.9	2.3	14.1
k1 – treed rich fen	1.4	0.3	0.0	0.0
k2 – shrubby rich fen	43.0	10.2	2.3	5.3
k3 – graminoid rich fen	1.4	0.3	0.2	14.3
l1 – marsh	< 0.1	< 0.1	0.0	0.0
Total Lowland	*305.6*	*72.8*	*23.6*	*7.7*
Natural Cover Class				
Burn	26.0	6.2	1.0	3.8
Regenerating burn	7.1	1.7	< 0.1	0.4
Flooded	1.8	0.4	0.4	22.2
Lake	7.8	1.9	0.0	0.0
Total Natural Cover Class	*42.7*	*10.2*	*1.4*	*3.3*
Anthropogenic Disturbance				
Cutline	1.6	0.4	0.1	6.3
ROW	0.2	< 0.1	< 0.1	10.6
Transportation	0.7	0.2	0.1	14.3
Wellsites	1.6	0.4	0.0	0.0
Total Disturbance	*4.1*	*1.0*	*0.2*	*4.9*
Total	**420.0**	**100.0**	**35.4**	**8.4**

6.3.2.2 Wetlands

Wetlands comprise a large proportion of the study area, with approximately 73% of the study area composed of swamps, bogs, fens and marshes (Table 6.3-2). Bogs comprise the largest area (225 ha), with smaller areas of fens (33 ha), swamps (48 ha) and marshes (0.04 ha).

Just under 8% (23.6 ha) of the wetlands in the study area will be disturbed by the Pilot footprint (Table 6.3-2). Overall, bogs will lose 8% of their area, fens 12% and swamps 6%. Most of the wetland area affected is classified as bog (BONS and BTNN), which is the most common wetland type within the study area.

Table 6.3-2 Alberta Wetland Inventory Classes in the Vegetation Study Area

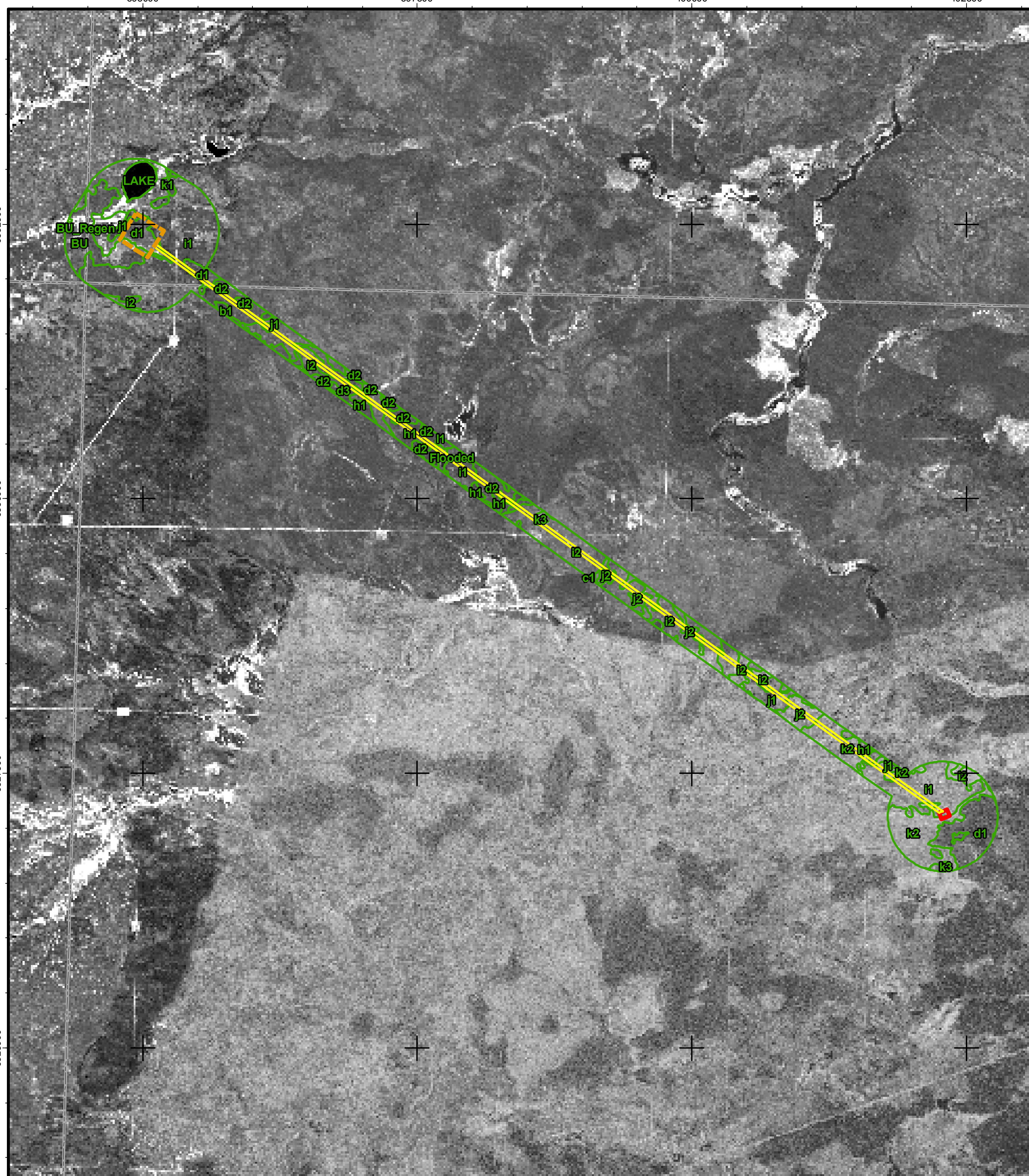
Alberta Wetland Inventory Class	Study Area (ha)	Percentage of Study Area (%)	Area Disturbed by Pilot (ha)	Percentage Disturbed (%)
Bogs				
BONS – shrubby bog	76.5	18.2	8.7	11.4
BTNI – wooded bog with internal lawns	54.8	13.0	< 0.1	0.1
BTNN – wooded bog without internal lawns	93.2	22.2	8.1	8.7
Total Bogs	*224.5*	*53.5*	*16.8*	*7.5*
Fens				
FONG – open, graminoid-dominated fen	1.4	0.3	0.2	14.3
FONS – open, shrub-dominated fen	16.4	3.9	2.3	14.0
FTNI – wooded fen with internal lawns	2.4	0.6	0.3	12.5
FTNN – wooded fen without internal lawns	12.8	3.0	1.1	8.6
Total Fens	*33.0*	*7.9*	*3.9*	*11.8*
Swamps				
SONS – deciduous swamp	42.9	10.2	2.3	5.4
STNN – coniferous swamp	5.1	1.2	0.5	9.8
Total Swamps	*48.0*	*11.4*	*2.8*	*5.8*
Marshes				
MONG - marsh	< 0.1	< 0.1	0.0	0.0
Total AWI Wetlands	**305.6**	**72.8**	**23.6**	**7.7**

6.3.2.3 Old Growth

Old growth forests contribute greatly to species diversity across a landscape and have higher species richness than most surrounding areas (Timoney, 1998). Old growth forests were determined in the study area based on tree age, and are different for each tree species type as different species mature at different rates. The age boundaries above which stands were considered old growth were:

- Deciduous: > 100 years
- Mixedwood: > 100 years
- White spruce: > 140 years
- Pine: > 120 years
- Black spruce and tamarack: > 140 years

A small area of the study area is made up of possible old growth forest. A treed rich fen (k1) consisting of black spruce and greater than 140 years of age, according to the AVI dataset, is present within the study area. This fen makes up only 1.4 ha of the study area, and will not be affected by clearing. Tree age for this area will be confirmed during the site-specific vegetation survey planned for the summer of 2008.



LEGEND

- DOVER CENTRAL PILOT CPF
- WATER SOURCE WELL
- ACCESS CORRIDOR
- ECOSITE PHASE

1:50,000
500 0 500
Metres
NAD 83 UTM ZONE 12

Project Code: 7349-514	Technical: BF	Date: 08/05/09
Senior: RL / Date: 08/05/09	Drawn by: GU	Date: 08/05/09

Reference:
Orthophoto obtained from AOSC, used under license

Disclaimer:
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ATHABASCA OIL SANDS CORP.

BASELINE ECOSITE PHASES

FIGURE 6.3-1

I:\7349_514\MAPS\FIGURES\010_VEGETATION\FIGURE_6.3-1_BASELINE_ECOSITE_PHASE.mxd

6.4 Aquatic Resources

Typical of the boreal landscape, northeastern Alberta has large tracts of forest and muskeg interspersed with water features. Field assessments of lakes and watercourses were conducted in the Pilot area to characterize current conditions and evaluate aquatic resources.

Surveys were conducted at eight watercourses and four waterbodies in and near the Pilot area during February 2008. Data collected were used in conjunction with historical information to compile a characterization of:

- surface water hydrology (stream flow and velocity);
- water quality;
- availability and suitability of fish habitat (e.g. over-wintering, feeding, spawning, rearing and migration potential);
- fish use of habitat based on capture data.

6.4.1 Waterbodies

Large waterbodies that exist beyond the lease boundary include Legend, Namir and Gardiner lakes to the north and Chipewyan, Grew and Mink lakes to the west. Some of these waterbodies are known to support sportfish species (ASRD, 2008) and likely offer high potential for forage fish habitat.

Numerous smaller waterbodies exist in the Pilot area concentrated in the northern and southwestern areas of the Dover lease. Waterbodies appear to be small and shallow with the largest measuring approximately 5.5 km wide. All four waterbodies assessed in February 2008 were less than 2 m deep with 0.5 to 1.0 m of ice cover. Substrates observed appeared to be primarily organic. Good watershed connectivity of these waterbodies with major watercourses in the area indicates the potential for sportfish habitat; however, overwintering potential is limited due to shallow depths.

6.4.2 Watercourses

Major watercourses in the lease area include the Ells, Dover, Dunkirk and Chipewyan rivers, Snipe Creek and tributaries to McKay River. All are part of the greater Athabasca River watershed except for Chipewyan River, which is a part of Peace River watershed.

The Ells and McKay rivers drain directly into Athabasca River, while the Dover and Dunkirk rivers drain into McKay River. Snipe Creek is a major tributary to the Dunkirk River. General flow for these watersheds is in a southeasterly direction. The Ells River drains Namir and Gardiner lakes north of the lease and also collects water from Chelsea Creek. Dover River drains waterbodies in the northern edge of the Dover lease and flows east to join McKay River. Snipe Creek drains two northern waterbodies situated on the lease, flowing southwest to join Dunkirk River. The Dunkirk River runs in a north-south direction through the Dover lease to the confluence with McKay River south of the lease boundary.

Chipewyan River is on the western edge of the Dover lease, flowing out of Chipewyan Lake and running north-south. General flow for this watercourse is southwest off the lease to Wabasca River, located west of the lease boundary.

Watershed basins in the Dover lease area are well defined and well drained. In larger watercourses, surface flows are moderate with erosional substrate. Sediments appear to be primarily sand, cobble and boulder with trace depositional silt and clay material. Habitat is diverse and potential exists for forage and sportfish spawning, rearing and feeding habitat on these watercourses. Smaller watercourses in the area may have reduced flow, greater depositional substrate and homogenous habitat providing potential forage but limited sportfish habitat.

6.4.3 Potential Fish Species in Area

Watercourses and waterbodies in and adjacent to the Pilot area potentially support a variety of fish species, as listed in Table 6.4-1 (ASRD, 2008). The Committee on the Status of Endangered Wildlife in Canada (COSEWIC) does not consider any of these species endangered, threatened or of special concern (COSEWIC, 2005). Arctic grayling is listed as Sensitive by ASRD.

Table 6.4-1 Fish Species Known to Occur in or Near the Dover Lease Area

Scientific Name	Common Name
Thymallus articus	Arctic grayling
Catastomus commersoni	white sucker
Catastomus catastomus	longnose sucker
Esox lucius	northern pike
Notropis hudsonius	spottail shiner
Couesius plumbeus	lake chub
Stizostedion vitreum	walleye
Perca flavescens	yellow perch
Coregonus clupeaformis	lake whitefish
Coregonus artedi	cisco
Rhinichthys cataractae	longnose dace
Cottus cognatus	slimy sculpin
Culea inconstans	brook stickleback
Percopsis omiscomaycus	trout perch
Pimaphales promelas	fathead minnow
Margariscus margarita	pearl dace
Phoxinus neogaeus	finescale dace
Phoxinus eos	northern redbelly dace
Hiodon alosoides	goldeye

6.4.4 Potential Impacts and Mitigation

Potential impacts on aquatic resources from the Pilot include runoff and erosion from site development and construction activities (e.g., roads and pipelines). To minimize potential impacts, the CPF site will be situated away from large waterbodies and major watercourses in the Dover lease. The site is located in a relatively level area to increase stability and minimize erosion. Runoff and site spills will be contained according to the industrial runoff drainage plan.

6.5 Historical Resources

An investigation of areas of potentially high historical value was conducted using the Listing of Historic Resources (ATPRC, 2008). No sites within the Dover lease area were identified as having historical resource value. This only suggests that there has been a limited amount of work done regarding historical assessments in the area and does not imply that historical resources are not present.

An aerial reconnaissance of the entire area was undertaken to ensure any activity conducted by AOSC in the Pilot area would not impact any obvious historical or archaeological sites. AOSC will consult with Alberta Tourism, Parks, Recreation and Culture (ATPRC) to obtain historical resources clearance prior to beginning construction of the Pilot.

6.6 Groundwater Resources

Baseline hydrogeologic conditions in the Dover lease area and a detailed hydrogeologic assessment of the Pilot is described in Appendix A. Key findings of the baseline and assessment are summarized in Section 4.9 (Hydrogeology).

6.7 Wildlife

The Pilot area provides habitat for a variety of wildlife species. Based on a review of available literature, a total of 221 wildlife species may potentially occur in the vicinity of the Pilot, including 44 mammals, 173 birds, and 4 reptiles and amphibians (ANHIC, 2007).

Searches of the COSEWIC (2007) and The General Status of Alberta Wild Species (ASRD, 2005) databases were conducted to identify species in the Pilot area that may be at risk. A summary of those findings is presented below:

- the woodland caribou is identified as At Risk by ASRD and as Threatened by COSEWIC;
- the olive-sided flycatcher is identified as Threatened by COSEWIC;
- the Canadian toad, northern long-eared bat, short-eared owl and wolverine are identified as May Be At Risk by ASRD; and
- 44 additional species were identified as either Sensitive or Undetermined by ASRD.

The Pilot is located within the Wabasca-Dunkirk Caribou Protection, as presented in Figure 6.7-1.

6.7.1 Wildlife Field Surveys

Woodland caribou from the West Side Athabasca River Herd (ASRD, 2007), moose, marten, fisher and lynx are of particular interest in areas surrounding the Pilot and were the focus of winter wildlife surveys conducted in March 2008 by AOSC. These species are representative indictors of other wildlife in the area for several reasons. Moose and caribou, for example, are wide-ranging, known to have specific habitat requirements, and are an important prey source for carnivores. Marten, fisher and lynx are managed as furbearers in Alberta and can be legally harvested for their pelts (ASRD, 2002) making them important economic resources. Additionally, woodland caribou, fisher, and lynx are considered sensitive on a provincial, and/or federal scale. Federally, woodland caribou in the boreal forest are listed as threatened (COSEWIC, 2007) and provincially they are considered at risk. Across Alberta, lynx and fisher are both listed as sensitive (ASRD, 2005), however, they are not federally listed (COSEWIC, 2007).

Winter wildlife surveys conducted by AOSC include an aerial ungulate inventory and a snow tracking survey. Each of these surveys is summarized below.

6.7.1.1 Winter Aerial Ungulate Survey

Aerial transect surveys were conducted by helicopter. Surveys were based on protocols suggested by ASRD for moose surveys in northern Alberta (Powell 2008 pers. comm.) as similar to Nielsen et al. (2006). A survey area of approximately 24 townships within the AOSC Dover lease area was systematically searched using 60 km long transects, with each transect separated by 2 km. In total, 20 transects were surveyed to assess 1,200 km of transect-line. Moose and caribou observed were classified by sex and age cohort and a GPS location was obtained at animal locations.

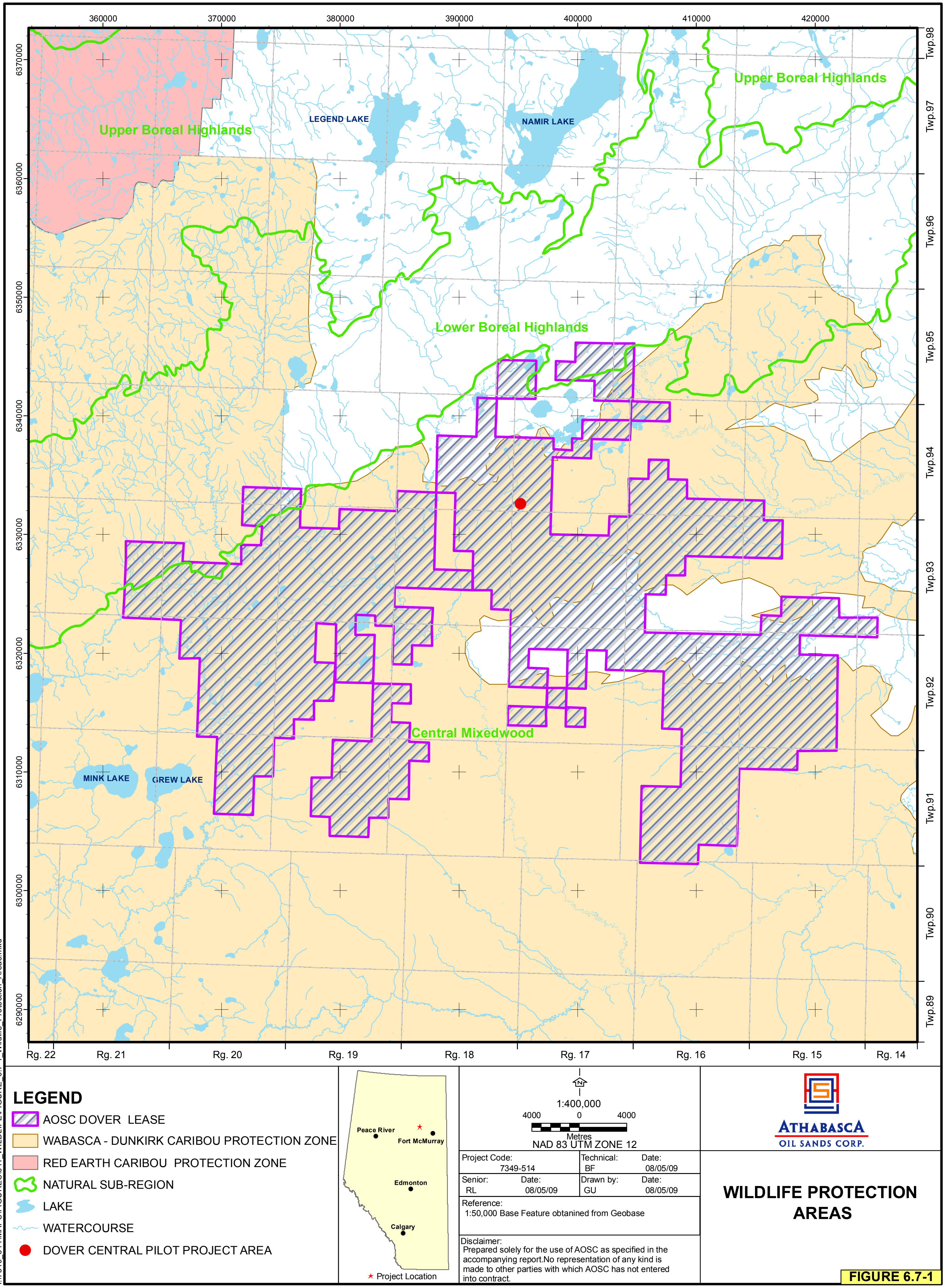
Additionally, an aerial reconnaissance survey was conducted within four townships surrounding the Pilot area. Survey effort was stratified by moose habitat type (high, medium and low habitat quality) and survey time was emphasized in areas of higher habitat quality. Winter moose habitat was estimated using a resource selection model based on AVI and surface hydrology mapping for the area. The survey flight path and animal observations (including animal species, age and sex cohort classes) were recorded.

In summary, 67 caribou, 115 moose and 41 other incidental wildlife sightings were made during the aerial survey. Thirty caribou observations and 55 moose observations were made during the aerial transect surveys. During the aerial reconnaissance survey, 37 caribou and 60 moose were observed. Other incidental wildlife observations included 1 black-backed woodpecker, 5 pileated woodpeckers, 28 sharp-tailed grouses, 4 otters, 2 wolves and 1 lynx.

6.7.1.2 Snow Tracking Survey

The winter tracking survey was conducted using Finnish Triangles (Hogmander and Penttinen, 1996). The Finnish Triangles have 2 km long sides for a total length of 6 km. Two triangles were randomly chosen in the survey area for a total survey length of 12 km. All wildlife tracks intercepting the transect line were counted and recorded. When tracks or sign of caribou, moose, lynx, marten, fisher, or wolf were encountered a GPS location was taken. Also recorded was information (location and human use) on anthropogenic developments encountered during the survey. Aside from tracks and anthropogenic features, vegetation cover was assessed at each 25 m interval and snow depth every 100 m.

A total of 2,874 tracks were detected from 8 species for both triangles. These species included fisher/marten, lynx, snowshoe hare, weasel, red squirrel, wolf, moose and birds. GPS coordinates were taken for focal species and included 15 fisher/marten track locations, 32 lynx track locations and 2 moose track locations. Anthropogenic features were also noted at three locations and included roads, and a cleared lease site.



WILDLIFE PROTECTION AREAS

FIGURE 6.7-1

6.8 Air Quality

It is important that air quality changes associated with the Pilot and other emission sources meet the respective ambient air quality objectives. Expected emissions from the Pilot and surrounding emission sources, the terrain and meteorology, the assessment approach, and a summary of the anticipated air quality changes due to the Pilot emissions are identified and quantified in Appendix C. A summary of the methodology used for the air quality modeling assessment and the modelling results compared to ambient air quality objectives is presented below.

6.8.1 Methodology

Air quality simulation (or dispersion) models provide a scientific means of relating industrial emissions to air quality changes through the use of mathematical equations that simulate transport, dispersion, transformation, and deposition processes. Dispersion models can address a range of spatial scales (hundreds of metres to thousands of kilometres) and temporal scales (minutes to years).

Regulatory agencies have relied on dispersion model predictions to address air quality management issues as part of the approval process. Numerous models are available for the air quality predictions and the appropriate selection depends on project-specific needs. In response to the regulatory use of these models, formal guidelines regarding the selection and application of these models have been developed (e.g., AENV, 2003a; AENV, 2003b; U.S. EPA, 2005).

- The CALPUFF model was applied with the meteorological fields predicted by CALMET to address overlapping effects of multiple sources, and predict hourly, daily and annual average ground-level concentrations. The model is a U.S. EPA approved multi-layer, multi-species puff dispersion model;
- The CALPUFF model can account for building wake effects. The U.S. EPA (2004) Building Profile Input Program (BPIP) was used to process the building information and prepare the data for input into CALPUFF. Building effects were only considered for Pilot sources;
- The CALMET model was used to provide three-dimensionally varying wind, temperature, and turbulence fields for use by the CALPUFF dispersion model. MM5 wind and temperature profiles generated on a 12 km grid for the year of 2002 were used as input data to the CALMET model;
- Hourly ambient O_3 concentrations observed in Fort Chipewyan during 2002 were used for the chemistry calculations;
- Terrain elevation data were obtained for a 50 by 50 km area approximately centered on the Pilot CPF;
- Multiple Cartesian receptor grids with a variable spacing ranging from 20 m around the CPF footprint, to 1,000 m beyond 5 km from the CPF were selected. A total of 3,789 receptors were selected;
- As recommended by AENV, the eight highest predicted hourly average concentrations in a year were considered to be outliers and disregarded. The ninth-highest values (equivalent to the 99.9th percentile) are therefore used as the basis for determining compliance with the hourly average ambient guidelines. For this assessment, the 99.9th percentile hourly predictions are referred to as the 'maximum' values in the assessment figures and tables provided; and
- Background ambient values (hourly, monthly, annual average of hourly measurements from 2003 to 2007) from the Fort Chipewyan station were added to the model predictions to account for natural emission sources, nearby sources, and other more distant sources.

Concentrations at or beyond the Pilot CPF footprint were compared to the ambient criteria.

6.8.2 Air Quality Impact Summary

A standard dispersion model approach was used to predict ambient air quality changes due to the operation of the Pilot. The cumulative effects with nearby and more distant source contributions within the 50 by 50 km modelling domain were also considered. Two compressor facilities and two gas plants were considered in the modelling domain.

The CALPUFF dispersion model predictions for the Pilot are summarized in Table 6.8-1. All maximum concentrations for SO_2, NO_2, CO and $PM_{2.5}$ due to the Pilot and cumulative impacts are predicted to be less than their respective Alberta Ambient Air Quality Objectives (AAAQO). In conclusion, the operation of the Pilot meets relevant ambient air quality criteria.

Table 6.8-1 Summary of the Maximum Predicted Concentrations with the CALPUFF Dispersion Model

Parameter	Averaging Period	Background Concentration	Maximum Predicted Concentrations[(a)] ($\mu g/m^3$)		AAAQO
			Pilot Only	Cumulative Impacts	
SO_2	1-h (9th)	2.0	33	33	450
	24-h	2.0	12	12	150
	Annual	2.0	2.5	2.5	30
NO_2	1-h (9th)	0.9	137	135	400
	24-h	0.9	115	115	200
	Annual	0.9	18.8	18.9	60
$PM_{2.5}$	24-h	2.4	5	5	30
CO	1-h (9th)	-	6,295	6,297	15,000
	8-h	-	4,284	4,284	6,000

Note: NO_2 values based on the ozone limiting method (OLM)

(a) Includes specified background concentration

"-"indicates no specified value

7 PUBLIC CONSULTATION

AOSC is committed to developing honest, transparent ongoing dialogue with the communities, local residents and with key stakeholder groups in the areas that AOSC operates.

AOSC is establishing long term working relationships with all key stakeholders and communities in the Pilot area by:

- engaging in timely, meaningful dialogue about AOSC activities;
- making financial and non-financial contributions to potentially affected communities;
- understanding, recognizing and respecting cultural differences within the communities; and
- identifying and responding to issues or concerns.

AOSC's approach to community and stakeholder engagement is designed to understand community and stakeholder issues, identify opportunities for resolution, and conduct ongoing dialogue. The consultation process is designed to be ongoing from initial planning through construction, operation and decommissioning of the Pilot.

7.1 Commitments, Principles and Objectives

AOSC is committed to conducting its business activities with openness, honesty and integrity while respecting community and stakeholder concerns.

AOSC believes that relationships with communities and local residents established initially represent a positive investment in any potential future role in the region. For this reason, AOSC's community engagement program is built on principles that reinforce mutual respect, understanding, trust and benefit. The program is designed to meet five objectives:

- provide communities and stakeholders with clear and timely information that meets their information needs so they can make informed decisions about AOSC's plans;
- identify community and stakeholder issues, concerns and ideas;
- provide communities and stakeholders with opportunities and venues to provide comments on company activities that may impact them;
- build long term mutually beneficial partnerships within the communities and with stakeholders who are potentially affected by AOSC's long term activities; and
- identify and participate in long term, sustainable mechanisms that benefit the quality of life for people living and working in the regions in which AOSC operates.

7.2 Community and Stakeholder Engagement Approach

AOSC recognizes that community and stakeholder engagement activities will continue throughout the life of all projects planned within AOSC's lease areas. In support of this, the following key activities are being undertaken for each project within AOSC's development framework:

- introduction of the Pilot and the initiation of dialogue with communities and key stakeholders;
- following discussion and review, consideration is given to community-specific consultation protocols;
- identification of initial community and stakeholder issues, concerns and ideas;
- identification of options and processes for addressing issues, concerns and expectations going forward; and

- development of community and stakeholder relationships that provide the basis for ongoing engagement.

7.3 Membership in Regional Associations

AOSC recognizes the value of the various multi stakeholder groups to ensure sustainable growth within the oil sands. Based on this, AOSC is currently evaluating its potential participation level in the key multi-stakeholder groups such as the Cumulative Environmental Management Association (CEMA), the Regional Issues Working Group (RIWG), the Wood Buffalo Environmental Association (WBEA), the Regional Aquatics Monitoring Program (RAMP), and the Athabasca Tribal Council (ATC) All Parties Core Agreement.

7.4 Regulatory Expectations

Informational Letter (IL) 96-07 (ERCB/AENC, 1996) sets out the expectations of both the ERCB and AENV in the approval and regulation of oil sands developments in Alberta. As specified in IL 96-07, all oil sands applications require consultation between the applicant and affected communities and stakeholders. AOSC has designed its Community and Stakeholder Engagement Program with IL 96-07 in mind.

IL 96-07 specifies that stakeholder consultation is the responsibility of the applicant and may include meetings with local groups and organizations as well as conducting public events. AOSC recognizes, however, that the Government of Alberta and the Government of Canada also have consultation responsibilities regarding the Pilot, in particular as they relate to First Nations, Métis and other Aboriginal peoples.

AOSC understands that ERCB Directive 023 (1991) is intended as a directive for applicants for the type and detail of information required in an application pursuant to the AOSCA. Directive 023 applies to all commercial oil sands projects. It stipulates that all applicants are encouraged to plan and carry out a suitable program to make the public aware of a proposed oil sands development, to obtain and incorporate, where feasible, the reaction of interested or affected parties and to provide documentation to the ERCB and AENV as to the nature and extent of the communication and any resolutions achieved.

AOSC understands that oil sands developments are subject to the Environmental Assessment Process pursuant to the AEPEA administered by AENV. The Environmental Assessment Process provides the means of reviewing oil sands developments to assess their potential effect on the environment. This process allows for full public participation and ensures that economic development occurs in an environmentally responsible manner. AOSC recognizes that, in part, the purpose of the Environmental Assessment Process is to involve the public in the review of proposed oil sands developments.

AOSC will meet or exceed the consultation requirements of Alberta's First Nations Consultation Guidelines on Land Management and Resource Development (Alberta Government, 2007b).

7.5 Identification of Stakeholders

A variety of local and regional stakeholders have been identified as being potentially affected by the Pilot. They include Aboriginal groups, local residents, trappers, landowners, businesses and industry, environmental and non-government organizations, and governments.

A summary of the stakeholders identified is presented in Table 7.5-1.

Table 7.5-1 Stakeholders

Stakeholder Group/Type	Community or Stakeholder
Fort McKay First Nation	Fort McKay Industrial Relations Corporation Fort McKay First Nation Group of Companies
Bigstone Cree Nation	Bigstone Cree Nation Consultation Office
Athabasca Chipewyan First Nation	Athabasca Chipewyan Industrial Relations Corporation Athabasca Chipewyan First Nation Industry Business Group
Mikisew Cree First Nation	Mikisew Cree Industrial Relations Corporation Mikisew Cree First Nation Industry Group of Companies
Fort McMurray No. 468 First Nation	Fort McMurray No. 468 Industrial Relations Corporation
Métis Organizations	Fort Chipewyan Métis Local 125 Fort McKay Métis Local 63 Fort McMurray Métis Local 1935 Wabasca/Demarais Métis Local 90
Aboriginal Organizations	Athabasca Tribal Council Wood Buffalo Métis Corporation
Municipal Government	Regional Municipality of Wood Buffalo Municipal District of Opportunity No. 17 Fort McMurray Community
Surface Disposition Holders (excluding other oil sands operators)	Aboriginal and non-Aboriginal Trappers P&NG rights holders
Regional Initiatives	Wood Buffalo Environmental Association Regional Aquatics Monitoring Program Cumulative Environmental Management Association
Regional Business Associations	Northeastern Alberta Aboriginal Business Association Fort McMurray Chamber of Commerce
Industry Associations	Regional Issues Working Group Alberta Forest Products Association Oil Sands Safety Association Canadian Oil Sands Network for Research and Development
Health Authorities	Nunee Health Authority Northern Lights Health Region
Oil Sands Operators	Chevron Sunshine Oil Sands Petro-Canada Grizzly Holdings Total E&P Southern Pacific Marathon

7.6 Consultation Program

The following section outlines the key steps which are being taken to execute the community and stakeholder engagement program for the Pilot.

- **Step 1:** This step consisted of initial introductory contacts with all key stakeholders. The purpose of these meetings was to introduce the Pilot, identify key issues specific to the Pilot, identify specific consultation requirements of the different groups and evaluate memberships in the different community-based consultation processes (e.g., Industry Relations Corporations [IRCs]). Step 1 also included the development of the "AOSC News" newsletter to distribute to the communities.

- **Step 2:** This step consists of detailed information meetings with some key stakeholders. The purpose of these meetings is to provide the key stakeholders with as much information as possible regarding the Pilot; obtain specific feedback that can contribute to the Pilot design; and understand any concerns these stakeholders may have.

- **Step 3:** This step of the consultation deals with community events (open houses, community meetings) that AOSC will conduct. These public events will provide a forum for AOSC to provide up to date information on the status of the Pilot and to solicit feedback from attendees.

During the regulatory review process for the Pilot, AOSC will enhance its presence in the region through the following efforts:

1. Maintaining an active presence in the region;
2. Regular engagement with all key stakeholders; and
3. Active participation in forums and initiatives that encourage information sharing, collaboration and dialogue, in which AOSC deems important to participate. These decisions will be made based on:
    - type of initiative or forum;
    - key issues;
    - proximity of the key issues with respect to AOSC projects; and
    - timing with respect to AOSC's project development timelines.

7.7 Consultation and Engagement Tracking

AOSC is also utilizing Consultation Manager ™ (CM) as the system to identify, document and track issues or commitments which develop through community engagement activities. Accountability focal points will be determined to ensure appropriate management strategies are developed and implemented. Where appropriate, potential mitigation strategies will be developed with communities and stakeholders. In support of this:

- stakeholder input will be tracked using CM and discussed on an ongoing basis with the development teams for consideration in their decision making; and
- where practical and feasible, the activities and projects may be adjusted to accommodate community and stakeholder issues and concerns.

7.8 Communication and Stakeholder Engagement Summary

7.8.1 Aboriginal

AOSC is consulting with those First Nations and Métis Locals within the RMWB and the Municipal District of Opportunity No. 17 who may be impacted by the Pilot.

Based on proximity to the Pilot, AOSC is working most closely with the community of Fort McKay. To ensure a mutually beneficial and collaborative partnership, AOSC has become a member of the Fort McKay Industrial Relations Corporation (IRC). Efforts are being made to understand the consultation requirements of the Mikisew Cree, Athabasca Chipewyan and Bigstone Cree First Nations; as well as Métis Locals that may be affected by the Pilot.

7.8.2 Industry Partners

AOSC is committed to building ongoing, cooperative and mutually beneficial relationships with the other oil sands lessees in the region. Numerous meetings to discuss access road, commercial and other community and stakeholder-related issues and concerns have and will continue to take place.

7.8.3 Surface Disposition Holders

AOSC is committed to building ongoing, cooperative and mutually beneficial relationships with other surface disposition holders including trappers and forestry companies. Numerous meetings to discuss commercial and other community and stakeholder-related issues and concerns have and will continue to take place.

7.8.4 Provincial and Municipal Government

AOSC has initiated regular meetings with provincial and municipal governments. The purpose of these meetings is to:

- Provide updates and other information;
- Establish a clear set of policy and regulatory expectations; and
- Clarify the regulatory review process for the Pilot.

7.8.5 AOSC Newsletter

AOSC has developed the "AOSC News" newsletter as a means of providing updated information to key stakeholders and communities. AOSC plans to distribute quarterly updates of the newsletter to ensure that stakeholders are well informed and have an opportunity to provide comments. Stakeholders can also communicate directly with AOSC team members by calling (403) 237-8227.

7.8.6 Community and Stakeholder Agreements

To date, in consultation with communities and stakeholders, AOSC has agreed to become a member of the Fort McKay IRC.

7.9 Consultation Results

Through the consultation process, stakeholders identified issues of potential concern to them. Many of these concerns related generally to industrial development in the region. No objections specifically related to the Pilot were identified. A summary of the key themes identified by individual stakeholders, along with AOSC's proposed mitigation measures/responses, is presented in Table 7.9-1.

7.10 Ongoing Consultation

AOSC will continue to engage communities and stakeholders in all aspects of the Pilot, from design, through construction, operations and decommissioning phases. New information regarding the Pilot will be conveyed through AOSC's corporate website (www.aosc.com), through the AOSC News newsletter, and through ongoing meetings with stakeholder groups and individuals. AOSC will also continue to maintain its stakeholder consultation database, and will provide updates on the progress of the public consultation initiatives to AENV and ERCB as required.

Table 7.9-1 Key Themes Identified During Consultation

Theme	Issue/Idea	AOSC Response
Environment		
Air	Air Quality/Flaring	• The flare system for the Pilot will be used for upset conditions. • AOSC is currently in discussions with Fort McKay regarding establishing an ambient air monitoring station within the lease area.
	Odours	• The facility will include a vapor recovery unit (VRU) to manage fugitive emissions which tend to be the source of most odours.
Land	Land Disturbance	• AOSC will design the Pilot to utilize existing disturbances and minimize new surface disturbance as much as possible.
	Land Fragmentation	• All required baseline terrestrial studies have been completed to quantify potential Pilot impacts. • The Pilot will be designed to minimize the potential impacts using appropriate mitigation and/or avoidance when feasible.
	Reclamation	• The C&R Plan will provide strategies for returning the landscape to equivalent capability at project end.
Water	Surface Use	• No surface water will be used for steam generation at the Pilot. • AOSC will ensure that all roads and bridges are designed to ensure surface water flow is not restricted and risk of impact from spills is minimized. • The CPF will be designed such that all process and surface water runoff within the footprint area is contained onsite. No water will be released offsite until tested to ensure that it meets provincial guidelines.
	Groundwater	• Only groundwater from AOSC's licensed groundwater source well will be used as make-up source water for steam generation for the Pilot. • AOSC will maximize water recycle at the facility to minimize the overall water requirements of the Pilot. • All liquid waste produced at the Pilot will be trucked offsite and disposed of at an approved waste management facility.

Table 7.9-1 Key Themes Identified During Consultation

Theme	Issue/Idea	AOSC Response
Noise	Noise and Proximity to Cabins	• Noise in relation to trapping and nuisance effects for trappers is currently compensated within the trapper's compensation program.
	Nuisance Noise and Wildlife Affects	• See above.
Cumulative Effects	Cumulative Effects	• Localized cumulative effects were considered for air quality and groundwater resources in the Pilot area.
Social		
Social	Local Hiring	• AOSC will look to hire locally qualified personnel as required for both construction and operation of the Pilot.
	Local Contracting	• AOSC is developing a contractor pre-qualification process for companies and service providers interested in potential opportunities. • AOSC will ensure that the requirements of the procurement process in place are clearly defined.
	Accommodation of Workers	• AOSC is currently engaged in discussions with other Industry partners, the RMWB and ASRD regarding access into the Dover lease area. The need for onsite accommodation of workers will be dependent on the results of those discussions. • Presently, AOSC does not have permanent onsite accommodations.
	Potential Impacts to Existing Infrastructure (Roads, Hospitals etc)	• The Pilot is expected to have a construction workforce of approximately 60 people and a permanent workforce of 10 staff. At these levels, AOSC does not anticipate this will add significant contributions to the existing infrastructure utilization numbers.
	Trapper Compensation	• AOSC has developed a trapper compensation program based on the widely used trapper compensation matrix from Fort McKay. • This program is applied to all trappers within AOSC lease areas.

Table 7.9-1 Key Themes Identified During Consultation

Theme	Issue/Idea	AOSC Response
Consultation		
Consultation	Joining the IRCs	• AOSC has developed a Community and Stakeholder Engagement Strategy. • AOSC is working with key aboriginal stakeholders to determine the most appropriate time to join as a funding IRC member. • AOSC will continue to work closely with all key aboriginal stakeholders as the Pilot proceeds.
	Participation/Investment in the Communities	• AOSC has developed a Community Investment Policy based around the key areas of interest. • AOSC will work closely with key stakeholders to identify mutually beneficial opportunities for AOSC to become more active in the communities.
	Timely Information Sharing	• AOSC has been meeting with key stakeholders to discuss the Pilot. • AOSC has also developed a newsletter ("AOSC News") that is being distributed to all key stakeholders. The newsletter will be updated regularly with new information. • AOSC's website (www.aosc.com) will be updated with new information.

8 CONSERVATION AND RECLAMATION PLAN

The purpose of the Conservation and Reclamation (C&R) Plan is to outline conservation and reclamation practices to be followed over the course of the Pilot. The C&R plan focuses on land and soil conservation, wetland management, surface disturbance, and reclamation concepts, as well as reclamation options. Site-specific environmental data (i.e., topography, soils, wetlands, vegetation and drainage) will be collected and submitted to ASRD as part of the environmental field reporting (EFR) requirements.

Information sources consulted and considered in the C&R plan design include:

- Pilot design;
- published biophysical information for the area;
- biophysical information (including soils and wildlife data) collected in the vicinity of the Pilot;
- other in-situ thermal recovery projects and their respective C&R plans; and
- oil and gas facilities reclamation experience.

Surface disturbances related to the Pilot will include the following:

- a CPF (8.4 ha);
- a source water well pad (0.48 ha) at 1-23-93-17 W4M; and
- an access corridor (26.52 ha) connecting the CPF and source water well pad that includes an access road, an aboveground power line and an underground pipeline for steam generation make-up water.

Details of the Pilot design are presented in Section 5.

8.1 Conservation and Reclamation Objectives and Key Activities

The objective of reclamation, defined by the AEPEA *Conservation and Reclamation Regulation* (AR 115/93), is to return areas disturbed for industrial development to equivalent land capability. This means that the ability of the land to support various land uses after conservation and reclamation should be "similar to the ability that existed prior to an activity being conducted on the land, but that the individual land uses will not necessarily be identical." Equivalent capability for forested lands is defined as "the condition in which ecosystem processes are functioning in a manner that will support the production of ecosystem goods and services consistent in quality and quantity as present prior to any activity being conducted on the land but that the individual land uses will not necessarily be identical" (Alberta Government, 2007a).

The objectives of C&R planning to achieve the desired environmental outcome include conserving existing resources as much as possible; adoption of measures to mitigate, minimize or prevent environmental impact; and application of suitable reclamation measures.

This C&R Plan presents general guidelines to mitigate potential impacts that may result from activities at the Pilot site. Key activities through the life of the Pilot that will integrate conservation and reclamation measures include facility siting, protection of waterbodies and wildlife, wetland management, salvage of organic material and mineral soil, weed control, surface water management, sediment and erosion control, waste handling and management, reclamation, revegetation and annual monitoring.

Reclamation objectives for the Pilot include the following:

- Reclamation to equivalent or improved land capability relative to that which existed prior to disturbance;
- Reclaimed areas will conform with surrounding surface landform and drainage patterns;
- Reclaimed lands will provide for self-sustaining ecosystems with a similar range of potential end uses relative to pre-disturbance conditions (including forestry, wetlands, wildlife habitat and traditional use); and
- Areas disturbed by industrial activities and no longer required for Pilot operation will be progressively reclaimed to minimize environmental impacts, such as soil erosion.

Site specific information pertaining to topography, soils, wetlands, vegetation and drainage will be provided by the EFRs. Adjustments may occur to the general C&R plan guidelines as a result of this additional information.

8.2 Environmental Protection Measures

8.2.1 Timber and Brush Management

AOSC will work with Al-Pac to coordinate integrated land management processes during development. For any land not previously cleared by Al-Pac or industry, AOSC will comply with the applicable guidelines presented below. Authorization from ASRD will be obtained for any surface disturbance requiring disposition authorization.

8.2.1.1 General Guidelines for Clearing Timber and Brush

Land will be cleared according to the *Migratory Birds Convention Act, Timber Management Regulation* (AR 60/73 Consolidated to AR 102/2000), the *Forest and Prairie Protection Act* and Al-Pac guidelines as they apply to site clearing, debris disposal and onsite firefighting equipment. Adequate firefighting equipment, in accordance with provincial guidelines and relative to degree of fire hazard, will be available for the Pilot during construction activities. In the event of a fire, AOSC will immediately implement the fire contingency plan and notify the required regulatory representative(s).

8.2.1.2 Merchantable Timber

Merchantable timber is defined as having a diameter at breast height (DBH) of 15 cm or greater. Any merchantable deciduous and coniferous timber present in the Pilot area will be salvaged. The timber salvage deck for the CPF area will be located onsite. Timber decks along the utility corridor between the CPF and the water source well pad will be located on additional temporary workspaces, as directed by ASRD. Existing cleared areas will be given preference for timber decks. Logs will be decked with butt ends facing the same direction and will be accessible for loading onto trucks for delivery to mills or all-weather access storage sites.

8.2.1.3 Non-Merchantable Timber and Brush

Non-merchantable timber will be cleared using a bulldozer, possibly equipped with a cutter blade or similar equipment to maintain ground surface integrity in areas where grading is not required. Stumps will be mulched (with a mulcher on a bulldozer) or grubbed. Woody debris will be disposed of using one of the following alternative methods:

- Some large woody debris may be used as rollback for barriers on linear right-of-ways (ROWs) and excess woody debris will be burned;
- Smaller woody debris may be chipped or mulched and used for erosion control and surface cover that is not to exceed a thickness of 10 cm; and
- Remaining woody debris may be chipped or mulched and incorporated with the salvaged topsoil (not to exceed one third of the topsoil volume).

8.2.2 Waterbody Protection

The Pilot is located within the Dunkirk River watershed and approximately 60 km west of Fort McKay, Alberta. The CPF is located south of a small unnamed lake and it is at least 100 m southeast of a stream that serves as outflow for the unnamed lake. The stream flows south to the Dunkirk River, which flows south and southeasterly to the McKay River. The McKay River flows east and northeast into the Athabasca River.

The topography in the Pilot area is a mixture of low-lying muskeg (e.g., bog and fen) and upland mixedwood forest (primarily black spruce and aspen). Numerous small waterbodies and wetlands are present in the surrounding area. General flow directions from the Pilot site are to the west and northeast lowland areas.

The Pilot includes a temporary alteration of surface runoff through the incorporation of ditches and surface runoff impoundments. Measures will be taken to minimize effects to wetlands and water bodies surrounding the Pilot. The source water well pad will have a perimeter ditch/berm system to prevent offsite flow from coming onsite, while onsite runoff will be contained in a graded lower corner catchment area. A ditch and earthen berm will be constructed around the CPF, where required, to contain onsite natural runoff and divert it into a lined runoff pond. The industrial runoff pond will be located on the southern portion of the CPF footprint. Natural runoff from the surrounding areas will be diverted around the production well and processing areas of the CPF. A description of the industrial runoff drainage plan for the Pilot is presented in Section 5.2.11.

Stormwater collected in the industrial runoff pond and pooled on the source water well pad site will be analyzed to confirm that it meets the criteria specified in ERCB Directive 055 (2001) and Surface Water Quality Guidelines for Use in Alberta (AENV, 1999b), before being discharged offsite. Water will be released in a controlled manner to prevent erosion. Collected water deemed not suitable for release will be sent for treatment or disposal at an approved facility.

Watercourse crossings along the access corridor will meet applicable legislative requirements and codes of practice to ensure minimal environmental impact. Applicable regulatory requirements in Alberta’s *Water Act*, *Fisheries Act*, and *Public Lands Act* and the federal *Fisheries Act* and *Navigable Water Protection Act* will be respected in the construction of crossings. Culverts and drains will be installed in the access road to maintain water flow and ecological integrity where deep peat areas (e.g., fens) are present. AOSC will monitor drains and culverts during operation to ensure water flow and integrity of wetland areas.

8.2.3 Wildlife Protection

Strategies to limit impact of Pilot construction activities on wildlife will be implemented where practicable. Tree and brush clearing will be conducted between August 30 and April 1 to protect migratory birds and their nests, and ensure compliance with Alberta’s *Wildlife Act*, and the federal *Migratory Birds Convention Act*. If clearing is required within the restricted time period, the area will be surveyed by a biologist to determine the presence of nesting birds, including raptors and owls. Obvious wildlife trails intersected by the Pilot will be kept free of woody debris, grade spoil and other Pilot-related materials to maintain the trail(s).

Feeding or harassment of wildlife will be prohibited. Any wildlife mortalities from collisions with vehicles will be reported to ASRD and Fish and Wildlife personnel.

8.2.3.1 Caribou Protection Plan

The presence of woodland caribou is a potential concern because of its "at risk" status (ASRD, 2005). Mitigation practices for caribou will be observed for the Pilot as prescribed in AOSC's Caribou Protection Plan (CPP) submitted for winter OSE programs.

The CPP will include drilling and construction plans and proposed mitigation measures, including an early-in/early-out construction strategy and restrictions on clearing or new soil construction during the calving season (May 1 to July 15). The construction camp for the Pilot will be situated onsite to lessen human and vehicle traffic during construction.

8.3 Soils Handling Plan

Since surface soils are important determinants of land capability, the following conservation measures for soil handling will be followed to conserve soil quantity and quality.

- unless otherwise authorized by a Conservation and Reclamation Inspector, soil salvage operations will be suspended if high wind velocities or wet conditions will result in degradation of topsoil or subsoil quality;
- salvaged soil will be stored out of the way of surface water flow and operational activities;
- topsoil will not be used for grading of the Pilot site; and
- remediation or disposal of any spilled contaminants will meet AENV requirements.

Soil construction activities completed annually and those planned for the following year will be reported to AENV in an Annual C&R Report.

8.3.1 Soil Salvage

The goal of soil salvage and management is to preserve soil integrity for site reclamation following decommissioning. Recommended soil salvage at the Pilot will involve "two lift" stripping of upland soil areas and a single lift of organic material from peatland areas. General soil salvage guidelines are provided below; however, an EFR will be completed prior to construction to obtain site-specific representative soil depths and profile information.

Preliminary soil inspections were completed in October 2007 at six locations slightly north of the CPF footprint. Upland soil types in the CPF footprint are considered to be similar to the types identified in 2007, based on interpretation of stereo aerial photography from 1995 and 1998. A summary of soil characteristics related to soil salvage recommendations for the soil types identified in 2007 is presented in Table 8.3-1. Upland soil salvage generally consists of duff (LFH), Ahe/Ae and/or AB horizons, with a shallow peat (organic) layer commonly occurring over mineral soils in depressions (Gleysolic), some of which do not have a developed A horizon.

Table 8.3-1 Soil Characteristics Related to Soil Salvage

Soil Series	Comments
Bitumount	Often peaty, Gleysolic glaciofluvial soils with shallow peat surface (8 to 43 cm thick). A horizons are commonly present, but may be absent; where present they are generally silt loam to sandy loam A horizons (5 to 20 cm thick) underlain by sandy loam to sandy clay loam Bg horizons.
Livock	An upland mineral Luvisolic soil over till with either LFH (0 to 15 cm thick) or shallow peat (0 to 20 cm) surface horizons. The generally sandy loam A horizons range from 5 to 50 cm (excluding one 80 cm outlier) but are commonly 10 to 20 cm thick, and average 20 cm. The underlying B horizons are generally sandy clay loam in texture.

8.3.1.1 CPF Footprint

Upland soils where poplar is predominant are present in approximately 70% of the Pilot CPF area, where the ecosite type is mainly upland d1 (Section 6.3). Mineral soil will be stripped to a minimum depth of 15 cm for topsoil salvage and will include surface organic materials (mulched woody debris, LFH/Om), and the underlying Ahe and/or Ae soil horizons to comprise the first lift. Colour change from a greyish Ae to brownish B subsoil can be used to guide topsoil stripping depth. Up to a maximum of 30 cm of suitable subsoil, as defined in Soil Quality Criteria Relative to Disturbance and Reclamation (SQCRDR) (Alberta Agriculture, 1987) will be salvaged from upland areas as the second lift at the Pilot CPF.

Surface organic material (woody debris and peat) and any underlying A horizon, if present, will be salvaged from the treed bog areas at the east and north corners of the CPF footprint, where black spruce is dominant. Peat will also be salvaged from a lowland area that roughly parallels the southwest Pilot boundary. Where peat depth is 40 cm or less, the peat will be salvaged down to the mineral soil. Peat may be stripped slightly deeper than 40 cm to reach mineral soil beneath. Preferred conditions for stripping of peat are discussed further in Section 8.3.2. Upper subsoil will not be salvaged from wet, peaty areas, because of anticipated saturated soil conditions.

8.3.1.2 Access Corridors and Source Water Well Pad

Upland soils are present in the northwest half of the access corridor between the CPF and source water well pad, based on a review of the published reconnaissance soil map (Turchenek and Lindsay, 1982) and a review of the ecosite phases identified along the access corridor (Figure 6.3-1). Soil inspections have not yet been conducted along the access corridor or at the source water well pad. A description of soil groups identified from the Alberta Oil Sands Environmental Research Program (AOSERP) soil map (Turchenek and Lindsay, 1982) for the proposed access corridor is presented in Table 8.3-2. Algar and Dover soil groups are commonly comingled where Dover soils occupy well drained upland positions and Algar soils occur in poorly drained upland depressions.

All LFH and underlying eluviated Ahe/Ae horizons and shallow surface peat in upland areas along the access corridor will be salvaged. A second lift of subsoil will be salvaged to a maximum depth of 30 cm from upland areas of the access corridor. Shallow peat layers will also be stripped and salvaged down to mineral soil found beneath the peat along the access corridor. Areas comprised of deep peat (greater than 40 cm) soils along the access corridor will be salvaged to a depth of 40 cm. Land use targets are discussed in Section 8.6.3.

More specific soil stripping depths and topsoil and subsoil volumes for the CPF, access corridor and source water well pad will be presented using additional soil data collected for site-specific EFRs for the CPF, source water well pad and associated access corridor.

Table 8.3-2 Soil Groups Identified in the Access Corridor and Source Water Well Pad Areas

Soil Group	Dominant Soils	Significant Soils	Comments
Algar	Shallow Peaty Gleysols	Gleyed Grey Luvisol	Shallow peaty Gleysols on waterlogged clayey and silty deposits; associated with imperfectly drained Gleyed Grey Luvisols that have LFH, Aeg from 5 to 20 cm thick over clayey Btg
Dover	Orthic Grey Luvisol	Gleyed Grey Luvisol	Soils developed on clayey parent material over till. LFH, Ae from 5 to 15 cm thick over a brownish, very firm Bt subsoil horizon
Eaglesham	Typic Mesisol (Organic)	Terric Mesisol Fibric Mesisol Typic Fibrisol	Complex of Organic soils developed from fen peat (sedges, reeds), usually more than 2 m deep; soils poorly to very poorly drained; less than 25% fiber content
Kenzie	Terric Mesisol (Organic)	Terric Fibric Mesisol Fibric Mesisol Terric Fibrisol	Extremely acidic, organic peats developed from sphagnum bog with or without black spruce; peat depth ranges from 0.4 to 4 m; soils very poorly drained
Mikkwa	Fibric Organic Cryosol	Mesic Organic Cryosol Typic Fibrisol	Extremely acidic Organic Cryosols developed from bog peat; permafrost layer within 0.5 to 2 m of the surface; soils very poorly drained; occur commonly with Kenzie soil group

Adapted from Turchenek and Lindsay, 1982

8.3.2 Stripping of Surface Soil, Including Frozen Soil

Stripping of topsoil in upland areas can be conducted before frost is deeper than 5 cm (mineral soil) using dozers. If mineral soils are frozen at the time of stripping, a soil cutter, mulcher, or similar attachment mounted on dozers will be required to loosen frozen topsoil and facilitate stripping and piling. Colour change from Ae to B horizons can be used to guide the maximum topsoil depth in upland mineral soils. Loosening of subsoil with a ripper mounted on a dozer may be required if it is frozen at the time of stripping and salvage.

In the CPF footprint, saturated deep peat will be preferentially stripped to 40 cm and salvaged when it is frozen to minimize degradation of soil quality under wet conditions. The salvaged peat will be preferably stored as replacement material for reclamation at the location of origin. Salvaged peat will be stockpiled, preferably on existing peat surface, and stabilized until needed.

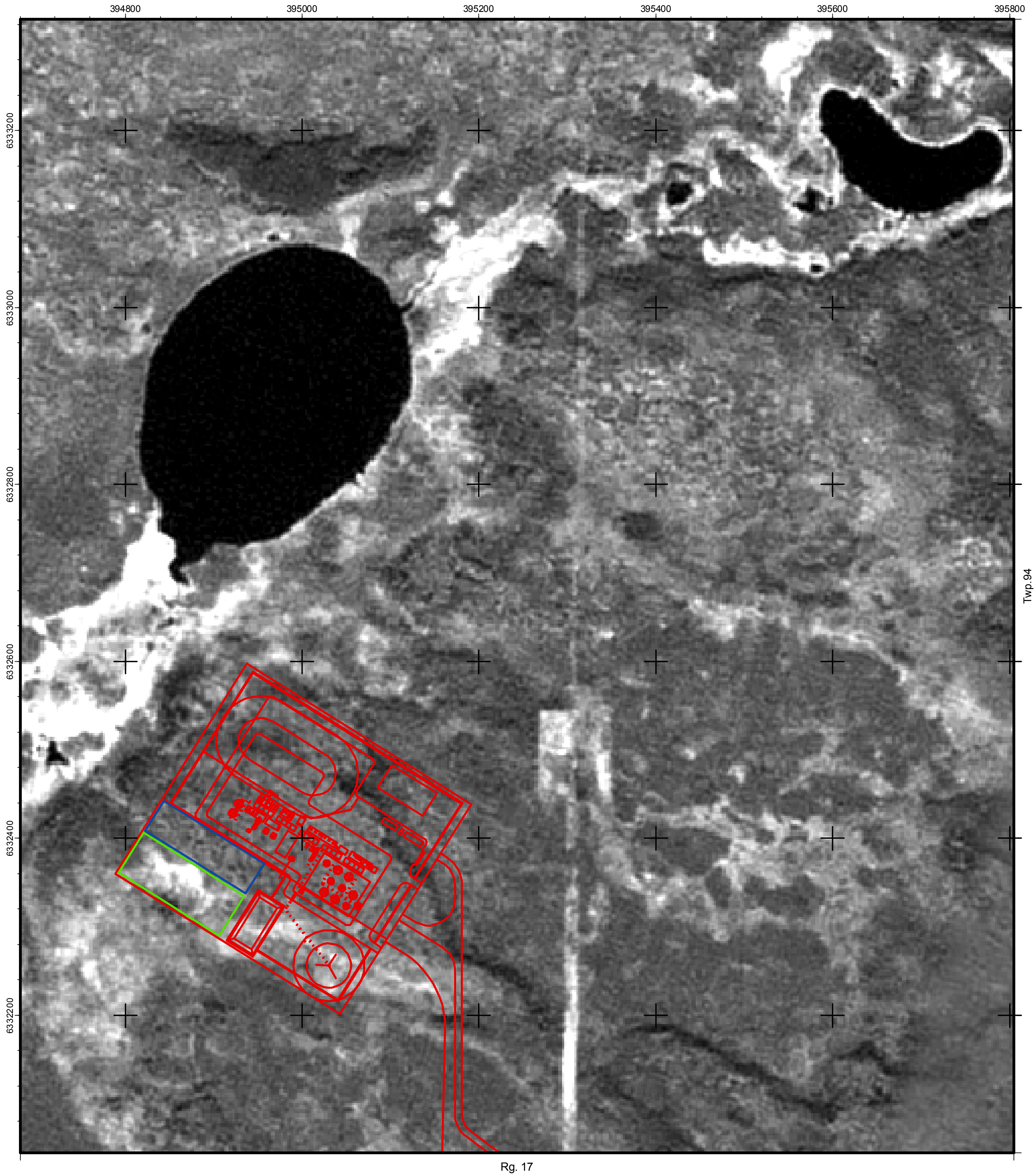
8.3.3 Stockpile Management

A stable foundation should be provided for soil stockpiles. Topsoil and subsoil stockpile areas are proposed for the southwest portion of the CPF footprint (Figure 8.3-1), where the piles should not interfere with construction and subsequent operation. Topsoil and subsoil storage areas for the access corridor between the CPF and the water source well are proposed along the access corridor (Figure 8.3-2). Recorded volumes and locations of stockpiled topsoil and subsoil will be documented in Annual C&R reports.

Salvaged peat will be piled separately from mineral topsoil and preferably onto peat adjacent to the topsoil. Areas where upper subsoil is stored will have all topsoil removed before any subsoil is piled there.

Stockpiles will not be located near or in watercourses and wetlands. A minimum distance of 1 m will be maintained between stockpiles. Piles will have a set back of 5 m from any adjacent standing timber. Stockpiles will be contoured to a stable slope gradient to minimize erosion, before being revegetated. Stockpiles will be monitored and if required, action will be taken to protect soil from erosion or degradation. Measures available for stabilizing stockpiles include seeding grasses and using controls such as silt fence, erosion control matting, or wood mulch cover. The stockpile height will be determined in consultation with ASRD. Approvals will be obtained from ASRD for any stockpiling of soil materials outside of the access corridor.

Topsoil and subsoil piles will be seeded with a blend of native grasses suitable for the Central Mixedwood Subregion. Species selection for the blend will be done in consultation with ASRD and contractors, with reference to the Native Plant Revegetation Guidelines for Alberta (NPWG, 2001). Stabilization of stockpile surfaces with engineered controls or tackifying agents will be implemented on an as needed basis.



LEGEND

DOVER CENTRAL PILOT

SUBSOIL STOCKPILE

TOPSOIL STOCKPILE

1:6,000

100 0 100

Metres

NAD 1983 UTM Zone 12N

Project Code: 7349-514	Technical: RL	Date: 15/04/08
Senior: RL	Date: 15/04/08	Drawn by: GU	Date: 15/04/08

Reference:
Orthophoto obtained from AOSC, used under license

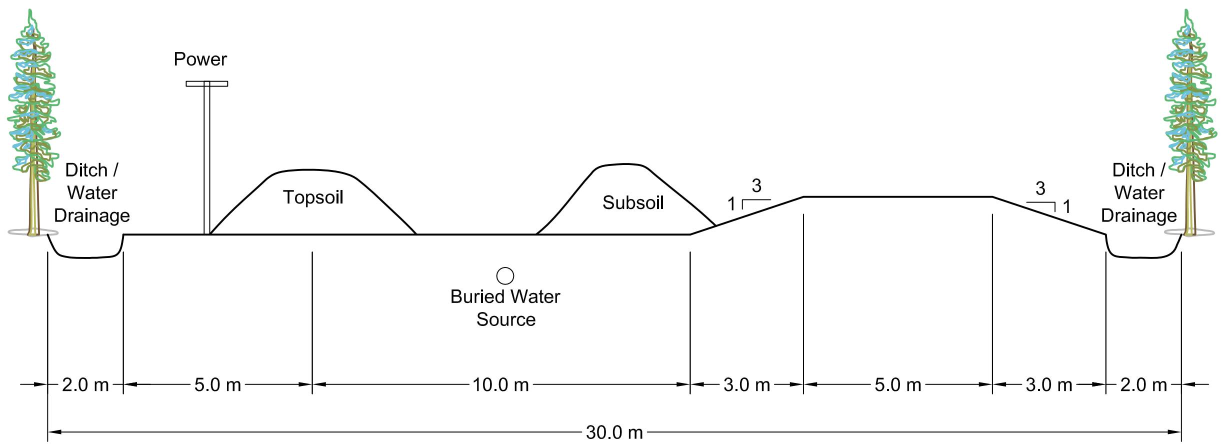
Disclaimer:
Prepared solely for the use of AOSC as specified in the accompanying report.No representation of any kind is made to other parties with which AOSC has not entered into contract.

ATHABASCA OIL SANDS CORP.

STOCKPILE LOCATIONS

FIGURE 8.3-1

I:\7349_514\MAPS\FIGURES\009_SOILS\FIGURE_8.3-1_STOCKPILE_LOCATIONS.mxd



SCALE 1:200 metres

2 0 2 4

Project Code: 7349-514	Technical: ## Date: 09/05/08
Senior: ## Date: 09/05/08	Drawn by: GDE Date: 09/05/08

Reference:

Disclaimer:
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ATHABASCA OIL SANDS CORP.

TYPICAL ACCESS CORRIDOR

FIGURE 8.3-2

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8.4 Weed Control Plan

8.4.1 Regulatory Requirements

The provincial *Weed Control Act* was developed for the control of existing invasive plant infestations and limiting the introduction and spread of recently introduced invasive plants in Alberta. Invasive plants designated as weeds are listed in the *Weed Regulation* (AR 171/2001) and categorized as restricted, noxious or nuisance. Species defined as 'restricted' in the *Weed Control Act* must be eliminated, and those classified as 'noxious' must be controlled.

ASRD provided a list of weed species of concern for the Pilot area within the RMWB. Scentless chamomile, ox-eye daisy and tansy were reported as weed species of concern for industrial sites and associated ROWs. Any occurrence of these species will be noted and controlled according to best management practices outlined below. Non-persistent annual weeds can be controlled by mowing when these are observed to be out-competing desired native plant species.

8.4.2 Weed and Non-Native Plant Control Methods

Establishment of native plants on soil stockpiles will help counter growth of annual weeds. Non-residual herbicides will be applied, if deemed necessary, to control any noxious and restricted weeds. Preventing the spread of weeds and controlling them will be managed as per the following regulatory requirements and industry best practices as listed below:

- Equipment to be mobilized to the Pilot site will be free of soil and debris to preclude the importation of weed seeds or other propagules;
- Invasive and /or persistent agronomic species will not be used for planting at the Pilot;
- A certificate of analysis will be obtained for each native seed component used in mixtures for reclamation, to ensure seed sources are free of problem weeds and invasive species;
- Restricted weeds will be eliminated and noxious weeds will be controlled;
- The Pilot area will be routinely monitored for weeds and weed control measures will be undertaken in a timely fashion;
- Straw bales will not be used for erosion control;
- Non-chemical control of weeds (mowing, cultivation, hand picking) is the preferred control measure, herbicides will be only be used when necessary, with appropriate approval(s);
- Any herbicides applied will be appropriate for non-target vegetation and weed species, licensed industrial pesticide applicator(s) will be contracted for herbicide selection and application in accordance with the *Pesticide Regulation* (AR 43/97). All federal and provincial regulations regarding the use, transportation and storage of herbicides will be followed;
- Non-selective herbicides will not be used where desirable plant species would be injured, either spot spraying of selective herbicides or mechanical weed control will be employed;
- Only an agronomic cereal crop will be used to control erosion if it is more appropriate than other methods for a specific site, and the crop is seeded at a reduced agronomic rate; and
- Soil sterilants will not be used through the life of the Pilot.

8.5 Reclamation During Operations

Cleared space on the CPF area will be generally required for operational activities during its lifetime. Interim reclamation will be undertaken as practicable during the Pilot life including, but not limited to, soil replacement over underground pipelines as the final step in pipeline construction, soil replacement and re-vegetation along edge areas of pads not required for operations, and erosion control of disturbed slopes and soil stockpiles. Silt fence and/or erosion control matting will be installed, if required, to initially control erosion or sedimentation until vegetation is established after soil stockpiles are seeded.

Temporary workspace areas used during construction will be subsoiled or disced to alleviate any soil compaction prior to replacement of salvaged soil. Level to gentle slopes along corridors will be allowed to revegetate naturally, whereas areas with slopes greater than 5% will be seeded to a blend of native grasses that is approved by ASRD. Salvaged soil piles and other areas prone to erosion will be monitored through the life of the Pilot.

Where necessary, implementation of erosion control measures will be timely and may include:

- Using silt fencing or settling ponds during construction and operation to contain sediment during runoff;
- Grading disturbed surfaces to prevent concentration of surface flow and formation of gullies on slopes;
- Avoiding excessive slope gradients in ditches and graded surfaces;
- Using ditches and culverts to control water flow and ditch banks will be vegetated;
- Using flow obstacles (e.g., rip rap, erosion control matting) in ditches to reduce water velocity, where necessary; and
- Suspending soil handling when significant risk of erosion may occur (high winds, intense rainfall).

8.6 Reclamation After Abandonment

An abandonment and reclamation plan will be submitted to AENV at least 6 months before decommissioning of the Pilot site. The plan will include details on final decommissioning, site abandonment and reclamation practices that comply with the regulatory regime current at that time. Current guidelines and criteria were used to develop the reclamation plan. Successful reclamation will result in a maintenance-free, self-sustaining ecosystem that is compatible with the surrounding area.

8.6.1 End Land Use Objectives

Reclamation objectives include achieving terrain, drainage and soil characteristics similar to pre-disturbance conditions in order to achieve equivalent land capability. One end land use objective is to return forested upland areas to reclaimed upland areas with end ecosite phases and land use that will be the same as, or similar to, pre-development conditions (forest, wildlife habitat and traditional land use). It is anticipated that, through proper replacement of salvaged soil horizons and proper reclamation techniques, closure soil profiles and properties of reclaimed upland areas will have a similar ability to support an aspen poplar and low bush cranberry cover type, with black spruce in lower landscape positions. Pre-disturbance land capability ratings were not determined based on the soil information collected in 2007, since soil analyses were not conducted. Land capability ratings for forest ecosystems will be determined based on site-specific soil surveys that will be completed in the summer of 2008.

AOSC will also incorporate wetland reclamation principles (Oil Sands Wetlands Working Group [OSWWG], 2000), where feasible, into reclaiming peatland areas that are disturbed. Areas between reclaimed upland and undisturbed peatland surrounding the CPF will be reclaimed by removing fill to leave a poorly drained, transitional area, where salvaged peat will be replaced. The reclamation objective for this transitional peatland area is to provide for surface conditions similar to adjacent peatland. Targets for the reclaimed transition zone will be ecosite phase ‘transitional g1’, which will support mosses, peatland vegetation and black spruce. A ‘transitional i1’ phase (treed bog) will be restored along the edges of the water well pad after the well is abandoned and the edges are excavated. The upland areas should be restored to Land Capability Classes 3 and 4, while the transitional areas to peatland should be restored to Class 5 (poorly drained).

Reclaimed portions of the Pilot that required no or minimal padding, (i.e., the access corridor), are anticipated to return to the same ecosite phases and Land Capability Classes as the pre-disturbance upland and peatland phases and Classes.

The re-vegetation plan for the Pilot is presented in Section 8.7. The Pilot area should develop with time into a maintenance-free, self-sustaining ecosystem that will support multiple uses including forestry and wildlife habitat. Increased access attributable to the Pilot following reclamation is not expected to have a marked effect on end land use capability, because of existing and anticipated new industrial disturbances within the vicinity of the Pilot site.

8.6.2 Site Decommissioning and Remediation

Pilot-related facilities and infrastructure will be decommissioned in consultation with regulators and regulatory documents, such as the AEPEA Approval. All surface equipment, structures and infrastructure will be removed in a manner that prevents release of potential contaminants. All production, geotechnical and groundwater monitoring wells will be abandoned in accordance with the applicable guidelines and regulations in effect at that time.

Where necessary, soils will be assessed for contaminants and remedial action taken according to regulatory requirements at the time, including AEPEA Approval conditions. The current guidelines used to assess soil quality with respect to released substances are contained in the Alberta Tier 1 Soil and Groundwater Remediation Guidelines (AENV, 2007). Any contaminated areas will be reassessed following remedial actions to confirm that specified endpoints for applicable parameters have been achieved.

8.6.3 Final Reclamation

As stated in Section 8.6.1, the C&R plan aims to reclaim forested sites to ecosite phases and land uses that will be the same as, or similar to, the pre-disturbance conditions. The general approach to reclamation of upland areas includes the following:

- Consultation with ASRD to review target end land use and reclamation goals;
- Removal of remaining concrete or debris and disposal at an approved facility;
- Removal of surface gravel, and reuse elsewhere as appropriate;
- Removal or partial removal of clay pads where appropriate;
- Removal of any erosion control structures and culverts before the site is re-contoured;

- Re-contouring subsoil grade to conform with the surrounding landform and drainage patterns (including removal of berms and ditches) and leaving a stable surface;
- Alleviation of compaction (ripping/discing) on operational surfaces, as needed;
- Replacement of salvaged subsoil and topsoil;
- Preparation of replaced soil for re-vegetation;
- Addition of naturally sourced amendments (e.g., peat), if required;
- Re-vegetation in consultation with stakeholders (e.g., ASRD); and
- Monitoring to assess reclamation success and implementing remedial measures (e.g., weed control, amelioration of drainage or erosion problems), as required.

After gravel salvage and de-compaction of the operational surface, reclamation will involve excavation of fill from pre-disturbance peatland areas along the southwest margin and east corner of the CPF, with placement of the fill in upland areas. Berm material on the CPF will be used to fill ditches and any remaining material will be redistributed on the upland areas. The edges of the upland area will be re-contoured to stable, short slopes ranging from 5 to 10% gradient. Upper subsoil will be replaced on the upland and prepared (e.g., disced and roto-spicked) as necessary before topsoil replacement. Salvaged mineral topsoil will then be redistributed across upland areas. If wet conditions or high winds prevail, topsoil replacement will be suspended to avoid degradation or loss of topsoil. Topsoil replacement will be done in a fashion that will leave small ridges and hollows, since these can produce diverse microsites for moisture retention and forest species plant establishment.

Reclamation will also restore peatland which will be transitional from the reclaimed uplands of the CPF to the adjacent undisturbed peatland. The central portion of the source water well pad constructed on peatland will be reclaimed to an upland area ecosite phase, using fill excavated from its margins. Edges will be excavated to a level slightly below the water table, followed by replacement of salvaged peat. This transition zone would be poorly drained with salvaged peat and woody debris replaced at the surface. In order to create small pockets of water to promote sphagnum establishment, small mounds/depressions that result from salvaged peat replacement will be left in place. Some salvaged peat may be incorporated with fill in the upland area of the source water well pad to improve soil condition.

Surface gravel from the access road to the source water well pad will be removed. The padded portion of road over deep peat maybe removed and fill returned to borrow areas. The remaining road grade in upland areas should be ripped to de-compact the subsoil. Culverts will be removed and the road grade will be re-contoured. Salvaged subsoil and then topsoil will be replaced along upland portions of the access corridor. Salvaged peat will be replaced in low areas where it was originally stripped. Reclaimed uplands will be revegetated with species as presented in Section 8.7.

Estimated volumes of soil materials to be salvaged and available for replacement on the CPF site are provided in Table 8.6-1.

Table 8.6-1 Estimated Volumes of Salvaged Surface Material Available for the CPF

Organic Material (Peat + LFH) (m^3)[(a)]	A Horizon Material (m^3) [(a)]	B Horizon Material (m^3)[(a)]
2,880 to 4,320	10,500	12,000

(a) Calculated from proposed salvage procedures and upland mineral soil area.

The material volumes in Table 8.6-1 are based on a minimum of 15 cm of mineral topsoil salvage (upper lift) material available for replacement, and from 20 to 30 cm of organic material available for surface replacement along the southwest end of the CPF area. An estimated 20 cm of upper subsoil was assumed to be available from upland mineral soil areas for replacement.

8.7 Revegetation

A sustainable cover of natural forest vegetation similar to what existed before Pilot disturbance is the goal to be achieved with final reclamation. Natural materials and processes will be used to the greatest extent possible. Revegetation will include a combination of herbaceous and woody species. Herbaceous seed mixes and application rates used will be designed to minimize surface erosion while providing adequate “biological space” for native woody species establishment.

The target plant community types for reclaimed areas on mineral soils will be the same as the pre-disturbance/control plant community types in the footprint area. The predominant CPF ecosite phase d1 (low-bush cranberry, aspen) and a ‘transitional g1’ are target ecosite end phases. A transitional area between deciduous uplands and surrounding peatland will have a reclamation target of a ‘transitional g1’ (Labrador tea, white spruce-jack pine) plant community. The target phases for the reclaimed water well pad upland area are anticipated to be f1 (horsetail, balsam-aspen) to g1 (Labrador tea, black spruce), and the reclaimed margins to be ‘transitional i1’ (treed bog).

Reclaimed upland portions of the access corridor will have the target end phases of d1 (low-bush cranberry, aspen), d2 (low-bush cranberry, aspen-white spruce) with some h1 (Labrador tea/ horsetail, black spruce-white spruce), and the potential for some d3 (low-bush cranberry, white spruce). Target end ecosite phases for reclaimed peatland along the access ROW will be mainly ‘transitional i1’ (treed bog), ‘transitional i2’ (shrubby bog) and j2 (shrubby poor fen).

Natural regeneration from seed and root stock in topsoil will be the preferred revegetation method for small and/or narrow sites such as the access corridor, where conditions are appropriate (e.g., lower potential for erosion and absence of weed issues). If natural re-vegetation establishment is slow or the area is prone to erosion, the problem areas will be planted with native species to promote revegetation.

Candidate native grass and forb species for applicable plant community types are listed in Table 8.7-1 while candidate native shrubs and trees are listed in Table 8.7-2. The species listed are the prime species considered for each ecosite phase, though species selected may be adjusted on a site-specific basis. Site-specific recommendations of species for upland and peatland areas will be provided in the EFRs that will be completed for the Pilot. Recommended species targets will be based on site assessments of ecosite pre-disturbance vegetation. Specific revegetation plans for each development area will be based on pre-disturbance vegetation, surrounding vegetation, landform and ecosite phase.

Herbaceous seed will be sourced, preferentially from Alberta, and certificates of analysis for each seed component used in mixtures will be reviewed to ensure that problem and invasive weeds are properly managed. Final species selection for reforestation and/or seeding will be done in consultation with ASRD and Al-Pac prior to planting.

Table 8.7-1 Native Herbaceous Species Candidates for Revegetation

Moisture Regime	Ecosite Phase	Growth Habit	Species	
			Common Name	Scientific Name
mesic	d1, d2	grass	hairy wild rye	*Elymus innovatus*
			fringed brome	*Bromus ciliatus*
			tickle grass	*Agrostis scabra*
			slender wheatgrass	*Agropyron trachycaulum* var. *trachycaulum*
			awned wheatgrass	*Agropyron trachycaulum* var. *unilaterale*
			spike trisetum	*Trisetum spicatum*
			fowl bluegrass	*Poa palustris*
		forb	American vetch	*Vicia americana*
			northern bedstraw	*Galium boreale*
			Common yarrow	*Solidago canadensis*
subhygric - hygric	g1	grass/sedge	fowl bluegrass	*Poa palustris*
			slough grass	*Beckmannia syzigachne*
			sedges	*Carex* spp.

Source: Gerling et al. (1996)

Table 8.7-2 Native Woody Species Candidates for Revegetation

Moisture Regime	Ecosite Phase	Growth Habit	Species	
			Common Name	Scientific Name
mesic	d1, d2	shrub	low bush cranberry	*Viburnum edule*
			green alder	*Alnus crispa*
			raspberry	*Rubus ideaus*
			Canada buffalo-berry	*Shepherdia canadensis*
			prickly rose	*Rosa acicularis*
			red-osier dogwood	*Cornus stolonifera*
		tree	balsam poplar	*Populus balsamifera*
			trembling aspen	*Populus tremuloides*
			white spruce	*Picea glauca*
subhygric - hygric	g1	shrub	willows	*Salix* spp.
			Labrador tea	*Ledum groenlandicum*
			bog cranberry	*Vacinium vitis-idaea*
			currants	*Ribes* spp.
		tree	black spruce	*Picea mariana*
			tamarack	*Larix lariciana*

Source: Gerling et al. (1996)

8.8 Monitoring

Monitoring for weed and erosion control, terrain conditions, drainage and re-vegetation success will be conducted throughout the life of the Pilot.

8.8.1 Reclamation Monitoring and Assessment

Environmental monitoring will be carried out to determine the progress and success of reclamation. Monitoring will be carried out to assess reclamation in terms of meeting the reclamation criteria at the time, and in accordance with the AEPEA Approval.

On-going reclamation activities and procedures will be documented. Documentation will include a description of the type of development which was present, and a description of the date and reclamation activity carried out for a specific site. A post-reclamation assessment will be conducted to document soil, landscape and vegetation conditions and will be included in the application for reclamation certification for the reclaimed area.

8.8.2 Stockpiled Topsoil and Temporary Reclamation

Stockpiled soil and any other temporary reclamation locations will be monitored until sufficient vegetation cover has established to prevent loss due to erosion. If erosion is observed, additional erosion control measures will be undertaken (Section 8.3.3). Weeds will be controlled by mowing and/or herbicide application, as required.

8.8.3 Final Reclamation

Reclamation monitoring will be carried out to ensure that the outcome of final reclamation will achieve the reclamation certificate criteria of the day. The current reclamation criteria include the Guide To: Reclamation Criteria for Wellsites and Associated Facilities 2007 – Forested Lands in the Green Area Update (Alberta Government, 2007a), as well as any conditions to be specified in the AEPEA Approval for the Pilot. The general objectives of reclamation monitoring include assessing the following:

- soil and terrain, to ensure that equivalent land capability is achieved, and reclamation criteria are met for reclamation certification;
- acceptable landscape parameters (drainage, erosion, stability, gravel and rocks, and debris);
- soil quality (e.g., texture, structure/compaction) and quantity (depth of replaced topsoil);
- vegetation, to ensure that it is re-established and self-sustaining for the target plant community and meets reclamation requirements; and
- reclamation issues that need remedial measures, such as erosion, site stability, weed infestation, drainage problems, or industrial debris, are assessed and addressed.

Soil assessments would not be carried out where there was no disturbance or apparent impact. Any reclamation deficiency will be assessed and corrective measures undertaken as needed.

Reclamation monitoring will initially be carried out annually or biannually. Monitoring will continue until the reclamation certificate is obtained. The pre-development, and/or adjacent control, biophysical conditions will provide a reference with which to assess reclamation success. A final post-reclamation assessment will be conducted at completion of reclamation to document soil, terrain and vegetation conditions and will be included in the application for reclamation certificate.

8.8.4 Terrain and Drainage Assessments

Drainage will be assessed by a visual inspection to ensure it is consistent with pre-disturbance conditions and conforms to offsite patterns (i.e., no evidence that surface or subsurface drainage was disrupted). Visual assessment of signs of erosion or slumping, and for reclaimed contours blending with the surroundings will be conducted. Gravel and rocks, and excess woody debris will be assessed as per the criteria. No industrial debris will remain onsite.

8.8.5 Post-Reclamation Soils Assessments

Soils will be assessed for the following:

- satisfactory soil replacement as required by criteria (e.g., topsoil depth – no bare areas);
- compaction (including soil structure) or other restricting layers; or
- soil texture (to assess potential plant establishment problems).

Soils will be sampled and analyzed to confirm any potential soil quality issues that cannot be determined otherwise. Soil analytical parameters may include texture, structure, compaction, pH, electrical conductivity, sodium adsorption ratio and macronutrient levels, as deemed necessary.

If any Pilot related areas are identified that require remediation, accredited laboratories will analyze representative soil samples before and after remediation is conducted to document changes and ensure that remediation objectives have been met.

8.8.6 Vegetation Assessment

The vegetation assessment will be carried out in accordance with the Guide To: Reclamation Criteria for Wellsites and Associated Facilities 2007 – Forested Lands in the Green Area Update (Alberta Government, 2007a) (or the guidelines of the day), as well as any conditions to be contained in the AEPEA Approval. Vegetation will be assessed for the following characteristics and will be compared to pre-disturbance and/or adjacent control vegetation:

- presence of dominant species and layers of vegetation (woody and herbaceous forest species);
- vegetation quantity (reasonable distribution and growth);
- vegetation quality (plant health); and
- presence of weeds as per the *Weed Control Act.*

Inspections will be conducted after the first growing season following reclamation and initial vegetation establishment. Any vegetation deficiencies will be assessed and corrective measures undertaken as required. The monitoring schedule for subsequent monitoring will depend upon any issues noted, additional reclamation work done and rate of revegetation. Vegetation will be assessed for achieving the re-vegetation objective including species composition (woody and herbaceous), woody species and tree growth, ground cover and health.

8.8.7 Weed Management

AOSC is committed to a weed control monitoring program during the life of the Pilot. The weed control program will include cultivation, mowing, manual picking and biological weed control methods, as required; selective herbicides may be required. Further details are presented in the weed control plan (Section 8.4).

8.8.8 Reporting

Results from the monitoring program will be reported to AENV in the Annual C&R Report as per AEPEA Approval conditions. All reclamation activities will be in compliance with and documented as required in the terms and conditions of the AEPEA Approval for the Pilot.

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APPENDIX A
DOVER CENTRAL PILOT PROJECT
APPLICATION
HYDROGEOLOGY ASSESSMENT

Report Prepared for:

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Prepared by:

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June 2008
Calgary, Alberta

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APPENDICES

1.0 INTRODUCTION

This appendix describes the methods and results of the hydrogeological study carried out in support of the application for approval for the Athabasca Oil Sands Corp. (AOSC) Dover Central Pilot Project (the Project).

1.1 Project Description

The Project is located approximately 90 km northwest of Fort McMurray, Alberta (Figure 1). The Project will consist of in-situ thermal recovery production of bitumen at a rate of 318 m^3/d (2,000 bpd). Over the 7 year life span of the assessment, the water demand, presented in Figure 2, will be variable and is outlined as follows:

Date	Water Demand (m^3/day)
Jul 1st 2010 – Jul 31st 2010	1275
Aug 1st 2010 – Sept 30th 2010	75
Oct 1st 2010 – Mar 31st 2011	575
Apr 1st 2011 – Sept 30th 2011	450
Oct1st 2011 – Mar 31st 2012	375
Apr 1st 2012 – Sept 30th 2012	175
Oct 1st 2012 – June 30th 2017	75

For the start of production the water demand will be met with a network of supply wells completed in the Lower Grand Rapids Formation. Preliminary information regarding the feasibility of the Lower Grand Rapids Aquifer as a water supply option for the Project was provided by a test well located at 01-23-093-17 W4M.

The Project footprint includes a Central Processing Facility (CPF) which will be located in the SW¼ of 06-094-17 W4M (Figure 1). The Lower Grand Rapids Aquifer supply wells will be located approximately 9 km southeast of the CPF in the vicinity of 01-23-093-17 W4M.

1.2 Study Area

The study area for this assessment incorporates 16 townships of land extending from Townships 91 to 94 and Ranges 16 to 19, west of the 4th Meridian. The study area lies in the Mackay Plains south of the Birch Mountains. The elevation ranges from approximately 475 metres above sea level (masl) in the southeast to approximately 675 masl in the northwest. The Dover and Dunkirk rivers flow southeast through the study area away from the Birch Mountains. The Mackay River is located south of the study area and flows east toward the Athabasca River which is located approximately 40 km east of the study area.

2.0 METHODOLOGY

The following work was completed to assess the potential impacts of the Project on groundwater resources:

- Baseline assessment of the existing
  - geologic conditions;
  - hydrogeologic conditions; and
  - local water users.
- Impact assessment to determine the potential effects to groundwater resources due to the construction, production and post-production phases of the Project.

2.1 Baseline Assessment

2.1.1 Geologic Mapping

To gain an understanding of the geologic and hydrogeologic units within the study area, a total of 377 wireline well logs were reviewed. The reviewed wireline data typically included: gamma ray, spontaneous potential, resistivity, neutron porosity and density porosity. Details regarding the geologic mapping are included in Attachment A.

2.1.2 Hydraulic Head Mapping

To map the hydraulic head distribution for key hydrostratigraphic units, the following data sources were used:

- published hydraulic head values from regional hydrogeologic studies;
- published hydraulic head values from adjacent operator environmental impact assessments (EIAs);
- published hydraulic head values from the Alberta Environment (AENV) Groundwater Information Centre (GIC) database;
- hydraulic head values collected by AOSC; and
- drill stem test (DST) pressure data from the EUB database.

2.1.3 Groundwater Chemistry Characterization

In order to characterize the groundwater chemistry within the study area, available groundwater chemistry data were compiled and assessed. Data sources for groundwater chemistry included:

- published groundwater chemistry results from adjacent operator EIAs;
- published groundwater chemistry results from regional hydrogeological studies;
- available groundwater chemistry results as requested from AENV's GIC;
- groundwater chemistry results collected by AOSC; and
- DST formation water analyses from the EUB database as available in Geofluids (2007).

For reasons such as sample contamination, sample mixing and/or analysis incompleteness, Hitchon et al. (1989) has shown that as few as one fifth of water analyses from DSTs are suitable for consideration after data culling occurs. The accepted data set for this study included 27% of the original data. The data culling methods are summarized in Attachment B.

2.1.4 Local Water Users

A search for registered water well users within the study area was conducted utilizing the AENV GIC database. Where possible, the total drilling depths and completion intervals were compared to geologic mapping information to establish the unit in which the well was completed. Available water well drilling reports are included in Attachment C. In addition to the GIC database, existing groundwater diversion licences were compiled.

2.2 Impact Assessment

Through the construction, production and post-production phase of the Project, components which have the potential to affect groundwater resources include the operation of surface facilities, groundwater withdrawal and steam injection. Quantitative methods utilized to predict the potential impacts due to groundwater withdrawal and steam injection are described in the following sub-sections.

2.2.1 Assessment of Impact Due to Groundwater Withdrawal

Water level changes due to groundwater withdrawal from the Lower Grand Rapids Aquifer were predicted using the method of Theis (1935; Equation 1). These water level changes were then interpreted in terms of aquifer productivity.

Equation 1.

$$s = \frac{Q}{4\pi T} W(u)$$

Where:

W(u) = well function

$u = \frac{r^2 S}{4Tt}$

s = drawdown [L]

Q= pumping rate [L^3/T]

T = transmissivity [L^2/T]

r = radius from well [L]

S = storativity [dimensionless]

t = time [T]

The 20-year safe yield (Q_{20}) or theoretical pumping rate at which a well could be pumped for 20 years without exceeding the available drawdown in the aquifer, is used as an analogue for aquifer productive capacity in Alberta. The Q_{20} as derived by Farvolden (1959) is:

Equation 2.

$$Q_{20} = (0.68)(T)(H_A)(F_S)$$

Where:

H_A = available drawdown (L)
F_S = safety factor

For this interpretation, a safety factor of 0.7 (70%) is used. The available drawdown for a confined aquifer is the difference between the hydraulic head in the aquifer and the top of the aquifer.

Assuming that the aquifer transmissivity does not change significantly due to drawdown, the predicted percent change in aquifer productivity (%AP) due to a change in hydraulic head (Δs) in the aquifer can be estimated as:

Equation 3.

$$\%AP = \frac{\Delta s}{H_A} * 100$$

2.2.2 <u>Assessment of Impact Due to Steam Injection</u>

The injection of high temperature steam into the wells will result in an increase in the temperature of the sediments and groundwater near the well bores. An increase in the temperature of the sediment and groundwater may increase the solubility of some minerals which occur naturally in the bedrock and unconsolidated sediments. Consequently, the liberation of some minerals may occur within the thermal plume.

For the purpose of this assessment, it was assumed that heat transport in the vicinity of the well bore can be described solely by the principles of conduction and forced convection (advection). The potential extent and magnitude of temperature change downgradient of the well bore can be described by the one dimensional conduction-convection equation:

Equation 4.

$$\frac{\partial}{\partial \times}\left(K_e \frac{\partial T}{\partial \times}\right) - \left(n\, \rho_w\, c_w\, V_x \frac{\partial T}{\partial x}\right) = \rho'\, c' \frac{\partial T}{\partial t}$$

Where:

x = principal component of space in the direction of maximum groundwater flow (L);
T = temperature (T);
K_e = effective thermal conductivity (E/(LTt));
n = porosity (%);
ρ_w = density of water (M/L^3);
c_w = specific heat capacity of water (E/(MT));
ρ' = density of rock and water (M/L^3);
c' = specific heat capacity of rock and water (E/(MT)); and
V_x = groundwater velocity in the direction of maximum groundwater flow (L/T).

For this assessment the following was assumed:

- the typical life-span of a production chamber and steam injection well is 7 years;
- the initial formation temperature is 6°C;
- the temperature of the steam in the well bore is 242°C;
- the temperature at the edge of the wellbore is equal to the temperature of the steam (242°C);
- specific heat capacities of the assessed formations were based on Dominico and Schwartz (1997; page 324):
  - Undifferentiated Overburden Aquifer/Aquitard – 220 cal/kg.°C
  - Lower Grand Rapids Aquifer – 192 cal/kg.°C

- thermal conductivity of the assessed formations were based on Dominico and Schwartz (1997; page 321):
  - Undifferentiated Overburden Aquifer/Aquitard – 0.3 cal/m.sec.°C
  - Lower Grand Rapids Aquifer – 0.9 cal/m.sec.°C
- representative groundwater flow velocities for the Undifferentiated Overburden Aquifer/Aquitard and Lower Grand Rapids Aquifer were calculated based on observed gradients and hydraulic conductivities.
  - Undifferentiated Overburden Aquifer/Aquitard – 1×10^{-8} m/s
  - Lower Grand Rapids Aquifer – 6×10^{-8} m/s

A finite difference approximation to this one dimensional equation was then solved in order to obtain a conservative estimate of temperature change downgradient of the well bore. The potential impacts were interpreted in terms of the proximity or predicted temperature changes to potential receptors.

3.0 BASELINE ASSESSMENT

3.1 Geology

Underlying the study area at approximately 420 to 450 metres below sea level (mbsl) is Precambrian crystalline basement which is unconformably overlain by Devonian, Cretaceous and Quaternary Period sediments. As presented in the stratigraphic/hydrostratigraphic column (Figure 3) the Devonian is separated into the Elk Point, Beaverhill Lake and Woodbend Groups. The sub-Cretaceous unconformity separates the Devonian deposits from the Cretaceous Period clastic sediments. The Cretaceous sediments consist of the Mannville and the Colorado Groups. Unconsolidated Quaternary sediments are unconformably deposited on Cretaceous bedrock. A Quaternary Channel, named the Birch Channel, has incised into the Cretaceous bedrock and is a prominent feature of the Quaternary geology and the top of bedrock surface in the region.

Regionally, the Precambrian basement and the Devonian sediments dip to the southwest at slopes of 3 to 5 m/km and 1 to 5 m/km, respectively (Bachu et al., 1993). Cretaceous sediments in the region also dip to the southwest at approximately 2 m/km (Bachu et al., 1993).

Based on detailed correlation, the uppermost bedrock units in the region include the La Biche Formation, the Viking Formation, the Joli Fou Formation, the Grand Rapids Formation and the Clearwater Formation (Figure 4). East of the study area, the McMurray and Waterways formations subcrop below the Quaternary sediments in the Athabasca River Valley (AGS, 1999).

3.1.1 Elk Point Group

The study area overlies a ridge of Precambrian basement that extends eastward from the Peace River Arch to Manitoba and Ontario where it outcrops as the Precambrian Shield. This ridge divides the Cold Lake salt basin into two parts. Mossop and Shetsen (1994) noted that on the ridge, the Contact Rapids Formation forms the lowermost Paleozoic sediments in the study area. The Elk Point Group, in the study area consists of a succession of clastic, carbonate and evaporitic units of the Contact Rapids, Keg River, Muskeg-Prairie and Watt Mountain Formations.

3.1.1.1 *Contact Rapids Formation*

The Contact Rapids Formation is an interbedded argillaceous dolostone and shale deposit. The top of the formation ranges from 369 to 392 mbsl and is approximately 25 m in thickness.

3.1.1.2 *Keg River Formation*

The Keg River Formation consists of reef and off-reef carbonate deposits. Within the study area, there are three wells that penetrate the Keg River Formation. Two of these wells, 00/06-13-091-18W4/00 and 00/10-16-091-18W4/00, encountered reefal carbonates ranging in thickness from 58 to 64 m. The third well, 00/10-34-091-18W4/00, was located approximately 5 km away and encountered an off-reef carbonate which is 16 m thick. The relatively close proximity of these three wells is indicative of the local nature of the reefal build-ups. The top of the Keg River Formation in these wells ranges from 306 to 352 mbsl.

3.1.1.3 *Prairie-Muskeg Formation*

The Keg River Formation reefs are enclosed and overlain in the study area by the salt (halite) deposits of the Prairie Formation. A thin anhydrite Muskeg Formation deposit also likely exists. The top of the Prairie-Muskeg Formation occurs from 83 to 107 mbsl in the study area and the entire succession reaches a maximum thickness of 269 m.

3.1.1.4 *Watt Mountain Formation*

The Watt Mountain Formation is a dolomitic shale that is approximately 13 m thick in the study area. The top of the formation occurs between 69 and 94 mbsl.

3.1.2 Beaverhill Lake Group

The Beaverhill Lake Group is interpreted by Hitchon et al. (1989) to represent a “major back-stepping and onlap of shallow marine carbonate platforms” (and associated sediments) “toward the interior of the continent”. Within the study area, the Beaverhill Lake Group consists of evaporite, carbonate and, alternating calcareous shale and carbonates of the Fort Vermillion, Slave Point and Waterways Formations, respectively.

3.1.2.1 *Fort Vermilion Formation*

The Fort Vermilion Formation is an anhydrite deposit that is approximately 10 m thick in the study area. The top of the formation occurs between 58 and 82 mbsl.

3.1.2.2 *Slave Point Formation*

The Slave Point Formation is a limestone deposit. The top of the formation occurs between 49 and 75 mbsl and is less than 10 m thick in the study area.

3.1.2.3 *Waterways Formation*

The Waterways Formation comprises alternating calcareous shale and carbonate units that are separated into the Firebag, Calumet, Christina, Moberly and Mildred Lake Members. The top of the formation occurs between 124 and 152 masl in the study area and ranges from 49 to 103 m in thickness.

3.1.3 Woodbend Group

The Woodbend Group is the uppermost Devonian Period unit within the study area and consists of the Cooking Lake, Ireton, Leduc and Grosmont formations. The lower Ireton is a limy shale partially contemporaneous with and separating the Grosmont and Cooking Lake Formations which are two stacked carbonate platforms (Bachu et al., 1993). The Leduc Formation is a reef buildup on the Cooking Lake Formation and therefore, it is difficult to differentiate the top of the Cooking Lake from the Leduc.

The Grosmont Formation is a westerly prograding carbonate platform and is the uppermost unit of the Woodbend Group. The Grosmont Formation was identified in seven of the twelve geophysical logs and appears to be restricted to the southwestern portion of the study area in Townships 91 and 92 in Range 19 (Figure 5). The location of the interpreted zero edge of the Grosmont Formation is consistent with that presented by Bachu et al. (1993) and trends in a northwest-southeast direction. Regionally, the Grosmont thickens west of the study area. The top of the formation occurs between 260 and 291 masl in the study area and ranges in thickness from 7 to 45 m.

3.1.4 Mannville Group

The Mannville Group unconformably lies on the sub-Cretaceous unconformity and consists of the McMurray, Clearwater and Grand Rapids Formations. Regionally, paleotopography on the sub-Cretaceous unconformity, sediment supply and variations in sea level affected the deposition of the Mannville Group (Bachu et al., 1993). The elevations, thicknesses and trends discussed in the following sections are based on the analysis of available logs in the study area. The Mannville Group is also illustrated in cross-section A-A’ (Figure 6) which transects the study area in a northwest-southeast direction (Figure 1).

3.1.4.1 *McMurray Formation*

The McMurray Formation is generally a sand dominated unit and, where present in the study area, is primarily bitumen and/or gas saturated. The EUB (2003), Flach (1984) and Wightman et al. (1995) indicate that the McMurray Formation ranges in thickness from 0 to approximately 30 m in the study area. According to Flach (1983) and Bachu et al. (1993), the top of the McMurray Formation occurs at approximately 300 masl in the study area.

3.1.4.2 *Clearwater Formation*

The basal unit of the Clearwater Formation is the Wabiskaw Member. Regionally, the Wabiskaw Member consists primarily of sandy to silty shales with some clean sand buildups (Bachu et al., 1993). The EUB (2003) indicates that Wabiskaw sands can be greater than 40 m thick (inclusive of the Wabiskaw D, C and A sands). Within the study area, the Wabiskaw Member primarily consists of sand with an average thickness of 40 m and is typically bitumen and/or gas saturated. The top of the Wabiskaw (Figure 7) occurs between 325 and 290 masl and dips gently to the northwest.

Above the Wabiskaw Member, the remainder of the Clearwater Formation is generally comprised of silt and shale. However, in the southeast corner of the study area, the unit becomes sandier where developments of up to approximately 5 m of sand exist. This is consistent with Bachu et al. (1993). The top of the Clearwater is distinguished by a shale unit and an associated characteristic resistivity decrease which can be regionally correlated. As illustrated in Figure 8, the top of the Clearwater Formation occurs between 413 and 351 masl and dips to the northwest. The incised channel feature in the southeast portion of the study area is interpreted to be the result of Quaternary erosion into the Clearwater by the Birch Channel (Figures 4 and 6). The Birch Channel is discussed in more detail in Section 3.1.6.

The top of the Clearwater to top of the Wabiskaw isopach is relatively consistent outside the area of the Birch Channel and ranges from 76 to 95 m thick.

3.1.4.3 *Grand Rapids Formation*

The Grand Rapids Formation is interpreted to represent a regional regressional sequence as the Clearwater Sea withdrew to the north and northwest (Bachu et al., 1993). Regionally, the Grand Rapids Formation interfingers with the Clearwater Formation and generally is comprised of coarsening-upward sequences that are separated by shales and silty beds. In the study area, two sand packages, the Lower and Upper Grand Rapids were identified and are interpreted to represent shoreface to shallow marine depositional environments due to the further basinward location of the study area and the spatial distribution of these sands. The Grand Rapids Formation is present throughout the study area, subcropping below Quaternary deposits in the southeast (Figure 4), with the exception of where it has been completely eroded by the Birch Channel (Figures 4 and 6).

Where present, the top of the Lower Grand Rapids sand occurs between 389 and 439 masl and dips towards the northwest (Figure 9). The steeper relative northwest dip that transects the study area along a northeast-southwest strike direction is primarily a function of the abrupt thinning of the sand unit further basinward (Figure 9). As presented in the net sand isopach map (Figure 10), the sands of the Lower Grand Rapids in the study area have a maximum thickness of 25 m and thin to 0 m in the northwest.

The top of the Upper Grand Rapids sand occurs between 412 and 455 masl where present in the study area and also dips to the northwest (Figure 11). The sands of the Upper Grand Rapids range in thickness from 0 to 18 m as presented in the net sand isopach map (Figure 12).

3.1.5 Colorado Group

The Colorado Group generally consists of thick successions of shale deposited in an overall regional transgression with some sand developments (Bachu et al., 1993). Within the study area, the Colorado Group consists of the Joli Fou, Viking and La Biche Formations.

3.1.5.1 *Joli Fou Formation*

The Joli Fou Formation is a marine shale unit with some basal sandstone in areas (Bachu et al., 1993). The formation subcrops in the southeastern portion of the study area and has been eroded within the Birch Channel (Figure 4). In most of the well logs the Joli Fou Formation occurs above the surface casing. Where identified in well logs, the Joli Fou Formation occurs between 433 and 470 masl and ranges in thickness from 11 to 23 m.

3.1.5.2 *Viking Formation*

The Viking Formation consists of a coarsening upwards sandstone unit (Bachu et al., 1993). The Viking Formation is interpreted to be absent in the southwest portion of the study area (Figures 4 and 6). Similar to the Joli Fou Formation, the Viking Formation typically occurs within the cased interval of the well logs. Northwest of the study area, the Viking can reach thicknesses of up to 40 m.

3.1.5.3 *La Biche Formation*

The La Biche Formation is a thick marine shale succession that contains the Fish Scale Zone, the Second White Speckled Shale and First White Speckled Shale marker horizons. The La Biche Formation is present in the north and west portions of the study area (Figures 4 and 6).

3.1.6 Quaternary Deposits

Outside of the Birch Channel, the Pleistocene glacial deposits are expected to be mainly comprised of clayey till with local deposits of sand and gravel. However, the spatial extent and continuity of specific units within the glacial deposits is largely unknown. Undifferentiated glacial deposits extend across the study area and range in thickness from approximately 5 m in the northwest portion of the study area to 70 m in the Birch Channel (Andriashek, 2001).

The Birch Channel was identified in wells located at AA/10-08-091-17W4/0, 00/10-29-91-17W4/00, 00/15-01-092-17W4/00, 00/16-27-092-16W4/00, AA/06-16-92-16W4/00 and AA/06-21-92-16W4/00. This is generally consistent with public literature (Andriashek, 2001); however wells AA/06-16-92-16W4/00 and AA/06-21-92-16W4/00 were not available at the time of the Andriashek (2001) publication and consequently there is a difference in the interpretation of the location of the channel from that of Andriashek's (2001) interpretation in Township 92 Range 16

W4M. It should be noted that, because of the limited site data and the narrow nature of these channels, it is possible that more than one channel is present within the study area.

The Birch Channel is interpreted to be present in the southeast corner of the study area and is deeply incised through the Grand Rapids Formation into the Clearwater Formation as shown in the Cretaceous sub-crop map (Figure 4) and cross-section A-A' (Figure 6). The channel is approximately 27.5 km in length in the study area. Andriashek and Atkinson (2007) have interpreted the channel to have formed through erosion by subglacial melt water. The channel has a low width to depth ratio and the elevation of the channel thalweg is interpreted to be nearly flat (Andriashek and Atkinson, 2007). Within the channel, the basal sands and gravel can be greater than 50 m thick and, according to the definition presented by Andriashek (2001), is referred to as the Empress Formation (Figure 6).

3.2 Hydrogeology

The geologic units were divided into 19 hydrostratigraphic units based on the interpreted relative permeability, thickness and mapped/expected continuity. The hydrostratigraphic column is presented in Figure 3 and is generally consistent with that presented by Bachu et al. (1993).

3.2.1 Undifferentiated Overburden Aquifer/Aquitard

For the purposes of this assessment, the Undifferentiated Overburden Aquifer/Aquitard refers to all sediments overlying the sand and gravel of the Empress Formation within the Birch Channel and overlying Cretaceous bedrock outside of the Birch Channel. The dominant lithology of the Undifferentiated Overburden Aquifer/Aquitard is expected to be clayey till with local deposits of sand and gravel.

Based on observed water levels in the shallow water wells (Table 1) and the abundance of wetlands and small lakes in this area, the groundwater table is expected to be near the ground surface. Some shallow groundwater discharges to springs and surface water bodies and some groundwater recharges the underlying bedrock aquifers. Shallow groundwater flow is more or less a muted representation of surface topography (Figure 13). As such, shallow groundwater in the Undifferentiated Overburden Aquifer/Aquitard flows toward surface drainage features such as the Dover, Dunkirk and Mackay rivers and their tributaries (Figure 13).

Available groundwater chemistry results are included in Tables 2 and 3. Regionally, Ozoray (1974) noted that major anions and cations evolve from a calcium-bicarbonate ($CaHCO_3$) type water in the shallow overburden to a sodium bicarbonate ($NaHCO_3$) type in the deeper overburden deposits. Locally, chemistry results from one well (Well ID 279598) located at NW-31-094-18 W4M, indicate that groundwater within the Undifferentiated Overburden Aquifer/Aquitard is a calcium-sulphate ($CaSO_4$) type (Figure 15).

The hydraulic conductivity of the Undifferentiated Overburden Aquifer/Aquitard is expected to be variable. The hydraulic conductivity of a sand and gravel unit within the Undifferentiated Overburden Aquifer/Aquitard located at 01-27-091-19 W4M was estimated to be at least 2.8×10^{-6} m/s based on pumping test results reported on the water well drilling report (Well ID 0292382). Details of the pumping test analysis are outlined in Attachment D. It should be noted that this hydraulic conductivity value is biased towards coarse grained sediments of the Undifferentiated Overburden Aquifer/Aquitard. Fine grained sediments of the Undifferentiated Overburden Aquifer/Aquitard such as the clayey till are expected to have hydraulic conductivity values several orders of magnitude lower than that of the sand and gravel units.

3.2.2 Empress Channel Aquifer

Within the Birch Channel, sand and gravel of the Empress Formation is present and can be up to 50 m thick (Figure 6). These deposits are referred to as the Empress Channel Aquifer for the purposes of this assessment. Based on pumping tests and production rates from wells completed in similar aquifers throughout the Athabasca Oil Sands region, the per well deliverability within the Empress Channel Aquifer can exceed 1,000 m^3/day. Groundwater chemistry results are not available within the study area. However, Petro-Canada (2007) has estimated the TDS concentration in the Empress Channel Aquifer (Birch Channel) to range from 100 to 1,000 mg/L based on results at their Mackay River SAGD Project east of the study area.

3.2.3 La Biche Aquitard

The marine shales of the Colorado Group La Biche Formation are referred to as the La Biche Aquitard. Hydraulic head values are unavailable for the La Biche Aquitard in the study area but it is expected that groundwater flow is predominantly vertical into the underlying deposits.

3.2.4 Viking Aquifer

Where identified in the northwest of the study area, the Viking Aquifer is greater than 30 m thick. Chemistry and hydraulic head data are not available within or in the vicinity of the study area. It is expected that TDS concentrations within the Viking Aquifer are less than 4,000 mg/L. Bachu et al. (1993) and Hitchon et al. (1989) both published regional data sets of hydraulic conductivity measurements from drill stem test (DST) and core analyses. Representative Viking Aquifer hydraulic conductivity values from those data sets range from 7×10^{-6} to 2×10^{-7} m/s.

3.2.5 Joli Fou Aquitard

The marine shales of the Colorado Group Joli Fou Formation are referred to as the Joli Fou Aquitard. Hydraulic head values are unavailable for the Joli Fou Aquitard in the study area but it is expected that groundwater flow is directed downwards into the underlying Grand Rapids Aquifers.

3.2.6 Grand Rapids

For the purposes of this study, the Grand Rapids Formation was divided into three hydrostratigraphic units: the Grand Rapids Aquifer/Aquitard, the Upper Grand Rapids Aquifer, and the Lower Grand Rapids Aquifer (Figures 3 and 6). The two coarsening upwards sand successions of the Grand Rapids are referred to as the Upper Grand Rapids Aquifer and the Lower Grand Rapids Aquifer. Both aquifers are completely eroded within the Birch Channel in the southeast portion of the study area (Figures 4 and 6). Interbedded silt and shale deposits that occur above and below the Upper and Lower Grand Rapids aquifers are referred to as the Grand Rapids Aquifer/Aquitard.

In the study area, the Upper Grand Rapids Aquifer ranges in thickness from 0 to 18 m. There are no chemistry or hydraulic head data available for the Upper Grand Rapids Aquifer within the study area.

The Lower Grand Rapids Aquifer is up to 27 m thick in the study area and is the proposed water source for steam generation for the project. Available Lower Grand Rapids Aquifer hydraulic head values are posted and contoured on Figure 14 and indicate that horizontal groundwater flow is directed east and southeast towards the Athabasca River where the Lower Grand Rapids Aquifer outcrops and discharges within the Athabasca River valley. Lower Grand Rapids Aquifer groundwater chemistry samples collected at 01-23-093-17 W4M are included in Tables 4, 5, 6 and 7 and indicate that the groundwater is a sodium-bicarbonate type (Figure 15) with a TDS concentration of approximately 1,320 mg/L.

Based on recovery data from pumping tests conducted at 10-29-092-17W4M and 01-23-093-17W4M and using the Theis Method (1935), the hydraulic conductivity of the aquifer was estimated to range from 6.7×10^{-6} to 1×10^{-5} m/s. Details of the pumping test analyses are included in Attachment D.

3.2.7 Clearwater Aquifer/Aquitard

As discussed in Section 3.1.4.2, the upper portion of the Clearwater Formation is primarily a shale/silt dominated unit with some thin sand developments. As such, this portion of the Clearwater is referred to as the Clearwater Aquifer/Aquitard. Shale units within the Clearwater Formation trap oil/gas accumulations within the region and are “regionally significant barrier(s) to flow” (Bachu et al., 1993). South of the study area, thick sand developments exist which are regionally extensive and have a higher relative hydraulic conductivity (Bachu et al., 1993).

3.2.8 Wabiskaw Aquifer/Bitumen Aquitard

On a regional scale, the Wabiskaw sands may be primarily water saturated in some areas; however, within the study area, the Wabiskaw sands are primarily bitumen and/or gas saturated. The bitumen saturated sands are likely to have a low hydraulic conductivity and are therefore referred to as the Wabiskaw Bitumen Aquitard. Thick, primarily water saturated portions of the Wabiskaw (Wabiskaw Aquifer) were not specifically identified within the study area.

Although thick water sand portions of the Wabiskaw Member were not identified in the study area, gas associated water analyses were obtained from DSTs within the study area. Available representative water analyses indicate that the Wabiskaw groundwater is a sodium-chloride bicarbonate ($Na\text{-}ClHCO_3$) type (Figure 15; Table 8) with TDS concentrations ranging from 3,671 to 7,417 mg/L. According to Bachu et al. (1993) groundwater flow is directed east towards the Athabasca River where the unit outcrops within the Athabasca River valley.

3.2.9 McMurray Aquifer/Bitumen Aquitard

Where present, the McMurray sands are primarily bitumen saturated and are considered to be an aquitard. Regionally, the base of the McMurray can be water saturated, however, within the study area, water saturated portions of the McMurray sands (McMurray Aquifer) were only identified approximately 15 km away, in Township 91, Range 16 W4M, and were relatively thin (typically less than 10 m) and discontinuous. The McMurray Aquifer was identified in wells 00/07-34-091-16W4/0, 00/08-27-091-16W4/3, AA/10-11-091-16W4/0 and 00/08-22-091-16W4/0. At these locations, the McMurray Aquifer was in direct contact with the bitumen saturated sands. The limited extent and thickness of the McMurray Aquifer is consistent with that presented by Wightman et al. (1995) and Flach (1984). Due to the discontinuous nature of this aquifer, its limited thickness, its distance from the CPF and possible pressure interactions with bitumen present in the formation, the McMurray Aquifer is not proposed to be utilized as a source or disposal zone for the Dover Central Pilot Project.

Bachu et al. (1993) estimates that the TDS concentration in the McMurray-Wabiskaw Aquifer system is approximately 5,000 mg/L and according to Hackbarth and Natasa (1979) the TDS concentration of the McMurray ranges from approximately 7,500 to 10,000 mg/L. At the Petro-Canada MacKay River Project (2005), TDS concentrations range from approximately 32,000 to 36,500 mg/L. Available representative water analyses indicate that the McMurray groundwater is a sodium-chloride bicarbonate type (Figure 15; Table 8) with TDS concentrations ranging from 4,200 to 6,624 mg/L. The water type and range in TDS concentrations are consistent with Bachu et al. (1993).

Hydraulic head values in the study area are expected to be approximately 425 masl (Hackbarth and Nastasa, 1979) and likely decreases to the southeast as the unit outcrops and discharges within the Athabasca River Valley.

3.2.10 Grosmont Aquifer

The Grosmont Aquifer is only present in the southwest of the study area and at least 18 km from the Central Processing Facility. The Grosmont is known to contain economic accumulations of gas in the study area. Due its distance from the CPF and potential pressure interactions with existing petroleum and natural gas producers, the Grosmont Aquifer is not proposed to be utilized as a source or disposal zone for the Dover Central Pilot Project.

According to Bachu et al. (1993), the TDS concentration of the formation waters regionally ranges from 10,000 to 70,000 mg/L. Within the study area, Bachu et al. (1993) suggests that the TDS concentration of the unit is approximately 10,000 mg/L and Hackbarth and Nastasa (1979) suggest that the TDS concentration of the Grosmont ranges from 5,000 to 10,000 mg/L. In the southwest of the study area, one water analyses was deemed to be representative and had a TDS concentration of 9,646 mg/L (Table 8) and is generally consistent with Bachu et al. (1993) and Hackbarth and Nastasa (1979). The water sample at this location suggests that groundwater in the Grosmont Formation is a sodium-chloride bicarbonate type (Figure 15; Table 8).

Hydraulic head values within the study area are estimated to be approximately 375 masl (Bachu et al., 1993). It is postulated by Bachu et al. (1993) that overlying aquifers discharge into the Grosmont and groundwater flow is towards the northwest where the Grosmont Formation outcrops and discharges in the Peace River Valley. Considering the presence of gas within the unit and the flow rates that were measured in the production tests, the unit is expected to have a relatively high permeability.

3.2.11 Ireton Aquitard

The Ireton Formation is considered to be a strong barrier to flow by both Bachu et al. (1993) and Hitchon et al. (1990) and is referred to as the Ireton Aquitard for the purposes of this study. The Ireton Aquitard is thought to be present in the study area based on available geophysical logs. However, as it could not be correlated with confidence due to the paucity of data, the thickness and extent of this aquitard is unknown.

3.2.12 Leduc/Cooking Lake/Beaverhill Lake Aquifer/Aquitard

The Leduc/Cooking Lake/Beaverhill Lake Aquifer/Aquitard system is present beneath the study area. Hydraulic heads in the study area range from 350 to 500 masl as mapped by Bachu et al. (1993) and groundwater flow is to the southeast towards the Athabasca River. The TDS concentration in the study area ranges between 20,000 and 40,000 mg/L (Bachu et al., 1993).

3.2.13 Watt Mountain Aquitard

The Watt Mountain Aquitard is present beneath the study area and is considered a weak aquitard. This becomes apparent where the Prairie-Muskeg Aquiclude is absent east of the study area (Bachu et al., 1993).

3.2.14 Prairie-Muskeg Aquiclude

Evaporitic salts of the Prairie-Muskeg Formations are present beneath the study area and are referred to as the Prairie-Muskeg Aquiclude. Hitchon et al. (1990) and Bachu et al. (1993) consider the Prairie-Muskeg succession to be a significant barrier to flow based on formation water analyses and hydraulic head distributions above and below the Prairie-Muskeg evaporites.

3.2.15 Keg River Aquifer

Permeable zones within the Keg River Formation are interpreted to be primarily constrained to reefal build-ups. Within the study area, both reef and off-reef carbonates have been identified with geophysical logs. However, it must be noted that the on-reef carbonates identified at 00/06-13-091-18W4/00 and 00/10-16-091-18W4/00 are not necessarily connected and consequently the aquifer may not be laterally extensive. On-reef carbonates of the Keg River have not been identified below the proposed CPF. The wells with on-reef Keg River carbonates are located at least 25 km south of the proposed CPF.

The Keg River Aquifer occurs below an evaporitic salt and therefore, has relatively high TDS concentrations. Bachu et al. (1993) suggests that the TDS concentration of the Keg River Aquifer within the study area is approximately 250,000 mg/L. Available TDS concentrations within the study area are consistent with Bachu et al. (1993) and range from 153,425 to 221,921 mg/L. However, none of the available water analyses from the Keg River were accepted after the culling process due to parameter incompleteness or evidence of sample contamination. Like the Grosmont Formation, the Keg River Aquifer contains accumulations of gas. Given the flow rate of the production test at the 00/06-13-091-18W4/00 well, the unit is expected to have a relatively high permeability at that location.

3.3 Local Water Users

The AENV GIC water well search identified 26 water wells registered in the study area. The locations of these wells are illustrated on Figure 16 and the completion details are listed in Table 1. The accompanying drilling reports are also included in Attachment C. Seventeen of the wells were for industrial use, eight were for domestic use and one was for observation purposes. Fourteen of the wells listed as industrial wells had completion depths greater than 300 metres below ground surface (mbgs). The “type of work” listed for these wells was for oil exploratory or DST purposes. It is interpreted that these wells were likely not intended for use as water wells. For all remaining wells, the total depth ranged from approximately 30 to 152 mbgs. The closest domestic water well to the proposed CPF is located 11 km to the southwest and is reported to be completed in an overburden aquifer.

Based on the total depths of the reported water wells, three registered water wells were interpreted to be completed in the Lower Grand Rapids Aquifer. The well location listed on each of these three drilling reports is 10-29-092-17 W4M, located 12 km south of the CPF and 9 km southwest of the AOSC Lower Grand Rapids Aquifer well. One well (Well ID 279905) is listed as an observation well and two wells (Well ID 0243283 and Well ID 0279904) are listed as industrial water wells. These two industrial wells were drilled to total depths of 102.7 m bgs (Well ID 0243283) and 105.5 m bgs (Well ID 0279904).

There is currently one existing groundwater diversion licence in the study area (licence # 00026507-00-00; Table 9). The groundwater diversion licence is associated with a water well located at 13-09-093-18 W4M (Well ID 150681), completed in an overburden aquifer. The licensed groundwater withdrawal rate is 75 m^3/day. There are no existing Lower Grand Rapids Aquifer groundwater diversion licenses.

4.0 IMPACT ASSESSMENT

The potential mechanisms for the Project to impact groundwater resources have been identified and are evaluated in this section. These mechanisms are:

- surface facility operations;
- groundwater withdrawal; and
- steam injection.

4.1 Operation of Surface Facilities

Accidental releases from surface facilities such as tanks, buildings and well casings have the potential to negatively impact groundwater quality. The potential risk to receptors will be dependent upon the location of the release, the volume of release, the duration of the release, the nature of the materials released and the subsurface hydraulic conditions (e.g., depth to groundwater, groundwater flow velocity and adsorption capacity of the soil).

As described in Section 3.2.1, the dominant lithology in the shallow subsurface is interpreted to be clayey till, which is expected to have a relatively low hydraulic conductivity. The closest water well to the Project completed in the Undifferentiated Overburden Aquifer/Aquitard, is approximately 11 km southwest of the CPF. Given the low hydraulic conductivity of the Undifferentiated Overburden Aquifer/Aquitard and the relatively large distance to the closest well, an accidental release would pose little threat to local groundwater users.

Potential impacts to groundwater quality will be mitigated through prevention and early detection. Industry standards and best management practices will be adhered to when designing, constructing and operating Project facilities. In addition, groundwater monitoring will be implemented to ensure early detection of potential Project related impacts to groundwater quality (Section 5.1).

As a result of the mitigative measures, groundwater monitoring, and the large distance to existing local groundwater wells, the potential impact to groundwater quality due to the operation of surface facilities is considered low.

4.2 Groundwater Withdrawal

4.2.1 Lower Grand Rapids Aquifer

Groundwater will be sourced from the Lower Grand Rapids Aquifer for the purpose of steam generation. The water withdrawal requirements will change temporally, as outlined in Section 1.1 and presented in Figure 2. Project related groundwater withdrawal rates in the initial start-up phase are projected to be 1,275 m^3/day. The long term average withdrawal rate is projected to be 75 m^3/day.

Withdrawal of groundwater from the Lower Grand Rapids Aquifer will decrease hydraulic heads in the vicinity of the supply wells, thus decreasing aquifer productivity. To evaluate the magnitude of these changes, the methods of Theis (1935; Section 2.2.1) were used to predict the aquifer response to pumping. Although a network of wells will be required during the start-up phase of the Project, for the purpose of assessing the spatial extent of water level changes in the Lower Grand Rapids Aquifer, one pumping center at 01-23-093-17 W4M was used. Upon the completion and testing of the additional well(s), a *Water Act* application will be submitted in accordance with the *Water Conservation and Allocation Guideline for Oilfield Injection* and the *Groundwater Evaluation Guideline.* Parameters derived from the 01-23-093-17 W4M pumping test (Attachment D.3) were assumed to be representative of the Lower Grand Rapids Aquifer and include:

- an aquifer thickness of 26 m;
- an available head of 58.5 m;
- a hydraulic conductivity of 6.7×10^{-6} m/s; and
- a specific storage of 3.9×10^{-6} m^{-1}.

The predicted drawdown in the Lower Grand Rapids Aquifer 1 km from the pumping centre for a period of 18 years from 2010 to 2028 is presented in Figure 17. The predicted drawdown in the Lower Grand Rapids Aquifer at the end of July 2010, March 2011, September 2012 and at the end of the Project life (end of June 2017) are presented in Figures 18 through to 21. The points in time for which each of the drawdown maps were generated are highlighted on Figure 17.

Drawdowns are predicted to propagate radially away from the pumping centre over time resulting in a maximum magnitude of drawdown at the end of July 2010 when the water withdrawal rate is 1,275 m^3/day (Figure 17). The magnitude of drawdown then decreases as the withdrawal rates are projected to decrease. Water levels are ultimately predicted to recover following the cessation of pumping at the end of June 2017 (Figure 17).

The lateral propagation of drawdown is expected to expand and contract following changes in the pumping rate (Figures 18 to 21). The maximum extent of the 5 m contour is 4.1 km from the pumped well and is predicted to occur at the end of March 2011. The drawdown at the existing Lower Grand Rapids Aquifer wells in 10-29-092-17 W4M is predicted to be less than 5 m for the duration of the Project. There are no groundwater diversion licences associated with these (or other wells) in the Lower Grand Rapids Aquifer in the study area.

Using Equation 3 (Section 2.1.1), the decrease in aquifer productivity can be predicted. A water level decrease of 5 m corresponds to a decrease in aquifer productivity of less than 10%. A decrease in aquifer productivity of less than 10% may be detectable; however, potential conflicts with existing or future users would likely not result and the magnitude of impact is ultimately considered low.

4.2.2 Shallow Aquifers and Surface Water Bodies

Theoretically, groundwater withdrawal from deeper sediments has the potential to increase the vertical flux of groundwater from shallower sediments and decrease water levels in shallow overburden aquifers and surface water bodies. In the vicinity of the planned source wells, the Lower Grand Rapids Aquifer occurs at a depth of approximately 80 mbgs. The low permeability sediments that separate the top of the Lower Grand Rapids Aquifer from shallow overburden aquifers and surface water bodies include those of the Grand Rapids Aquifer/Aquitard, Joli Fou Aquitard and the Undifferentiated Overburden Aquifer/Aquitard that are predominantly fine grained (silt/clay). These fine grained low permeability sediments will mitigate water level decreases in the Lower Grand Rapids Aquifer from propagating vertically and affecting water levels in shallow overburden aquifers and surface water bodies. Water levels changes in shallow overburden aquifers and surface water bodies due to groundwater withdrawal from the Lower Grand Rapids Aquifer are expected to be less than detectable.

The Birch Channel is located approximately 11 km away from the pumping centre and is interpreted to be in contact with the Lower Grand Rapids Aquifer (Figure 6). The furthest the 5 m drawdown contour is predicted to propagate away from the pumping centre is 4.1 km and occurs at the end of March 2011. At this time the theoretical drawdown in the Lower Grand Rapids Aquifer adjacent to the Birch Channel is less than 1 m. A drawdown of this magnitude is considered to represent a low impact.

4.3 Steam Injection

The in-situ thermal recovery process involves the injection of steam into the bitumen reservoir to improve the mobility of the bitumen. The steam is produced at surface and injected into the bitumen reservoir through steel well casings drilled to depth. The Project proposes to inject steam at a temperature of 242°C.

Project operations may affect the thermal regime of subsurface aquifers because the steam temperature far exceeds the ambient temperature of groundwater in the aquifers through which the wells are drilled. High temperature steam in the well bore will result in the development of a heat plume in the vicinity of the well bores. Under baseline conditions, minerals in the groundwater and minerals in the sediments are considered to be in thermodynamic equilibrium. As temperatures in the subsurface increases, mineral solubilities may change and a new thermodynamic equilibrium will be achieved. For some minerals, the solubility will increase resulting in increased concentrations in the pore water of the aquifers and aquitards. However, once temperature conditions return to baseline conditions, the baseline thermodynamic equilibrium should re-establish.

Potential impacts are primarily considered for those aquifers which are potable or non-saline. Potential effects to the Undifferentiated Overburden Aquifer/Aquitard, the Upper Grand Rapids Aquifer and the Lower Grand Rapids Aquifer are therefore considered. For the purpose of the assessment, the potential effects to the Upper Grand Rapids Aquifer are considered analogous to those presented for the Lower Grand Rapids Aquifer. It should be noted that the wells are in an area where the Empress Channel Aquifer is not present and therefore steam injection related impacts to this unit are not expected.

As presented in Figure 22, the thermal plume is predicted to extend less than 100 m from the well bores in the Undifferentiated Overburden Aquifer/Aquitard and the Lower Grand Rapids Aquifer following the assessed period of 7 years of steam injection. The variation in the extent of the thermal plume between the Undifferentiated Overburden Aquifer/Aquitard and the Lower Grand Rapids Aquifer (Figure 22) is a result of the contrasting rates of forced convection which is primarily a function of the groundwater flow velocity for that specific formation.

The closest existing domestic water well is located 11 km southwest of the proposed wells. Considering the predicted extent of the thermal plume is less than 100 m, and the distance to existing domestic water wells is large, the impact as a result of steaming is considered low.

5.0 MONITORING

The potential hydrogeologic effects were described with respect to the following project operations:

- surface facility operations;
- groundwater withdrawal; and
- steam injection.

This section describes existing and proposed groundwater monitoring plans for each of the operation components.

5.1 Surface Facilities

A network of groundwater monitoring wells will be installed at the CPF footprint location to establish baseline data for groundwater levels, flow conditions and groundwater quality. Data from the groundwater monitoring program will provide information on:

- geologic and hydrogeologic properties of the shallow Quaternary sediments;
- pre-development groundwater levels and groundwater chemistry; and
- temporal groundwater levels and groundwater quality during project operations.

Groundwater monitoring well networks for the CPF footprint location will primarily focus on the shallowest groundwater-bearing zones and therefore target the most vulnerable hydrostratigraphic unit with respect to potential effects associated with surface facility operations. Monitoring wells will be installed on-site and adjacent to areas exposed to potential sources of accidental releases. At least one on-site monitoring well location will consist of a nested pair with one well completed at the water table and a second monitoring well completed at a depth of approximately 10 mbgs. The deeper well of the nest will provide a measure of the direction and magnitude of the vertical hydraulic gradient and monitor groundwater quality below the water table aquifer. At least one monitoring well will be located hydraulically upgradient of the site to serve as a background (control) well.

Groundwater samples will be collected regularly from each monitoring well and analyzed for field parameters, including temperature, pH, Electrical Conductivity (EC), Dissolved Oxygen (DO) and Oxidation Reduction Potential (ORP). Laboratory analyses may include the indicator parameters, which are based on potential effect to groundwater quality associated with heavy oil facilities, listed below.

Analytical Parameters That May be Used in the Groundwater Monitoring Program

Source of Potential Effect	Routine[(a)]	Dissolved Metals[(b)]	Dissolved Organic Carbon	BTEX, F1 and F2[(c)]	NO_2-NO_3 and NH_4	Phenols
Bitumen	X	---	X	X	---	X
Diluent	X	---	X	X	---	---
Produced Water	X	X	X	X	---	---
Effluent Discharge	X	---	---	---	X	---
Process Chemicals	X	---	X	---	---	---

X Analytical parameter recommended to be included in groundwater monitoring program in vicinity of identified potential source.

--- Analytical parameter not recommended to be included in groundwater monitoring program in vicinity of identified potential source.

(a) Routine water includes EC, pH, total dissolved solids, sodium, potassium, calcium, magnesium, manganese, iron, hydroxide, chloride, carbonate, bicarbonate, sulphate, hardness and alkalinity.

(b) Dissolved metals includes aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, chromium, cobalt, copper, iron, lead, lithium, manganese, molybdenum, nickel, phosphorus, selenium, silicon, strontium, sulphur, thallium, tin, titanium, uranium, vanadium, zinc and zirconium.

(c) BTEX includes benzene, toluene, ethylbenzene and xylenes, F1 includes hydrocarbon fractions C_5-C_{10} and F2 includes hydrocarbon fractions C_{10}-C_{16}.

Should significant changes in groundwater quality be detected, an incident-specific groundwater response plan will be developed and implemented (Section 5.4).

5.2 Groundwater Withdrawal

AOSC will responsibly manage groundwater usage by operating all wells as per the terms and conditions of associated groundwater diversion (Water Act) licenses. In addition, AOSC will responsibly manage the Project groundwater usage by:

- Monitoring actual water usage from the Lower Grand Rapids Aquifer.

- Monitoring water level changes in select aquifers near the groundwater source wells.

- Conducting annual reviews and interpretations of water level and water usage data including a comparison of actual changes in water level compared to the predictions. If necessary, the annual review will include recommendations to further mitigate effects and/or improve monitoring.

5.3 Steam Injection

As described in Section 5.1, a groundwater monitoring program is proposed for the CPF footprint location. The monitoring program will include water levels, temperature, and analysis of major ions and dissolved metals.

5.4 Groundwater Response Plan

If major changes in groundwater quality are detected as a result of Project operations, an incident-specific response plan will be developed and implemented. Aspects of the plan include:

- conducting confirmatory sampling;
- notifying AENV on confirmation of effect; and
- identifying the source(s) of effect.

Once the source(s) of effect have been identified, a site specific risk management strategy based on the nature and concentration of contaminants and potential receptors in the area will be developed. The risk management strategy will be submitted to AENV for approval and may include a site specific remediation plan. The risk management strategy will then be implemented.

6.0 SUMMARY

Based on the description of the Project and the hydrogeological assessment completed for this application, the following summary is presented.

- The Project will consist of production of bitumen at a rate of 318 m^3/d (2,000 bpd).

- The water demand will be variable over the 7 year assessment period and will be met with a network of supply wells completed in the Lower Grand Rapids Aquifer.

- Groundwater flow in the Lower Grand Rapids Aquifer is directed east and southeast towards the Athabasca River where the Lower Grand Rapids Aquifer outcrops and discharges within the Athabasca River valley.

- A 4 hour pumping test was completed on March 11, 2008 by Matrix personnel at the 01-23-093-17W4M/00 well. The well was pumped at a rate of 322 L/min. The hydraulic conductivity of the Lower Grand Rapids Aquifer was determined to be 6.7×10^{-6} m/s. A 72 hour pumping test is planned at this well in 2008/2009.

- Lower Grand Rapids Aquifer chemistry samples collected at 01-23-093-17 W4M indicate that the groundwater is a sodium-bicarbonate type with a TDS concentration of approximately 1,320 mg/L.

- There are 26 water wells registered in the study area. Three of these wells, located at 10-29-092-17 W4M, are interpreted to be completed in the Lower Grand Rapids Aquifer.

- There is currently one existing groundwater diversion licence in the study area associated with a water well completed in an overburden aquifer located 11 km southwest of the CPF.

- A decrease in aquifer productivity of less than 10% is predicted to extend up to 4.1 km from the pumping centre at the end of March 2011. Since the closest existing well completed in the Lower Grand Rapids Aquifer is located 9 km from the pumping center and there are no licensed users of the Lower Grand Rapids Aquifer in the study area, the magnitude of decreased aquifer productivity is ultimately considered low.

- Groundwater removal from the Lower Grand Rapids Aquifer is predicted to have a non-detectable impact on water levels in shallow overburden aquifers and surface water bodies.

- Given the low hydraulic conductivity of the Undifferentiated Overburden Aquifer/Aquitard and the relatively large distance to the closest well, an accidental release would pose little threat to existing local groundwater users.

- Impacts to groundwater quality as a result of steam injection are anticipated to be localized and limited to within 100 m of the wells. These thermal impacts do not represent a threat to existing groundwater users because the nearest groundwater user is 11 km away.

- A groundwater monitoring program will be established to obtain information on the effects of the project operations on groundwater levels and groundwater quality.

- If, through groundwater monitoring, it is established that groundwater quality has been impacted by ongoing operations or an accidental release, a groundwater response plan will be initiated.

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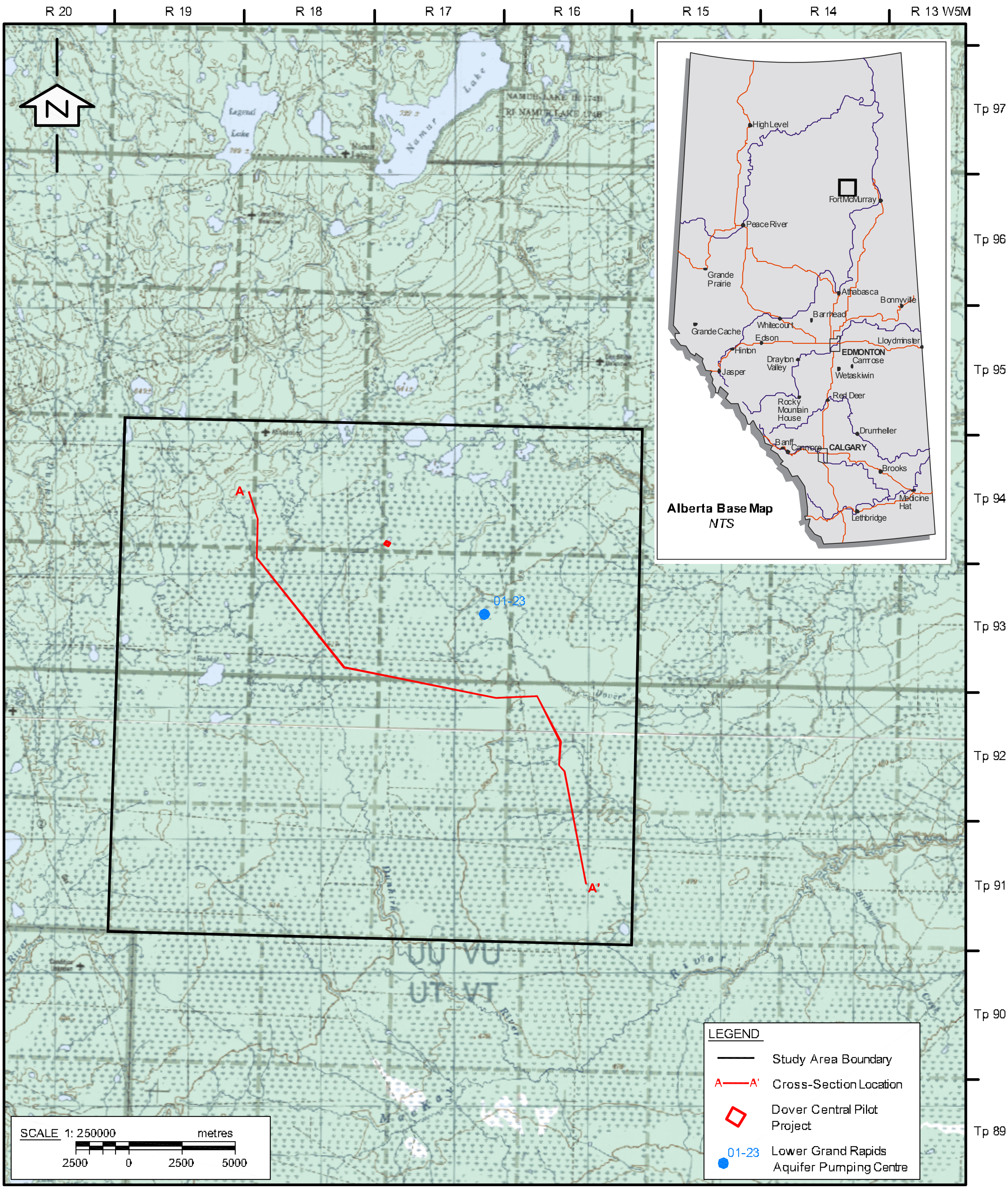
8.0 LIMITATIONS

We certify that we supervised and carried out the work as described in this report. The report is based on and limited by circumstances and conditions referred to throughout the report and on information available at the time of the site investigation. Matrix Solutions Inc. has exercised reasonable skill, care and diligence to assess the information acquired during the preparation of this report. Matrix Solutions Inc. believes this information is accurate but cannot guarantee or warrant its accuracy or completeness. Information provided by others was believed to be accurate but cannot be guaranteed.

The information presented in this report was acquired, compiled and interpreted exclusively for the purposes described in this report. Matrix Solutions Inc. does not accept any responsibility for the use of this report, in whole or in part, for any purpose other than intended or to any third party for use whatsoever.

FIGURES



MAP REFERENCE: 1:250 000, ALGAR LAKE 84A & NAMUR LAKE 84H

Matrix Solutions Inc.
ENVIRONMENT & ENGINEERING

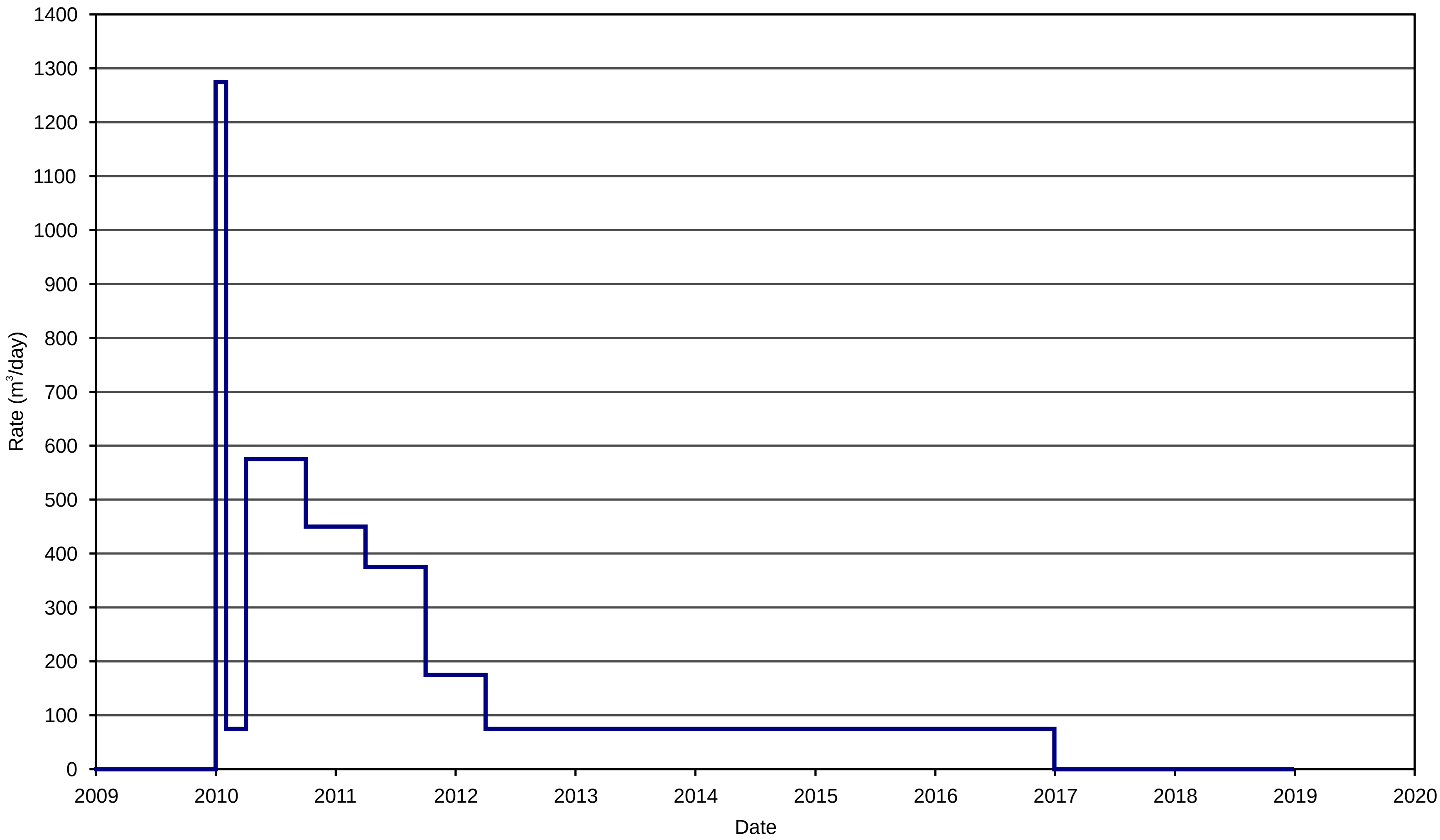
ATHABASCA OIL SANDS CORP.

LOCATION OF STUDY AREA

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-LP-07	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 1



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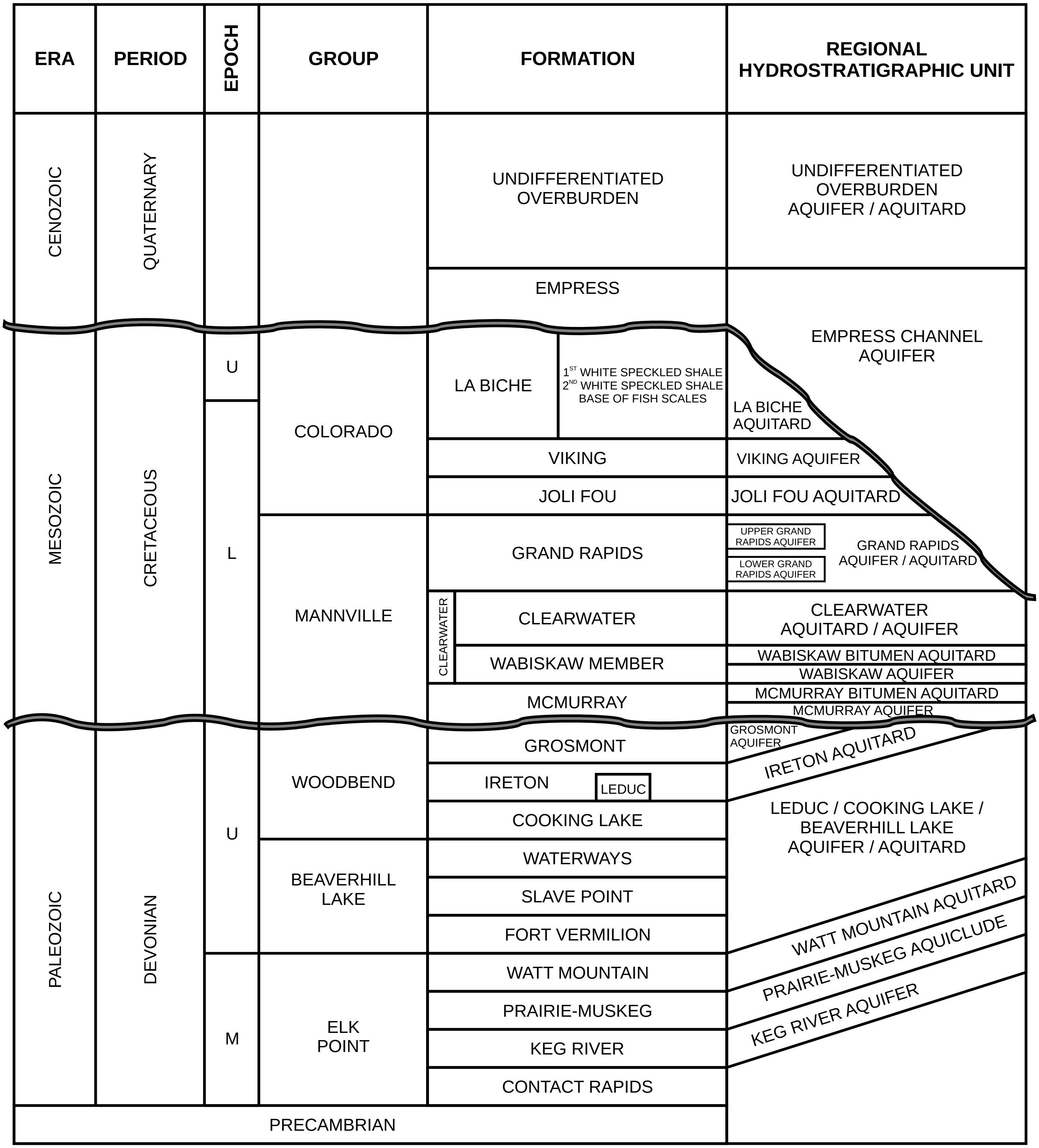
ATHABASCA OIL SANDS CORP.

PROJECTED GROUNDWATER WITHDRAWAL RATES
LOWER GRAND RAPIDS AQUIFER

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-Graph-08	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 2



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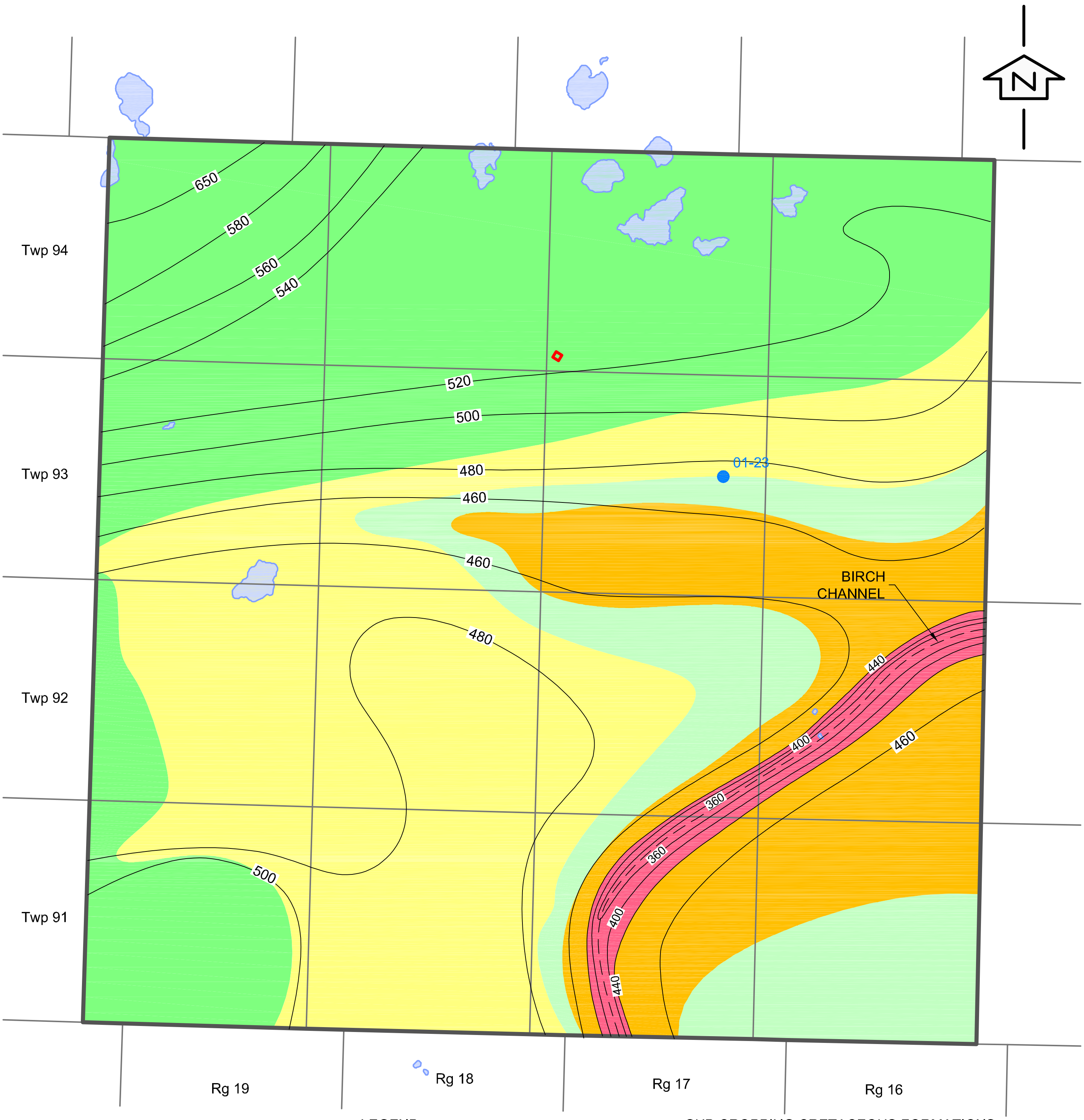
ATHABASCA OIL SANDS CORP.

STRATIGRAPHIC / HYDROSTRATIGRAPHIC COLUMN

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-Strat-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 3**



LEGEND

- Study Area
- Thalweg of Birch Channel
- 400 Top of Bedrock Contour (masl)
- Dover Central Pilot Project
- 01-23 Lower Grand Rapids Aquifer Pumping Centre

SUB CROPPING CRETACEOUS FORMATIONS

- La Biche Formation
- Viking Formation
- Joli Fou Formation
- Grand Rapids Formation
- Clearwater Formation

SCALE 1:250000 kilometres
2.5 0 2.5 5

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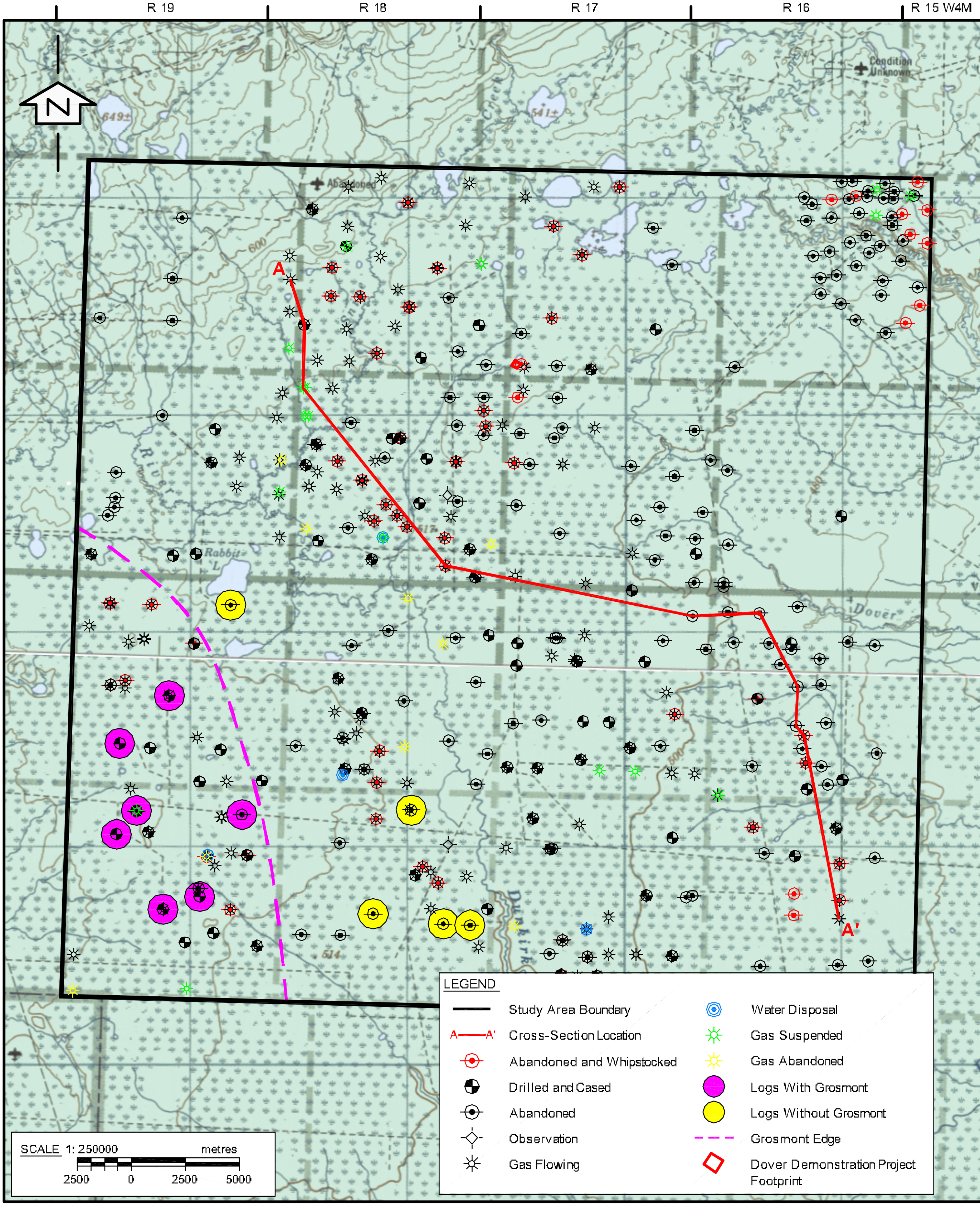
ATHABASCA OIL SANDS CORP.

CRETACEOUS SUB-CROP MAP

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-BASE-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 4**



MAP REFERENCE: 1:250 000, ALGAR LAKE 84A & NAMUR LAKE 84H

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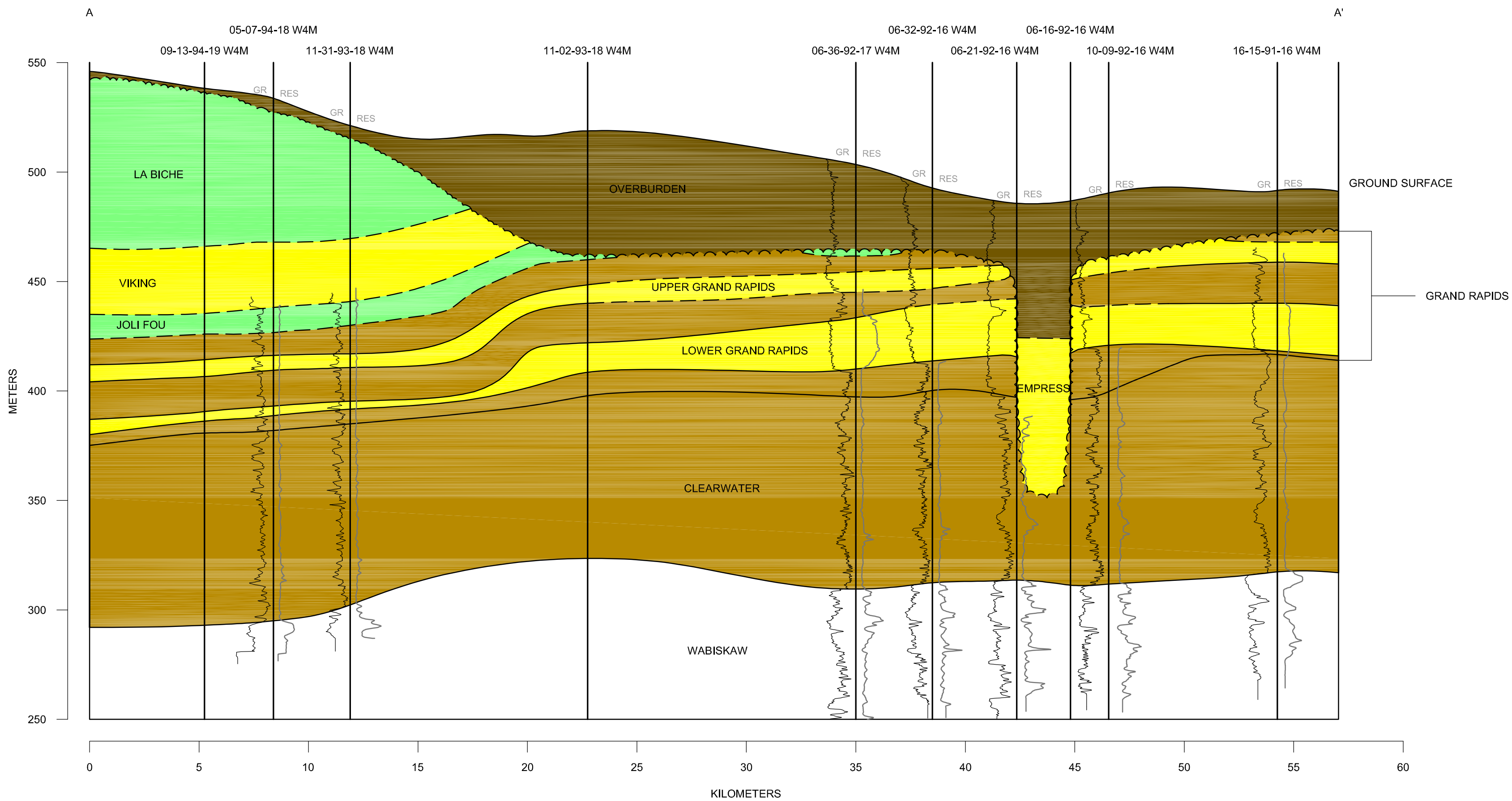
ATHABASCA OIL SANDS CORP.

LOCATION OF WELLS WHERE GROSMONT FORMATION WAS IDENTIFIED

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-LP-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	FIGURE 5



LEGEND

- Aquifer
- Aquitard
- Aquifer / Aquitard
- Undifferentated Overburden Aquifer / Aquitard

HORIZONTAL SCALE 1:200000 kilometres (2 0 2 4)

VERTICAL SCALE 1:2000 metres (20 0 20 40)

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ATHABASCA OIL SANDS CORP.

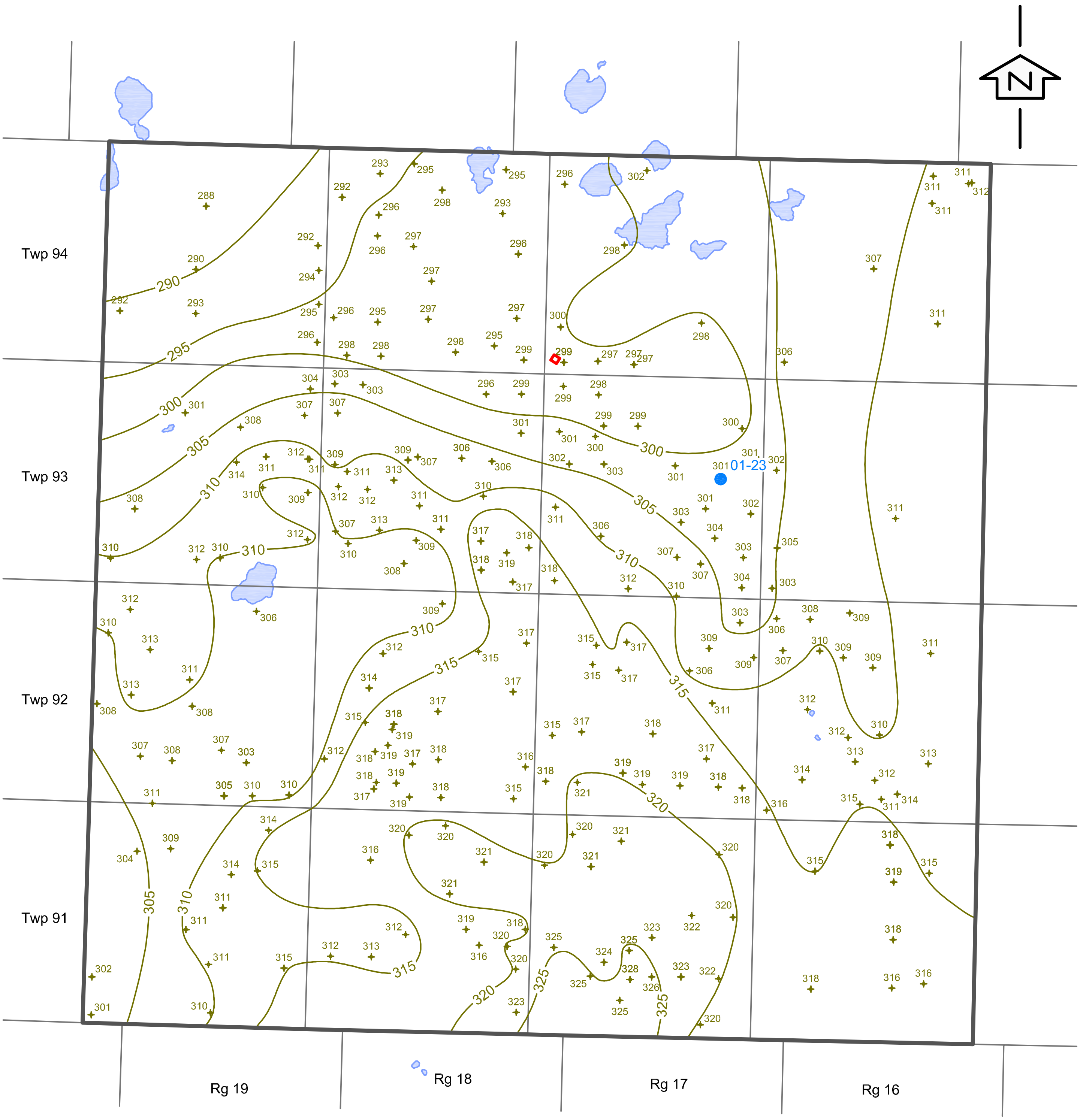
HYDROSTRATIGRAPHIC CROSS-SECTION A-A'

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-XS-07	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 6

*PLOT 1:1 = Letter (P)



LEGEND

Study Area

405 Structure Contour (masl)

320 Unit Elevation (masl)

Dover Central Pilot Project

01-23 Lower Grand Rapids Pumping Centre

SCALE 1:250000 kilometres

2.5 0 2.5 5

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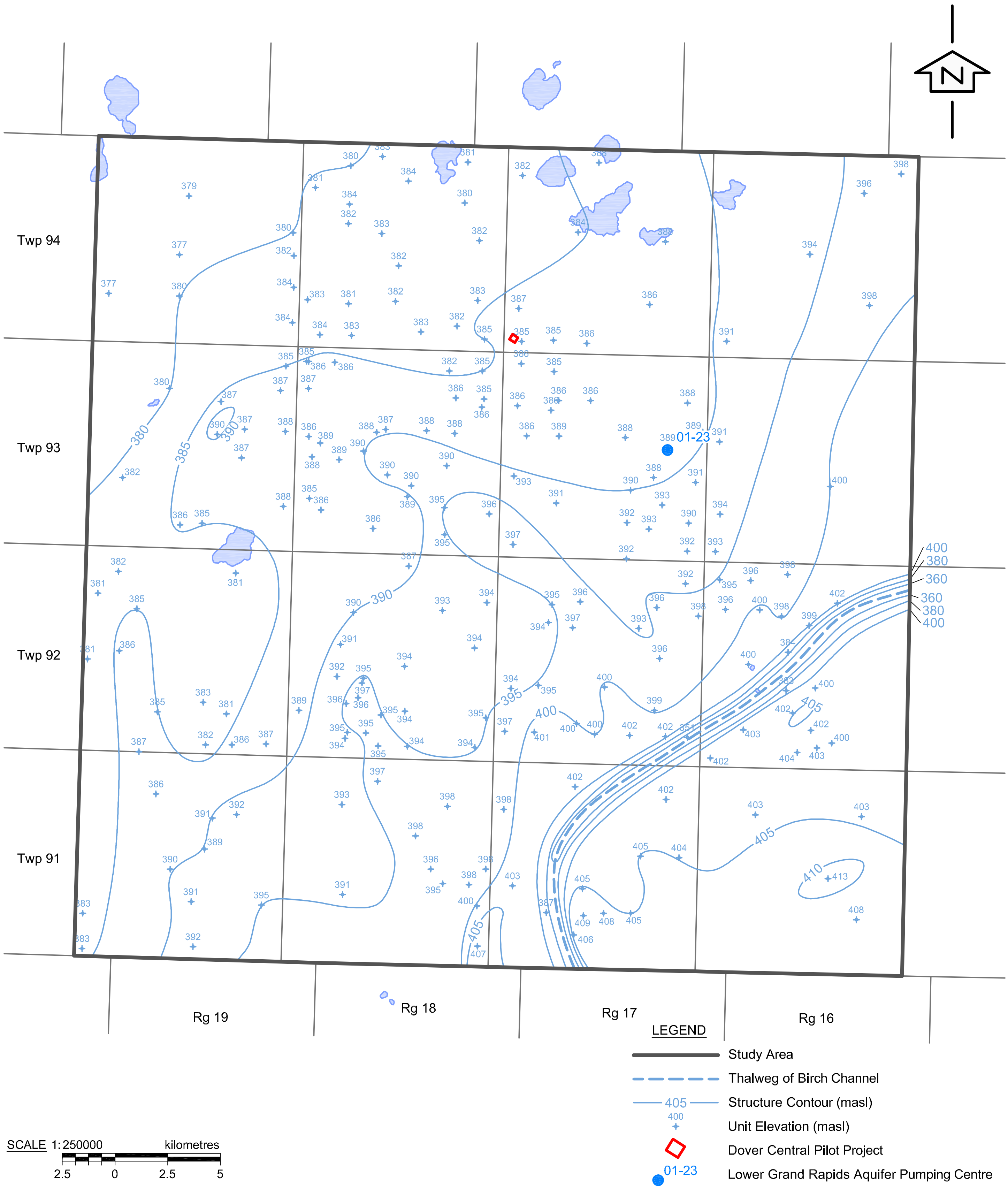
ATHABASCA OIL SANDS CORP.

STRUCTURE MAP
TOP OF WABISKAW MEMBER

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-BASE-07	ED	GS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 7**

F:\7349 AOSC\Drafting\2007\7349-BASE-07.dwg - WABISKAW - Monday, May 12, 2008 1:52:25 PM - Zachary Steele

*PLOT 1:1 = Letter (P)



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ATHABASCA OIL SANDS CORP.

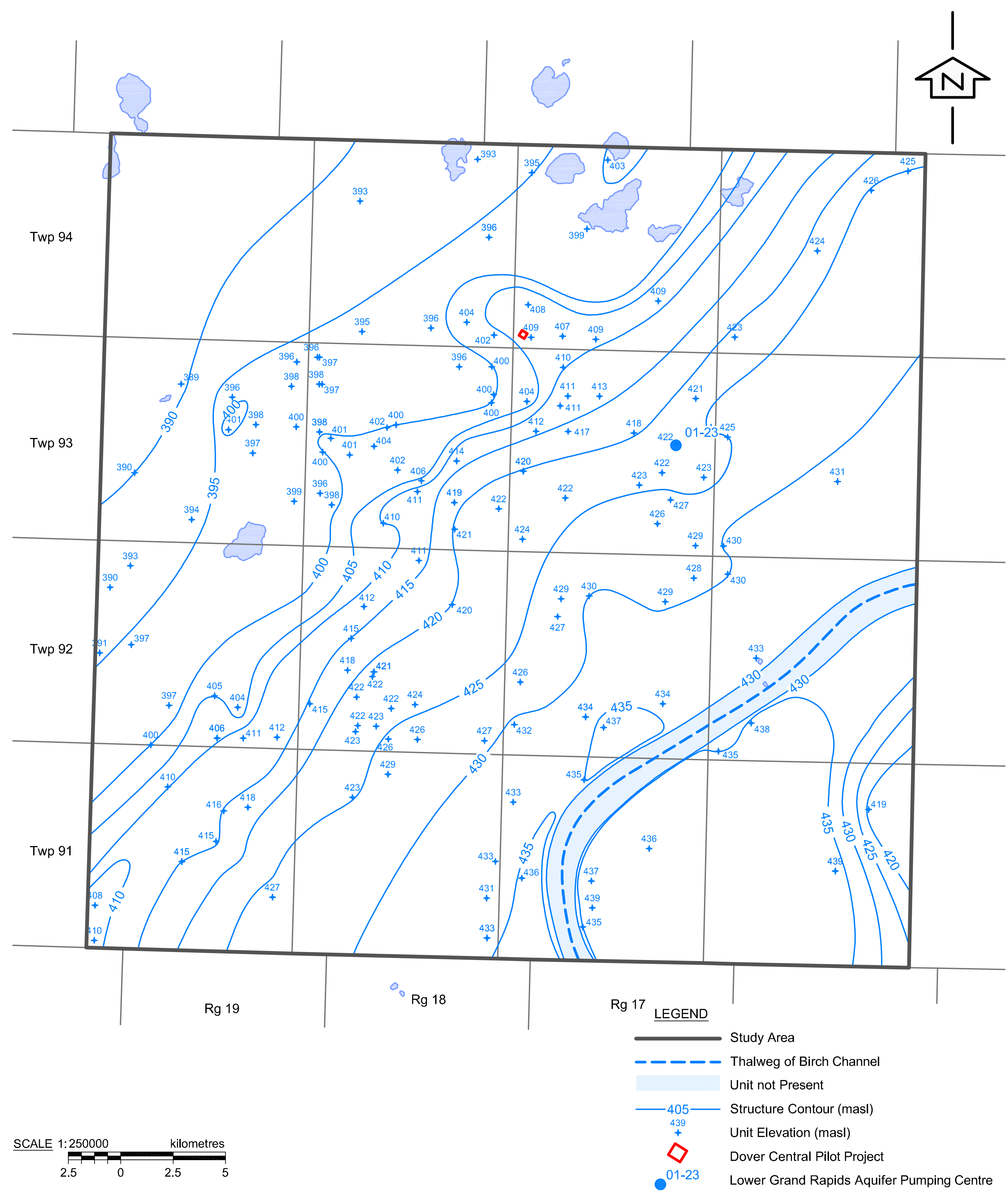
STRUCTURE MAP
TOP OF CLEARWATER FORMATION

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	GS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 8

F:\7349 AOSC\Drafting\2007\7349-BASE-07.dwg - CLEARWATER - Monday, May 12, 2008 1:52:25 PM - Zachary Steele



ATHABASCA OIL SANDS CORP.

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STRUCTURE MAP
TOP OF LOWER GRAND RAPIDS SAND

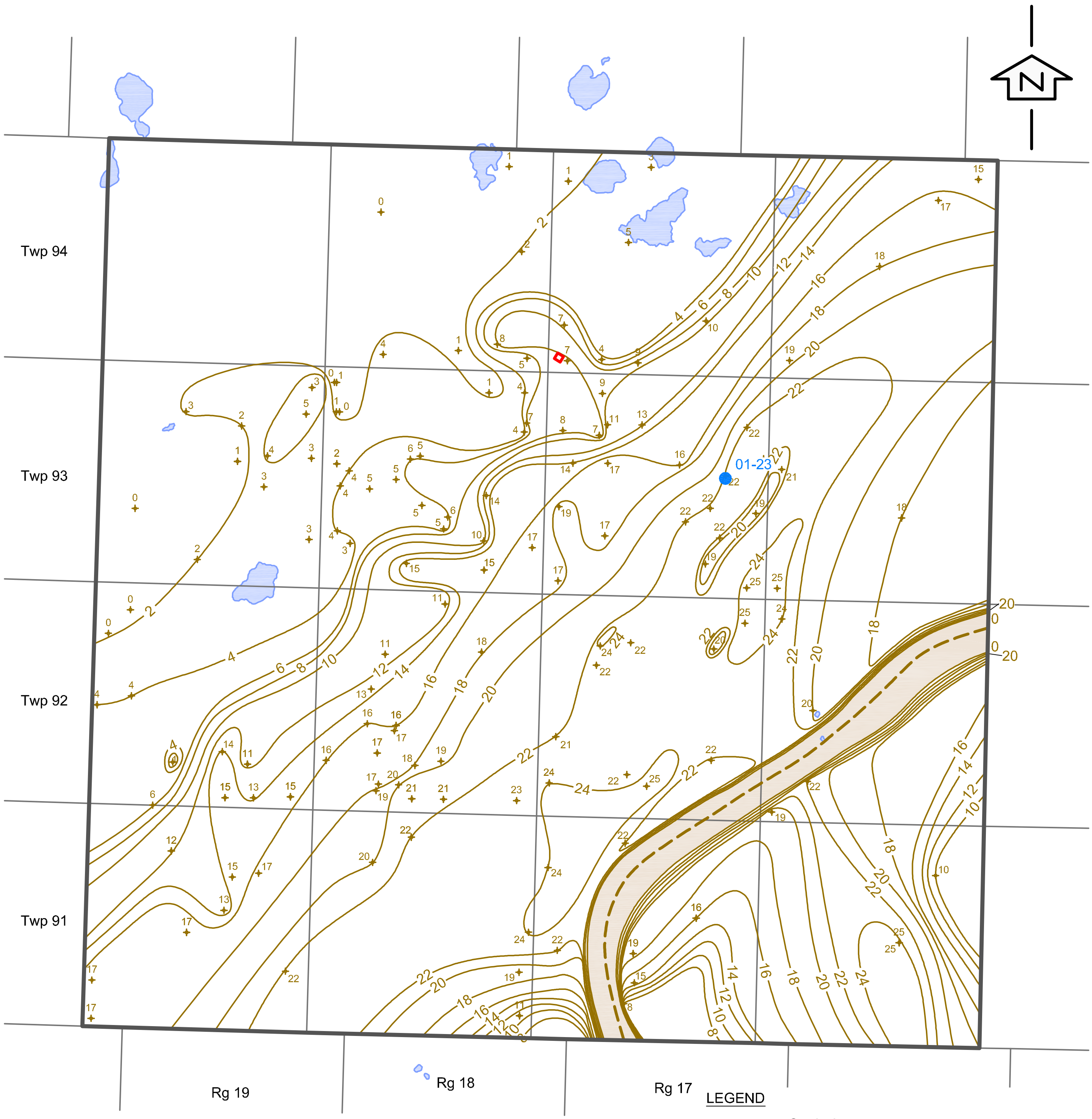
DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	GS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 9

*PLOT 1:1 = Letter (P)

F:\7349 AOSC\Drafting\2007\7349-BASE-07.dwg - LGA - Monday, May 12, 2008 1:52:25 PM - Zachary Steele



LEGEND

- Study Area
- Thalweg of Birch Channel
- Unit not Present
- 18 — Isopach Contour (m)
- 12 — Unit Thickness (m)
- Dover Central Pilot Project
- 01-23 — Lower Grand Rapids Aquifer Pumping Centre

SCALE 1:250000 kilometres

2.5 0 2.5 5

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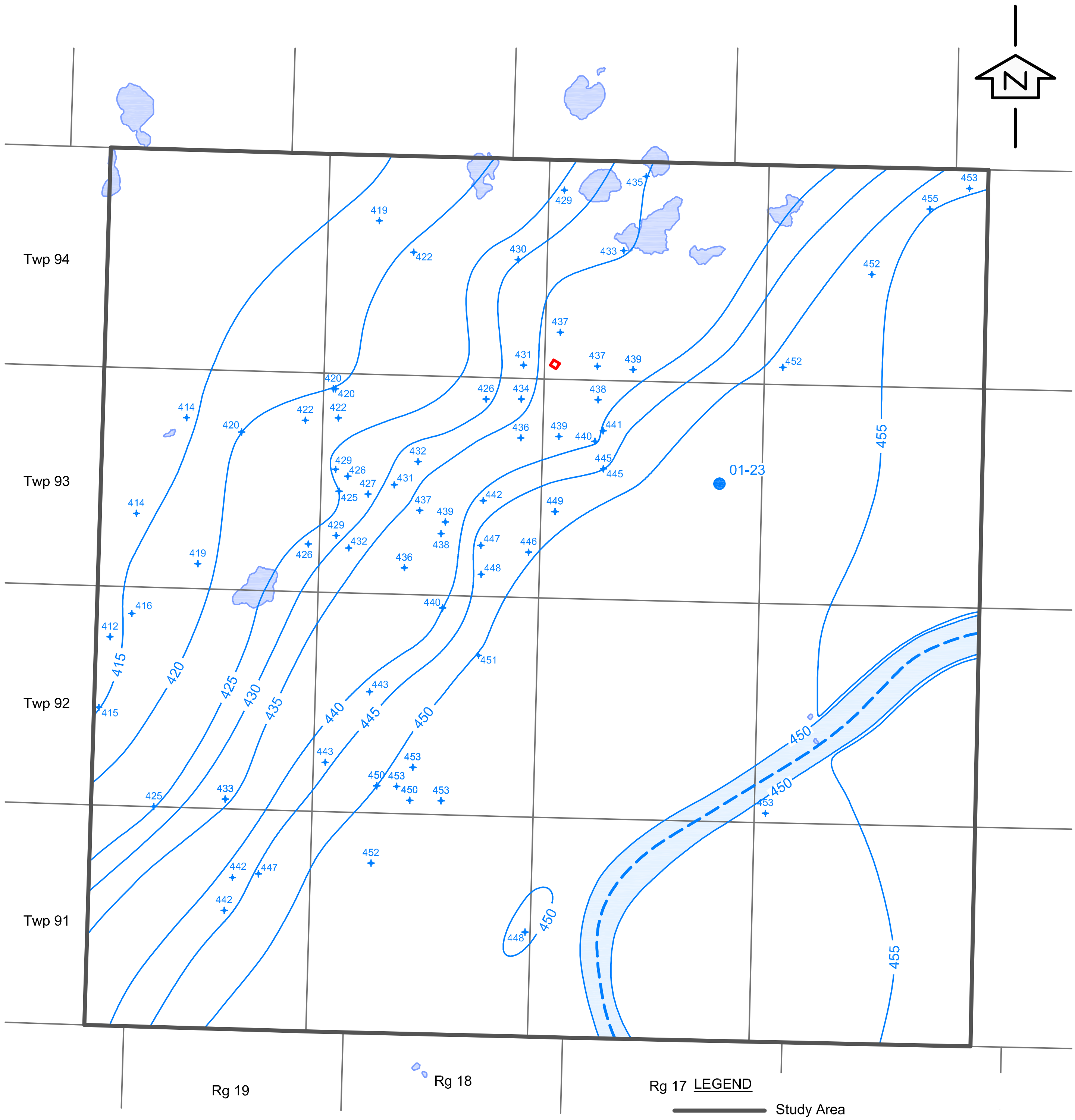
ATHABASCA OIL SANDS CORP.

ISOPACH MAP
LOWER GRAND RAPIDS
NET SAND THICKNESS

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	GS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 10



LEGEND

- Study Area
- Thalweg of Birch Channel
- Unit not Present
- 450 Structure Contour (masl)
- 450 Unit Elevation(masl)
- Dover Central Pilot Project
- 01-23 Lower Grand Rapids Aquifer Pumping Centre

SCALE 1:250000 kilometres

2.5 0 2.5 5

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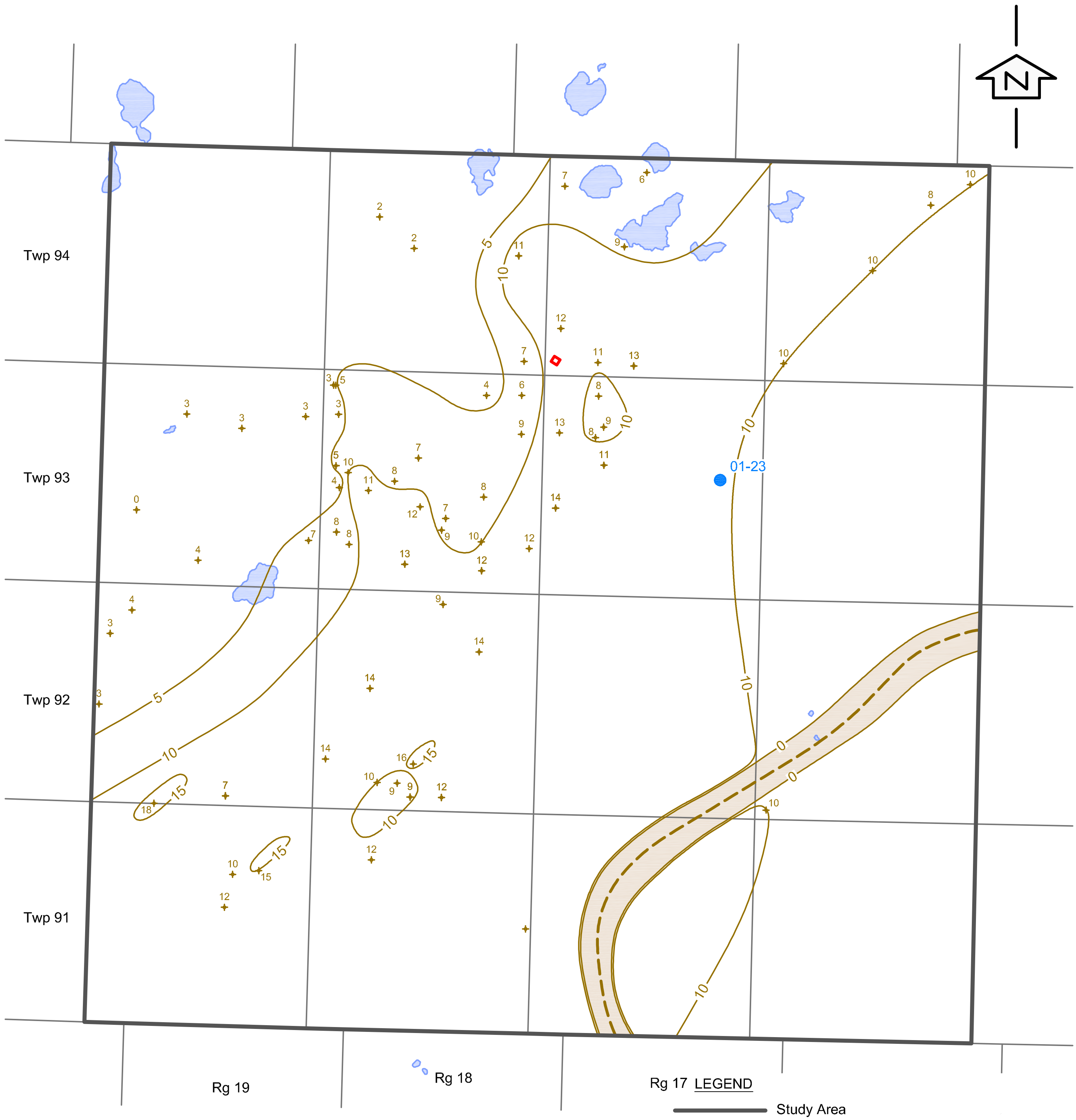
ATHABASCA OIL SANDS CORP.

STRUCTURE MAP
TOP OF UPPER GRAND RAPIDS SAND

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	GS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 11



LEGEND

- Study Area
- Thalweg of Birch Channel
- Unit not Present
- 10 Isopach Contour (m)
- 12 Unit Thickness (m)
- Dover Central Pilot Project
- 01-23 Lower Grand Rapids Aquifer Pumping Centre

SCALE 1:250000 kilometres

2.5 0 2.5 5

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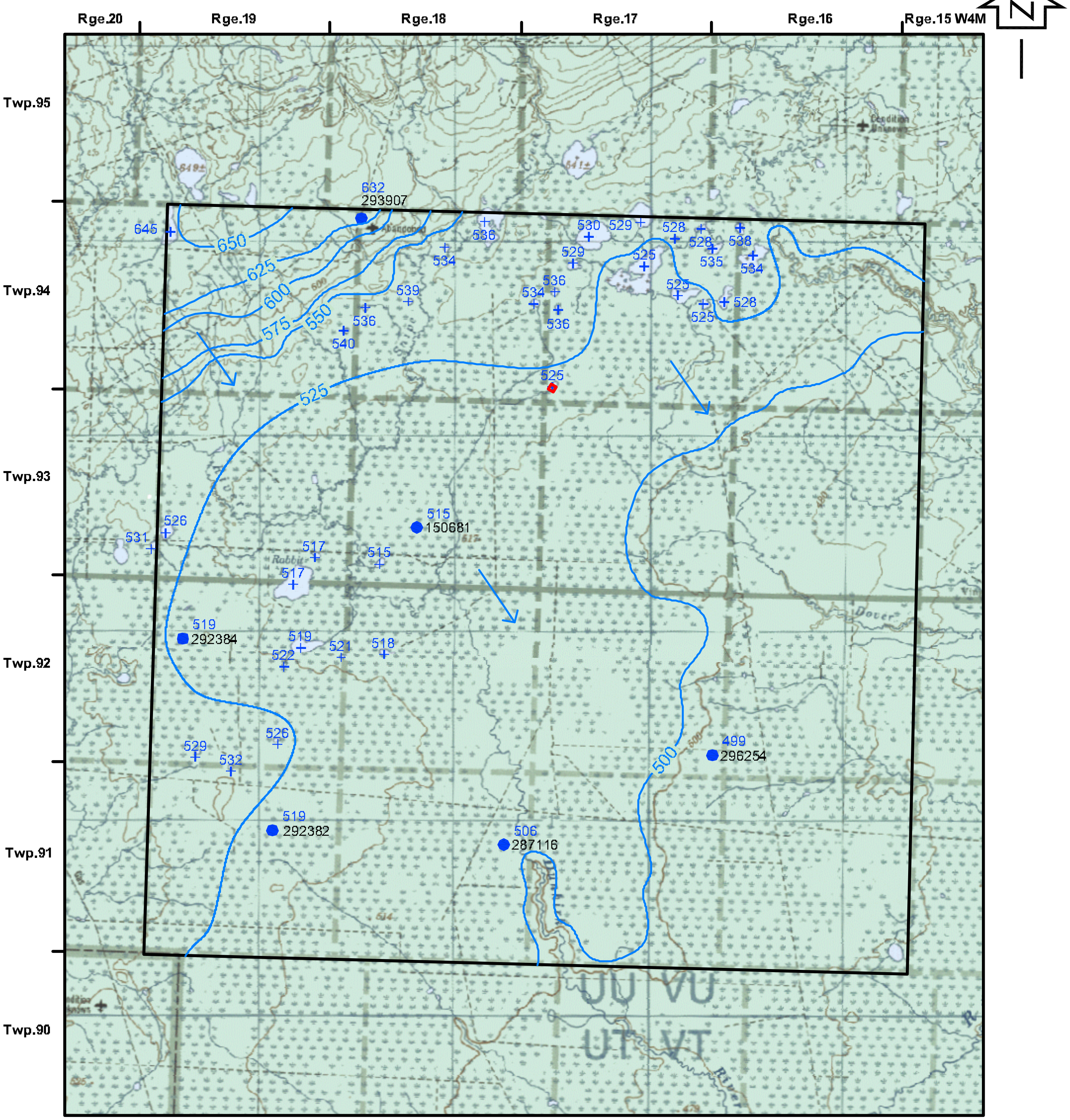
ATHABASCA OIL SANDS CORP.

ISOPACH MAP
UPPER GRAND RAPIDS
NET SAND THICKNESS

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	GS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 12



MAP REFERENCE: 1:250 000, 84A/84H

SCALE
1:300 000
3 0 3 6 km

LEGEND

92612	AENV Well ID Number
	Study Area
480 +	Surface Water Elevations Based on DEM Data (masl)
480 ●	Hydraulic Head (masl)
500	Hydraulic Head Contour (masl)
	Direction of Groundwater Flow
	Dover Central Pilot Project

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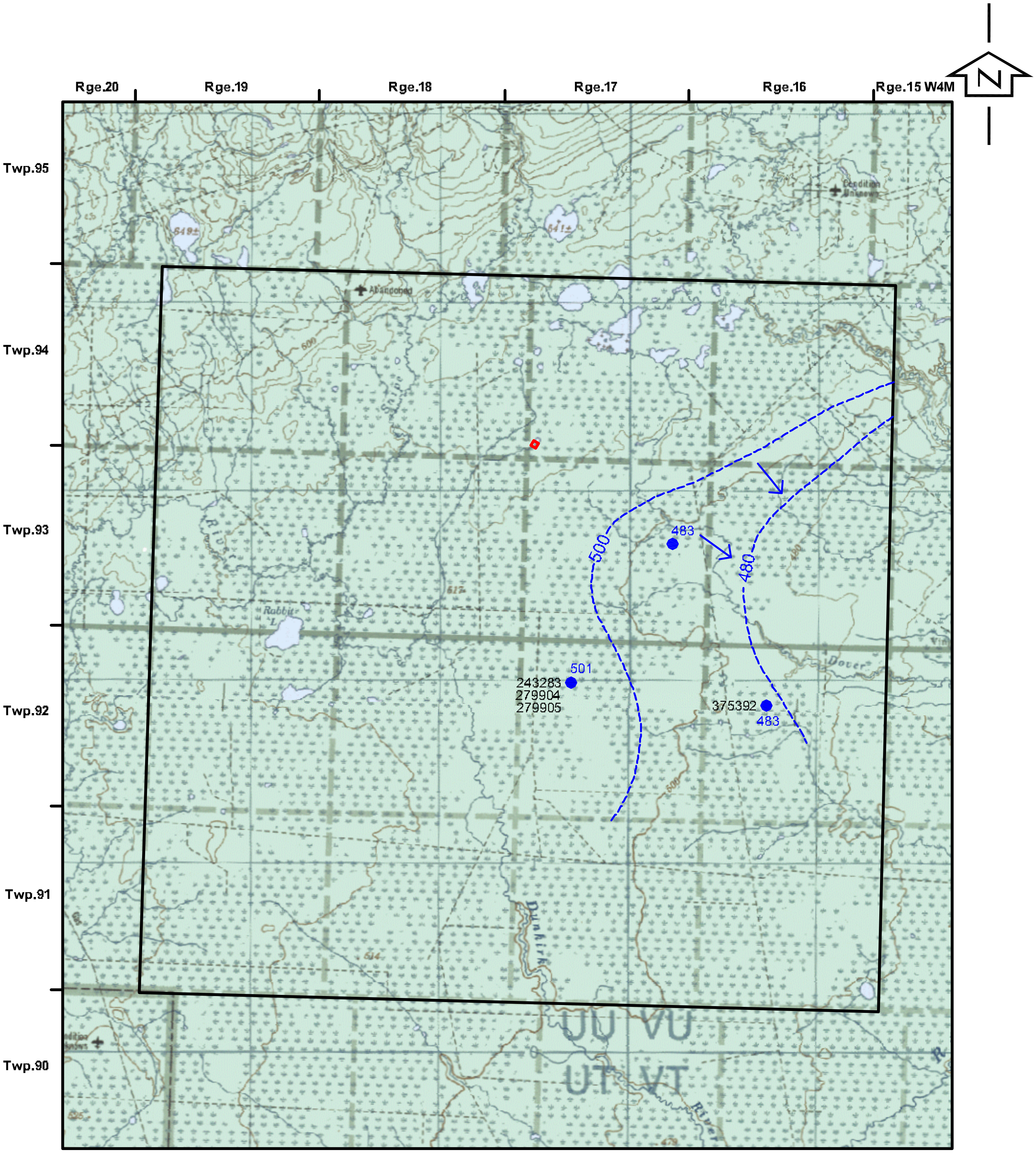
ATHABASCA OIL SANDS CORP.

UNDIFFERENTIATED OVERBURDEN AQUIFER/AQUITARD HYDRAULIC HEAD MAP

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-RT-07	ED	GS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 13**



MAP REFERENCE: 1:250 000, 84A/84H

SCALE
1:300 000
3 0 3 6 km

LEGEND

279904 AENV Well ID Number
Study Area
Direction of Groundwater Flow
501 Hydraulic Head (masl)
-500- Hydraulic Head Contour (masl)
Dover Central Pilot Project

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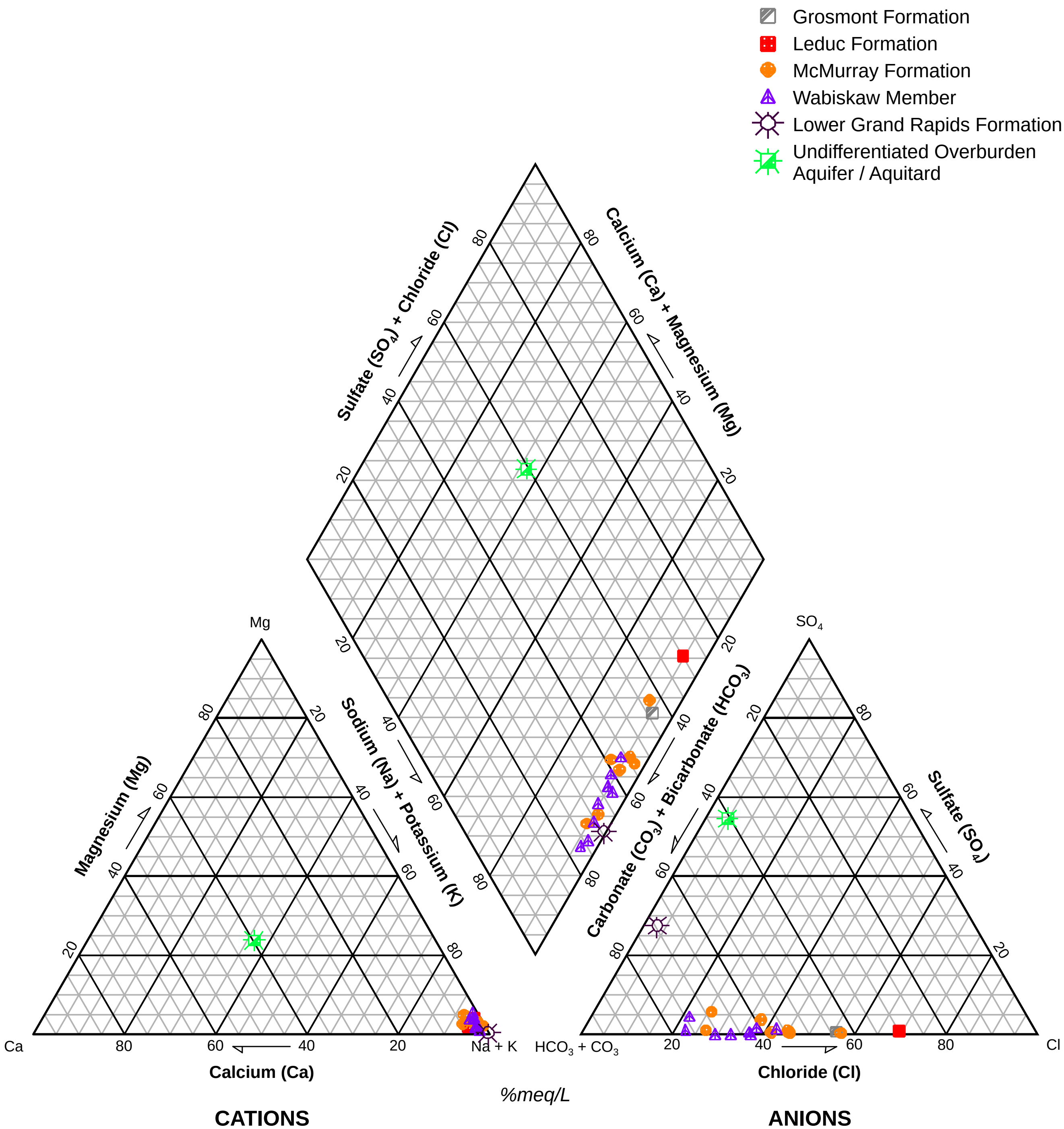
ATHABASCA OIL SANDS CORP.

LOWER GRAND RAPIDS AQUIFER HYDRAULIC HEAD MAP

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-RT-07	ED	ADF	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 14



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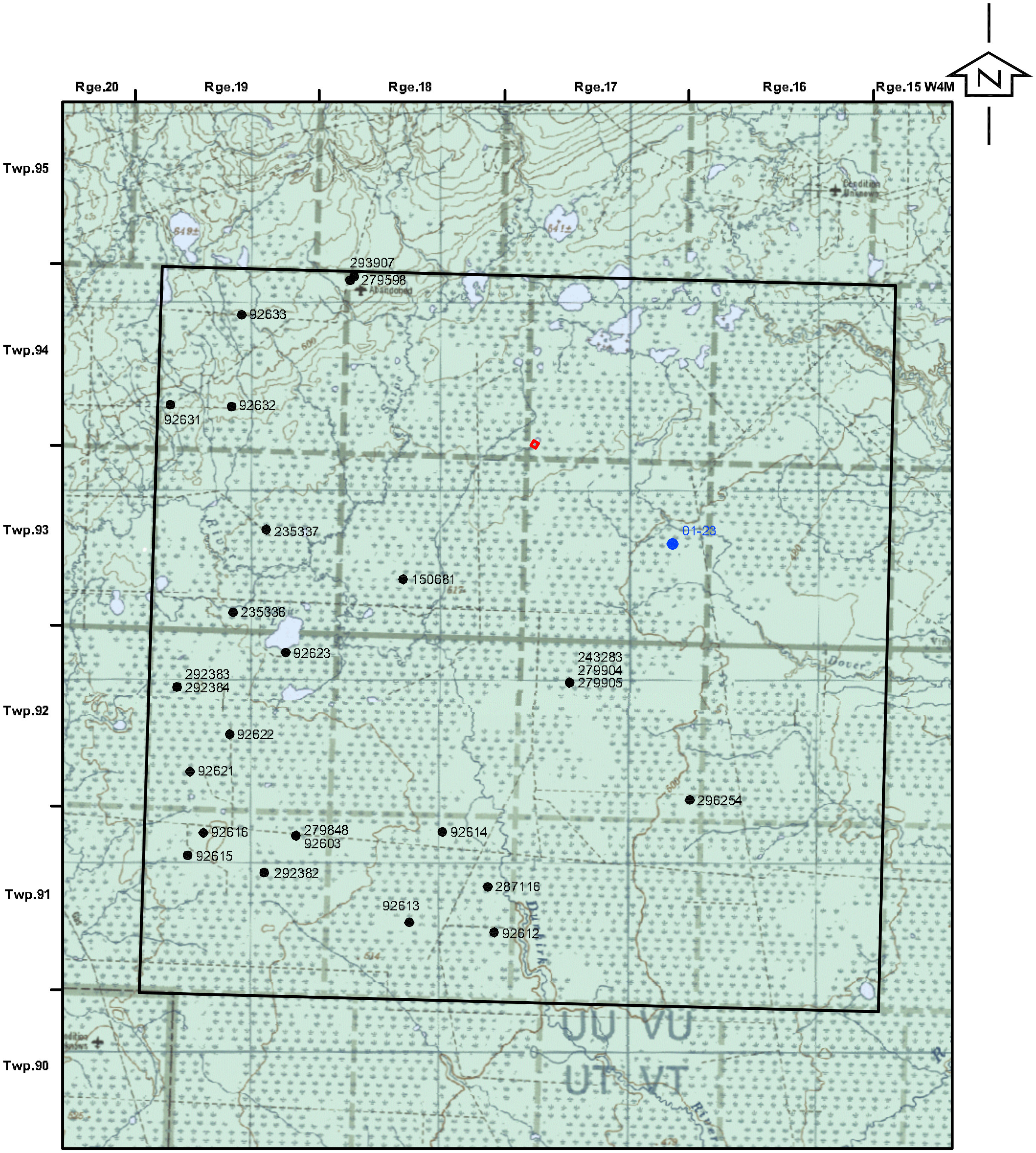
ATHABASCA OIL SANDS CORP.

WATER QUALITY ANALYSIS PIPER DIAGRAM

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-PD-08	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 15**



MAP REFERENCE: 1:250 000, 84A/84H

LEGEND

92612 ● Well Location and AENV Well ID Number

01-23 ● Water Well Drilled by AOSC (Winter 2008)

Study Area

Dover Central Pilot Project

SCALE

1:300 000

3 0 3 6 km

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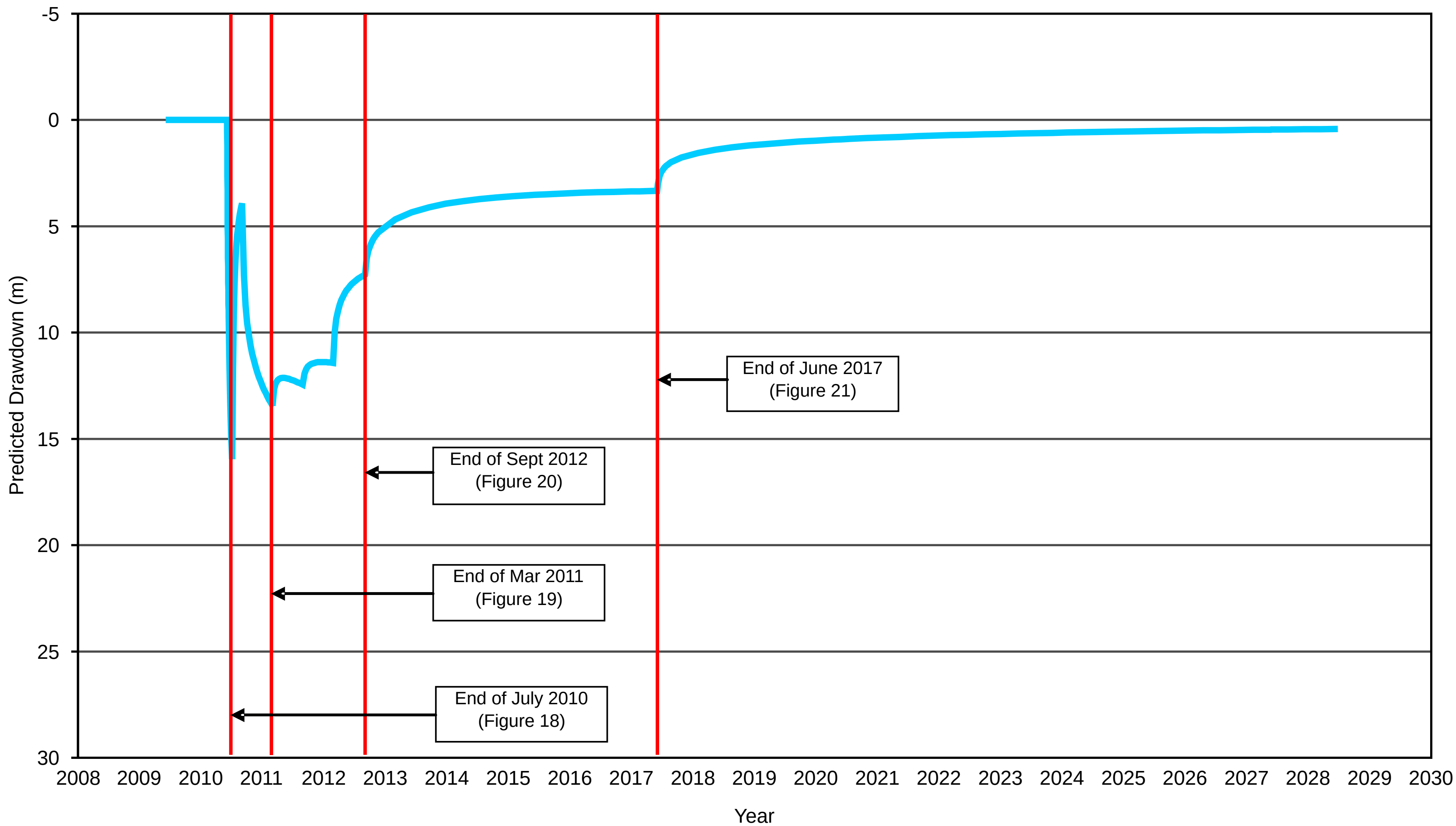
ATHABASCA OIL SANDS CORP.

WATER WELL LOCATION MAP

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-RT-07	ED	ADF	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 16



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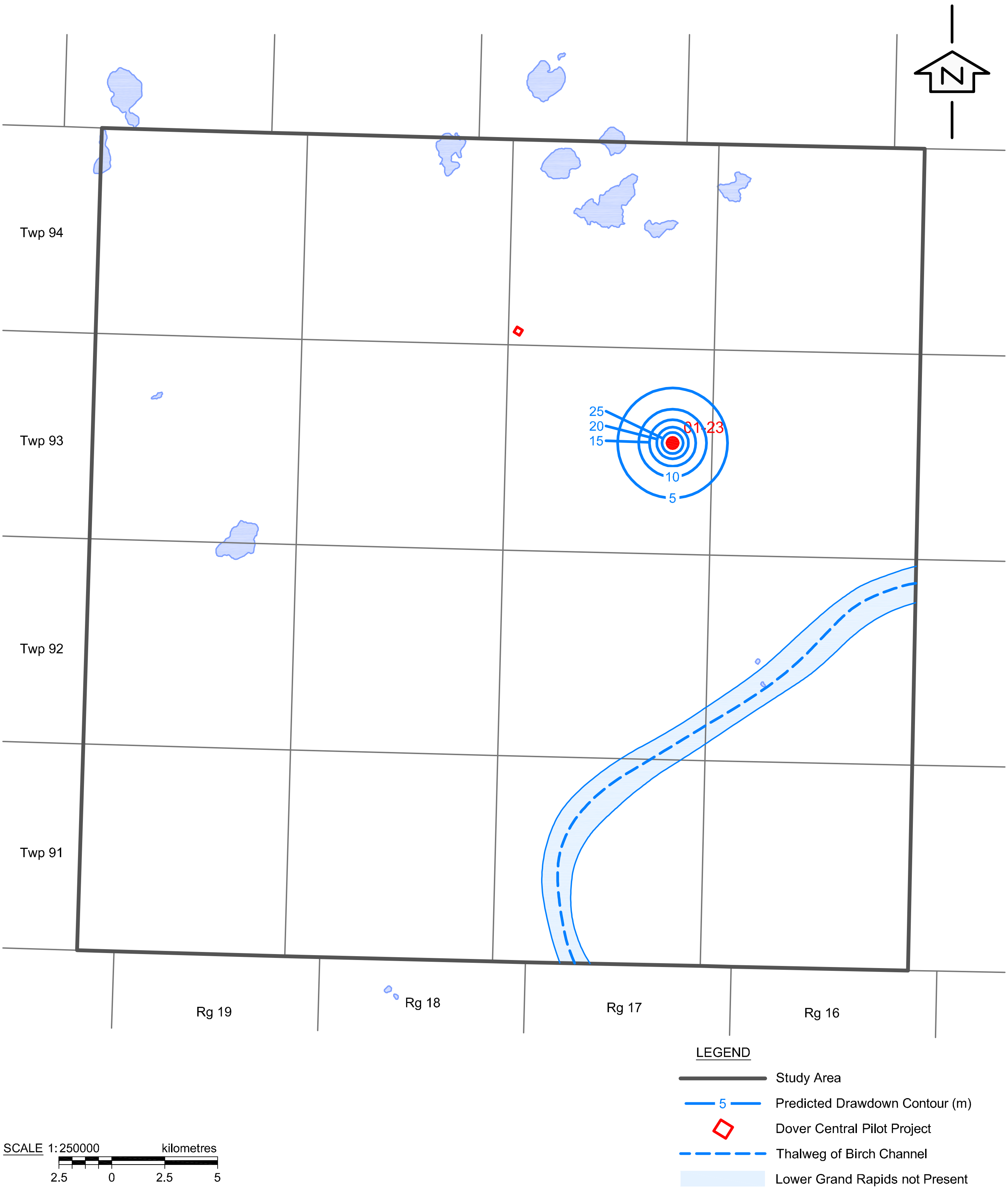
ATHABASCA OIL SANDS CORP.

PREDICTED DRAWDOWN
LOWER GRAND RAPIDS AQUIFER
1 KM FROM PUMPING CENTRE (01-23-093-17 W4M)

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-Graph-08	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 17



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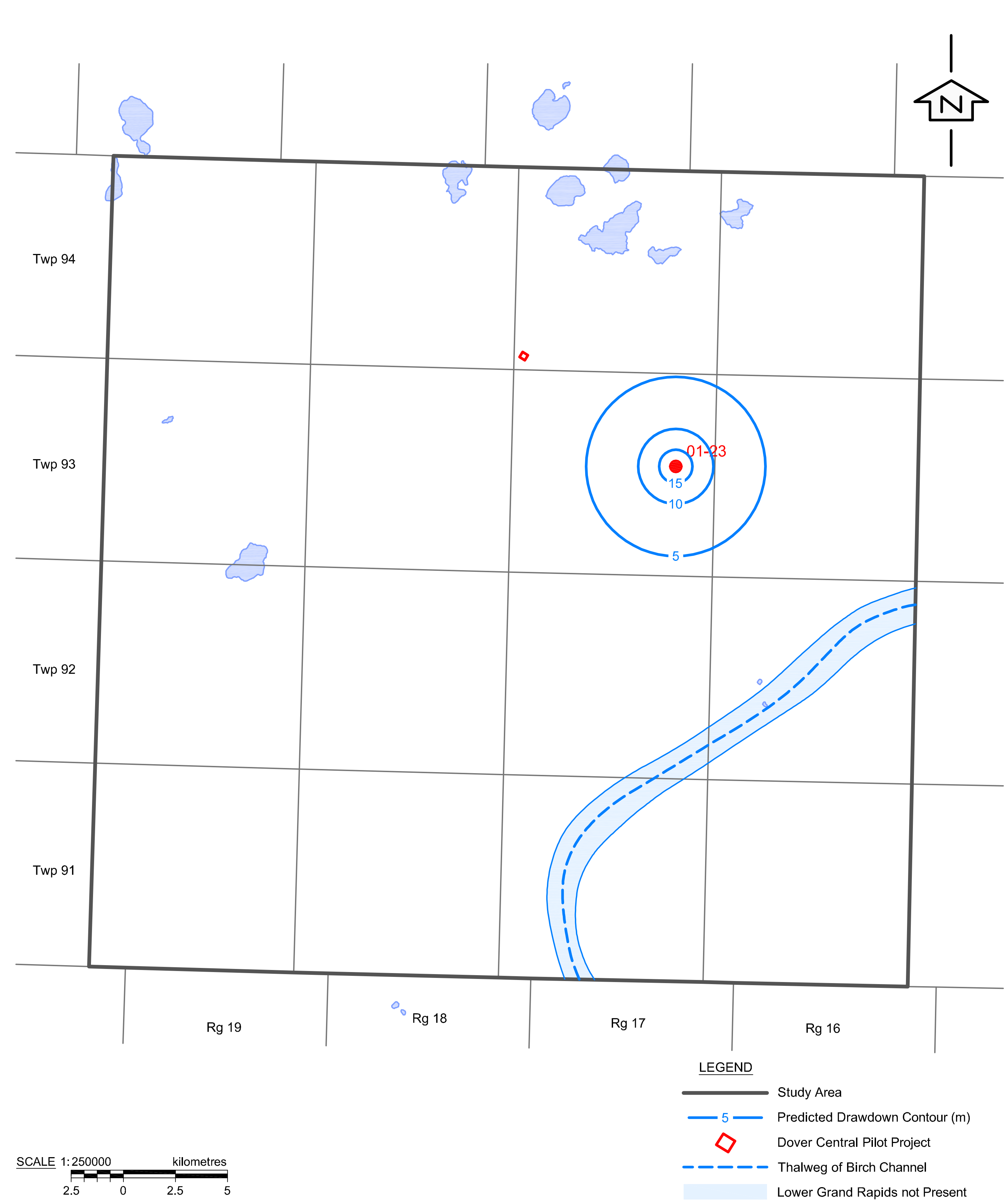
ATHABASCA OIL SANDS CORP.

PREDICTED DRAWDOWN
LOWER GRAND RAPIDS AQUIFER
END OF JULY 2010

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-BASE-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 18**



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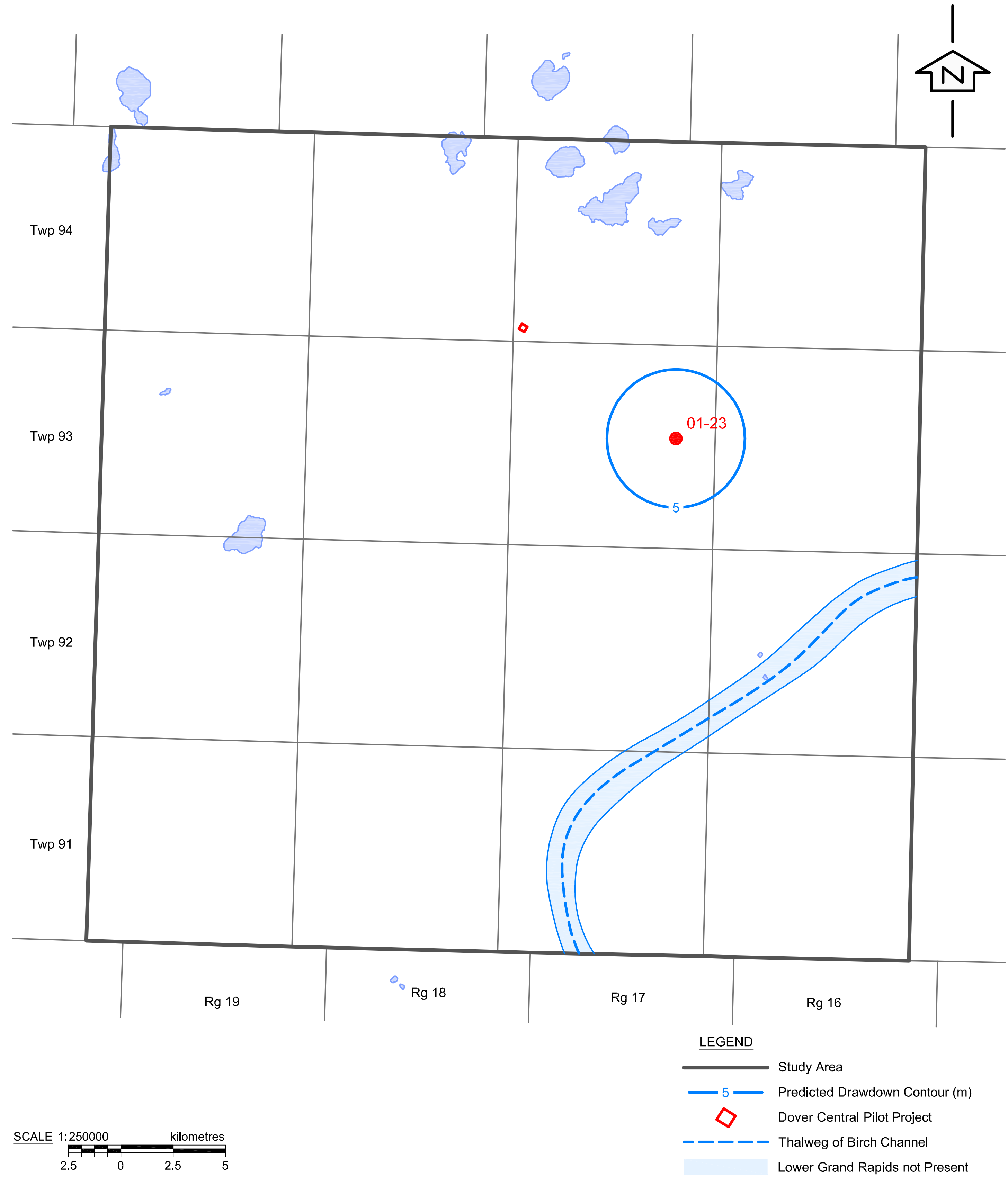
ATHABASCA OIL SANDS CORP.

PREDICTED DRAWDOWN
LOWER GRAND RAPIDS AQUIFER
END OF MARCH 2011

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-BASE-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 19**



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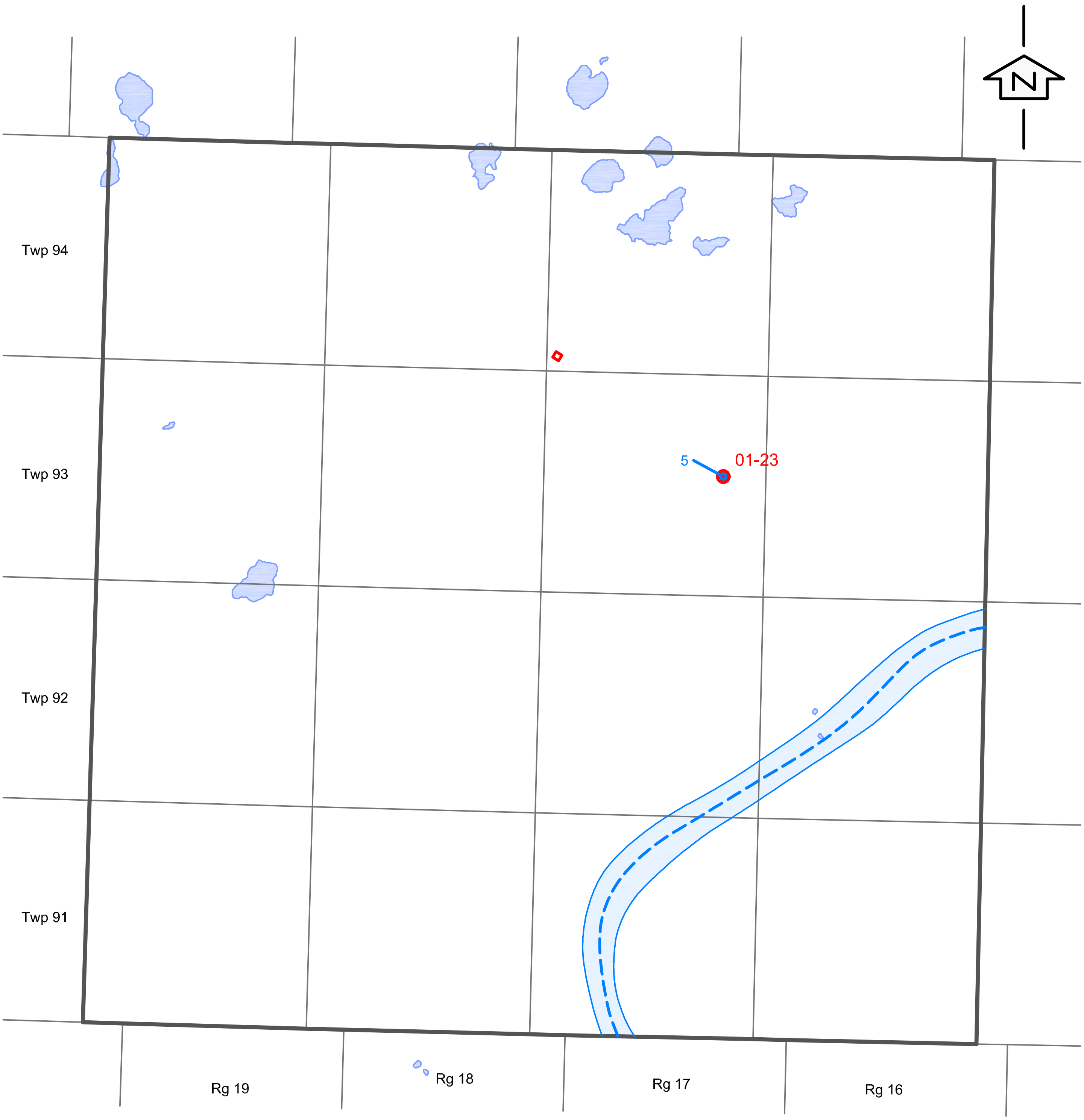
ATHABASCA OIL SANDS CORP.

PREDICTED DRAWDOWN
LOWER GRAND RAPIDS AQUIFER
END OF SEPTEMBER 2012

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-BASE-07	ED	ZS	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE 20**



LEGEND

- Study Area
- 5 Predicted Drawdown Contour (m)
- Dover Central Pilot Project
- Thalweg of Birch Channel
- Lower Grand Rapids not Present

SCALE 1:250000 kilometres

2.5 0 2.5 5

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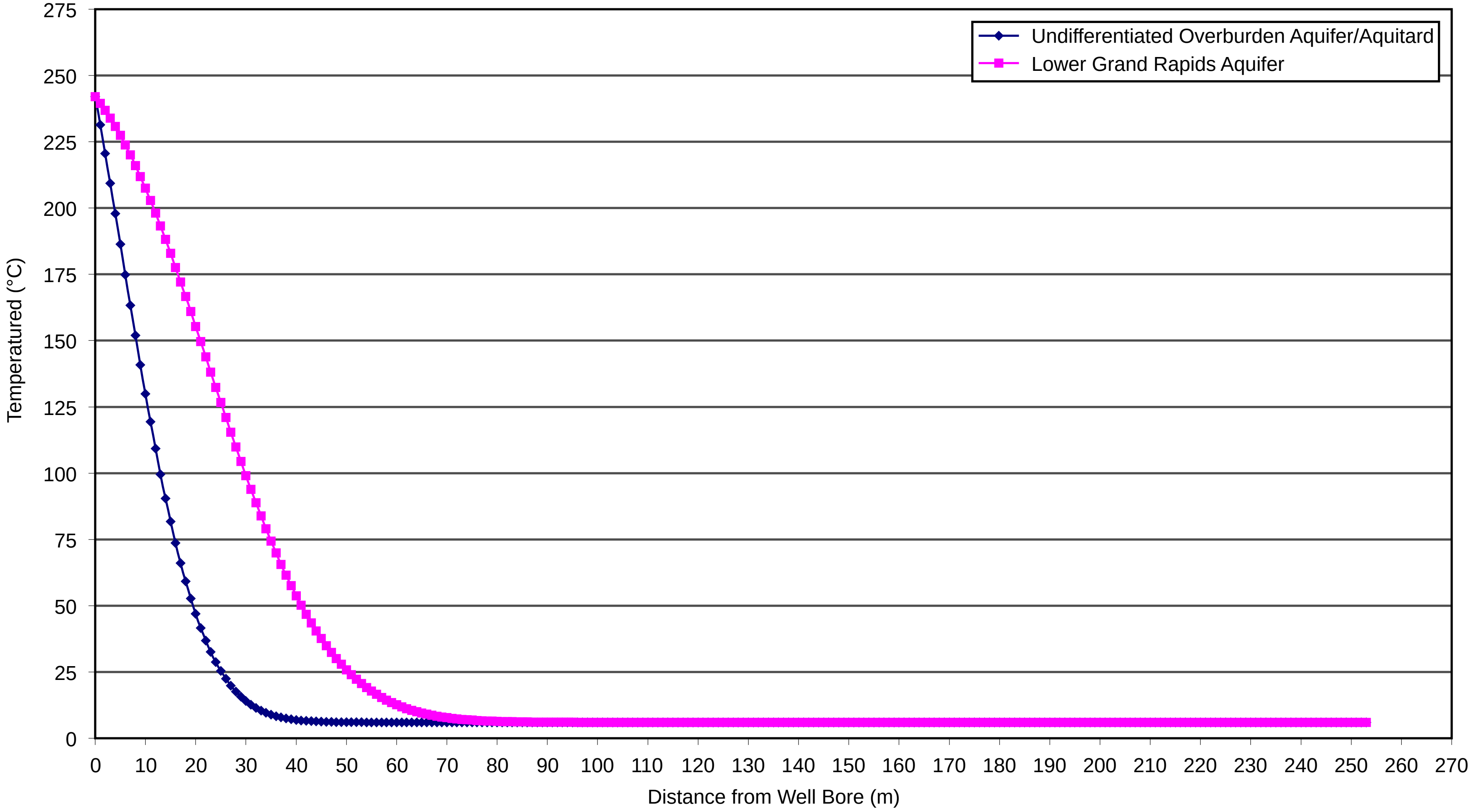
ATHABASCA OIL SANDS CORP.

PREDICTED DRAWDOWN
LOWER GRAND RAPIDS AQUIFER
END OF JUNE 2017

DATE:	FILE (DWG):	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-BASE-07	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 21



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ATHABASCA OIL SANDS CORP.

SIMULATED TEMPERATURE AFTER 7 YEARS CONTINUOUS STEAMING

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-Graph-08	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE 22

TABLES

TABLE 1

WATER WELLS IN TOWNSHIPS 091-094 AND RANGES 16-19, WEST OF THE 4th MERIDIAN

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Water Well Number	Well ID*	Location (W4M)	Well Owner	Total Depth (m)	Top of Screen (m)	Bottom of Screen (m)	Depth to Water (m)	Date of Information	Proposed Use For Well	Type of Work
1	92603	08-35-091-19	Pan American Petro	409.33	---	---	---	26-Mar-63	Industrial	Drill Stem
2	92612	06-13-091-18	Texaco Can	939.96	---	---	---	28-Feb-59	Industrial	Drill Stem
3	92613	10-16-091-18	Pan American Petro	970.74	---	---	---	26-Feb-66	Industrial	Drill Stem
4	92614	10-34-091-18	Pan American Petro	921.06	---	---	---	23-Feb-67	Industrial	Drill Stem
5	92615	11-29-091-19	Miami Oil	318.20	---	---	---	21-Mar-74	Industrial	Drill Stem
6	92616	8-32-091-19	Pan American Petro	426.70	---	---	---	01-Mar-63	Industrial	Drill Stem
7	92621	6-8-092-19	Miami Oil	338.62	---	---	---	30-Mar-74	Industrial	Oil
8	92622	10-16-092-19	Miami Oil	333.13	---	---	---	29-Mar-74	Industrial	Oil
9	92623	6-35-092-19	Amoco Can	405.36	---	---	---	26-Mar-74	Industrial	Drill Stem
10	92631	06-07-094-19	Dome Petro	314.54	---	---	---	20-Feb-74	Industrial	Oil
11	92632	06-09-094-19	Dome Petro	315.76	---	---	---	24-Feb-74	Industrial	Oil
12	92633	07-28-094-19	Dome Petro	368.79	---	---	---	28-Feb-74	Industrial	Oil
13	150681	13-9-093-18	Petrocan	67.05	---	---	1.89	10-Feb-90	Domestic	New Well
14	235336	10-04-093-19	Amoco#F-1	308.14	---	---	---	09-Mar-74	Industrial	Oil
15	235337	07-22-093-19	Amoco#C-2	380.98	---	---	---	20-Mar-74	Industrial	Oil
16	243283	10-29-092-17	Eba Engineering	102.71	---	---	12.95	09-Mar-81	Industrial	New Well
17	279598	NW-31-094-18	Paramount Res Ltd	30.48	---	---	---	---	Domestic	Chemistry
18	279848	08-35-091-19	Pan American Oil	85.34	---	---	---	---	Industrial	Structure
19	279904	10-29-092-17	Eba Engineering	105.46	---	---	13.78	24-Feb-81	Industrial	New Well
20	279905	10-29-092-17	Eba Engineering	152.39	86.86	102.41	14.93	19-Feb-81	Observation	Test Hole
21	287116	13-24-091-18	Rio Alta Expl	73.15	---	---	2.13	17-Feb-97	Domestic	New Well
22	292382	1-27-091-19	Rio Alta Expl	35.05	---	---	5.49	26-Feb-99	Domestic	New Well
23	292383	01-30-092-19	Paramount Res Ltd	48.77	---	---	---	27-Feb-99	Domestic	Test Hole-
24	292384	01-30-092-19	Paramount Res Ltd	73.15	---	---	10.45	26-Feb-99	Domestic	New Well
25	293907	12-31-094-18	Paramount Res Ltd	39.62	---	---	3.66	09-Feb-00	Domestic	New Well
26	296254	15-01-092-17	Paramount Res Ltd	27.43	---	---	2.13	07-Mar-01	Domestic	New Well

Notes:

--- - not available

* - Alberta Environment, Alberta Groundwater Data on CDROM, Groundwater Information Centre (GIC), 2003; updated from Abacus Data Graphics AbaData website http://www.abacusdatagraphics.com/AbaData/mgMainLogin.asp, February 26, 2008.

** - when no specific LSD is available, distance is calculated from centre of the quarter section indicated

*** - the data provided for these wells on the GIC CD and Abadata database website was not field-verified by Matrix personnel.

TABLE 2.

GROUNDWATER QUALITY RESULTS - ROUTINE WATER CHEMISTRY - UNIDIFFERENTIATED OVERBURDEN AQUIFER/AQUITARD

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Location	Well ID*	Sample Date	Field Temp °C	Field EC uS/cm	Lab EC uS/cm	Field pH	Lab pH	Ca mg/L	Mg mg/L	Na mg/L	K mg/L	Extractable Fe mg/L	Extractable Mn mg/L	Cl mg/L	SO_4 mg/L	HCO_3 mg/L	CO_3 mg/L	SiO_2 mg/L	F mg/L	Br mg/L	Iodide mg/L	Hardness $CaCO_3$ mg/L	TDS mg/L
NW-31-094-18 W4M	279598	06-Feb-85	---	---	1258	---	7.6	110.0	40.0	114	5.3	3.2	---	25	379	360	---	11.4	0.36	---	---	442	853
Minimal Detection Limit			**0.1**	**0.2**	**0.02**	**0.1**	**0.1**	**0.5**	**0.1**	**1**	**0.1**	**0.05**	**0.01**	**1**	**0.5**	**5**	**5**	**0.1**	**0.05**	**0.1**	**0.1**	**-**	**-**

TABLE 3.

GROUNDWATER QUALITY RESULTS - NUTRIENTS AND INDICATOR PARAMATERS - UNDIFFERENTIATED OVERBURDEN AQUIFER/AQUITARD

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Location	Well ID*	Sample Date	NO_2-N mg/L	NO_3-N mg/L	$NO_3 + NO_2$-N mg/L	DOC mg/L	TOC mg/L	TIC mg/L	Phenol mg/L	Sulphide mg/L
NW-31-094-18 W4M	279598	06-Feb-85	<0.05	---	---	---	---	---	---	---
Minimal Detection Limit			**0.05**	**0.1**	**0.1**	**1**	**1**	**1**	**0.001**	**0.002**

Notes:

--- - not analyzed / not available

* - Alberta Environment, Alberta Groundwater Data on CDROM, Groundwater Information Centre (GIC), 2003; updated from Abacus Data Graphics AbaData website http://www.abacusdatagraphics.com/AbaData/mgMainLogin.asp, February 26, 2008.

TABLE 4.

GROUNDWATER QUALITY RESULTS - ROUTINE WATER CHEMISTRY - LOWER GRAND RAPIDS AQUIFER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Location	Sample Date	Field Temp °C	Field EC uS/cm	Lab EC uS/cm	Field pH	Lab pH	Ca mg/L	Mg mg/L	Na mg/L	K mg/L	Extractable Fe mg/L	Extractable Mn mg/L	Cl mg/L	SO_4 mg/L	HCO_3 mg/L	CO_3 mg/L	SiO_2 mg/L	F mg/L	Br mg/L	Iodide mg/L	Hardness $CaCO_3$ mg/L	TDS mg/L
01-23-093-17 W4M	11-Mar-08	4.0	1580	1990	8.7	8.8	1.3	0.8	543	3.8	0.1	<0.01	21	263	847	67	5.7	2.43	0.1	<0.1	7	1320
Minimal Detection Limit		**0.1**	**0.2**	**0.02**	**0.1**	**0.1**	**0.5**	**0.1**	**1**	**0.1**	**0.05**	**0.01**	**1**	**0.5**	**5**	**5**	**0.1**	**0.05**	**0.1**	**0.1**	**-**	**-**

TABLE 5.

GROUNDWATER QUALITY RESULTS - NUTRIENTS AND INDICATOR PARAMATERS - LOWER GRAND RAPIDS AQUIFER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Point	Sample Date	NO_2-N mg/L	NO_3 -N mg/L	$NO_3 + NO_2$ -N mg/L	DOC mg/L	TOC mg/L	TIC mg/L	Phenol mg/L	Sulphide mg/L
01-23-093-17 W4M	11-Mar-08	<0.05	0.1	0.1	8	---	187	0.003	0.016
Minimal Detection Limit		**0.05**	**0.1**	**0.1**	**1**	**1**	**1**	**0.001**	**0.002**

Notes:

--- - not analyzed

TABLE 6.

GROUNDWATER QUALITY RESULTS - METALS - LOWER GRAND RAPIDS AQUIFER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Location	Sample Date	Matrix Sample Number	Total or Dissolved	Al mg/L	Sb mg/L	As mg/L	Ba mg/L	Be mg/L	B mg/L	Cd mg/L	Cr mg/L	Co mg/L	Cu mg/L	Fe mg/L	Pb mg/L
01-23-093-17 W4M	11-Mar-08	7349080311001	Total	2.44	0.0006	0.0008	0.128	<0.001	4.84	<0.0002	0.0138	0.0016	0.0030	2.25	0.0040
01-23-093-17 W4M	11-Mar-08	7349080311001	Dissolved	0.01	0.0005	<0.0004	0.0905	<0.0005	3.69	<0.0001	0.0020	0.0001	0.0019	0.024	0.0002

Sample Location	Sample Date	Matrix Sample Number	Total or Dissolved	Mn mg/L	Mo mg/L	Ni mg/L	Se mg/L	Ag mg/L	Sr mg/L	Tl mg/L	Sn mg/L	Ti mg/L	U mg/L	V mg/L	Zn mg/L
01-23-093-17 W4M	11-Mar-08	7349080311001	Total	0.023	0.0024	0.0074	0.0015	<0.0004	0.155	<0.0001	<0.0004	0.128	0.0004	0.0162	0.029
01-23-093-17 W4M	11-Mar-08	7349080311001	Dissolved	0.007	0.0007	0.0054	0.0007	<0.0002	0.125	<0.00005	<0.0002	0.005	<0.0001	0.0010	0.016

TABLE 7.

GROUNDWATER QUALITY RESULTS - DISSOLVED HYDROCARBONS - LOWER GRAND RAPIDS AQUIFER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

Sample Location	Sample Date	MSI Sample Number	Benzene mg/L	Toluene mg/L	Ethylbenzene mg/L	Xylenes mg/L	Total BTEX mg/L	TVH mg/L	TEH C_{11}-C_{30} mg/L
01-23-093-17 W4M	11-Mar-08	7349080311001	<0.0005	<0.0005	<0.0005	<0.0005	ND	<0.1	<0.05
Minimal Detection Limit			**0.0005**	**0.0005**	**0.0005**	**0.0005**	**---**	**0.1**	**0.05**

Notes:

--- - not analyzed

ND - not detected

TABLE 8

WATER QUALITY ANALYSIS AFTER DATA CULLING PROCEDURE

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI Parsed	FM Name National	Latitude NAD27	Longitude NAD27	Sodium (mg/L)	Potassium (mg/L)	Calcium (mg/L)	Magnesium (mg/L)	Iron (mg/L)	Chloride (mg/L)	Bicarbonate (mg/L)	Sulfate (mg/L)	Carbonate (mg/L)	Hydroxide	pH	TDS Calculated
100/04-07-091-19W4/00	Grosmont	56.87502289	113.05820465	3125	25	48	53		2700	3660	35			7.5	9646
100/05-24-094-18W4/00	Leduc Formation	57.16616440	112.76319122	4150	22	143	40		4900	3633	47	0	0	8.2	12935
100/05-24-094-18W4/00	Leduc Formation	57.16616440	112.76319122	3740	16	42	88		3995	2263	64	342		8.7	10550
100/10-01-091-18W4/00	McMurray Formation	56.86559296	112.75067139	1910	25	6	21		1312	2647	10	18		8.8	5949
100/07-14-091-18W4/00	McMurray Formation	56.89188766	112.77876282	1329	17	26	24		586	2712	25			8	4719
100/11-34-092-18W4/00	McMurray Formation	57.02672195	112.81182098	1795	30	34	28		1200	2898	13			7.8	5998
100/11-04-093-18W4/00	McMurray Formation	57.04228210	112.84050751	1150	100	36	34		773	2074	100			8	4267
100/11-10-093-18W4/00	McMurray Formation	57.05625153	112.81437683	1290	15	13	22		921	1921	18	0	0	8.2	4200
100/11-21-093-18W4/00	McMurray Formation	57.08335114	112.83963776	1885	51	32	22		800	3538	236	60		8.7	6624
100/06-21-094-17W4/00	McMurray Formation	57.16819000	112.68088531	2820	33	124	40		2526	3285	9	0	0	7.9	8837
100/07-18-091-17W4/00	Wabiskaw	56.89172745	112.72465515	1195	4	24	12		613	2531	3			8.3	4382
100/06-33-091-17W4/00	Wabiskaw	56.93450928	112.67768860	1634	14	20	38		873	3081	2			7.8	5662
100/06-33-091-17W4/00	Wabiskaw	56.93450928	112.67768860	1080	8	16	24		640	1891	12	0	0	8.3	3671
100/10-26-091-18W4/00	Wabiskaw	56.92483139	112.77674866	1618	50	24	10		561	3325	160			8.1	5748
100/11-12-091-19W4/00	Wabiskaw	56.88071442	112.91944122	2140	33	31	26		1330	3852	4	0	0	8.1	7416
100/10-05-092-18W4/00	Wabiskaw	56.95261765	112.85797119	1868	30	30	21		675	3977	49			7.9	6650
100/06-10-092-18W4/00	Wabiskaw	56.96488571	112.81184387	1240	20	29	27		770	2135	46			7.9	4267
100/06-06-093-17W4/00	Wabiskaw	57.03710556	112.73079681	2149	157	20	68	15	1493	3440	75			7.3	7417

IHS Energy, 2003. “GeoFluids.” A digital oil, gas and water chemistry database available in AccuMap, Calgary, Alberta. Date accessed October 20th 2007
***Hydro Fax Resources Ltd, 2007. "Athabasca Water Analyses Twp's 91-94 Rge's 14-19W4"**

TABLE 9

GROUNDWATER DIVERSIONS IN TOWNSHIPS 091-094 AND RANGES 16-19, WEST OF THE 4th MERIDIAN

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

Applicant	Project	Location	Latitude	Longitude	Approval ID	Water Allocation ID	Source	Quantity (m^3)	PUMP RATE (m^3/day)	Consumptive Use (m^3)	Specific Purpose	Licenced Date	Expiry Date	Upper Prod'n Interval (m)	Lower Prod'n Interval (m)
PETRO-CANADA	PETRO-CANADA INC, WR, 25016	13-9-093-18 W4M	57.0581	-112.8456	26507	5559	Unnamed Aquifer - Unclassified	1230	72.01	1230	CAMPS	13-Mar-1990	--	31.6	33.2

AENV, 2008. Authorization/Approval Viewer. Licence # 00026507-00-00. Protection and Enforcement. http://environment.alberta.ca/1057.html

ATTACHMENT A

ATTACHMENT A

GEOLOGIC MAPPING

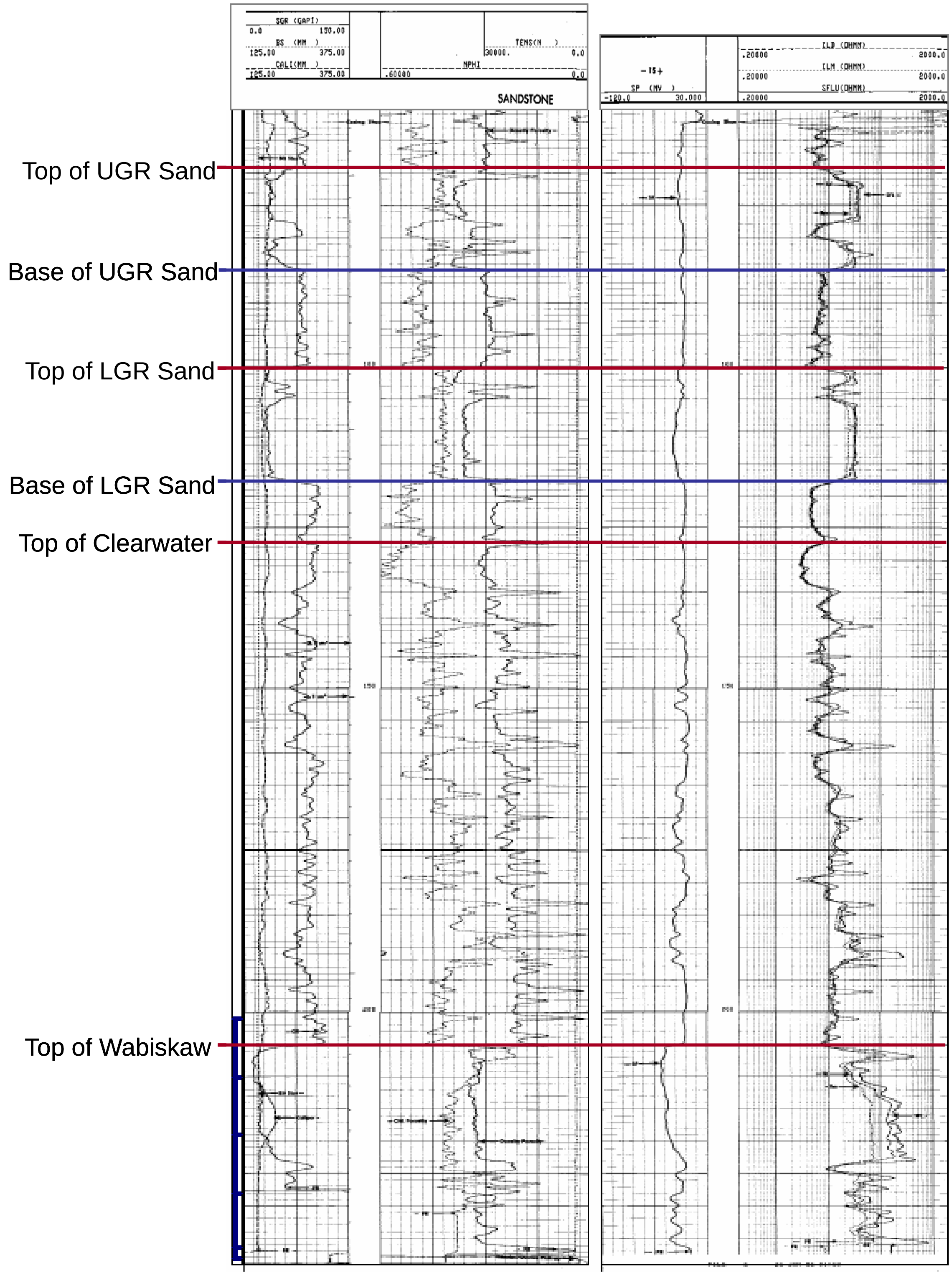
The majority of the mapping was limited to Cretaceous units as there were few wells in the study area that penetrated greater than 25 m into the Devonian units. The Cretaceous geologic picks included the top of the Joli Fou Formation, the top of the Upper Grand Rapids sand, the base of the Upper Grand Rapids sand, the top of the Lower Grand Rapids sand, the base of the Lower Grand Rapids sand, the top of the Clearwater Formation, the top of the Wabiskaw Member sands and the base of the Wabiskaw/McMurray sands. The geologic picks selected are presented in Tables A1 to A8. A Cretaceous type log is presented in Figure A1.

Based on the geologic picks, structure maps were created for the top of the Upper Grand Rapids sand, the top of the Lower Grand Rapids sand, the top of the Clearwater Formation and the top of the Wabiskaw Member sands. Net sand isopach maps were generated for the Upper Grand Rapids sand and Lower Grand Rapids sand. Each map was hand contoured in order to incorporate the overlying, underlying and unit specific geologic interpretations. The net sand isopach was based on a maximum gamma ray cut-off of 75 API, and good spontaneous potential and porosity development. It should be noted that cemented sandstone concretions were incorporated into the net sand isopach as it is expected that they are not laterally extensive and therefore, would not limit the aquifer's water supply potential in a regional sense.

There were 12 logs available which penetrated greater than 25 m into the Devonian units. Of these, one (UWI 06-13-091-18 W4M) included a Canadian Stratigraphic Inc. (CanStrat) log which provided detailed lithological information. The Devonian geologic picks for the 12 logs within the study area were generally based on the lithological information and geologic picks made on the CanStrat log. Where possible, the geologic picks made on the Devonian logs included the Precambrian basement, Contact Rapids Formation, Keg River Formation, Muskeg Formation, Watt Mountain Formation, Fort Vermilion Formation, Slave Point Formation, Waterways Formation and Woodbend Group (Table A9). A type log for the Devonian picks is presented in Figure A2. Given the limited data coverage, maps were not generated for the Devonian Formations. The discussion in the geology section of this report is based on the 12 reviewed logs and regional geologic/hydrogeologic reports.

UWI 100/06-26-092-18W4/0

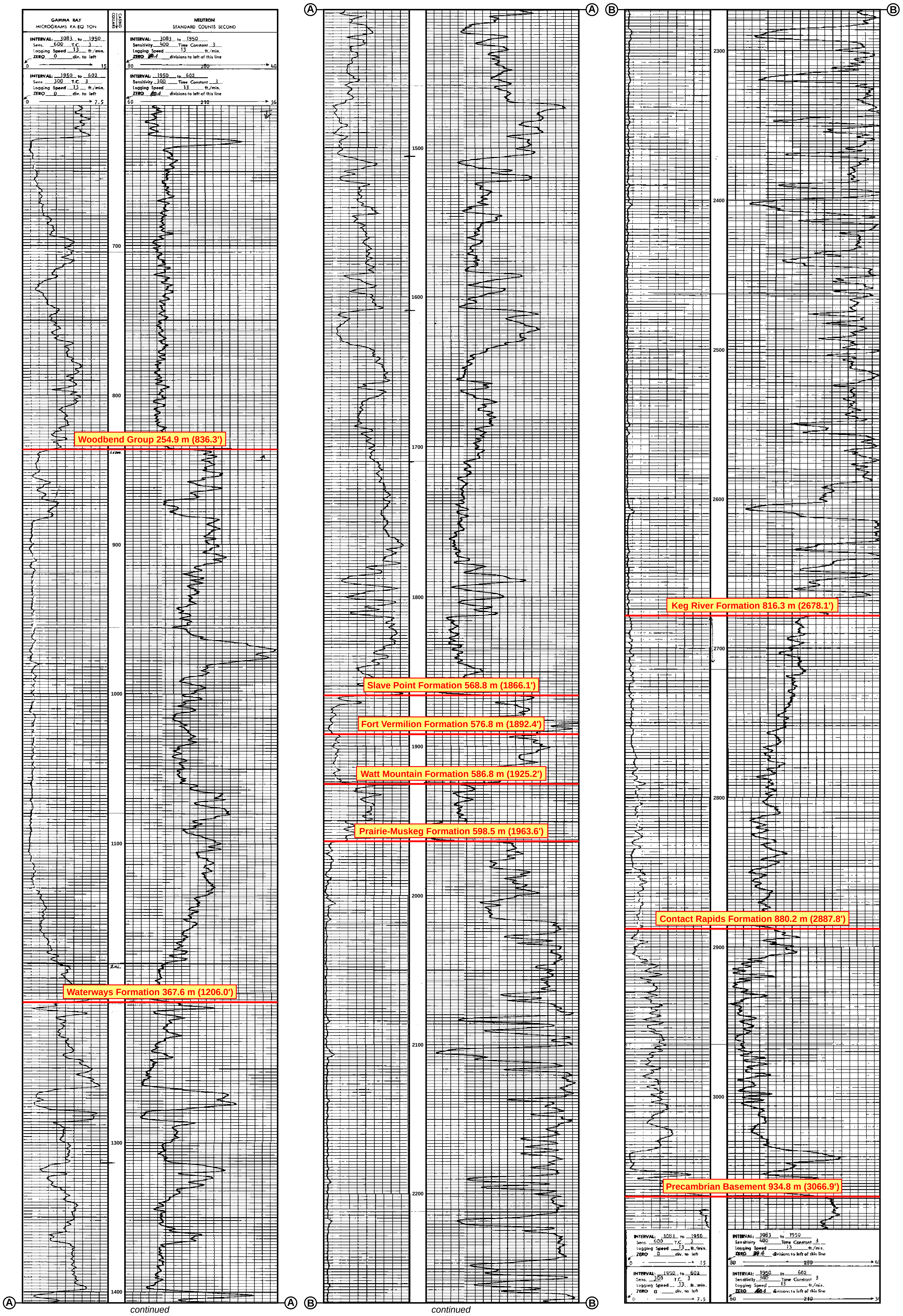
KB 520.30 m



Matrix Solutions Inc. ENVIRONMENT & ENGINEERING	ATHABASCA OIL SANDS CORP.
	TYPE LOG CRETACEOUS

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:		
MAY 2008	7349-WL-07	ED	BSW	SR	DOVER CENTRAL PILOT PROJECT	**FIGURE A1**

UWI 100/06-13-091-18 W4M
KB 511.50



Matrix Solutions Inc.
ENVIRONMENT & ENGINEERING

ATHABASCA OILS SANDS CORP.

TYPE LOG - DEVONIAN

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-WL2-07	ED	GDE	SR

DOVER CENTRAL PILOT PROJECT

FIGURE A2

TABLE A-1

TOP OF JOLI FOU FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	455.6	13.4
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	460.9	13.9
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	457.3	15.4
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	461.3	11.7
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	461.8	11.9
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	461.7	11.8
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	435.6	23.2
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	444.5	28.2
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	459.6	17.4
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	458.7	19.4
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	445.8	31.9
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	468.2	16.2
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	466.2	14.5
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	470.1	16.6
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	447.8	14.4
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	447.4	18.7
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	454.0	23.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	458.7	22.0
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	455.4	18.5
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	454.1	20.0
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	451.9	25.5
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	453.0	17.5
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	455.5	16.0

TABLE A-2

TOP OF UPPER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	448.4	13.9	
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	442.3	14.1	11.9
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	447.0	15.8	14.9
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	442.0	12.6	9.6
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	453.1	9.8	9.8
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	452.6	13.3	12.1
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	452.6	13.3	12.1
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	450.4	10.0	9.1
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	450.4	10.0	9.1
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	452.6	13.4	8.6
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	452.6	13.4	8.6
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	449.8	15.2	10.3
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	449.8	15.2	10.3
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	449.8	15.2	10.3
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	442.8	14.0	14.0
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	452.7	17.1	15.6
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	452.7	17.1	15.6
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	443.4	14.1	13.7
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	443.4	14.1	13.7
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	451.0	15.7	13.5
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	439.5	12.2	8.6
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	433.2	12.4	7.4
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	433.0	12.3	7.4
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	433.2	12.4	7.4
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	425.4	17.7	17.7
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	414.5	3.5	3.5
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	412.4	3.2	3.2
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	416.4	3.5	3.5
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	449.3	14.2	14.2
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	449.3	14.2	14.2
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	445.4	11.0	11.0
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	445.4	11.0	11.0
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	447.9	11.6	11.6
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	447.9	11.6	11.6
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	436.1	12.6	12.6
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	436.1	12.6	12.6
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	432.4	11.1	8.4
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	428.7	15.5	8.3
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	438.4	11.9	9.4
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	447.2	12.7	10.3
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	447.2	12.7	10.3
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	445.7	12.2	12.2
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	442.2	8.5	8.5
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	439.3	6.9	6.9
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	436.6	12.2	12.2

TABLE A-2

TOP OF UPPER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	427.4	10.5	10.5
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	431.3	10.7	8.4
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	424.6	8.9	4.4
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	425.8	10.2	10.2
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	429.0	15.3	5.1
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	429.0	15.3	5.1
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	432.2	6.8	6.8
100/14-30-093-18W4/0	385387.53	6330021.01	521.3	422.2	7.6	2.5
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	420.3	8.5	4.5
100/12-31-093-18W4/0	385163.55	6331314.23	524.5	419.5	10.4	3.4
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	418.8	4.1	4.1
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	425.5	11.8	7.1
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	413.9	4.7	0.0
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	421.7	2.6	2.6
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	420.0	3.4	3.4
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	413.8	5.0	2.8
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	452.0	10.1	10.1
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	451.7	9.9	9.9
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	454.6	10.1	7.7
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	453.5	10.4	10.4
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	439.3	12.6	12.6
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	439.3	12.6	12.6
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	433.4	9.7	8.7
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	428.7	9.2	7.0
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	434.9	7.6	5.8
100/06-21-094-18W4/0	388733.32	6337370.78	543.4	422.0	8.2	1.6
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	430.0	14.6	11.1
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	430.0	14.6	11.1
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	419.4	6.6	2.0
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	431.0	13.5	7.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	436.7	17.5	12.0
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	436.9	10.5	10.5
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	434.1	13.0	6.0
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	426.4	10.0	4.0
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	435.5	10.5	8.5
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	437.6	8.5	8.0
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	439.2	15.0	13.0
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	439.5	10.0	7.5
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	452.3	15.0	12.0
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	441.4	8.9	8.9
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	415.5	9.0	1.0
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	418.9	6.5	1.0

TABLE A-3

BASE OF UPPER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	443.5
100/04-06-091-19W4/0	374510.64	6303460.92	515.8	422.6
100/04-07-091-19W4/0	374547.21	6305136.30	513.6	421.2
100/10-16-091-19W4/0	378693.22	6307224.84	529.0	427.5
100/10-16-091-19W4/2	378693.22	6307224.84	529.0	427.3
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	428.2
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	431.1
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	429.4
100/13-28-091-19W4/0	378020.72	6310793.05	538.8	423.6
100/13-28-091-19W4/2	378020.72	6310793.05	538.8	423.6
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	443.4
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	444.3
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	444.4
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	438.2
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	439.3
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	439.3
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	439.4
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	439.4
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	439.2
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	439.2
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	434.6
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	434.6
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	434.6
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	428.9
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	435.7
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	435.7
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	429.2
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	429.4
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	435.4
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	427.4
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	426.1
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	426.1
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	424.7
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	420.7
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	420.7
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	420.7
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	407.6
100/04-09-092-19W4/0	378084.87	6314683.39	532.2	420.6
100/04-11-092-19W4/0	381359.14	6314590.37	528.4	418.1
100/04-11-092-19W4/2	381359.14	6314590.37	528.4	418.1
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	411.0
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	409.2
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	412.8

TABLE A-3

BASE OF UPPER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/06-06-093-17W4/0	394956.03	6322623.49	515.6	439.3
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	435.1
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	435.1
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	434.4
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	434.4
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	436.3
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	436.3
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	423.5
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	423.5
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	421.3
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	413.1
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	426.5
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	434.5
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	434.5
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	433.5
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	433.7
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	432.4
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	424.4
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	416.9
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	420.6
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	415.7
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	415.6
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	413.7
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	413.7
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	417.1
102/11-25-093-18W4/0	393581.34	6329527.36	526.0	428.0
100/14-30-093-18W4/0	385387.53	6330021.01	521.3	414.6
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	411.8
100/12-31-093-18W4/0	385163.55	6331314.23	524.5	409.6
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	414.8
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	413.7
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	409.2
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	419.1
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	416.6
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	408.8
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	441.9
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	441.9
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	444.5
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	443.0
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	426.7
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	426.7
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	423.7
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	419.5

TABLE A-3

BASE OF UPPER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	427.3
100/10-02-094-18W4/0	392296.66	6332983.24	526.4	413.1
100/10-03-094-18W4/0	390591.22	6332706.77	527.4	413.3
100/07-05-094-18W4/0	387297.78	6332535.74	525.4	409.1
100/06-21-094-18W4/0	388733.32	6337370.78	543.4	413.8
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	415.4
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	415.4
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	412.8
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	417.5
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	419.2
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	426.4
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	421.1
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	416.4
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	425.0
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	429.1
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	424.2
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	429.5
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	430.2
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	437.3
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	428.9
AA/03-18-092-17W4/0	394855.70	6315796.51	524.6	439.2
AA/10-08-093-17W/40	397004.40	6324588.60	509.9	440.3
AA/10-26-092-17W4/0	401776.10	6319633.00	520.9	443.6
AA/10-29-092-17W4/0	396803.00	6319771.30	514.1	443.0
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	432.5
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	406.5
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	412.4

TABLE A-4

TOP OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/16-15-091-16W4/0	409894.48	6306771.66	495.2	439.3	25.0	25.0
100/16-15-091-16W4/2	409894.48	6306771.66	495.2	439.3	25.0	25.0
100/14-04-091-17W4/0	397835.92	6304105.10	512.6	435.0	13.3	7.5
100/14-04-091-17W4/2	397835.92	6304105.10	512.6	435.0	13.3	7.5
100/10-09-091-17W4/0	398291.72	6305017.04	511.6	438.6	14.7	14.7
100/10-09-091-17W4/2	398291.72	6305017.04	511.6	438.6	14.7	14.7
100/10-09-091-17W4/3	398291.72	6305017.04	511.6	438.6	14.7	14.7
100/07-16-091-17W4/0	398246.27	6306296.81	511.1	437.1	18.8	18.8
100/07-16-091-17W4/2	398246.27	6306296.81	511.1	437.1	18.8	18.8
100/07-18-091-17W4/0	394926.47	6306433.56	511.2	435.9	22.4	22.4
100/06-23-091-17W4/0	401004.46	6307844.52	503.8	435.6	15.8	15.8
100/06-23-091-17W4/2	401004.46	6307844.52	503.8	435.6	15.8	15.8
100/06-23-091-17W4/3	401004.46	6307844.52	503.8	435.6	15.8	15.8
100/11-30-091-17W4/0	394517.31	6310063.87	516.2	433.0	23.8	23.8
100/06-33-091-17W4/0	397899.01	6311129.34	515.1	434.9	22.0	22.0
100/10-01-091-18W4/0	393265.99	6303573.99	509.4	433.4	13.2	10.9
100/10-01-091-18W4/2	393265.99	6303573.99	509.4	433.4	13.2	10.9
100/15-12-091-18W4/0	393246.73	6305479.42	511.2	430.5	19.0	19.0
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	432.6	23.9	23.9
100/07-33-091-18W4/0	388534.05	6311395.07	520.1	428.6	21.5	21.5
100/07-33-091-18W4/2	388534.05	6311395.07	520.1	428.6	21.5	21.5
100/04-06-091-19W4/0	374510.64	6303460.92	515.8	409.6	17.5	16.6
100/04-07-091-19W4/0	374547.21	6305136.30	513.6	408.2	17.2	16.8
100/11-12-091-19W4/0	383020.44	6305524.95	518.6	426.8	22.2	22.2
100/10-16-091-19W4/0	378693.22	6307224.84	529.0	415.0	17.1	17.1
100/10-16-091-19W4/2	378693.22	6307224.84	529.0	415.0	17.1	17.1
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	414.6	15.4	12.7
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	418.4	16.6	16.6
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	416.1	16.8	14.9
100/13-28-091-19W4/0	378020.72	6310793.05	538.8	409.6	15.1	11.7
100/13-28-091-19W4/2	378020.72	6310793.05	538.8	409.6	15.1	11.7
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	435.4	19.4	19.4
1AA/04-08-092-16W4/0	405877.57	6313834.97	497.7	438.4	21.9	21.9
100/03-20-092-16W4/0	406115.82	6316937.22	495.3	433.5	20.3	20.3
100/16-04-092-17W4/0	398830.68	6313627.61	509.2	436.8	25.5	25.5
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	432.1	23.7	23.7
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	432.1	23.7	23.7
100/03-09-092-17W4/0	397972.13	6314132.59	513.3	433.6	22.1	22.1
100/03-09-092-17W4/2	397972.13	6314132.59	513.3	433.6	22.1	22.1
100/11-28-092-17W4/0	398140.72	6319907.61	515.5	429.7	22.2	22.2
100/03-29-092-17W4/0	396633.98	6318924.89	516.1	427.1	22.0	22.0
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	426.9	23.2	23.2
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	425.8	21.3	21.3
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	425.8	21.3	21.3
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	426.1	20.7	20.7

TABLE A-4

TOP OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	426.1	20.7	20.7
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	423.4	18.5	19.9
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	423.4	18.5	19.9
100/10-05-092-18W4/0	386984.99	6313430.59	524.3	422.7	19.1	19.1
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	422.1	18.5	17.0
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	422.1	18.4	17.0
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	422.1	18.4	17.0
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	415.3	16.3	16.3
100/10-08-092-18W4/0	387037.17	6315080.86	523.7	421.8	17.0	17.0
100/10-08-092-18W4/2	387037.17	6315080.86	523.7	421.8	17.0	17.0
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	422.1	18.4	17.8
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	422.1	18.4	17.8
100/06-10-092-18W4/0	389827.62	6314720.80	520.7	424.5	19.1	19.1
100/04-16-092-18W4/0	387790.14	6316056.36	523.0	422.3	17.0	17.0
100/05-16-092-18W4/0	387864.86	6316284.78	522.7	421.4	16.9	15.7
100/05-16-092-18W4/2	387864.86	6316284.78	522.7	421.4	16.9	15.7
100/05-16-092-18W4/3	387864.86	6316284.78	522.7	421.4	16.9	15.7
100/06-17-092-18W4/0	386602.65	6316364.95	522.3	418.2	17.0	15.9
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	415.3	15.5	13.2
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	415.3	15.5	13.2
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	420.4	18.0	18.0
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	411.1	14.0	11.1
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	412.1	15.8	15.0
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	412.1	15.8	15.0
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	410.5	14.2	12.6
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	406.2	16.0	15.3
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	406.2	16.0	15.3
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	406.2	16.0	15.3
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	400.4	5.7	5.7
100/04-09-092-19W4/0	378084.87	6314683.39	532.2	397.0	4.2	0.9
100/10-10-092-19W4/0	380256.49	6315140.83	528.6	405.4	13.7	13.7
100/04-11-092-19W4/0	381359.14	6314590.37	528.4	404.3	14.1	10.7
100/04-11-092-19W4/2	381359.14	6314590.37	528.4	404.3	14.1	10.7
100/13-17-092-19W4/0	376275.60	6317583.04	532.5	396.6	4.2	4.2
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	391.4	3.8	3.8
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	390.5	3.4	0.0
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	393.1	3.3	0.0
100/07-15-093-16W4/0	410000.89	6325372.16	479.6	431.1	18.1	18.1
100/06-06-093-17W4/0	394956.03	6322623.49	515.6	424.2	17.2	17.2
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	420.0	18.6	18.6
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	420.0	18.6	18.6
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	416.5	17.0	17.0
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	416.5	17.0	17.0
100/10-28-093-17W4/0	398633.54	6329446.25	511.0	412.7	16.0	12.5
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	420.6	15.4	15.4

TABLE A-4

TOP OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	420.6	15.4	15.4
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	410.0	14.6	14.6
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	410.0	14.6	14.6
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	398.5	4.9	2.5
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	396.0	5.1	3.8
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	410.6	12.6	5.3
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	419.4	14.4	10.2
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	419.4	14.4	10.2
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	422.4	16.9	16.9
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	414.2	14.0	14.0
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	406.1	5.6	5.6
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	402.4	4.6	4.6
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	401.0	4.8	4.8
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	403.9	5.1	5.1
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	399.9	4.4	4.4
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	400.5	4.3	4.3
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	398.2	3.9	1.7
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	398.2	3.9	1.7
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	400.1	4.6	4.6
100/11-21-093-18W4/0	388492.15	6327951.24	521.0	401.9	5.9	5.9
102/11-25-093-18W4/0	393581.34	6329527.36	526.0	399.9	6.8	6.8
100/14-30-093-18W4/0	385387.53	6330021.01	521.3	397.2	2.5	0.0
102/14-30-093-18W4/0	385252.12	6330023.77	521.5	398.0	2.6	1.2
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	396.6	4.0	1.4
100/12-31-093-18W4/0	385163.55	6331314.23	524.5	395.8	3.8	0.0
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	394.0	2.0	2.0
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	398.8	4.1	3.0
100/11-14-093-19W4/0	382080.20	6326734.59	518.7	397.0	3.1	3.1
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	390.0	2.7	0.0
100/07-22-093-19W4/0	380921.87	6327853.32	525.2	401.4	3.0	1.1
100/07-22-093-19W4/2	380921.87	6327853.32	525.2	401.4	3.0	1.1
100/11-23-093-19W4/0	382231.42	6328090.83	518.6	398.4	4.4	4.4
100/10-24-093-19W4/0	384156.65	6327986.66	519.0	400.0	3.6	2.6
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	398.1	4.9	4.9
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	395.9	2.2	2.2
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	389.3	3.3	3.3
100/07-36-093-19W4/0	384185.02	6331086.71	524.2	396.1	3.4	3.4
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	423.1	19.3	19.3
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	424.2	18.4	18.4
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	426.2	17.1	17.1
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	425.1	15.5	15.5
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	408.6	13.8	8.9
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	408.6	13.7	8.9
100/06-06-094-17W4/0	395367.41	6332256.76	530.5	409.1	14.7	6.9
100/12-11-094-17W4/0	401438.47	6333997.24	527.3	408.7	13.2	9.6

TABLE A-4

TOP OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)	Gross Isopach (m)	Net Sand (m)
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	398.7	4.8	4.8
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	394.9	4.2	0.8
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	402.5	5.2	2.7
100/10-02-094-18W4/0	392296.66	6332983.24	526.4	403.9	13.7	8.2
100/10-03-094-18W4/0	390591.22	6332706.77	527.4	396.1	4.2	1.0
100/07-05-094-18W4/0	387297.78	6332535.74	525.4	395.2	4.3	4.3
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	395.6	5.1	2.1
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	395.6	5.1	2.1
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	393.1	2.8	0.0
100/09-35-094-18W4/0	392817.23	6340761.15	558.3	392.5	3.7	0.8
100/06-31-92-16W4/0	404757.88	6320950.47	504.8	429.8	23.5	23.5
100/06-36-92-17W4/0	403140.23	6320763.78	507.2	428.2	24.5	24.5
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	402.0	8.0	5.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	408.2	13.5	7.0
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	406.9	12.0	3.5
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	399.6	5.5	3.5
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	396.4	4.5	1.0
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	400.0	5.0	4.0
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	409.6	15.5	9.0
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	403.7	7.5	7.5
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	410.5	14.0	7.0
100/16-24-93-17W4/0	403961.01	6327962.53	501.0	425.5	23.0	23.0
100/08-23-93-17W4/0	402295.99	6327223.33	502.6	421.6	21.5	21.5
100/10-22-93-17W4/0	400279.77	6327692.85	504.3	417.8	18.5	16.0
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	412.2	15.5	13.5
100/01-15-93-17W4/0	400537.43	6325202.67	502.6	422.6	21.5	21.5
100/06-14-93-17W4/0	401624.27	6325796.32	500.9	422.4	22.0	22.0
100/14-02-93-17W4/0	401402.18	6323358.08	504.1	426.1	19.0	19.0
100/07-13-93-17W4/0	403617.37	6325570.91	497.4	422.9	19.0	19.0
100/06-01-93-17W4/0	403216.78	6322311.92	508.3	428.8	25.0	25.0
100/11-19-93-16W4/0	404751.21	6327496.03	497.5	424.5	21.5	21.4
100/06-06-93-16W4/0	404552.90	6322289.94	501.3	430.3	26.5	25.0
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	423.3	19.5	19.5
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	412.4	13.7	10.7
AA/03-18-092-17W4/0	394855.70	6315796.54	524.6	425.7	21.0	21.0
AA/10-08-093-17W4/0	397004.40	6324588.60	509.9	421.6	18.7	17.2
AA/10-11-092-17W4/0	401659.20	6314759.50	505.9	433.7	22.0	22.0
AA/10-11-093-17W4/0	402027.70	6324497.50	500.2	426.6	21.8	21.8
AA/10-26-091-16W4/0	411485.90	6309712.70	489.0	419.4	9.5	9.5
AA/10-26-092-17W4/0	401776.10	6319633.00	520.9	429.3	20.4	20.4
AA/10-29-092-17W4/0	396803.00	6319771.30	514.1	429.2	23.9	23.9
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	411.1	14.1	11.3
AA/11-25-093-17W4/0	403232.40	6329338.00	504.1	421.4	22.1	22.1
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	391.5	3.9	0.0
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	393.9	3.2	0.0

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/16-15-091-16W4/0	409894.48	6306771.66	495.2	414.3
100/16-15-091-16W4/2	409894.48	6306771.66	495.2	414.3
1AA/10-29-091-16W4/0	406451.45	6309804.39	493.4	409.7
100/14-04-091-17W4/0	397835.92	6304105.10	512.6	421.7
100/14-04-091-17W4/2	397835.92	6304105.10	512.6	422.1
100/10-09-091-17W4/0	398291.72	6305017.04	511.6	423.9
100/10-09-091-17W4/2	398291.72	6305017.04	511.6	423.6
100/10-09-091-17W4/3	398291.72	6305017.04	511.6	423.9
100/11-10-091-17W4/0	399247.24	6305136.82	509.4	426.2
100/11-10-091-17W4/2	399247.24	6305136.82	509.4	426.4
100/12-11-091-17W4/0	400534.96	6305136.95	505.2	425.8
100/12-11-091-17W4/2	400534.96	6305136.95	505.2	425.8
100/07-16-091-17W4/0	398246.27	6306296.81	511.1	418.2
100/07-16-091-17W4/2	398246.27	6306296.81	511.1	418.2
100/07-18-091-17W4/0	394926.47	6306433.56	511.2	413.5
100/06-23-091-17W4/0	401004.46	6307844.52	503.8	419.7
100/06-23-091-17W4/2	401004.46	6307844.52	503.8	419.7
100/06-23-091-17W4/3	401004.46	6307844.52	503.8	419.6
100/06-24-091-17W4/0	402833.33	6307768.92	501.8	409.3
100/11-30-091-17W4/0	394517.31	6310063.87	516.2	409.2
100/06-33-091-17W4/0	397899.01	6311129.34	515.1	412.9
100/10-01-091-18W4/0	393265.99	6303573.99	509.4	420.2
100/10-01-091-18W4/2	393265.99	6303573.99	509.4	420.2
100/15-08-091-18W4/0	386868.74	6306018.56	514.8	402.1
100/15-12-091-18W4/0	393246.73	6305479.42	511.2	411.5
100/06-13-091-18W4/0	392864.02	6306482.42	511.5	408.1
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	408.7
100/07-14-091-18W4/0	391626.21	6306537.04	509.9	406.3
100/13-14-091-18W4/0	391054.32	6307231.54	517.1	407.1
100/16-22-091-18W4/0	390329.78	6308799.94	516.8	409.2
100/16-22-091-18W4/2	390329.78	6308799.94	516.8	409.2
100/10-26-091-18W4/0	391844.08	6310205.89	514.2	409.6
100/07-33-091-18W4/0	388534.05	6311395.07	520.1	407.1
100/07-33-091-18W4/2	388534.05	6311395.07	520.1	407.0
100/06-03-091-19W4/0	379776.91	6303548.03	521.5	401.1
100/04-06-091-19W4/0	374510.64	6303460.92	515.8	392.1
100/04-07-091-19W4/0	374547.21	6305136.30	513.6	391.0
100/11-10-091-19W4/0	379689.33	6305681.50	523.7	400.6
100/11-12-091-19W4/0	383020.44	6305524.95	518.6	404.5
100/10-16-091-19W4/0	378693.22	6307224.84	529.0	398.0
100/10-16-091-19W4/2	378693.22	6307224.84	529.0	398.0
100/02-22-091-19W4/0	380321.83	6308181.71	526.0	397.5
100/02-22-091-19W4/2	380321.83	6308181.71	526.0	397.5
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	399.2
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	401.8

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	399.2
100/13-28-091-19W4/0	378020.72	6310793.05	538.8	394.5
100/13-28-091-19W4/2	378020.72	6310793.05	538.8	394.5
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	416.0
1AA/04-08-092-16W4/0	405877.57	6313834.97	497.7	416.4
100/03-20-092-16W4/0	406115.82	6316937.22	495.3	413.2
100/16-02-092-17W4/0	402181.14	6313514.10	505.2	414.4
100/16-02-092-17W4/2	402181.14	6313514.10	505.2	414.4
100/16-03-092-17W4/0	400489.99	6313571.62	507.6	412.8
100/16-04-092-17W4/0	398830.68	6313627.61	509.2	411.3
100/13-05-092-17W4/0	395962.50	6313723.37	519.7	411.8
100/13-05-092-17W4/2	395962.50	6313723.37	519.7	411.9
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	408.4
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	408.2
100/03-09-092-17W4/0	397972.13	6314132.59	513.3	411.5
100/03-09-092-17W4/2	397972.13	6314132.59	513.3	411.5
100/05-15-092-17W4/0	399292.57	6315863.37	509.2	412.0
100/05-17-092-17W4/0	396150.51	6315949.22	519.4	404.8
102/13-21-092-17W4/0	397784.99	6318671.97	518.1	407.1
102/13-21-092-17W4/2	397784.99	6318671.97	518.1	407.1
100/02-23-092-17W4/0	401911.83	6317216.51	505.5	407.7
100/04-26-092-17W4/0	400918.63	6318647.39	510.4	404.9
100/11-28-092-17W4/0	398140.72	6319907.61	515.5	407.4
100/03-29-092-17W4/0	396633.98	6318924.89	516.1	405.1
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	403.7
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	404.5
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	404.5
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	405.4
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	405.4
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	404.9
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	404.9
100/10-05-092-18W4/0	386984.99	6313430.59	524.3	403.5
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	403.6
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	403.6
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	403.6
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	399.0
100/10-08-092-18W4/0	387037.17	6315080.86	523.7	404.7
100/10-08-092-18W4/2	387037.17	6315080.86	523.7	404.7
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	403.7
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	403.7
100/13-09-092-18W4/0	387607.25	6315357.20	523.8	405.7
100/06-10-092-18W4/0	389827.62	6314720.80	520.7	405.4
100/07-12-092-18W4/0	393668.66	6314403.43	520.9	405.6
100/11-15-092-18W4/0	389814.20	6316851.04	520.5	404.1
100/04-16-092-18W4/0	387790.14	6316056.36	523.0	405.3

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/05-16-092-18W4/0	387864.86	6316284.78	522.7	404.5
100/05-16-092-18W4/2	387864.86	6316284.78	522.7	404.5
100/05-16-092-18W4/3	387864.86	6316284.78	522.7	404.5
100/06-17-092-18W4/0	386602.65	6316364.95	522.3	401.2
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	399.8
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	399.8
100/06-24-092-18W4/0	393128.25	6317719.50	522.2	405.1
100/10-25-092-18W4/0	393716.67	6319866.96	523.7	404.3
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	402.3
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	397.1
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	396.3
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	396.3
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	396.3
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	390.2
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	390.2
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	390.2
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	394.7
100/04-09-092-19W4/0	378084.87	6314683.39	532.2	392.8
100/10-10-092-19W4/0	380256.49	6315140.83	528.6	391.7
100/04-11-092-19W4/0	381359.14	6314590.37	528.4	390.2
100/04-11-092-19W4/2	381359.14	6314590.37	528.4	390.2
100/13-17-092-19W4/0	376275.60	6317583.04	532.5	392.3
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	387.6
100/02-29-092-19W4/0	377112.72	6319578.50	541.3	392.2
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	387.0
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	389.8
100/06-35-092-19W4/0	381806.21	6321270.31	523.6	390.5
100/07-15-093-16W4/0	410000.89	6325372.16	479.6	413.0
100/06-06-093-17W4/0	394956.03	6322623.49	515.6	407.0
100/02-10-093-17W4/0	400360.63	6323657.29	504.6	403.1
100/03-12-093-17W4/0	403288.05	6323640.01	500.9	401.8
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	401.4
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	401.4
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	399.5
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	399.4
100/10-28-093-17W4/0	398633.54	6329446.25	511.0	396.7
100/11-31-093-17W4/0	395345.18	6331199.97	530.7	396.4
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	405.3
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	405.3
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	395.4
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	395.4
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	393.6
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	390.9
100/11-10-093-18W4/0	389942.81	6324894.02	518.9	397.9
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	397.9

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	404.9
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	404.9
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	405.5
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	400.1
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	400.5
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	397.9
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	396.2
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	398.9
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	395.4
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	395.0
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	394.3
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	394.3
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	395.5
100/11-21-093-18W4/0	388492.15	6327951.24	521.0	395.9
100/09-22-093-18W4/0	390859.83	6328024.62	524.8	396.5
100/09-22-093-18W4/2	390859.83	6328024.62	524.8	396.5
102/10-23-093-18W4/0	392195.31	6327895.25	524.7	396.7
102/11-25-093-18W4/0	393581.34	6329527.36	526.0	393.1
100/14-30-093-18W4/0	385387.53	6330021.01	521.3	394.7
102/14-30-093-18W4/0	385252.12	6330023.77	521.5	395.4
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	392.6
100/12-31-093-18W4/0	385163.55	6331314.23	524.5	392.0
100/12-32-093-18W4/0	386505.69	6331270.12	524.7	392.9
100/14-03-093-19W4/0	380204.78	6323634.07	523.0	391.4
100/14-03-093-19W4/2	380204.78	6323634.07	523.0	391.4
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	392.1
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	394.6
100/11-14-093-19W4/0	382080.20	6326734.59	518.7	393.9
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	387.2
100/07-22-093-19W4/0	380921.87	6327853.32	525.2	398.3
100/07-22-093-19W4/2	380921.87	6327853.32	525.2	398.3
100/11-23-093-19W4/0	382231.42	6328090.83	518.6	394.0
100/10-24-093-19W4/0	384156.65	6327986.66	519.0	396.4
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	393.2
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	393.7
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	386.0
100/07-36-093-19W4/0	384185.02	6331086.71	524.2	392.7
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	403.8
1AA/10-11-094-16W4/0	411861.00	6333957.69	504.7	408.9
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	405.8
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	409.1
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	409.6
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	394.8
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	394.8
100/06-06-094-17W4/0	395367.41	6332256.76	530.5	394.4

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/12-11-094-17W4/0	401438.47	6333997.24	527.3	395.5
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	394.0
1AA/07-23-094-17W4/0	402182.97	6336987.37	526.7	398.5
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	390.7
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	397.3
100/10-02-094-18W4/0	392296.66	6332983.24	526.4	390.2
100/10-03-094-18W4/0	390591.22	6332706.77	527.4	391.9
100/07-05-094-18W4/0	387297.78	6332535.74	525.4	390.9
100/07-06-094-18W4/0	385795.38	6332572.68	530.7	391.4
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	390.8
100/05-07-094-18W4/2	385213.47	6334231.23	535.9	391.1
100/06-08-094-18W4/0	387155.48	6334040.00	530.2	388.3
100/08-09-094-18W4/0	389383.69	6334163.11	529.6	390.2
100/08-16-094-18W4/0	389532.31	6335843.81	540.9	390.4
100/11-20-094-18W4/0	387149.20	6337841.10	551.9	389.7
100/11-20-094-18W4/2	387149.20	6337841.10	551.9	389.6
100/06-21-094-18W4/0	388733.32	6337370.78	543.4	391.8
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	390.5
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	390.6
100/13-27-094-18W4/0	389998.55	6339864.07	547.0	390.9
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	390.3
100/11-30-094-18W4/0	385586.01	6339549.57	596.3	387.1
100/11-30-094-18W4/2	385586.01	6339549.57	596.3	387.7
100/06-32-094-18W4/0	387259.49	6340587.70	589.4	386.9
100/11-33-094-18W4/0	388764.50	6341022.36	592.7	390.5
100/09-35-094-18W4/0	392817.23	6340761.15	558.3	388.9
100/09-01-094-19W4/0	384486.18	6333145.06	530.5	391.1
100/06-07-094-19W4/0	375778.56	6334536.89	591.9	381.8
100/06-09-094-19W4/0	379126.83	6334415.06	569.7	385.3
100/09-12-094-19W4/0	384558.89	6334821.55	539.2	390.2
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	388.1
100/11-16-094-19W4/0	379133.61	6336365.48	612.4	381.0
100/07-24-094-19W4/0	384522.81	6337409.07	560.6	387.0
100/07-28-094-19W4/0	379585.59	6339157.11	642.2	385.3
100/11-03-92-16W4/0	409370.95	6312974.38	484.8	411.3
100/10-09-92-16W4/0	408218.90	6314631.01	491.3	420.3
100/04-10-92-16W4/0	409086.49	6313811.29	485.8	421.8
100-06-15-92-16W4/0	409289.90	6315815.46	486.0	419.0
100/04-27-92-16W4/0	408999.93	6318779.62	487.1	412.1
100/06-28-92-16W4/0	407697.26	6319222.76	489.2	410.7
100/10-30-92-16W4/0	405031.51	6319540.84	498.3	407.8
100/06-32-92-16W4/0	406232.43	6320913.29	494.7	408.2
100/11-33-92-16W4/0	407982.79	6321194.99	485.6	411.6
100/06-31-92-16W4/0	404757.88	6320950.47	504.8	406.3
100/06-36-92-17W4/0	403140.23	6320763.78	507.2	403.7

TABLE A-5

BASE OF LOWER GRAND RAPIDS FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	394.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	394.7
100/08-25-92-17W4/0	403744.99	6319229.97	501.9	412.4
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	394.9
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	394.1
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	391.9
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	395.0
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	394.1
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	396.2
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	396.5
100/16-24-93-17W4/0	403961.01	6327962.53	501.0	402.5
100/08-23-93-17W4/0	402295.99	6327223.33	502.6	400.1
100/10-22-93-17W4/0	400279.77	6327692.85	504.3	399.3
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	396.7
100/01-15-93-17W4/0	400537.43	6325202.67	502.6	401.1
100/06-14-93-17W4/0	401624.27	6325796.32	500.9	400.4
100/14-02-93-17W4/0	401402.18	6323358.08	504.1	407.1
100/07-13-93-17W4/0	403617.37	6325570.91	497.4	403.9
100/06-01-93-17W4/0	403216.78	6322311.92	508.3	403.8
100/06-07-93-16W4/0	404777.62	6324065.08	496.0	406.0
100/11-19-93-16W4/0	404751.21	6327496.03	497.5	403.0
100/06-06-93-16W4/0	404552.90	6322289.94	501.3	403.8
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	403.8
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	398.7
100/02-10-093-17W4/0	400359.90	6323669.74	504.6	403.2
AA/03-18-092-17W4/0	394855.70	6315796.57	524.6	404.7
AA/06-28-092-16W/40	407705.10	6319226.40	489.4	410.9
AA/10-08-093-17W4/0	397004.40	6324588.60	509.9	402.9
AA/10-11-092-17W4/0	401659.20	6314759.50	505.9	411.6
AA/10-11-093-17W4/0	402027.70	6324497.50	500.2	404.9
AA/10-26-091-16W4/0	411485.90	6309712.70	489.0	409.9
AA/10-26-092-17W4/0	401776.10	6319633.00	520.9	408.9
AA/10-29-092-16W4/0	406660.40	6319520.30	493.5	411.7
AA/10-29-092-17W4/0	396803.00	6319771.30	514.1	405.2
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	397.0
AA/11-25-093-17W4/0	403232.40	6329338.00	504.1	399.4

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
1AA/10-11-091-16W4/0	411239.55	6304826.65	493.9	408.4
100/16-15-091-16W4/0	409894.48	6306771.66	495.2	412.7
100/16-15-091-16W4/2	409894.48	6306771.66	495.2	412.7
1AA/10-29-091-16W4/0	406451.45	6309804.39	493.4	403.0
100/14-04-091-17W4/0	397835.92	6304105.10	512.6	406.2
100/14-04-091-17W4/2	397835.92	6304105.10	512.6	406.6
100/10-09-091-17W4/0	398291.72	6305017.04	511.6	408.6
100/10-09-091-17W4/2	398291.72	6305017.04	511.6	408.5
100/10-09-091-17W4/3	398291.72	6305017.04	511.6	408.3
100/11-10-091-17W4/0	399247.24	6305136.82	509.4	407.6
100/11-10-091-17W4/2	399247.24	6305136.82	509.4	407.6
100/12-11-091-17W4/0	400534.96	6305136.95	505.2	405.3
100/12-11-091-17W4/2	400534.96	6305136.95	505.2	405.3
100/07-16-091-17W4/0	398246.27	6306296.81	511.1	405.3
100/07-16-091-17W4/2	398246.27	6306296.81	511.1	405.2
100/07-18-091-17W4/0	394926.47	6306433.56	511.2	403.2
100/06-23-091-17W4/0	401004.46	6307844.52	503.8	404.6
100/06-23-091-17W4/2	401004.46	6307844.52	503.8	404.7
100/06-23-091-17W4/3	401004.46	6307844.52	503.8	404.5
100/06-24-091-17W4/0	402833.33	6307768.92	501.8	403.9
100/11-30-091-17W4/0	394517.31	6310063.87	516.2	398.5
100/06-33-091-17W4/0	397899.01	6311129.34	515.1	402.4
100/04-36-091-17W4/0	402212.96	6310529.79	502.0	402.5
100/04-36-091-17W4/2	402212.96	6310529.79	502.0	402.5
100/10-01-091-18W4/0	393265.99	6303573.99	509.4	406.9
100/10-01-091-18W4/2	393265.99	6303573.99	509.4	407.3
100/15-08-091-18W4/0	386868.74	6306018.56	514.8	390.7
100/15-12-091-18W4/0	393246.73	6305479.42	511.2	399.8
100/06-13-091-18W4/0	392864.02	6306482.42	511.5	398.1
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	397.9
100/07-14-091-18W4/0	391626.21	6306537.04	509.9	395.0
100/13-14-091-18W4/0	391054.32	6307231.54	517.1	396.3
100/16-22-091-18W4/0	390329.78	6308799.94	516.8	397.7
100/16-22-091-18W4/2	390329.78	6308799.94	516.8	397.6
100/10-26-091-18W4/0	391844.08	6310205.89	514.2	397.6
100/07-33-091-18W4/0	388534.05	6311395.07	520.1	397.1
100/07-33-091-18W4/2	388534.05	6311395.07	520.1	397.0
100/06-03-091-19W4/0	379776.91	6303548.03	521.5	391.6
100/04-06-091-19W4/0	374510.64	6303460.92	515.8	383.2
100/04-07-091-19W4/0	374547.21	6305136.30	513.6	382.8
100/11-10-091-19W4/0	379689.33	6305681.50	523.7	391.2
100/11-12-091-19W4/0	383020.44	6305524.95	518.6	395.0
100/10-16-091-19W4/0	378693.22	6307224.84	529.0	389.6
100/10-16-091-19W4/2	378693.22	6307224.84	529.0	389.6

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/02-22-091-19W4/0	380321.83	6308181.71	526.0	389.2
100/02-22-091-19W4/2	380321.83	6308181.71	526.0	389.1
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	390.2
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	392.2
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	390.8
100/13-28-091-19W4/0	378020.72	6310793.05	538.8	386.4
100/13-28-091-19W4/2	378020.72	6310793.05	538.8	386.3
100/16-03-092-16W4/0	410077.37	6313201.56	486.9	404.4
100/08-04-092-16W4/0	408431.08	6312760.35	491.2	404.2
100/08-04-092-16W4/2	408431.08	6312760.35	491.2	404.2
100/08-04-092-16W4/3	408431.08	6312760.35	491.2	404.2
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	402.1
1AA/04-08-092-16W4/0	405877.57	6313834.97	497.7	402.6
100/03-20-092-16W4/0	406115.82	6316937.22	495.3	400.3
100/16-02-092-17W4/0	402181.14	6313514.10	505.2	402.2
100/16-02-092-17W4/2	402181.14	6313514.10	505.2	402.3
100/16-03-092-17W4/0	400489.99	6313571.62	507.6	401.9
100/16-04-092-17W4/0	398830.68	6313627.61	509.2	400.2
100/13-05-092-17W4/0	395962.50	6313723.37	519.7	400.7
100/13-05-092-17W4/2	395962.50	6313723.37	519.7	400.6
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	396.8
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	396.6
100/03-09-092-17W4/0	397972.13	6314132.59	513.3	399.6
100/03-09-092-17W4/2	397972.13	6314132.59	513.3	399.7
100/05-15-092-17W4/0	399292.57	6315863.37	509.2	400.1
100/05-17-092-17W4/0	396150.51	6315949.22	519.4	394.8
102/13-21-092-17W4/0	397784.99	6318671.97	518.1	396.9
102/13-21-092-17W4/2	397784.99	6318671.97	518.1	397.2
100/02-23-092-17W4/0	401911.83	6317216.51	505.5	396.5
100/04-26-092-17W4/0	400918.63	6318647.39	510.4	392.9
100/11-28-092-17W4/0	398140.72	6319907.61	515.5	396.2
100/03-29-092-17W4/0	396633.98	6318924.89	516.1	394.4
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	393.6
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	394.6
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	394.2
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	395.7
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	395.3
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	394.7
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	394.8
100/10-05-092-18W4/0	386984.99	6313430.59	524.3	394.3
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	394.8
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	394.8
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	394.7
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	388.5

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/10-08-092-18W4/0	387037.17	6315080.86	523.7	395.6
100/10-08-092-18W4/2	387037.17	6315080.86	523.7	395.3
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	394.6
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	394.3
100/13-09-092-18W4/0	387607.25	6315357.20	523.8	396.4
100/06-10-092-18W4/0	389827.62	6314720.80	520.7	394.3
100/07-12-092-18W4/0	393668.66	6314403.43	520.9	394.6
100/11-15-092-18W4/0	389814.20	6316851.04	520.5	394.2
100/04-16-092-18W4/0	387790.14	6316056.36	523.0	396.9
100/05-16-092-18W4/0	387864.86	6316284.78	522.7	394.9
100/05-16-092-18W4/2	387864.86	6316284.78	522.7	394.4
100/05-16-092-18W4/3	387864.86	6316284.78	522.7	394.8
100/06-17-092-18W4/0	386602.65	6316364.95	522.3	391.8
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	391.1
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	390.9
100/06-24-092-18W4/0	393128.25	6317719.50	522.2	394.3
100/10-25-092-18W4/0	393716.67	6319866.96	523.7	394.3
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	392.8
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	387.3
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	386.5
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	386.7
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	385.8
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	381.8
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	381.7
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	381.7
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	386.7
100/04-09-092-19W4/0	378084.87	6314683.39	532.2	385.0
100/10-10-092-19W4/0	380256.49	6315140.83	528.6	383.5
100/04-11-092-19W4/0	381359.14	6314590.37	528.4	381.2
100/04-11-092-19W4/2	381359.14	6314590.37	528.4	381.2
100/13-17-092-19W4/0	376275.60	6317583.04	532.5	385.8
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	381.4
100/02-29-092-19W4/0	377112.72	6319578.50	541.3	385.3
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	381.4
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	382.3
100/06-35-092-19W4/0	381806.21	6321270.31	523.6	381.4
100/07-15-093-16W4/0	410000.89	6325372.16	479.6	400.3
100/02-03-093-17W4/0	400329.60	6321943.49	509.1	391.8
100/06-06-093-17W4/0	394956.03	6322623.49	515.6	396.7
100/02-10-093-17W4/0	400360.63	6323657.29	504.6	392.4
100/03-12-093-17W4/0	403288.05	6323640.01	500.9	390.4
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	392.6
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	392.2
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	389.0

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	388.7
100/10-28-093-17W4/0	398633.54	6329446.25	511.0	385.8
100/11-31-093-17W4/0	395345.18	6331199.97	530.7	385.6
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	395.2
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	395.3
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	385.7
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	385.5
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	386.3
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	385.1
100/11-10-093-18W4/0	389942.81	6324894.02	518.9	388.6
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	388.7
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	395.2
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	395.2
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	396.2
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	390.4
100/03-15-093-18W4/2	390128.12	6325411.66	522.7	390.2
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	389.6
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	388.6
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	390.1
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	387.5
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	388.6
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	386.1
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	386.1
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	387.3
100/11-21-093-18W4/0	388492.15	6327951.24	521.0	387.8
100/09-22-093-18W4/0	390859.83	6328024.62	524.8	387.6
100/09-22-093-18W4/2	390859.83	6328024.62	524.8	387.5
102/10-23-093-18W4/0	392195.31	6327895.25	524.7	388.2
102/11-25-093-18W4/0	393581.34	6329527.36	526.0	385.0
102/14-30-093-18W4/0	385252.12	6330023.77	521.5	386.9
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	385.6
100/12-31-093-18W4/0	385163.55	6331314.23	524.5	385.2
100/12-32-093-18W4/0	386505.69	6331270.12	524.7	385.8
100/14-03-093-19W4/0	380204.78	6323634.07	523.0	384.8
100/14-03-093-19W4/2	380204.78	6323634.07	523.0	384.6
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	385.6
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	387.5
100/11-14-093-19W4/0	382080.20	6326734.59	518.7	387.4
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	381.6
100/07-22-093-19W4/0	380921.87	6327853.32	525.2	390.1
100/07-22-093-19W4/2	380921.87	6327853.32	525.2	390.1
100/11-23-093-19W4/0	382231.42	6328090.83	518.6	386.7
100/10-24-093-19W4/0	384156.65	6327986.66	519.0	387.6
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	386.9

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	386.7
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	380.4
100/07-36-093-19W4/0	384185.02	6331086.71	524.2	384.9
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	391.2
1AA/10-11-094-16W4/0	411861.00	6333957.69	504.7	398.2
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	393.8
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	396.0
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	397.7
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	385.6
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	385.2
100/06-06-094-17W4/0	395367.41	6332256.76	530.5	385.2
100/12-11-094-17W4/0	401438.47	6333997.24	527.3	385.7
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	384.0
1AA/07-23-094-17W4/0	402182.97	6336987.37	526.7	387.5
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	381.5
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	388.1
100/10-02-094-18W4/0	392296.66	6332983.24	526.4	382.0
100/10-03-094-18W4/0	390591.22	6332706.77	527.4	383.4
100/07-05-094-18W4/0	387297.78	6332535.74	525.4	382.7
100/07-06-094-18W4/0	385795.38	6332572.68	530.7	384.1
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	383.1
100/05-07-094-18W4/2	385213.47	6334231.23	535.9	383.4
100/06-08-094-18W4/0	387155.48	6334040.00	530.2	380.5
100/08-09-094-18W4/0	389383.69	6334163.11	529.6	382.4
100/12-12-094-18W4/0	393284.70	6334198.60	530.7	382.8
100/12-12-094-18W4/2	393284.70	6334198.60	530.7	382.4
100/08-16-094-18W4/0	389532.31	6335843.81	540.9	382.1
100/11-20-094-18W4/0	387149.20	6337841.10	551.9	382.1
100/11-20-094-18W4/2	387149.20	6337841.10	551.9	382.0
100/06-21-094-18W4/0	388733.32	6337370.78	543.4	383.5
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	382.3
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	382.2
100/13-27-094-18W4/0	389998.55	6339864.07	547.0	384.0
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	383.5
100/11-30-094-18W4/0	385586.01	6339549.57	596.3	381.1
100/11-30-094-18W4/2	385586.01	6339549.57	596.3	380.8
100/06-32-094-18W4/0	387259.49	6340587.70	589.4	380.5
100/11-33-094-18W4/0	388764.50	6341022.36	592.7	383.0
100/09-35-094-18W4/0	392817.23	6340761.15	558.3	380.7
100/09-01-094-19W4/0	384486.18	6333145.06	530.5	383.8
100/06-07-094-19W4/0	375778.56	6334536.89	591.9	377.3
100/06-09-094-19W4/0	379126.83	6334415.06	569.7	379.6
100/09-12-094-19W4/0	384558.89	6334821.55	539.2	383.7
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	381.9

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/11-16-094-19W4/0	379133.61	6336365.48	612.4	376.8
100/07-24-094-19W4/0	384522.81	6337409.07	560.6	380.0
100/07-28-094-19W4/0	379585.59	6339157.11	642.2	378.8
100/11-03-92-16W4/0	409370.95	6312974.38	484.8	402.8
100/10-09-92-16W4/0	408218.90	6314631.01	491.3	402.3
100/04-10-92-16W4/0	409086.49	6313811.29	485.8	401.8
100-06-15-92-16W4/0	409289.90	6315815.46	486.0	400.0
100/04-27-92-16W4/0	408999.93	6318779.62	487.1	398.6
100/06-28-92-16W4/0	407697.26	6319222.76	489.2	398.2
100/10-30-92-16W4/0	405031.51	6319540.84	498.3	395.8
100/06-32-92-16W4/0	406232.43	6320913.29	494.7	395.7
100/11-33-92-16W4/0	407982.79	6321194.99	485.6	398.1
100/06-31-92-16W4/0	404757.88	6320950.47	504.8	394.8
100/06-36-92-17W4/0	403140.23	6320763.78	507.2	392.2
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	384.5
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	387.2
100/08-25-92-17W4/0	403744.99	6319229.97	501.9	398.4
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	385.4
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	385.1
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	382.4
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	385.5
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	385.1
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	386.2
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	385.5
100/16-24-93-17W4/0	403961.01	6327962.53	501.0	389.0
100/08-23-93-17W4/0	402295.99	6327223.33	502.6	388.6
100/10-22-93-17W4/0	400279.77	6327692.85	504.3	388.3
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	386.2
100/01-15-93-17W4/0	400537.43	6325202.67	502.6	389.6
100/06-14-93-17W4/0	401624.27	6325796.32	500.9	387.9
100/14-02-93-17W4/0	401402.18	6323358.08	504.1	393.1
100/07-13-93-17W4/0	403617.37	6325570.91	497.4	391.4
100/06-01-93-17W4/0	403216.78	6322311.92	508.3	392.3
100/06-07-93-16W4/0	404777.62	6324065.08	496.0	393.5
100/11-19-93-16W4/0	404751.21	6327496.03	497.5	391.0
100/06-06-93-16W4/0	404552.90	6322289.94	501.3	393.3
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	392.8
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	389.9
00/07-26-094-18W4/0	392667.89	6338827.69	558.4	380.4
AA/03-18-092-17W4/0	394855.70	6315796.59	524.6	393.9
AA/10-08-093-17W4/0	397004.40	6324588.60	509.9	391.3
AA/10-11-092-17W4/0	401659.20	6314759.50	505.9	399.2
AA/10-11-093-17W4/0	402027.70	6324497.50	500.2	392.5
AA/10-26-091-16W4/0	411485.90	6309712.70	489.0	403.3

TABLE A-6

TOP OF CLEARWATER FORMATION

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
AA/10-26-092-17W4/0	401776.10	6319633.00	520.9	396.1
AA/10-26-093-18W4/0	392244.70	6329577.20	527.3	386.4
AA/10-29-092-16W4/0	406660.40	6319520.30	493.5	400.2
AA/10-29-092-17W4/0	396803.00	6319771.30	518.3	394.6
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	386.2
AA/11-25-093-17W4/0	403232.40	6329338.00	504.1	388.2
100/15-01-092-17W4/0	403230.48	6313470.71	504.2	350.9
00/02-09-092-16W4/0	408370.20	6313984.37	495.0	405.0
100/06-16-92-16W4/0	407909.27	6315693.40	488.9	382.9
AA/06-21-92-16W4/0	408003.08	6317511.32	488.0	384.0
00/16-27-092-16W4/0	410339.96	6319838.70	484.1	401.8
AA/10-08-091-17W4/0	396529.03	6305165.55	509.2	387.2

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/08-10-091-16W4/0	409837.00	6304642.15	496.9	316.3
1AA/10-11-091-16W4/0	411239.55	6304826.65	493.9	316.4
100/16-15-091-16W4/0	409894.48	6306771.66	495.2	317.5
100/16-15-091-16W4/2	409894.48	6306771.66	495.2	317.5
100/08-27-091-16W4/0	409918.56	6309319.89	493.3	319.2
100/08-27-091-16W4/2	409918.56	6309319.89	493.3	319.2
100/08-27-091-16W4/3	409918.56	6309319.89	493.3	319.2
1AA/10-29-091-16W4/0	406451.45	6309804.39	493.4	315.0
100/07-34-091-16W4/0	409761.39	6310954.62	488.7	318.4
100/07-34-091-16W4/2	409761.39	6310954.62	488.7	318.4
100/07-34-091-16W4/3	409761.39	6310954.62	488.7	318.4
100/14-04-091-17W4/0	397835.92	6304105.10	512.6	324.5
100/14-04-091-17W4/2	397835.92	6304105.10	512.6	324.5
100/10-09-091-17W4/0	398291.72	6305017.04	511.6	327.6
100/10-09-091-17W4/2	398291.72	6305017.04	511.6	327.6
100/10-09-091-17W4/3	398291.72	6305017.04	511.6	327.6
100/11-10-091-17W4/0	399247.24	6305136.82	509.4	325.9
100/11-10-091-17W4/2	399247.24	6305136.82	509.4	325.9
100/12-11-091-17W4/0	400534.96	6305136.95	505.2	323.0
100/12-11-091-17W4/2	400534.96	6305136.95	505.2	323.0
100/12-12-091-17W4/0	402191.94	6305056.20	502.6	322.5
100/12-12-091-17W4/2	402191.94	6305056.20	502.6	322.5
100/12-12-091-17W4/3	402191.94	6305056.20	502.6	322.5
100/11-15-091-17W4/0	399255.06	6306864.51	507.4	323.2
100/07-16-091-17W4/0	398246.27	6306296.81	511.1	325.4
100/07-16-091-17W4/2	398246.27	6306296.81	511.1	325.4
102/01-17-091-17W4/0	397140.39	6305783.52	510.2	324.1
100/07-18-091-17W4/0	394926.47	6306433.56	511.2	324.5
100/06-23-091-17W4/0	401004.46	6307844.52	503.8	322.1
100/06-23-091-17W4/2	401004.46	6307844.52	503.8	322.1
100/06-23-091-17W4/3	401004.46	6307844.52	503.8	322.1
100/06-24-091-17W4/0	402833.33	6307768.92	501.8	320.1
100/10-29-091-17W4/0	396562.65	6310002.05	515.4	321.4
100/10-29-091-17W4/2	396562.65	6310002.05	515.4	321.4
100/11-30-091-17W4/0	394517.31	6310063.87	516.2	320.3
100/05-32-091-17W4/0	395752.50	6311421.80	515.9	319.9
100/05-32-091-17W4/2	395752.50	6311421.80	515.9	319.9
100/06-33-091-17W4/0	397899.01	6311129.34	515.1	321.0
100/04-36-091-17W4/0	402212.96	6310529.79	502.0	320.2
100/04-36-091-17W4/2	402212.96	6310529.79	502.0	320.2
100/10-01-091-18W4/0	393265.99	6303573.99	509.4	323.3
100/10-01-091-18W4/2	393265.99	6303573.99	509.4	323.3
100/15-07-091-18W4/0	385074.95	6306050.50	513.1	311.6
100/15-08-091-18W4/0	386868.74	6306018.56	514.8	313.1
100/15-12-091-18W4/0	393246.73	6305479.42	511.2	320.1
100/06-13-091-18W4/0	392864.02	6306482.42	511.5	320.1

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	318.3
100/07-14-091-18W4/0	391626.21	6306537.04	509.9	316.0
100/13-14-091-18W4/0	391054.32	6307231.54	517.1	319.0
100/10-16-091-18W4/0	388387.99	6307003.99	516.9	312.0
100/16-22-091-18W4/0	390329.78	6308799.94	516.8	320.8
100/16-22-091-18W4/2	390329.78	6308799.94	516.8	320.8
100/10-26-091-18W4/0	391844.08	6310205.89	514.2	320.8
100/07-33-091-18W4/0	388534.05	6311395.07	520.1	320.1
100/07-33-091-18W4/2	388534.05	6311395.07	520.1	320.1
100/10-34-091-18W4/0	390148.78	6311805.38	521.2	320.5
100/06-03-091-19W4/0	379776.91	6303548.03	521.5	309.8
100/04-06-091-19W4/0	374510.64	6303460.92	515.8	300.9
100/04-07-091-19W4/0	374547.21	6305136.30	513.6	301.9
100/11-10-091-19W4/0	379689.33	6305681.50	523.7	310.8
100/11-12-091-19W4/0	383020.44	6305524.95	518.6	314.8
100/10-16-091-19W4/0	378693.22	6307224.84	529.0	310.6
100/10-16-091-19W4/2	378693.22	6307224.84	529.0	310.6
100/02-22-091-19W4/0	380321.83	6308181.71	526.0	311.4
100/02-22-091-19W4/2	380321.83	6308181.71	526.0	311.4
102/02-22-091-19W4/0	380327.86	6308192.12	526.5	312.6
100/02-26-091-19W4/0	381848.41	6309814.71	527.8	315.4
100/01-27-091-19W4/0	380693.08	6309647.97	528.1	313.6
100/13-28-091-19W4/0	378020.72	6310793.05	538.8	309.4
100/13-28-091-19W4/2	378020.72	6310793.05	538.8	309.4
100/11-29-091-19W4/0	376539.18	6310683.50	524.6	304.2
100/08-35-091-19W4/0	382341.27	6311607.65	526.4	313.6
100/16-03-092-16W4/0	410077.37	6313201.56	486.9	313.7
100/08-04-092-16W4/0	408431.08	6312760.35	491.2	314.7
100/08-04-092-16W4/2	408431.08	6312760.35	491.2	314.7
100/08-04-092-16W4/3	408431.08	6312760.35	491.2	314.7
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	315.9
1AA/04-08-092-16W4/0	405877.57	6313834.97	497.7	314.5
100/03-20-092-16W4/0	406115.82	6316937.22	495.3	312.3
100/15-01-092-17W4/0	403230.48	6313470.71	504.2	318.4
100/16-02-092-17W4/0	402181.14	6313514.10	505.2	318.4
100/16-02-092-17W4/2	402181.14	6313514.10	505.2	318.4
100/16-03-092-17W4/0	400489.99	6313571.62	507.6	319.2
100/16-04-092-17W4/0	398830.68	6313627.61	509.2	318.9
100/13-05-092-17W4/0	395962.50	6313723.37	519.7	320.8
100/13-05-092-17W4/2	395962.50	6313723.37	519.7	320.8
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	318.3
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	318.3
100/03-09-092-17W4/0	397972.13	6314132.59	513.3	319.4
100/03-09-092-17W4/2	397972.13	6314132.59	513.3	319.4
100/05-15-092-17W4/0	399292.57	6315863.37	509.2	318.3
100/05-17-092-17W4/0	396150.51	6315949.22	519.4	316.5

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
102/13-21-092-17W4/0	397784.99	6318671.97	518.1	317.2
102/13-21-092-17W4/2	397784.99	6318671.97	518.1	317.2
100/02-23-092-17W4/0	401911.83	6317216.51	505.5	311.2
100/04-26-092-17W4/0	400918.63	6318647.39	510.4	306.1
100/11-28-092-17W4/0	398140.72	6319907.61	515.5	316.6
100/03-29-092-17W4/0	396633.98	6318924.89	516.1	315.2
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	314.8
100/06-03-092-18W4/0	389941.50	6313052.44	522.2	318.1
100/06-03-092-18W4/2	389941.50	6313052.44	522.2	318.0
100/07-04-092-18W4/0	388552.70	6313071.73	523.4	319.4
100/07-04-092-18W4/2	388552.70	6313071.73	523.4	319.4
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	318.5
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	318.5
100/10-05-092-18W4/0	386984.99	6313430.59	524.3	317.4
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	317.9
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	317.9
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	317.9
100/06-07-092-18W4/0	384802.82	6314759.98	528.5	312.5
100/10-08-092-18W4/0	387037.17	6315080.86	523.7	317.9
100/10-08-092-18W4/2	387037.17	6315080.86	523.7	317.9
100/07-09-092-18W4/0	388690.65	6314535.94	523.1	317.3
100/07-09-092-18W4/2	388690.65	6314535.94	523.1	317.3
100/13-09-092-18W4/0	387607.25	6315357.20	523.8	319.3
100/06-10-092-18W4/0	389827.62	6314720.80	520.7	318.1
100/07-12-092-18W4/0	393668.66	6314403.43	520.9	316.5
100/11-15-092-18W4/0	389814.20	6316851.04	520.5	316.5
100/04-16-092-18W4/0	387790.14	6316056.36	523.0	319.2
100/05-16-092-18W4/0	387864.86	6316284.78	522.7	317.9
100/05-16-092-18W4/2	387864.86	6316284.78	522.7	317.9
100/05-16-092-18W4/3	387864.86	6316284.78	522.7	317.6
100/06-17-092-18W4/0	386602.65	6316364.95	522.3	314.9
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	314.0
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	314.0
100/06-24-092-18W4/0	393128.25	6317719.50	522.2	316.7
100/10-25-092-18W4/0	393716.67	6319866.96	523.7	317.3
100/06-26-092-18W4/0	391604.30	6319500.43	520.3	315.1
100/11-34-092-18W4/0	390010.50	6321602.46	514.1	309.0
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	309.8
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	309.8
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	309.7
100/07-03-092-19W4/0	380375.18	6313123.84	537.4	305.0
100/07-03-092-19W4/2	380375.18	6313123.84	537.4	305.0
100/07-03-092-19W4/3	380375.18	6313123.84	537.4	305.0
100/02-05-092-19W4/0	377210.68	6312798.20	534.3	310.5
100/06-08-092-19W4/0	376679.40	6314878.25	533.4	306.5
100/04-09-092-19W4/0	378084.87	6314683.39	532.2	308.2

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/10-10-092-19W4/0	380256.49	6315140.83	528.6	307.2
100/04-11-092-19W4/0	381359.14	6314590.37	528.4	303.3
100/04-11-092-19W4/2	381359.14	6314590.37	528.4	303.3
100/10-16-092-19W4/0	378967.71	6317082.85	530.4	307.7
100/10-16-092-19W4/2	378967.71	6317082.85	530.4	307.7
100/13-17-092-19W4/0	376275.60	6317583.04	532.5	312.6
100/12-18-092-19W4/0	374771.64	6317193.95	527.5	308.1
100/02-29-092-19W4/0	377112.72	6319578.50	541.3	313.0
100/11-30-092-19W4/0	375268.29	6320320.61	532.2	310.2
100/08-31-092-19W4/0	376234.25	6321355.30	533.8	311.9
100/06-35-092-19W4/0	381806.21	6321270.31	523.6	306.5
100/07-15-093-16W4/0	410000.89	6325372.16	479.6	311.2
100/02-03-093-17W4/0	400329.60	6321943.49	509.1	309.7
100/03-04-093-17W4/0	398206.86	6322268.71	510.8	312.0
100/06-06-093-17W4/0	394956.03	6322623.49	515.6	318.3
100/02-10-093-17W4/0	400360.63	6323657.29	504.6	307.2
100/03-12-093-17W4/0	403288.05	6323640.01	500.9	302.5
100/06-18-093-17W4/0	394997.05	6325870.41	516.6	311.4
100/06-18-093-17W4/2	394997.05	6325870.41	516.6	311.4
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	303.3
100/10-20-093-17W4/2	397136.28	6327767.17	512.2	303.3
100/10-28-093-17W4/0	398633.54	6329446.25	511.0	298.9
100/11-31-093-17W4/0	395345.18	6331199.97	530.7	299.5
100/06-01-093-18W4/0	393114.87	6322567.45	522.5	317.0
100/06-01-093-18W4/2	393114.87	6322567.45	522.5	317.0
100/06-01-093-18W4/3	393114.87	6322567.45	522.5	317.0
100/11-02-093-18W4/0	391719.05	6323093.18	522.6	317.7
100/11-02-093-18W4/2	391719.05	6323093.18	522.6	317.7
100/11-04-093-18W4/0	388314.75	6323381.82	515.7	307.5
100/11-04-093-18W4/2	388314.75	6323381.82	515.7	307.5
100/01-07-093-18W4/0	385848.96	6324261.99	515.9	309.5
100/11-07-093-18W4/0	385292.45	6324810.09	514.8	307.4
100/07-09-093-18W4/0	388851.33	6324401.83	518.2	308.9
100/07-09-093-18W4/2	388851.33	6324401.83	518.2	308.9
100/11-10-093-18W4/0	389942.81	6324894.02	518.9	311.3
100/11-10-093-18W4/2	389942.81	6324894.02	518.9	311.3
100/06-11-093-18W4/0	391703.74	6324371.91	522.7	317.2
100/06-11-093-18W4/2	391703.74	6324371.91	522.7	317.2
100/04-12-093-18W4/0	392847.97	6323854.22	519.7	318.6
100/04-12-093-18W4/2	392847.97	6323854.22	519.7	318.6
100/07-12-093-18W4/0	393825.13	6324074.40	517.7	317.9
100/11-14-093-18W4/0	391811.68	6326355.63	523.7	310.2
100/07-16-093-18W4/2	388995.42	6325924.70	518.7	311.3
100/11-17-093-18W4/0	386705.58	6326647.33	519.5	311.8
100/16-17-093-18W4/0	387867.35	6327057.51	523.0	312.6
100/14-18-093-18W4/2	385419.19	6326778.44	519.2	312.1

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/02-19-093-18W4/0	385809.08	6327439.72	519.9	311.0
100/06-19-093-18W4/0	385269.25	6327746.25	517.7	308.5
100/06-19-093-18W4/2	385269.25	6327746.25	517.7	308.5
100/10-21-093-18W4/0	388921.61	6328083.24	521.2	306.9
100/11-21-093-18W4/0	388492.15	6327951.24	521.0	309.1
100/09-22-093-18W4/0	390859.83	6328024.62	524.8	305.8
100/09-22-093-18W4/2	390859.83	6328024.62	524.8	305.8
102/10-23-093-18W4/0	392195.31	6327895.25	524.7	305.8
100/14-30-093-18W4/0	385387.53	6330021.01	521.3	307.3
100/11-31-093-18W4/0	385264.79	6331311.41	524.4	303.0
100/12-32-093-18W4/0	386505.69	6331270.12	524.7	303.4
100/14-03-093-19W4/0	380204.78	6323634.07	523.0	310.0
100/14-03-093-19W4/2	380204.78	6323634.07	523.0	310.0
100/10-04-093-19W4/0	379162.19	6323556.65	524.0	311.7
100/11-06-093-19W4/0	375368.36	6323620.40	534.0	310.0
100/11-06-093-19W4/2	375368.36	6323620.40	534.0	310.0
100/07-12-093-19W4/0	384053.66	6324432.94	519.0	312.0
100/10-13-093-19W4/0	384079.94	6326508.78	518.7	309.2
100/11-14-093-19W4/0	382080.20	6326734.59	518.7	310.5
100/01-18-093-19W4/0	376438.86	6325793.93	529.8	307.8
100/07-22-093-19W4/0	380921.87	6327853.32	525.2	314.3
100/07-22-093-19W4/2	380921.87	6327853.32	525.2	314.3
100/11-23-093-19W4/0	382231.42	6328090.83	518.6	310.5
100/10-24-093-19W4/0	384156.65	6327986.66	519.0	311.1
102/10-24-093-19W4/0	384076.89	6327995.24	520.2	312.0
100/10-25-093-19W4/0	383926.14	6329922.35	521.6	307.1
100/08-27-093-19W4/0	381103.01	6329401.92	527.0	308.4
100/11-28-093-19W4/0	378664.32	6330032.84	530.7	301.0
100/07-36-093-19W4/0	384185.02	6331086.71	524.2	303.8
1AA/06-06-094-16W4/0	405091.95	6332267.46	524.3	306.1
1AA/10-11-094-16W4/0	411861.00	6333957.69	504.7	310.9
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	306.9
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	311.0
100/11-35-094-16W4/0	411662.06	6340480.19	542.3	311.2
103/06-36-094-16W4/0	413220.33	6340151.52	536.0	310.9
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	312.0
1AB/06-36-094-16W4/0	413364.89	6340181.99	534.6	312.4
100/06-04-094-17W4/0	398458.07	6332163.56	522.5	297.2
100/06-04-094-17W4/2	398458.07	6332163.56	522.5	297.2
100/06-06-094-17W4/0	395367.41	6332256.76	530.5	298.7
100/12-11-094-17W4/0	401438.47	6333997.24	527.3	298.1
100/12-21-094-17W4/0	398040.72	6337437.77	528.7	297.6
100/03-31-094-17W4/0	395409.19	6340122.82	541.7	295.7
100/10-33-094-17W4/0	399032.77	6340729.44	537.0	302.0
100/10-02-094-18W4/0	392296.66	6332983.24	526.4	295.3
100/10-03-094-18W4/0	390591.22	6332706.77	527.4	297.9

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/07-05-094-18W4/0	387297.78	6332535.74	525.4	298.4
100/07-06-094-18W4/0	385795.38	6332572.68	530.7	297.8
100/05-07-094-18W4/0	385213.47	6334231.23	535.9	296.1
100/05-07-094-18W4/2	385213.47	6334231.23	535.9	296.1
100/06-08-094-18W4/0	387155.48	6334040.00	530.2	295.0
100/08-09-094-18W4/0	389383.69	6334163.11	529.6	297.3
100/12-12-094-18W4/0	393284.70	6334198.60	530.7	296.6
100/12-12-094-18W4/2	393284.70	6334198.60	530.7	296.6
100/08-16-094-18W4/0	389532.31	6335843.81	540.9	296.9
100/11-20-094-18W4/0	387149.20	6337841.10	551.9	296.2
100/11-20-094-18W4/2	387149.20	6337841.10	551.9	296.2
100/06-21-094-18W4/0	388733.32	6337370.78	543.4	296.7
100/05-24-094-18W4/0	393361.29	6337037.96	544.0	296.2
100/05-24-094-18W4/2	393361.29	6337037.96	544.0	296.2
100/13-27-094-18W4/0	389998.55	6339864.07	547.0	297.8
100/03-29-094-18W4/0	387204.01	6338766.83	544.1	296.0
100/11-30-094-18W4/0	385586.01	6339549.57	596.3	292.5
100/11-30-094-18W4/2	385586.01	6339549.57	596.3	292.5
100/06-32-094-18W4/0	387259.49	6340587.70	589.4	292.6
100/11-33-094-18W4/0	388764.50	6341022.36	592.7	295.3
100/09-35-094-18W4/0	392817.23	6340761.15	558.3	295.0
100/09-01-094-19W4/0	384486.18	6333145.06	530.5	296.0
100/06-07-094-19W4/0	375778.56	6334536.89	591.9	292.3
100/06-09-094-19W4/0	379126.83	6334415.06	569.7	293.0
100/09-12-094-19W4/0	384558.89	6334821.55	539.2	295.3
100/09-13-094-19W4/0	384560.44	6336319.70	541.5	293.6
100/11-16-094-19W4/0	379133.61	6336365.48	612.4	290.0
100/07-24-094-19W4/0	384522.81	6337409.07	560.6	292.3
100/07-28-094-19W4/0	379585.59	6339157.11	642.2	288.1
100/11-03-92-16W4/0	409370.95	6312974.38	484.8	311.3
100/10-09-92-16W4/0	408218.90	6314631.01	491.3	313.3
100/04-10-92-16W4/0	409086.49	6313811.29	485.8	311.8
100-06-15-92-16W4/0	409289.90	6315815.46	486.0	309.5
100/06-16-92-16W4/0	407909.27	6315693.40	488.9	312.4
100/06-21-92-16W4/0	378865.40	6318250.69	488.0	310.5
100/04-27-92-16W4/0	408999.93	6318779.62	487.1	309.1
100/06-28-92-16W4/0	407697.26	6319222.76	489.2	308.7
100/10-30-92-16W4/0	405031.51	6319540.84	498.3	306.8
100/06-32-92-16W4/0	406232.43	6320913.29	494.7	307.7
100/11-33-92-16W4/0	407982.79	6321194.99	485.6	309.1
100/06-31-92-16W4/0	404757.88	6320950.47	504.8	305.8
100/06-36-92-17W4/0	403140.23	6320763.78	507.2	303.2
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	299.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	299.7
100/08-25-92-17W4/0	403744.99	6319229.97	501.9	309.4
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	297.4

TABLE A-7

TOP OF WABISKAW MEMBER

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	299.1
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	296.4
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	300.5
100/06-32-93-17W4/0	396901.02	6330825.52	518.6	298.1
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	301.2
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	299.5
100/16-24-93-17W4/0	403961.01	6327962.53	501.0	300.5
100/08-23-93-17W4/0	402295.99	6327223.33	502.6	300.6
100/10-22-93-17W4/0	400279.77	6327692.85	504.3	301.3
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	301.7
100/01-15-93-17W4/0	400537.43	6325202.67	502.6	303.1
100/06-14-93-17W4/0	401624.27	6325796.32	500.9	301.4
100/14-02-93-17W4/0	401402.18	6323358.08	504.1	307.1
100/07-13-93-17W4/0	403617.37	6325570.91	497.4	301.9
100/06-01-93-17W4/0	403216.78	6322311.92	508.3	304.3
100/06-07-93-16W4/0	404777.62	6324065.08	496.0	305.0
100/11-19-93-16W4/0	404751.21	6327496.03	497.5	302.0
100/06-06-93-16W4/0	404552.90	6322289.94	501.3	303.3
AA/07-02-091-17W4/0	401384.76	6303023.76	504.3	319.8
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	316.3
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	311.9
00/07-26-094-18W4/0	392667.89	6338827.69	558.4	293.4
AA/10-08-091-17W4/0	396529.03	6305165.55	509.2	325.2
100/06-06-094-17W4/0	395366.40	6332260.60	530.5	298.7
100/11-34-092-18W4/0	390009.50	6321606.20	514.1	309.2
AA/03-18-092-17W4/0	394855.70	6315796.73	524.6	314.6
AA/06-28-092-16W4/0	407705.10	6319226.40	489.2	309.1
AA/07-08-091-16W4/0	406265.20	6304596.00	496.8	318.2
AA/10-08-093-17W4/0	397004.40	6324588.60	509.9	306.3
AA/10-08-093-18W4/0	387233.50	6324851.10	519.7	312.8
AA/10-11-092-16W4/0	411444.70	6314540.00	487.1	312.9
AA/10-11-092-17W4/0	401659.20	6314759.50	505.9	317.1
AA/10-11-093-17W4/0	402027.70	6324497.50	500.2	303.5
AA/10-26-091-16W4/0	411485.90	6309712.70	489.0	314.6
AA/10-26-092-16W4/0	411549.20	6319405.90	478.5	310.8
AA/10-26-092-17W4/0	401776.10	6319633.00	520.9	309.2
AA/10-29-092-16W4/0	406660.40	6319520.30	493.5	310.3
AA/10-29-092-17W4/0	396803.00	6319771.30	514.8	315.1
AA/10-29-093-17W4/0	397125.00	6329454.00	513.6	299.5
AA/11-25-093-17W4/0	403232.40	6329338.00	504.1	299.7
00/02-09-092-16W4/0	408370.20	6313984.37	495.0	317.0

TABLE A-8

BASE OF WABISKAW SAND

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
1AA/10-11-091-16W4/0	411239.55	6304826.65	493.9	273.8
100/16-15-091-16W4/0	409894.48	6306771.66	495.2	274.5
100/16-15-091-16W4/2	409894.48	6306771.66	495.2	274.5
1AA/10-29-091-16W4/0	406451.45	6309804.39	493.4	275.2
100/10-09-091-17W4/0	398291.72	6305017.04	511.6	289.5
100/10-09-091-17W4/2	398291.72	6305017.04	511.6	289.5
100/10-09-091-17W4/3	398291.72	6305017.04	511.6	289.5
100/11-10-091-17W4/0	399247.24	6305136.82	509.4	288.4
100/11-10-091-17W4/2	399247.24	6305136.82	509.4	288.1
100/11-15-091-17W4/0	399255.06	6306864.51	507.4	284.0
100/07-18-091-17W4/0	394926.47	6306433.56	511.2	281.3
100/06-23-091-17W4/0	401004.46	6307844.52	503.8	281.1
100/06-23-091-17W4/2	401004.46	6307844.52	503.8	280.8
100/06-23-091-17W4/3	401004.46	6307844.52	503.8	280.8
100/06-24-091-17W4/0	402833.33	6307768.92	501.8	278.7
100/11-30-091-17W4/0	394517.31	6310063.87	516.2	275.7
100/05-32-091-17W4/0	395752.50	6311421.80	515.9	280.4
100/05-32-091-17W4/2	395752.50	6311421.80	515.9	280.5
100/06-33-091-17W4/0	397899.01	6311129.34	515.1	281.9
100/10-01-091-18W4/0	393265.99	6303573.99	509.4	278.3
100/10-01-091-18W4/2	393265.99	6303573.99	509.4	278.5
100/15-07-091-18W4/0	385074.95	6306050.50	513.1	273.0
100/15-08-091-18W4/0	386868.74	6306018.56	514.8	273.5
100/15-12-091-18W4/0	393246.73	6305479.42	511.2	280.3
100/06-13-091-18W4/0	392864.02	6306482.42	511.5	278.3
100/16-13-091-18W4/0	393664.21	6307230.90	511.2	278.1
100/07-14-091-18W4/0	391626.21	6306537.04	509.9	275.4
100/13-14-091-18W4/0	391054.32	6307231.54	517.1	276.3
100/16-22-091-18W4/2	390329.78	6308799.94	516.8	283.6
100/10-26-091-18W4/0	391844.08	6310205.89	514.2	278.2
100/16-03-092-16W4/0	410077.37	6313201.56	486.9	279.8
100/08-04-092-16W4/0	408431.08	6312760.35	491.2	275.8
100/08-04-092-16W4/2	408431.08	6312760.35	491.2	276.0
100/08-04-092-16W4/3	408431.08	6312760.35	491.2	275.9
100/06-06-092-16W4/0	404314.31	6312495.73	500.4	277.2
1AA/04-08-092-16W4/0	405877.57	6313834.97	497.7	286.1
100/03-20-092-16W4/0	406115.82	6316937.22	495.3	276.2
100/15-01-092-17W4/0	403230.48	6313470.71	504.2	277.2
100/16-02-092-17W4/0	402181.14	6313514.10	505.2	281.9
100/16-02-092-17W4/2	402181.14	6313514.10	505.2	282.1
100/16-03-092-17W4/0	400489.99	6313571.62	507.6	280.7
100/16-04-092-17W4/0	398830.68	6313627.61	509.2	278.6
100/13-05-092-17W4/0	395962.50	6313723.37	519.7	279.6
100/13-05-092-17W4/2	395962.50	6313723.37	519.7	279.9
100/14-06-092-17W4/0	394566.87	6313767.35	524.5	277.3
100/14-06-092-17W4/2	394566.87	6313767.35	524.5	277.7
100/03-09-092-17W4/0	397972.13	6314132.59	513.3	279.0

TABLE A-8

BASE OF WABISKAW SAND

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/03-09-092-17W4/2	397972.13	6314132.59	513.3	279.1
100/05-15-092-17W4/0	399292.57	6315863.37	509.2	273.4
102/13-21-092-17W4/0	397784.99	6318671.97	518.1	268.7
102/13-21-092-17W4/2	397784.99	6318671.97	518.1	268.7
100/02-23-092-17W4/0	401911.83	6317216.51	505.5	273.4
100/11-28-092-17W4/0	398140.72	6319907.61	515.5	269.9
100/06-01-092-18W4/0	393143.54	6312997.17	518.7	274.2
100/11-04-092-18W4/0	387974.87	6313686.23	523.8	277.0
100/11-04-092-18W4/2	387974.87	6313686.23	523.8	276.7
100/10-05-092-18W4/0	386984.99	6313430.59	524.3	275.6
102/10-05-092-18W4/0	387092.36	6313717.80	525.6	276.3
102/10-05-092-18W4/2	387092.36	6313717.80	525.6	276.4
102/10-05-092-18W4/3	387092.36	6313717.80	525.6	276.1
100/07-12-092-18W4/0	393668.66	6314403.43	520.9	275.6
100/11-15-092-18W4/0	389814.20	6316851.04	520.5	271.9
100/04-16-092-18W4/0	387790.14	6316056.36	523.0	277.1
100/05-16-092-18W4/0	387864.86	6316284.78	522.7	275.1
100/05-16-092-18W4/2	387864.86	6316284.78	522.7	274.9
100/05-16-092-18W4/3	387864.86	6316284.78	522.7	275.1
100/06-17-092-18W4/0	386602.65	6316364.95	522.3	270.8
100/06-20-092-18W4/0	386776.46	6317882.71	521.3	271.9
100/06-20-092-18W4/2	386776.46	6317882.71	521.3	271.8
100/10-25-092-18W4/0	393716.67	6319866.96	523.7	268.1
100/06-01-092-19W4/0	383239.01	6313163.25	527.3	265.4
100/06-01-092-19W4/2	383239.01	6313163.25	527.3	265.5
100/06-02-092-19W4/0	381620.85	6313120.59	530.6	267.4
100/06-08-092-19W4/0	376679.40	6314878.25	533.4	269.6
100/02-03-093-17W4/0	400329.60	6321943.49	509.1	276.5
100/10-20-093-17W4/0	397136.28	6327767.17	512.2	273.7
1AA/10-11-094-16W4/0	411861.00	6333957.69	504.7	273.8
1AA/01-21-094-16W4/0	409038.46	6336387.31	532.2	268.9
100/14-26-094-16W4/0	411610.99	6339280.42	534.4	272.3
100/11-35-094-16W4/0	411662.06	6340480.19	542.3	269.2
103/06-36-094-16W4/0	413220.33	6340151.52	536.0	273.7
1AA/06-36-094-16W4/0	413365.18	6340198.25	534.6	274.5
100/11-03-92-16W4/0	409370.95	6312974.38	484.8	276.3
100/04-10-92-16W4/0	409086.49	6313811.29	485.8	277.3
100-06-15-92-16W4/0	409289.90	6315815.46	486.0	283.5
100/06-16-92-16W4/0	407909.27	6315693.40	488.9	267.9
100/06-21-92-16W4/0	378865.40	6318250.69	488.0	277.0
100/04-27-92-16W4/0	408999.93	6318779.62	487.1	279.1
100/06-28-92-16W4/0	407697.26	6319222.76	489.2	281.2
100/10-30-92-16W4/0	405031.51	6319540.84	498.3	281.8
100/06-32-92-16W4/0	406232.43	6320913.29	494.7	275.7
100/11-33-92-16W4/0	407982.79	6321194.99	485.6	276.1
100/06-31-92-16W4/0	404757.88	6320950.47	504.8	280.8
100/06-36-92-17W4/0	403140.23	6320763.78	507.2	275.2

TABLE A-8

BASE OF WABISKAW SAND

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	Easting	Northing	KB (masl)	Depth (masl)
100/06-01-94-18W4/0	393600.29	6332366.18	527.5	265.0
100/06-07-94-17W4/0	395228.87	6333819.57	530.2	263.2
100/08-25-92-17W4/0	403744.99	6319229.97	501.9	279.4
100/06-05-94-17W4/0	396871.38	6332314.81	531.4	267.4
100/06-36-93-18W4/0	393497.08	6330858.19	526.6	269.1
100/06-35-93-18W4/0	391935.99	6330856.19	524.9	271.4
100/06-25-93-18W4/0	393478.61	6329137.53	523.5	271.5
100/06-30-93-17W4/0	395167.38	6329202.16	516.2	266.2
100/06-29-93-17W4/0	396760.00	6328991.00	510.5	267.5
100/16-24-93-17W4/0	403961.01	6327962.53	501.0	275.0
100/08-23-93-17W4/0	402295.99	6327223.33	502.6	272.6
100/10-22-93-17W4/0	400279.77	6327692.85	504.3	275.3
100/10-19-93-17W4/0	395606.39	6327772.88	510.2	268.2
100/01-15-93-17W4/0	400537.43	6325202.67	502.6	275.6
100/06-14-93-17W4/0	401624.27	6325796.32	500.9	272.4
100/14-02-93-17W4/0	401402.18	6323358.08	504.1	277.6
100/07-13-93-17W4/0	403617.37	6325570.91	497.4	276.9
100/06-01-93-17W4/0	403216.78	6322311.92	508.3	277.8
100/06-07-93-16W4/0	404777.62	6324065.08	496.0	279.5
100/11-19-93-16W4/0	404751.21	6327496.03	497.5	277.5
100/06-06-93-16W4/0	404552.90	6322289.94	501.3	277.8
AA/07-02-091-17W4/0	401384.76	6303023.76	504.3	280.3
AA/10-29-091-18W4/0	386838.23	6310290.92	521.3	279.8
AA/08-29-092-18W4/0	387385.77	6319404.34	517.9	274.7
AA/10-08-091-17W4/0	396529.03	6305165.55	509.2	285.7
100021009317W400	400359.90	6323669.96	504.6	277.0
1AA101109217W400	401659.20	6314759.50	505.9	279.6
1AA101109317W400	402027.70	6324497.50	500.2	273.5
1AA102609116W400	411485.90	6309712.70	489.0	277.8

TABLE A-9

DEVONIAN PICKS

Athabasca Oil Sands Corp.
Dover Central Pilot Project Hydrogeological Assessment

UWI	KB masl	Easting	Northing	Precambrian masl	Contact Rapids masl	Keg River masl	Prairie-Muskeg masl	Watt Mountain masl	Fort Vermilion masl	Slave Point masl	Waterways masl	Grosmont masl	Woodbend masl
00/02-22-091-19W4/0	526.0	380321.83	6308181.71	---	---	---	---	---	---	---	---	286.0	---
02/08-32-091-19W4/0	538.6	377465.23	6311753.48	---	---	---	---	---	---	---	---	291.4	---
00/08-35-091-19W4/0	526.4	382341.27	6311607.65	---	---	---	---	---	---	---	139.3	262.4	---
00/11-29-091-19W4/0	524.6	376539.18	6310683.50	---	---	---	---	---	---	---	---	260.0	---
00/10-16-091-19W4/0	529.0	378693.22	6307224.84	---	---	---	---	---	---	---	---	281.2	---
00/10-16-092-19W4/0	530.4	378967.71	6317082.85	---	---	---	---	---	---	---	---	265.2	---
00/06-08-092-19W4/0	533.4	376679.40	6314878.25	---	---	---	---	---	---	---	---	279.8	---
00/07-14-091-18W4/0	509.9	391626.21	6306537.04	---	---	---	---	---	---	---	149.0	---	253.6
00/06-35-092-19W4/0	523.6	381806.21	6321270.31	---	---	---	---	---	---	---	132.3	---	254.6
00/10-34-091-18W4/0	521.2	390148.78	6311805.38	---	-368.5	-351.7	-83.0	-69.4	-58.3	-49.0	152.0	---	260.5
00/06-13-091-18W4/0	511.5	392864.02	6306482.42	-423.0	-369.4	-305.6	-87.0	-74.8	-65.0	-57.3	144.0	---	256.6
00/10-16-091-18W4/0	516.9	388387.99	6307003.99	-452.8	-392.3	-333.6	-107.3	-94.0	-82.8	-75.1	123.9	---	235.1

ATTACHMENT B

ATTACHMENT B

GROUNDWATER QUALITY DATA AND CULLING

B.1 INTRODUCTION

Hitchon et al. (1990) showed that due to sample contamination, sample mixing and/or sample incompleteness, about one fifth of water analysis from drill stem tests (DST) are suitable for consideration after data culling occurs. The raw data consisted of 66 water analyses (Table B.1-1) from DSTs and of these, 18 (27%) were accepted as potentially representative of formation water. It should be noted that the formation names associated with the DSTs, as provided in the Geofluids (2007) database, (Table B.1-1) were assumed to be accurate.

B.2 DRILL STEM TESTS WATER ANALYSES DATA CULLING

The DST water analyses data were culled on the basis of the potassium and sodium ratio, pH, ionic balance and carbonate concentrations. Data were placed in an electronic spreadsheet and culled based on a culling routine. It must be noted that, based on the cut-offs chosen, accepted values may in fact not be representative of formation water and rejected values may in fact be representative of formation water. The following cut-offs were used in the routine based on Matrix Solutions Inc.'s experience in the region.

B.2.1 Sodium to Potassium Ratio

Water samples with a Na:K ratio less that 0.7 were culled from the database. Based on regional water analyses results, natural potassium concentrations in Cretaceous formation water is typically less that 10 mg/L. Elevated potassium concentrations, relative to the sodium concentration, are indicative of potassium chloride mud filtrate sample contamination.

B.2.2 pH

Based on regional water analyses results, typical Cretaceous formations are slightly basic. Water analyses with pH values less that 7.0 and greater than 8.8 were culled.

B.2.3 Ionic Balance

The ratio of the sum of the anions versus the sum of the cations (or ionic balance) of any water sample should theoretically be 1. A deviation from 1 indicates a sample ionic imbalance and a potential improper analyses or a contaminated sample. For the purpose of this study, ionic balance values between 0.9 and 1.1 were deemed to be acceptable.

B.2.4. Carbonate

Based on regional water analyses results in the Cretaceous, natural carbonate concentrations are interpreted to be less than 50 mg/L. For the purpose of this study, carbonate concentrations in the Cretaceous less than 100 mg/L were deemed acceptable. Higher Carbonate concentrations are expected for the Devonian sediments.

Lastly, any water analyses which appeared anomalous or were incomplete were considered to be potentially not representative and were culled.

B.3 REFERENCES

Bachu, S., Underschultz, J.R. and B. Hitchon, 1990. "Regional Subsurface Hydrogeology Peace River Arch area, Alberta and British Columbia." Canadian Society of Petroleum Geologists, Vol. 38A, pp. 196-217.

Hitchon, B., Bachu, S., Ing, C.M., Lytviak, A. and J.R. Underschultz, 1989. "Hydrogeological and Geothermal Regimes in the Phanerozoic Succession, Cold Lake Area, Alberta and Saskatchewan." Alberta Research Council, Bulletin No. 59, Edmonton, Alberta.

TABLE B.1-1

WATER QUALITY ANALYSIS

Athabasca Oil Sands Corp.

Dover Central Pilot Project Hydrogeological Assessment

UWI Parsed	Latitude	Longitude	Ground Elevation	KB Elevation	*Remarks	Formation	Sampling Point	DST Number	A Interval From	A Interval To	B Interval From	B Interval To	C Interval From	C Interval To	Sodium mg/L	Potassium mg/L	Calcium mg/L	Magnesium mg/L	Barium mg/L	Strontium mg/L	Iron (Qualitative) mg/L	Iron mg/L	Boron mg/L	Chloride mg/L	Bromide mg/L	Iodide mg/L	Bicarbonate mg/L	Sulfate mg/L	Carbonate mg/L	Hydroxide mg/L	Hydrogen Sulfide	TDS @ 110c mg/L	TDS @ 180c mg/L	TDS @ Ignition mg/L	TDS Calculated mg/L	Organics	Density	Density Temp	Refractive Index	Refractive Index Temp	Resistivity Ohm	Resistivity Temp C	pH	pH Temp C
100/03-28-095-18W4/00	57.267131805	112.869407654	680.3	684.7	Filtrate	CLEARWATER FM	STOCK TANK		398.0	403.5					33	8	56	29			PRESENT			114			98	59			NIL	448		308	397	TRACE	1.000	25.0	1.3330	25	13.500	25	7.5	23
100/10-08-095-18W4/00	57.229854584	112.886978149	632.4	635.8	Formation Dilute	DETRITAL BEDS	WATER PUMP		351.0	364.0					1885	188	3544	1179			MUCH			12500			171	72			NIL	24410		15520	19539	PRESENT	1.014	25.0	1.3369	25	0.288	25	6.1	23
100/04-07-091-19W4/00	56.875022888	113.058204651	510.4	513.6	Fresh Water	GROSMONT FM	FLOW PROVER								3125	25	48	53			PRESENT			2700			3660	35			NIL	11950		6700	9646	TRACE	1.003	25.0	1.3338	25	0.812	25	7.5	23
100/11-29-091-19W4/00	56.925300598	113.028244019	521.2	526.4	Fresh/Filtrate	GROSMONT FM	ABOVE TOOL	1	247.2	259.1					2436		27	2			PRESENT			400			4382	1169			NIL	9700		7860	8416	MUCH	1.008	16.0	1.3344	25	0.782	25	7.4	21
100/11-29-091-19W4/00	56.925300598	113.028244019	521.2	526.4	Mud Incomplete	GROSMONT FM	TOP OF TOOL	2	286.5	318.2											PRESENT			115							NIL	3380		2220	115	PRESENT			1.3334	25	3.130	25	7.3	21
102/08-32-091-19W4/00	56.935405731	113.013694763	535.5	538.6	Fresh Water	GROSMONT FM	BOTTOM	1	256.0	265.2					381		274	34			PRESENT			309			1320	130				2112		1352	2448	SMALL AMO	1.002	16.0			3.880	20	7.6	
102/08-32-091-19W4/00	56.935405731	113.013694763	535.5	538.6	Fresh Water	GROSMONT FM	TOP	1	256.0	265.2					595		256	47			PRESENT			449			1560	207				2760		1704	3114		1.002	16.0			2.700	20	7.6	
100/11-09-090-18W4/00	56.793861389	112.814819336	499.3	503.2	Incomplete	KEG RIVER FM	TOOL	1	849.2	883.9							2100							143000			280	8020	25		NIL	248200		245200	153425		1.165	16.0	1.3710	25	0.050	20	8.7	24
100/06-13-091-18W4/00	56.891693115	112.758438110	507.8	511.5	Incomplete	KEG RIVER FM	DST	3	816.9	826.0							2640				FAINT TRA			205842			191	3301			NIL			308530	211974		1.212	16.0	1.3796	25	0.045	25	6.8	
100/10-34-091-18W4/00	56.938858032	112.805290222	517.9	521.2	Contaminant	KEG RIVER FM	D.P. TOP	3	326.1	331.6					83057		2635	530			TRACE			130200			31	5384	84		NIL	257270		217630	221921	PRESENT	1.146	16.0	1.3688	25	0.056	20	10.1	22
100/08-35-091-19W4/00	56.935092926	112.933555603	524.0	526.4	Fresh Water	LEDUC FM	BOTTOM	1	345.9	364.2					2547		50	49						2414			2950	43				6636		5480	8053	SMALL AMO	1.004	16.0			1.110	20	7.9	
100/10-04-093-19W4/00	57.041622162	112.991493225	520.3	524.0	Formation High CA	LEDUC FM	STOCK TANK		256.6	262.7					3754		4234	452			TRACE			13842			1269	30			NIL				23581		1.016	16.0	1.3362	25	0.292	25	7.2	
100/10-04-093-19W4/00	57.041622162	112.991493225	520.3	524.0		LEDUC FM	STOCK TANK								3048		4145	476						12313			1869	26	0	0	ABSENT				21877		1.015	60.0	1.3362	25	0.283	25	7.3	
100/07-05-094-18W4/00	57.124305725	112.861373901	522.0	525.4	Formation High CA	LEDUC FM	SEPARATOR		229.0	237.0	239	240	244	246	3600	40	5626	428			PRESENT			16900			620	2			NIL	30480		26700	27216	PRESENT	1.020	25.0	1.3386	25	0.185	25	7.3	22
100/08-09-094-18W4/00	57.139411926	112.827674866	526.2	529.6	Acidic High CA	LEDUC FM	SEPARATOR		232.0	233.0	234	240	243	244	1300	163	8112	4773			MUCH			30300			93	156			NIL	51340		35840	44897	TRACE	1.034	25.0	1.3436	25	0.149	25	5.2	23
100/06-21-094-18W4/00	57.168052673	112.839843750	539.0	543.4	Formation Water High CA	LEDUC FM	STOCK TANK		265.3	275.6					2805	70	2783	109			VERY MUCH			9900			220	35			NIL	17920		14220	15922	PRESENT	1.011	25.0	1.3358	25	0.364	25	6.6	22
100/05-24-094-18W4/00	57.166164398	112.763191223	539.6	544.0		LEDUC FM	SEPARATOR		278.0	283.4					4150	22	143	40			TRACE			4900			3633	47			NIL	12790		10120	12935	TRACE	1.008	25.0	1.3354	25	0.557	25	8.2	23
100/05-24-094-18W4/00	57.166164398	112.763191223	539.6	544.0	Fresh Water/Filtrate	LEDUC FM	STOCK TANK		278.0	280.0					3740	16	42	88			TRACE			3995			2263	64	342		NIL	10980		8430	10550	TRACE	1.007	25.0	1.3343	25	0.664	25	8.7	24
100/11-10-091-17W4/00	56.881038666	112.653167725	506.4	509.4	Fresh Water/Contaminant	MCMURRAY FM	STOCK TANK		206.0	211.5					2025	31	8	32			PRESENT			1700			2562	21	120		NIL	5408		4596	6499	TRACE	0.960	25.0	1.3398	25	2.050	25	8.7	23
100/10-01-091-18W4/00	56.865592957	112.750671387	506.4	509.4	Fresh Water/Contaminant	MCMURRAY FM	SEPARATOR		208.5	209.5	212	213	217	219	1910	25	6	21			NIL			1312			2647	10	18		NIL	4668		3728	5949	TRACE	0.960	25.0	1.3398	25	2.300	25	8.8	23
100/06-13-091-18W4/00	56.891693115	112.758438110	507.8	511.5	Fresh Water/Contaminant	MCMURRAY FM	TOP OF TOOL	1	167.3	206.3					661		60				NIL			494			703	168	84		NIL			2120	2170		1.007	16.0	1.3326	25	3.779	25	7.5	
100/07-14-091-18W4/00	56.891887665	112.778762817	507.0	510.5	Murky Fresh Water	MCMURRAY FM	BOTTOM	1	185.0	204.5					1329	17	26	24			PRESENT			586			2712	25			NIL	3815		2830	4719	TRACE	1.002	25.0	1.3331	25	2.020	25	8.0	22
100/12-19-092-14W4/00	56.997024536	112.254875183	446.7	450.7	Fresh Water	MCMURRAY FM	Test Separator		137.5	141.3					1630	30	489	34						1067			1455	18	0	0					4723		0.997	15.6	1.3360	22	1.240	25	7.6	
100/11-34-092-18W4/00	57.026721954	112.811820984	510.9	514.1	Fresh Water	MCMURRAY FM	TANK		223.0	229.0					1795	30	34	28			NIL			1200			2898	13			NIL	4612		3800	5998	TRACE	0.997	25.0	1.3335	25	1.470	25	7.8	23
100/11-04-093-18W4/00	57.042282104	112.840507507	512.7	515.7	Fresh Water	MCMURRAY FM	VESSEL		225.0	228.0					1150	100	36	34			NIL			773			2074	100			NIL	3630		1800	4267	PRESENT	0.956	25.0	1.3400	25	3.130	25	8.0	23
100/11-10-093-18W4/02	57.056251526	112.814376831	515.7	518.9	Fresh Water	MCMURRAY FM	TANK		208.0	214.0					1290	15	13	22			NIL			921			1921	18			NIL	3316		2312	4200	PRESENT	0.950	25.0	1.3403	25	3.370	25	8.2	23
100/06-19-093-18W4/00	57.080707550	112.892715454	514.7	517.7		MCMURRAY FM	SEPARATOR		222.5	227.5	230	234																																
100/11-21-093-18W4/00	57.083351135	112.839637756	517.4	521.0	Fresh Water/Filtrate	MCMURRAY FM	SEPARATOR		223.5	227.5					1885	51	32	22			PRESENT			800			3538	236	60		NIL	5256		3580	6624	PRESENT	0.995	25.0	1.3341	25	1.540	25	8.7	22
100/10-04-093-19W4/00	57.041622162	112.991493225	520.3	524.0	Formation Water	MCMURRAY FM	BTM SWAB TEST		297.2	297.2					3835		805	1123			PRESENT			10180			742				NIL				16685		1.012	16.0	1.3351	24	0.343	25	6.3	
100/12-31-094-15W4/00	57.199298859	112.413246155	527.8	531.3	Filtrate	MCMURRAY FM	TEST SEPARATOR		219.5	223.0	224	225			174	32	26	38			<0.1			319			1160	176			NIL			670	1925		0.962	21.0	1.3370	25	4.810	25	7.8	25
100/06-21-094-17W4/00	57.168190002	112.680885315	524.7	528.7	Fresh Water	MCMURRAY FM	High Pressure Separator		327.9	599.0					2820	33	124	40						2526			3285	9	0	0					8837		0.994	15.6	1.3360	22	1.030	25	7.9	
100/11-10-094-18W4/00	57.142433167	112.811889648	531.7	536.0		MCMURRAY FM	Not Provided		299.0	461.8					499	78	1360	30						91			465	69	0	0					2592		0.989	15.6	1.3370	24	1.220	25	7.1	
100/16-28-094-18W4/00	57.189308167	112.824333191	543.8	547.2	Fresh Water	MCMURRAY FM	Separator		321.5	469.8					935	99	3010	62						106			414	168	0	0					4794		0.979	15.6	1.3400	23	1.040	25	7.3	
100/16-28-094-18W4/00	57.189308167	112.824333191	543.8	547.2	Fresh Water	MCMURRAY FM	Separator		321.5	469.8					749	68	1960	40						129			381	94	0	0					3421		0.964	15.6	1.3410	23	1.680	25	7.3	
100/15-22-095-15W4/00	57.263816833	112.345695496	568.8	568.8	Formation/Contaminant	MCMURRAY FM	SEPARATOR		271.9	280.1					5213		32	101						5776			2721	958	276						15077		1.016	16.0			0.540	16	8.9	
100/15-07-095-17W4/00	57.232833862	112.747756958	547.0	551.0	Fresh High CA	MCMURRAY FM	Not Provided		375.0	529.0					889	88	1890	64						199			657	64	0	0					3851		1.005	15.6	1.3350	24	0.790	25	6.9	
100/11-08-095-17W4/00	57.229782104	112.730674744	547.0	551.0		MCMURRAY FM	Test Separator		334.7	578.0					1204	103	2090	65						274			890	84	0	0					4710		0.998	15.6	1.3370	22	0.740	25	7.0	
100/07-04-095-18W4/00	57.210678101	112.859428406	598.5	602.9	Fresh Water	MCMURRAY FM	SEPARATOR		319.0	321.0					3450	35	72	80						4250			2275	28			NIL	9324		8492	10190	PRESENT	1.007	25.0	1.3342	25	0.647	25	8.0	22
100/05-14-095-18W4/00	57.240787506	112.818618774	623.7	627.7		MCMURRAY FM	Not Provided		430.0	608.0					1300	86	831	61						418			804	401	0	0					3901		1.004	15.6	1.3350	24	0.960	25	7.7	
100/10-25-095-18W4/00	57.272453308	112.774971008	665.3	668.3	Filtrate	MCMURRAY FM	STOCK TANK		372.5	375.5	377	378	380	381	190	25	161	117			MUCH			1200			68	16			NIL	2430		1140	1777	PRESENT	1.001	25.0	1.3332	25	2.730	25	5.2	24
100/11-10-093-18W4/00	57.056251526	112.814376831	515.7	518.9		MCMURRAY WABISKAW	TANK		208.0	214.0					1290	15	13	22						921			1921	18	0	0	NIL	3316		2312	4200	PRESENT	0.950	25.0	1.3403	25	3.370	25	8.2	23
100/16-15-091-16W4/00	56.897895813	112.479095459	491.7	495.2		UNDEFINED	SEPARATOR								2740	39	59	33			N.D.			2259			3424	10	0	0	N.D.				8564		1.006	15.6	1.3340	21	0.982	25	8.0	
100/06-12-095-18W4/00	57.227485657	112.785469055	572.4	576.3		UNDEFINED	Production Test Separator		360.0	622.0					398	81	733	18						613			447	196	0	0					2486		0.982	15.6	1.3380	23	1.520	25	6.5	
100/11-31-090-17W4/00	56.851409912	112.703628540	500.7	503.9	Fresh Water	WABISKAW	SEPARATOR		180.0	182.0					1285	4	20	15			PRESENT			700			2532	3	30		NIL	3736		3184	4589	TRACE	0.990	25.0	1.3342	25	2.160	25	8.5	23
100/11-33-090-17W4/00	56.850620270	112.653190613	499.9	502.9	Fresh Water	WABISKAW	SEPARATOR		181.5	187.0					1265	4	16	14			NIL			750			2312	8			NIL	3472		2716	4369	TRACE	0.998	25.0	1.3331	25	2.070	25	8.4	23
100/07-18-091-17W4/00	56.891727448	112.724655151	508.2	511.2	Fresh Water	WABISKAW	SEPARATOR		187.0	191.0					1195	4	24	12			PRESENT			613			2531	3			NIL	3700		2460	4382	TRACE	0.998	25.0	1.3330	25	2.020	25	8.3	23
100/06-33-091-17W4/00	56.934509277	112.677688599	512.1	515.1	Fresh Water/Gas	WABISKAW	TANK		194.0	197.0					1634	14	20	38						873			3081	2			NIL				5662		0.990	25.0			2.041	25	7.8	25
100/06-33-091-17W4/00	56.934509277	112.677688599	512.1	515.1		WABISKAW	SEPARATOR		194.0	199.0					1080	8	16	24						640			1891	12	0	0	NIL	2832		1224	3671	TRACE	1.000	25.0	1.3330	25	2.270	25	8.3	23
100/12-23-091-18W4/00	56.908512115	112.789299011	510.8	516.4		WABISKAW									1310	25500	75	64				22.9		788			503	30600			N.D.				58863		1.057	25.0		25	0.160	25	8.1	25
100/10-26-091-18W4/00	56.924831390	112.776748657	511.1	514.3	Fresh Water	WABISKAW	MIDDLE	1	194.1	197.8					1618	50	24	10			MUCH			561			3325	160			NIL	3945		3115	5748	NIL	1.003	25.0	1.3336	25	1.680	25	8.1	18
100/11-12-091-19W4/00	56.880714417	112.919441223	514.8	518.6	Fresh Water Contaminant	WABISKAW	Production Test Separator		202.8	203.8					2140	33	31	26						1330			3852	4	0	0					7416		0.989	15.6	1.3360	24	1.470	25	8.1	
100/10-14-091-19W4/00	56.895305634	112.939445496	521.8	526.3	Fresh Water HI CA	WABISKAW	Separator		299.0	431.0					579	93	3820	31						83			1111	65	0	0					5782		1.014	15.6	1.3370	22	0.540	25	6.7	
100/03-06-092-16W4/00	56.946811676	112.570899963	496.7	500.5	Fresh Water HI CA	WABISKAW	Test Separator		265.8	322.0					1150	112	2580	63						342			165	88	0	0					4500		0.987	15.6	1.3380	23	0.730	25	6.0	
100/10-05-092-18W4/00	56.952617645	112.857971191	521.2	524.4	Fresh Water	WABISKAW	BOTTOM	1	208.0	211.5					1868	30	30	21			PRESENT			675			3977	49			NIL	4495		3470	6650	NIL	1.002	25.0	1.3336	25	1.470	25	7.9	20
100/06-10-092-18W4/00	56.964885712	112.811843872	517.5	520.7	Fresh Water	WABISKAW	SEPARATOR		203.0	208.0					1240	20	29	27			NIL			770			2135	46			NIL	4020		2372	4267	TRACE	0.971	25.0	1.3372	25	2.820	25	7.9	23
100/06-02-092-19W4/00	56.948566437	112.945953369	527.0	530.6		WABISKAW	TOP	2	216.0	267.5					1440	23	24	13						288			763	905	372	0	NIL	3820		1620	3828	PRESENT	1.002	25.0	1.3337	25	2.930	25	9.5	23
100/06-02-092-19W4/00	56.948566437	112.945953369	527.0	530.6	Mud	WABISKAW	BOTTOM	1	216.0	228.0					1370	19	23	2						250			1104	765	306	0	NIL	4080		1720	3839	PRESENT	1.002	25.0	1.3335	25	2.780	25	9.7	23
100/06-02-092-19W4/00	56.948566437	112.945953369	527.0	530.6		WABISKAW	TOP	2	216.0	267.5					1440	23	24	13						288			763	905	372	0	NIL	3820		1620	3456	PRESENT	1.002	25.0	1.3337	25	2.930	25	9.5	23
100/03-31-093-14W4/00	57.106121063	112.248237610	420.5	424.5	Fresh Water	WABISKAW	Test Separator		109.5	113.5					4540	30	6	71						5741			2178	111	196	0					12873		1.005	15.6	1.3360	22	0.540	25	8.8	
100/06-06-093-17W4/00	57.037105560	112.730796814	512.6	515.6	Fresh Water	WABISKAW	SEPARATOR		197.0	200.0					2149	157	20	68				15		1493			3440	75			NIL				7417		1.010	25.0			1.333	25	7.3	25
100/11-19-093-17W4/00	57.084247589	112.731353760	510.0	514.0	Fresh Water HI CA	WABISKAW	Not Provided		319.0	540.0					491	115	2400	37						140			612	242	0	0					4037		1.002	15.6	1.3360	24	0.800	25	6.8	
100/07-22-093-19W4/00	57.080642700	112.964469910	521.5	524.9	Mud Filtrate	WABISKAW		1	203.0	217.0					831		9	19			PRESENT			92			1628	237	118		PRESENT	2495		1300	2934	NIL	1.003	16.0	1.3336	25	3.270	25	9.0	
100/02-30-095-17W4/00	57.267276764	112.747985840	660.8	664.4	Fresh High CA	WABISKAW	Low Pressure Separator		507.0	657.0					1210	149	1640	73						386			177	172	0	0					3807		0.998	15.6	1.3370	23	0.750	25	6.6	
100/10-03-095-18W4/00	57.216152191	112.831436157	588.1	591.5	Acid Water	WABISKAW	SEPARATOR		312.0	317.0					645	407	5646	729			VERY MUCH			17600				121			NIL	33220		22730	25148	MUCH	1.022	25.0	1.3390	25	0.226	25	3.9	23
100/11-11-095-18W4/00	57.230388641	112.814674377	601.9	604.9		WABISKAW	TOP OF TOOL		309.0	314.0											TRACE			300							NIL	3100		1970	300	PRESENT			1.3337	25	2.230	25	8.5	23
100/04-13-095-18W4/00	57.238342285	112.789009094	610.0	612.1	Mud Filtrate/Incomplete	WABISKAW	BOTTOM	2	314.0	329.9											TRACE			195							NIL	3730		2430	195	MUCH			1.3337	25	2.470	25	9.1	22

IHS Energy, 2003. "GeoFluids." A digital oil, gas and water chemistry database available in AccuMap, Calgary, Alberta. Date accessed October 20th 2007

***Hydro Fax Resources Ltd, 2007. "Athabasca Water Analyses Twps. 91- 94 Rge's 14-19W4"**

ATTACHMENT C

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0092603
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: PAN AMERICAN PETRO	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
08	35	091	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 523.95 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed: 1963/03/26 Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1963/03/02
Date Completed (yyyy/mm/dd): 1963/03/26
Well Depth: 409.35 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Installation Method:

Fittings
Top: Bottom:

Pack:
Grain Size: Amount:

Geophysical Log Taken: ELECTRIC
Retained on Files: ELECTRIC yes

Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 1 Documents Held: 4

Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:

Comments:

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.: 0092612
Map Verified: Field
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: TEXACO CAN
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
06	13	091	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 507.8 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: Yes
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1959/02/12
Date Completed (yyyy/mm/dd): 1959/02/28
Well Depth: 940 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top:
Bottom:
Pack:
Grain Size:
Amount:
Geophysical Log Taken: ELECTRIC
Retained on Files: ELECTRIC yes
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 2
Documents Held: 5
Pitless Adapter Type:
Drop Pipe Type:
Length:
Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

Alberta Environment

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0092613
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: PAN AMERICAN PETRO	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	16	091	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 516.94 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed: 1966/02/26 Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1966/02/06	Date Completed (yyyy/mm/dd): 1966/02/26
Well Depth: 970.79 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M
Perforations from: 0 M to: 0 M from: 0 M to: 0 M from: 0 M to: 0 M	Perforations Size: 0 CM x 0 CM 0 CM x 0 CM 0 CM x 0 CM
Perforated by:	
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:	
Fittings Top:	Bottom:
Pack: Grain Size:	Amount:
Geophysical Log Taken: Retained on Files:	
Additional Test and/or Pump Data Chemistries taken By Driller: No Held: 0	Documents Held: 1
Pitless Adapter Type: Drop Pipe Type: Length:	Diameter:
Comments:	

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Alberta Environment

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0092614
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: PAN AMERICAN PETRO	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	34	091	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 517.86 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed: 1967/02/23 Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters) Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1967/02/02	Date Completed (yyyy/mm/dd): 1967/02/23
Well Depth: 921.11 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M
Perforations from: 0 M to: 0 M	Perforations Size: 0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
Perforated by:	
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:	
Fittings Top:	Bottom:
Pack: Grain Size:	Amount:
Geophysical Log Taken: Retained on Files:	
Additional Test and/or Pump Data Chemistries taken By Driller: No Held: 2	Documents Held: 3
Pitless Adapter Type: Drop Pipe Type: Length:	Diameter:
Comments:	

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.: 0092615
Map Verified: Field
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: MIAMI OIL
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
11	29	091	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 521.21 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/10
Date Completed (yyyy/mm/dd): 1974/03/21
Well Depth: 318.21 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top:
Bottom:
Pack:
Grain Size:
Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 2
Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length:
Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0092616
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: PAN AMERICAN PETRO
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
08	32	091	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 535.23 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed: 1963/03/01
Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Drawdown	Depth To water level (meters) Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1963/02/20
Date Completed (yyyy/mm/dd): 1963/03/01
Well Depth: 426.72 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken: ELECTRIC
Retained on Files: ELECTRIC yes
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 3 Documents Held: 6
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0092621
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: MIAMI OIL	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
06	08	092	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 529.44 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory
Reclaimed Well
Date Reclaimed: Materials Used:
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: Yes Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)		
Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/24	Date Completed (yyyy/mm/dd): 1974/03/30
Well Depth: 338.63 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M
Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
Perforated by:	
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:	
Fittings Top:	Bottom:
Pack: Grain Size:	Amount:
Geophysical Log Taken: Retained on Files:	
Additional Test and/or Pump Data Chemistries taken By Driller: No Held: 0	Documents Held: 1
Pitless Adapter Type: Drop Pipe Type: Length:	Diameter:
Comments:	

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.: 0092622
Map Verified: Field
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: MIAMI OIL
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	16	092	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 526.39 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: Yes
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/22
Date Completed (yyyy/mm/dd): 1974/03/29
Well Depth: 333.15 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:

Fittings
Top:
Bottom:
Pack:
Grain Size:
Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0
Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length:
Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

Alberta Environment

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0092623
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: AMOCO CAN	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
06	35	092	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 519.99 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Drill Stem Test Hole
Reclaimed Well
Date Reclaimed: Materials Used:
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: Yes Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/15	Date Completed (yyyy/mm/dd): 1974/03/26
Well Depth: 405.38 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M
Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM

Screen Installation Method:

Fittings
Top: Bottom:

Pack:
Grain Size: Amount:

Geophysical Log Taken:
Retained on Files:

Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1

Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:

Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0092631
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: DOME PETRO	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
06	07	094	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 589.79 M How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory
Reclaimed Well
Date Reclaimed: 1974/02/20 Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/02/15	Date Completed (yyyy/mm/dd): 1974/02/20
Well Depth: 314.55 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

Alberta Environment

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0092632
Map Verified:	Field
Date Report Received:	
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER		Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN	City or Town: UNKNOWN AB CA	Postal Code:
WellOwner's Name: DOME PETRO	Well Location Identifier:	
P.O. Box Number:	Mailing Address:	Postal Code:
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
06	09	094	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 568.15 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory
Reclaimed Well
Date Reclaimed: 1974/02/24 Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/02/21	Date Completed (yyyy/mm/dd): 1974/02/24
Well Depth: 315.77 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type:
Size OD: 0 CM	Size OD: 0 CM
Wall Thickness: 0 CM	Wall Thickness: 0 CM
Bottom at: 0 M	Top: 0 M Bottom: 0 M
Perforations from: 0 M to: 0 M	Perforations Size: 0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
Perforated by:	
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:	
Fittings Top:	Bottom:
Pack: Grain Size:	Amount:
Geophysical Log Taken: Retained on Files:	
Additional Test and/or Pump Data Chemistries taken By Driller: No Held: 0	Documents Held: 1
Pitless Adapter Type: Drop Pipe Type: Length:	Diameter:
Comments:	

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.: 0092633
Map Verified: Field
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: DOME PETRO
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
07	28	094	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 639.78 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory Reclaimed Well
Date Reclaimed: 1974/02/28
Materials Used: Unknown
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day 0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters) Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/02/25
Date Completed (yyyy/mm/dd): 1974/02/28
Well Depth: 368.81 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M

Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0150681
Map Verified:	Not Verified
Date Report Received:	1990/04/23
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: MCALLISTER HOLDINGS LTD.
Drilling Company Approval No.:
Mailing Address: | City or Town: | Postal Code:
WellOwner's Name: PETROCAN
Well Location Identifier:
P.O. Box Number: | Mailing Address: DUNKIRK | Postal Code:
City: | Province: | Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
13	09	093	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot | Block | Plan
Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed: | Materials Used:
Method of Drilling: Rotary
Flowing Well: No | Rate: Liters
Gas Present: | Oil Present:
Proposed well use: Domestic
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): 1990/02/10
Start Time: 11:00 AM
Test Method: Air
Non pumping static level: 1.89 M
Rate of water removal: 159.11 Liters/Min
Depth of pump intake: 0 M
Water level at end of pumping: 5.49 M
Distance from top of casing to ground level: CM
Depth To water level (meters)
Drawdown | Elapsed Time Minutes:Sec | Recovery
Total Drawdown: 3.66 M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: 0 Liters/Min
Recommended pump intake: 29.26 M
Type Pump Installed
Pump Type: SUB
Pump Model: JACUZZI
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
3.05	Brown Sand
5.49	Gray Sand
12.5	Gray Sandy Till
24.38	Gray Sand
28.04	Coarse Grained Sand
29.26	Gray Till
41.45	Coarse Grained Sand
48.77	Gray Fine Grained Sand
57.91	Brown Sandy Till
62.79	Gravel
67.06	Gray Shale

5. Well Completion

Date Started(yyyy/mm/dd): 1990/02/10
Date Completed (yyyy/mm/dd): 1990/02/10
Well Depth: 67.06 M | Borehole Diameter: 0 CM
Casing Type: Steel | Liner Type:
Size OD: 14.12 CM | Size OD: 0 CM
Wall Thickness: 0.48 CM | Wall Thickness: 0 CM
Bottom at: 31.7 M | Top: 0 M Bottom: 0 M

Perforations | Perforations Size:
from: 0 M to: 0 M | 0 CM x 0 CM
from: 0 M to: 0 M | 0 CM x 0 CM
from: 0 M to: 0 M | 0 CM x 0 CM

Perforated by:

Seal: Cuttings
from: 0 M to: 12.19 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Steel | Screen ID: 10.16 CM
from: 31.7 M to: 33.22 M | Slot Size: 0.04 CM
Screen Type: | Screen ID: 0 CM
from: 0 M to: 0 M | Slot Size: 0 CM
Screen Installation Method: Attached To Casing

Fittings
Top: Coupler | Bottom: Plug
Pack: Artificial
Grain Size: 12/20 | Amount: 900
Geophysical Log Taken: ELECTRIC
Retained on Files: ELECTRIC yes
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 | Documents Held: 2
Pitless Adapter Type:
Drop Pipe Type:
Length: M | Diameter: CM
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.: VA4003
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1 Pump Test 1 page1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.: 0235336
Map Verified: Not Verified
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: AMOCO#F-1 CHIPEWYAN
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	04	093	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 520.29 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: Yes
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters) Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/02
Date Completed (yyyy/mm/dd): 1974/03/09
Well Depth: 308.15 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top:
Bottom:
Pack:
Grain Size:
Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 1
Documents Held: 2
Pitless Adapter Type:
Drop Pipe Type:
Length:
Diameter:
Comments:
GAS PAY ZONE(NET): 13' IN WABISKAW.

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

Alberta Environment

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.: 0235337
Map Verified: Not Verified
Date Report Received:
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: AMOCO#C-2 CHIPEWYAN
Well Location Identifier:
P.O. Box Number:
Mailing Address:
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
07	22	093	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 521.51 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Oil Exploratory Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: Yes
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd): 1974/03/11
Date Completed (yyyy/mm/dd): 1974/03/20
Well Depth: 381 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Seal: from: 0 M to: 0 M
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 1 Documents Held: 2
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:
GAS FOUND IN PRODUCING ZONES: WABISKAW/D-3

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0243283
Map Verified:	Map
Date Report Received:	1981/04/03
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: M&M DRILLING CO. LTD.
Drilling Company Approval No.: 118890
Mailing Address: BOX 1, SITE 22, RR 2
City or Town: STRATHMORE AB CA
Postal Code: T1P 1K5
WellOwner's Name: EBA ENGINEERING
Well Location Identifier:
P.O. Box Number:
Mailing Address: 5664 BURLEIGH CRES. SE,
Postal Code: T2H 3H0
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	29	092	17	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description
0.61	Muskeg
6.1	Gray Clay
9.75	Gray Sandy Clay
10.36	Rocks
11.28	Sandy Clay
15.24	Sand
20.42	Sandy Clay
21.95	Sand
48.77	Sandy Clay
82.91	Soft Shale
83.82	Hard Sandstone
88.39	Sandy Shale
89	Hard Sandstone
96.01	Soft Shale
99.67	Hard Sandstone
102.72	Sandy Shale

5. Well Completion

Date Started(yyyy/mm/dd): 1981/03/04
Date Completed (yyyy/mm/dd): 1981/03/09
Well Depth: 102.72 M
Borehole Diameter: 0 CM
Casing Type: Steel
Liner Type:
Size OD: 17.78 CM
Size OD: 0 CM
Wall Thickness: 0.48 CM
Wall Thickness: 0 CM
Bottom at: 80.77 M
Top: 0 M Bottom: 0 M
Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type: Stainless Steel
Screen ID: 15.24 CM
from: 80.77 M to: 100.58 M
Slot Size: 0.06 CM
Screen Type:
Screen ID: 0 CM
from: 0 M to: 0 M
Slot Size: 0 CM
Screen Installation Method: Telescoped
Fittings
Top: Packer
Bottom: Other
Pack: Sand
Grain Size: 10/20
Amount: 130 Bags
Geophysical Log Taken: ELECTRIC and GAMMA
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: Yes
Held: 0
Documents Held: 3
Pitless Adapter Type:
Drop Pipe Type:
Length: M
Diameter: CM
Comments:

6. Well Yield

Test Date (yyyy/mm/dd): 1981/03/09
Start Time: 8:00 AM
Test Method: Pump
Non pumping static level: 12.95 M
Rate of water removal: 340.95 Liters/Min
Depth of pump intake: 48.16 M
Water level at end of pumping: 14.02 M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
21.57	1:00	34.46
24.33	2:00	28.53
25.57	3:00	25.21
26.41	4:00	23.47
27.79	6:00	21.87
28.74	8:00	21.07
29.79	10:00	20.43
31.32	13:00	20.13
31.85	16:00	19.77
32.46	20:00	19.36
32.75	25:00	19.04
33.39	32:00	18.63
33.7	40:00	18.35
33.98	50:00	17.99
34.53	64:00	17.68
34.99	80:00	17.43
35.52	100:00	17.07
35.62	120:00	16.83
35.77	140:00	16.6
36.07	160:00	16.43
36.21	180:00	16.27
36.34	200:00	16.12
36.44	220:00	16.02
36.53	240:00	15.92
36.67	270:00	15.76

Total Drawdown: 35.36 M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: 0 Liters/Min
Recommended pump intake: 0 M
Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1 **Pump Test 1** page1 page2

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0279598
Map Verified:	Not Verified
Date Report Received:	1984/02/17
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: PARAMOUNT RES LTD
Well Location Identifier:
P.O. Box Number:
Mailing Address: LEGEND PLANT SITE
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
NW	31	094	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: Chemistry Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Unknown
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Domestic
Anticipated Water Requirements/day
0 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description

5. Well Completion

Date Started(yyyy/mm/dd):
Date Completed (yyyy/mm/dd):
Well Depth: 30.48 M
Borehole Diameter: 0 CM
Casing Type:
Size OD: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Liner Type:
Size OD: 0 CM
Wall Thickness: 0 CM
Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:

Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 4
Documents Held: 4
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0279848
Map Verified:	Field
Date Report Received:	1965/11/01
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: UNKNOWN DRILLER
Drilling Company Approval No.: 99999
Mailing Address: UNKNOWN
City or Town: UNKNOWN AB CA
Postal Code:
WellOwner's Name: PAN AMERICAN OIL #2
Well Location Identifier:
P.O. Box Number:
Mailing Address: CHIP LAKE STN
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
08	35	091	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: 523.95 M
How Obtain: Survey-Tra

3. Drilling Information

Type of Work: Structure Test Hole
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Unknown
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
3.05	Glacial Gravel
12.19	Sandstone
15.24	Dark Gray Shale & Sandstone
18.29	Brownish Gray Silty Till
21.34	Sandy Till
30.48	Sandstone
33.53	Glacial Sandstone & Gravel
36.58	Glacial Sand
45.72	Sandstone
48.77	Shaly Sand & Sandstone
60.96	Gray Sandstone
73.15	Glacial Gravel
76.2	Salt & Pepper Sandstone
79.25	Sandstone
85.34	Dark Gray Silty Shale

5. Well Completion

Date Started(yyyy/mm/dd):
Date Completed (yyyy/mm/dd):
Well Depth: 85.34 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M
Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0
Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Alberta Environment

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0279904
Map Verified:	Field
Date Report Received:	1981/04/03
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: M&M DRILLING CO. LTD.		Drilling Company Approval No.: 118890
Mailing Address: BOX 1, SITE 22, RR 2	City or Town: STRATHMORE AB CA	Postal Code: T1P 1K5
WellOwner's Name: EBA ENGINEERING	Well Location Identifier:	
P.O. Box Number:	Mailing Address: 5664 BURLEIGH CRES SE, CALGARY	Postal Code: T2H 1Z8
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	29	092	17	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 498.35 M
How Obtain: Estimated

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed: Materials Used:
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Industrial
Anticipated Water Requirements/day
0 Liters

6. Well Yield

Test Date (yyyy/mm/dd): 1981/02/24
Start Time: 11:00 AM
Test Method: Bailer & Pump
Non pumping static level: 13.78 M
Rate of water removal: 113.65 Liters/Min
Depth of pump intake: 0 M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
18.2	1:00	67.6
22.4	2:00	
26.24	3:00	54.14
28.8	4:00	
34.75	6:00	48.22
37.64	8:00	38.04
38.07	10:00	33.24
39.78	13:00	27.14
40.87	16:00	24.01
44.52	20:00	19.6
46.54	25:00	17.37
48.94	32:00	15.93
53.77	40:00	15.5
53.52	50:00	15.27
54.78	64:00	15.12
56.33	80:00	14.99
56.99	100:00	14.87
59.45	120:00	14.75
61.9	140:00	14.65
62.5	160:00	14.6
63.13	180:00	14.56
63.84	200:00	14.47
65.45	220:00	14.42
65.61	240:00	14.37
66.13	270:00	14.31

Total Drawdown: 0 M

If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: 40.91 Liters/Min

Recommended pump intake: 96.01 M

Type Pump Installed
Pump Type:
Pump Model:
H.P.:

Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
3.05	Muskeg
10.67	Sandy Clay & Boulders
37.19	Sandy Clay & Rocks
65.53	Sandy Clay
73.76	Soft Shale
74.68	Sandstone
81.38	Soft Shale
82.91	Sandstone
96.62	Soft Shale
99.06	Hard Sandstone
105.46	Sandy Shale & Sandstone

5. Well Completion

Date Started(yyyy/mm/dd): 1981/02/19	Date Completed (yyyy/mm/dd): 1981/02/24
Well Depth: 105.46 M	Borehole Diameter: 0 CM
Casing Type: Steel	Liner Type:
Size OD: 17.78 CM	Size OD: 0 CM
Wall Thickness: 0.48 CM	Wall Thickness: 0 CM
Bottom at: 98.76 M	Top: 0 M Bottom: 0 M
Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Stainless Steel Screen ID: 15.24 CM
from: 98.76 M to: 104.85 M Slot Size: 0.05 CM

Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM

Screen Installation Method: Telescoped

Fittings
Top: Welded Bottom: Washdown

Pack: Frac Sand
Grain Size: 20-30 Amount: 40 Bags

Geophysical Log Taken:
Retained on Files:

Additional Test and/or Pump Data
Chemistries taken By Driller: Yes
Held: 0 Documents Held: 5

Pitless Adapter Type:
Drop Pipe Type:
Length: M Diameter: CM

Comments:
DRILLER REPORTS WATER IS SOFT

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0279905
Map Verified:	Field
Date Report Received:	1981/03/01
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: M&M DRILLING CO. LTD.		Drilling Company Approval No.: 118890
Mailing Address: BOX 1, SITE 22, RR 2	City or Town: STRATHMORE AB CA	Postal Code: T1P 1K5
WellOwner's Name: EBA ENGINEERING LTD	Well Location Identifier:	
P.O. Box Number:	Mailing Address: 5664 BURLEIGH CRES SE, CALGARY	Postal Code: T2H 1Z8
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
10	29	092	17	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: 498.35 M
How Obtain: Estimated

3. Drilling Information

Type of Work: Test Hole Reclaimed Well Date Reclaimed:	Materials Used:	Proposed well use: Observation
Method of Drilling: Rotary		Anticipated Water Requirements/day 0 Liters
Flowing Well: No Gas Present: No	Rate: Liters Oil Present: No	

4. Formation Log

Depth from ground level (meters)	Lithology Description
3.66	Muskeg
9.14	Gray Sandy Clay & Rocks
13.72	Sandy Clay
15.24	Sand
88.09	Gray Sandy Clay
89.31	Sandstone
98.15	Gray Sandy Shale
100.58	Sandstone
109.73	Gray Sandy Shale
110.34	Sandstone
115.82	Sandy Shale & Sandstone
125.58	Sandy Shale
126.19	Sandstone
130.15	Sandy Shale
131.06	Sandstone
134.72	Sandy Shale
135.64	Bentonite
148.44	Shale
149.96	Sandstone
150.88	Shale
151.79	Sandstone
152.4	Shale

5. Well Completion

Date Started(yyyy/mm/dd): 1981/02/16	Date Completed (yyyy/mm/dd): 1981/02/19
Well Depth: 152.4 M	Borehole Diameter: 0 CM
Casing Type:	Liner Type: Steel
Size OD: 0 CM	Size OD: 14.12 CM
Wall Thickness: 0 CM	Wall Thickness: 0.48 CM
Bottom at: 0 M	Top: 2.44 M Bottom: 102.41 M
Perforations from: 86.87 M to: 102.41 M from: 0 M to: 0 M from: 0 M to: 0 M	Perforations Size: 0 CM x 0 CM 0 CM x 0 CM 0 CM x 0 CM
Perforated by:	
Seal: Driven from: 0 M	to: 86.87 M
Seal: from: 0 M	to: 0 M
Seal: from: 0 M	to: 0 M
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Type: from: 0 M to: 0 M	Screen ID: 0 CM Slot Size: 0 CM
Screen Installation Method:	
Fittings Top:	Bottom:
Pack: Grain Size:	Amount:
Geophysical Log Taken: Retained on Files:	
Additional Test and/or Pump Data Chemistries taken By Driller: Yes Held: 0	Documents Held: 5
Pitless Adapter Type: Drop Pipe Type: Length: M	Diameter: CM

Comments:
DRILLER REPORTS WATER IS SOFT. WATER LEVEL MEASURMENTS DATED 1981-02-26 IS AN ESTIMATE BASED ONLY ON DATE OF PREVIOUS W.L. MEASUREMENTS THAT WERE DATED.

6. Well Yield

Test Date (yyyy/mm/dd): 1981/02/26	Start Time: 8:00 AM
Test Method: Water Levels Only	
Non pumping static level:	13.75 M
Rate of water removal:	Liters/Min
Depth of pump intake:	0 M
Water level at end of pumping:	20.97 M
Distance from top of casing to ground level:	CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
13.74	1:00	20.96
13.74	2:00	20.96
13.74	3:00	20.96
13.74	4:00	20.96
13.74	6:00	20.96
13.74	8:00	20.89
13.74	10:00	20.83
13.74	13:00	20.69
13.74	16:00	20.48
13.74	20:00	20.23
13.76	25:00	19.92
13.76	32:00	19.57
13.78	40:00	19.22
13.81	50:00	19.16
13.95	64:00	18.49
14.18	80:00	18.14
14.45	100:00	17.83
14.74	120:00	17.54
15	140:00	17.32
15.24	160:00	17.12
15.47	180:00	16.95
15.69	200:00	16.81
15.9	220:00	16.65
16.09	240:00	16.65
16.35	270:00	16.39

Total Drawdown: 7.32 M

If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: 0 Liters/Min

Recommended pump intake: 0 M

Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.:
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

ALBERTA ENVIRONMENT
CHEMICAL ANALYSIS REPORT

WELL NAME: PARAMOUNT RES LTD
LOCATION: LSD NW SEC 31 TWP 094 RG 18 M 4
WELL DEPTH: 100
AQUIFER:
SAMPLING DATE: 2/6/1985 TIME: 0

WELL ID No:0279598
SAMPLE No: 1284
WATER LEVEL: -9
LABORATORY: AE
PRINT DATE: 2/26/2008

FIELD:	**MG/L**	**FIELD:**	**MG/L**
BICARBONATE	-9	CARBONATE	-9
CHLORIDE	-9	CONDUCTIVITY	-9
DISSOLVED OXYGEN	-9	EH	-9
IRON	-9	MANGANESE	-9
PH	-9	SULPHATE	-9
S2	-9	TEMPERATURE°C	-9
TOTAL ALKALINITY	-9	TOTAL HARDNESS	-9

LABORATORY: Analysis Date: 2/21/1985

COD	-9	CONDUCTIVITY	1258
DIC	-9	FLUORIDE	0.36
ION BALANCE	0.96	PH	7.6
SAR	-9	SIO2	11.4
TOTAL ALKALINITY	296	TC	-9
TDS	853	TN	-9
DOC	-9		
AMMONIUM-N	-9	BICARBONATE	359.8817
CALCIUM	110.778	CARBONATE	-9
CHLORIDE	25.0346	MAGNESIUM	40.033152
NITRATE-N	-9	NITRITE-N	0.0504*
PHOSPHATE	-9	POTASSIUM	5.2535
SODIUM	113.9995	SULPHATE	379.7616
$NO_2 + NO_3$	0.0144*	TOTAL HARDNESS	442
ALUMINUM	-9	ARSENIC	-9
BARIUM	-9	BERYLLIUM	-9
CADMIUM	-9	CHROMIUM	-9
COBALT	-9	COPPER	-9
IRON	3.17	LEAD	-9
MANGANESE	-9	MERCURY	-9
MOLYBDENUM	-9	NICKEL	-9
SELENIUM	-9	STRONTIUM	-9
VANADIUM	-9	ZINC	-9
HYDROCARBONS	-9	PESTICIDES	-9
PHENOLICS	-9	OTHER 3	0

Remarks:
-9 indicates that no analysis was done for this parameter
*Indicates concentrations less than.
Temperature reported in Degree Centigrade. Conductivity reported in microsiemens/cm, pH in pH units. Alkalinity and Hardness expressed as Calcium Carbonate. FE, VA, PB, AL, AG expressed as extractable. FE in field measurements and all remaining metals expressed as total.

EH - Oxidation-Reduction Potential
DIC - Dissolved Inorganic Carbon
DOC - Dissolved Organic Carbon
TDS - Total Dissolved Solids
SAR - Sodium Adsorption Ratio
COD - Chemical Oxygen Demand
TN - Total Particulate Nitrogen
TC - Total Particulate Carbon

NOTE: This data may not be fully checked.
The Province disclaims all responsibility for its accuracy

Report 1 Report 2 Report 3 Report 4

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.: 0287116
Map Verified: Not Verified
Date Report Received: 1997/03/12
Measurements: Metric

1. Contractor & Well Owner Information

Company Name: LAKELAND DRILLING LTD.
Drilling Company Approval No.: 38404
Mailing Address: BOX 1388
City or Town: ST PAUL AB CA
Postal Code: T0A 3A0
WellOwner's Name: RIO ALTA EXPL
Well Location Identifier:
P.O. Box Number:
Mailing Address: 3A 242 MACALPINE CRES, FORT MCMURRAY
Postal Code:
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
13	24	091	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Domestic
Anticipated Water Requirements/day 909.2 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description
4.57	Brown Soft Clay
5.18	Sand
10.67	Blue Till & Clay
11.28	Sand
16.76	Blue Clay
25.6	Sand
37.8	Blue Clay
40.23	Fine Grained Sand
49.07	Gray Hard Clay
59.44	Silty Sand
73.15	Gray Hard Shale

5. Well Completion

Date Started(yyyy/mm/dd): 1997/02/17
Date Completed (yyyy/mm/dd): 1997/02/17
Well Depth: 73.15 M
Borehole Diameter: 0 CM
Casing Type: Plastic
Liner Type:
Size OD: 12.7 CM
Size OD: 0 CM
Wall Thickness: 0.67 CM
Wall Thickness: 0 CM
Bottom at: 23.16 M
Top: 0 M Bottom: 0 M
Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:
Seal: Bentonite Chips/Tablets
from: 0 M to: 18.29 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type: Stainless Steel
Screen ID: 12.7 CM
from: 23.16 M to: 24.69 M
Slot Size: 0.03 CM
Screen Type:
Screen ID: 0 CM
from: 0 M to: 0 M
Slot Size: 0 CM
Screen Installation Method: Attached To Casing
Fittings
Top: Coupler
Bottom: Plug
Pack: Artificial
Grain Size: 10-20
Amount: 6 Bags
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0
Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: M
Diameter: CM
Comments:
DRILLER REPORTS DISTANCE FROM TOP OF CASING TO GROUND LEVEL: 1.6'.

6. Well Yield

Test Date (yyyy/mm/dd): 1997/02/17
Start Time: 6:00 PM
Test Method: Air
Non pumping static level: 2.13 M
Rate of water removal: 81.83 Liters/Min
Depth of pump intake: 24.38 M
Water level at end of pumping: 24.38 M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
	1:00	6.85
	2:00	3.95
	3:00	3.08
	4:00	2.89
	5:00	2.85
	6:00	2.8
	7:00	2.77
	8:00	2.74
	120:00	2.13

Total Drawdown: 22.25 M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: 45.46 Liters/Min
Recommended pump intake: 18.29 M
Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.: 5449Q
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0292382
Map Verified:	Not Verified
Date Report Received:	1999/03/15
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: LAKELAND DRILLING LTD.		Drilling Company Approval No.: 38404
Mailing Address: BOX 1388	City or Town: ST PAUL AB CA	Postal Code: T0A 3A0
WellOwner's Name: RIO ALTA EXPL	Well Location Identifier:	
P.O. Box Number:	Mailing Address: 2500 205 5 AVE SW, CALGARY	Postal Code: T2P 2V7
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
01	27	091	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed: Materials Used:
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Domestic
Anticipated Water Requirements/day 681.9 Liters

6. Well Yield

Test Date (yyyy/mm/dd): 1999/02/26
Start Time: 2:00 PM
Test Method: Air

Non pumping static level:	5.49 M
Rate of water removal:	68.19 Liters/Min
Depth of pump intake:	30.18 M
Water level at end of pumping:	30.18 M
Distance from top of casing to ground level:	CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
5.94	1:00	17.75
6	2:00	12.85
6	3:00	9.81
6.02	4:00	8.03
6.02	5:00	6.93
6.02	6:00	6.3
6.02	7:00	5.94
6.02	8:00	5.84
6.02	9:00	5.69
6.02	10:00	5.61
6.02	14:00	5.54
6.02	20:00	5.51
6.02	30:00	5.49
6.02	40:00	5.49
6.02	50:00	5.49
6.02	90:00	
6.02	120:00	

Total Drawdown: 24.69 M

If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: 45.46 Liters/Min

Recommended pump intake: 24.38 M

Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
0.3	Muskeg
6.4	Brown Till
15.85	Blue Till
18.9	Sand
20.12	Blue Till
24.69	Sand & Gravel
26.21	Blue Till
30.78	Sand & Gravel
35.05	Blue Till

5. Well Completion

Date Started(yyyy/mm/dd): 1999/02/26	Date Completed (yyyy/mm/dd): 1999/02/26
Well Depth: 35.05 M	Borehole Diameter: 0 CM
Casing Type: Plastic	Liner Type:
Size OD: 12.7 CM	Size OD: 0 CM
Wall Thickness: 0.66 CM	Wall Thickness: 0 CM
Bottom at: 28.65 M	Top: 0 M Bottom: 0 M

Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal: Cement/Grout
from: 0 M to: 24.38 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Stainless Steel Screen ID: 12.7 CM
from: 28.65 M to: 30.18 M Slot Size: 0.03 CM

Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM

Screen Installation Method: Attached To Casing

Fittings
Top: Packer Bottom: Plug

Pack: Artificial
Grain Size: 10-20 Amount: 5 Bags

Geophysical Log Taken: ELECTRIC
Retained on Files:

Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1

Pitless Adapter Type:
Drop Pipe Type:
Length: M Diameter: CM

Comments:
DRILLER REPORTS DISTANCE FROM TOP OF CASING TO GROUND LEVEL: 2'.

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.: 5449Q
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1 **Pump Test 1** page1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0292383
Map Verified:	Not Verified
Date Report Received:	1999/05/10
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: HILL DRILLING LTD.
Drilling Company Approval No.: 115418
Mailing Address: BOX 508
City or Town: THORHILD AB CA
Postal Code: T0A 3J0
WellOwner's Name: PARAMOUNT RES LTD
Well Location Identifier:
P.O. Box Number:
Mailing Address: 4000 350 7 AVE SW, CALGARY
Postal Code: T2P 3W5
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
01	30	092	19	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: Test Hole-Abandoned
Reclaimed Well
Date Reclaimed: 1999/02/27
Materials Used: Bentonite Product
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Domestic
Anticipated Water Requirements/day 4546 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description
16.76	Brown Clay
23.47	Black Clay & Rocks
24.08	Sand
24.69	Sandy Gravel
42.06	Clay & Rocks
46.02	Fine Grained Sand
48.77	Sand & Rocks

5. Well Completion

Date Started(yyyy/mm/dd): 1999/02/27
Date Completed (yyyy/mm/dd): 1999/02/27
Well Depth: 48.77 M
Borehole Diameter: 0 CM
Casing Type:
Liner Type:
Size OD: 0 CM
Size OD: 0 CM
Wall Thickness: 0 CM
Wall Thickness: 0 CM
Bottom at: 0 M
Top: 0 M Bottom: 0 M
Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method:
Fittings
Top: Bottom:
Pack:
Grain Size: Amount:
Geophysical Log Taken: ELECTRIC
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: Diameter:
Comments:

6. Well Yield

Test Date (yyyy/mm/dd):
Start Time:
Test Method:
Non pumping static level: M
Rate of water removal: Liters/Min
Depth of pump intake: M
Water level at end of pumping: M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery

Total Drawdown: M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: Liters/Min
Recommended pump intake: M
Type pump installed
Pump type:
Pump model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: DWIGHT HILL
Certification No.: VB8143
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0292384
Map Verified:	Not Verified
Date Report Received:	1999/05/10
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: HILL DRILLING LTD.		Drilling Company Approval No.: 115418
Mailing Address: BOX 508	City or Town: THORHILD AB CA	Postal Code: T0A 3J0
WellOwner's Name: PARAMOUNT RES LTD	Well Location Identifier:	
P.O. Box Number:	Mailing Address: 4000 350 7 AVE SW, CALGARY	Postal Code: T2P 3W5
City:	Province: AB	Country: CA

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
01	30	092	19	4

Location in Quarter
0 M from S Boundary
0 M from W Boundary

Lot Block Plan

Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed: Materials Used: Unknown
Method of Drilling: Auger
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Domestic
Anticipated Water Requirements/day 4546 Liters

6. Well Yield

Test Date (yyyy/mm/dd): 1999/02/27
Start Time: 9:00 AM
Test Method: Pump
Non pumping static level: 10.45 M
Rate of water removal: 68.19 Liters/Min
Depth of pump intake: 45.72 M
Water level at end of pumping: 10.97 M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
10.46	0:00	
11.13	1:00	10.44
11.13	2:00	10.46
11.18	3:00	
11.18	10:00	
11.18	30:00	
11.18	60:00	
11.18	120:00	

Total Drawdown: 0.61 M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: 68.19 Liters/Min
Recommended pump intake: 45.72 M
Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
17.07	Brown Clay
17.68	Brown Fine Grained Sand
36.58	Black Clay & Rocks
66.45	Brown Fine Grained Sand
73.15	Gray Coarse Grained Sandstone

5. Well Completion

Date Started(yyyy/mm/dd): 1999/02/25	Date Completed (yyyy/mm/dd): 1999/02/26
Well Depth: 73.15 M	Borehole Diameter: 0 CM
Casing Type: Plastic	Liner Type:
Size OD: 12.7 CM	Size OD: 0 CM
Wall Thickness: 0.64 CM	Wall Thickness: 0 CM
Bottom at: 68.58 M	Top: 0 M Bottom: 0 M
Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:

Seal: Bentonite Chips/Tablets
from: 0 M to: 65.53 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M

Screen Type: Stainless Steel Screen ID: 8.89 CM
from: 68.58 M to: 70.1 M Slot Size: 0.04 CM
Screen Type: Screen ID: 0 CM
from: 70.1 M to: 71.63 M Slot Size: 0 CM
Screen Installation Method: Attached To Casing

Fittings
Top: Coupler Bottom: Plug
Pack: Artificial
Grain Size: 10-20 Amount: 15 Bags
Geophysical Log Taken:
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: M Diameter: CM

Comments:
DRILLER REPORTS DISTANCE FROM TOP OF CASING TO GROUND LEVEL: 1.5'.

7. Contractor Certification

Driller's Name: DWIGHT HILL
Certification No.: VB8143
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1 **Pump Test 1** page1

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Alberta Environment

Well I.D.:	0293907
Map Verified:	Not Verified
Date Report Received:	2000/02/24
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: TANGEDAL DRILLING LTD.		Drilling Company Approval No.: 119350
Mailing Address: BOX 1	City or Town: ATHABASCA AB CA	Postal Code: T9S 2A2
WellOwner's Name: PARAMOUNT RES LTD	Well Location Identifier:	
P.O. Box Number:	Mailing Address: 4000 350 7 AVE SW, CALGARY	Postal Code: T2P 3W5
City:	Province:	Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
12	31	094	18	4

Location in Quarter
0 M from Boundary
0 M from Boundary

Lot Block Plan

Well Elev: M
How Obtain: Not Obtain

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed: Materials Used:
Method of Drilling: Rotary
Flowing Well: No Rate: Liters
Gas Present: No Oil Present: No

Proposed well use: Domestic
Anticipated Water Requirements/day 3636.8 Liters

6. Well Yield

Test Date (yyyy/mm/dd): 2000/02/09
Start Time: 7:53 PM
Test Method: Pump & Air
Non pumping static level: 3.66 M
Rate of water removal: 22.73 Liters/Min
Depth of pump intake: 23.77 M
Water level at end of pumping: 23.77 M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
3.66	0:00	
7.62	2:00	
12.19	7:00	
14.99	12:00	
16.89	17:00	
18.29	22:00	
20.27	32:00	
21.11	37:00	
21.87	42:00	
21.95	47:00	
23.16	52:00	
23.67	57:00	
23.77	62:00	
23.77	72:00	
23.77	120:00	

Total Drawdown: 20.12 M
If water removal was less than 2 hr duration, reason why:

Recommended pumping rate: 22.73 Liters/Min
Recommended pump intake: 23.77 M
Type Pump Installed
Pump Type:
Pump Model:
H.P.: .5
Any further pumptest information?

4. Formation Log

Depth from ground level (meters)	Lithology Description
3.05	Light Brown Clay
7.92	Coarse Grained Gravel & Boulders
12.8	Light Gray Clay
14.02	Light Brown Fine Grained Sand
26.82	Dark Brown Hard Clay & Rocks
29.26	Brown Coarse Grained Sandstone
32	Light Gray Hard Sandstone
39.62	Dark Gray Clay & Rocks

5. Well Completion

Date Started(yyyy/mm/dd): 2000/01/25	Date Completed (yyyy/mm/dd): 2000/02/09
Well Depth: 39.62 M	Borehole Diameter: 0 CM
Casing Type: Plastic	Liner Type:
Size OD: 12.55 CM	Size OD: 0 CM
Wall Thickness: 0.66 CM	Wall Thickness: 0 CM
Bottom at: 26.82 M	Top: 0 M Bottom: 0 M
Perforations	Perforations Size:
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM
from: 0 M to: 0 M	0 CM x 0 CM

Perforated by:
Seal: Bentonite Chips/Tablets
from: 3.66 M to: 24.69 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type: Stainless Steel Screen ID: 10.16 CM
from: 26.82 M to: 28.35 M Slot Size: 0.03 CM
Screen Type: Screen ID: 0 CM
from: 0 M to: 0 M Slot Size: 0 CM
Screen Installation Method: Attached To Casing
Fittings
Top: Coupler Bottom: Washdown
Pack: Artificial
Grain Size: 10-20 Amount: 500 Pounds
Geophysical Log Taken: ELECTRIC
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0 Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: M Diameter: CM
Comments:
DRILLER REPORTS DISTANCE FROM TOP OF CASING TO GROUND LEVEL: 1.33'.

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.: VC6110
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

Report 1 **Pump Test 1** page1

Alberta Environment

Water Well Drilling Report

The data contained in this report is supplied by the Driller. The province disclaims responsibility for its accuracy.

Well I.D.:	0296254
Map Verified:	Not Verified
Date Report Received:	2001/04/04
Measurements:	Metric

1. Contractor & Well Owner Information

Company Name: TANGEDAL DRILLING LTD.
Drilling Company Approval No.: 119350
Mailing Address: BOX 1
City or Town: ATHABASCA AB CA
Postal Code: T9S 2A2
WellOwner's Name: PARAMOUNT RES LTD
Well Location Identifier:
P.O. Box Number:
Mailing Address: BAY 7A 242 MACALPINE CR, FT MCMURRAY
Postal Code: T9H 4A6
City:
Province:
Country:

2. Well Location

1/4 or LSD	Sec	Twp	Rge	Westof M
15	01	092	17	4

Location in Quarter
0 M from Boundary
0 M from Boundary
Lot Block Plan
Well Elev: M
How Obtain: Estimated

3. Drilling Information

Type of Work: New Well
Reclaimed Well
Date Reclaimed:
Materials Used:
Method of Drilling: Rotary
Flowing Well: No
Rate: Liters
Gas Present: No
Oil Present: No
Proposed well use: Domestic
Anticipated Water Requirements/day 1818.4 Liters

4. Formation Log

Depth from ground level (meters)	Lithology Description
4.27	Light Brown Clay
5.18	Light Gray Silty Clay
9.14	Light Gray Silty Clay
12.19	Light Brown Coal
13.72	Green Hard Sandstone & Coal
19.81	Green Soft Sandstone & Coal
27.43	Light Brown Sand & Coal

5. Well Completion

Date Started(yyyy/mm/dd): 2001/03/02
Date Completed (yyyy/mm/dd): 2001/03/07
Well Depth: 27.43 M
Borehole Diameter: 0 CM
Casing Type: Plastic
Liner Type:
Size OD: 12.57 CM
Size OD: 0 CM
Wall Thickness: 0.66 CM
Wall Thickness: 0 CM
Bottom at: 18.59 M
Top: 0 M Bottom: 0 M
Perforations
from: 0 M to: 0 M
from: 0 M to: 0 M
from: 0 M to: 0 M
Perforations Size:
0 CM x 0 CM
0 CM x 0 CM
0 CM x 0 CM
Perforated by:
Seal: Bentonite Chips/Tablets
from: 0 M to: 8.53 M
Seal:
from: 0 M to: 0 M
Seal:
from: 0 M to: 0 M
Screen Type: Stainless Steel
from: 18.59 M to: 20.12 M
Screen ID: 10.16 CM
Slot Size: 0.03 CM
Screen Type:
from: 0 M to: 0 M
Screen ID: 0 CM
Slot Size: 0 CM
Screen Installation Method: Attached To Casing
Fittings
Top: Coupler
Bottom: Washdown
Pack: Sand
Grain Size: 10-20
Amount: 1250 Pounds
Geophysical Log Taken: ELECTRIC
Retained on Files:
Additional Test and/or Pump Data
Chemistries taken By Driller: No
Held: 0
Documents Held: 1
Pitless Adapter Type:
Drop Pipe Type:
Length: M
Diameter: CM
Comments:
DRILLER REPORTS DISTANCE FROM TOP OF CASING TO GROUND LEVEL: 2'.

6. Well Yield

Test Date (yyyy/mm/dd): 2001/03/07
Start Time: 2:10 PM
Test Method: Air
Non pumping static level: 2.13 M
Rate of water removal: 90.92 Liters/Min
Depth of pump intake: 12.19 M
Water level at end of pumping: 10.67 M
Distance from top of casing to ground level: CM

Depth To water level (meters)

Drawdown	Elapsed Time Minutes:Sec	Recovery
	0:00	10.67
	5:00	2.19
	7:00	2.15
	10:00	2.13
	20:00	2.13
	25:00	2.13
	30:00	2.13
	35:00	2.13
	40:00	2.13
	50:00	2.13
	60:00	2.13
	90:00	2.13
	120:00	2.13

Total Drawdown: 8.53 M
If water removal was less than 2 hr duration, reason why:
Recommended pumping rate: 68.19 Liters/Min
Recommended pump intake: 15.24 M
Type Pump Installed
Pump Type:
Pump Model:
H.P.:
Any further pumptest information?

7. Contractor Certification

Driller's Name: UNKNOWN DRILLER
Certification No.: VC6110
This well was constructed in accordance with the Water Well regulation of the Alberta Environmental Protection & Enhancement Act. All information in this report is true.
Signature Yr Mo Day

ATTACHMENT D

ATTACHMENT D.1

1.0 01-27-091-19 W4M HYDRAULIC TEST SUMMARY

A 170 minute pumping test was completed on March 15, 1999 at 01-27-091-19 W4M (Well ID 0292382). The well was pumped at a rate of 68 L/min. Using the Theis Recovery method (1935), the transmissivity of a sand and gravel unit within the Undifferentiated Overburden Aquifer/Aquitard at this location is estimated to be 1.3 × 10^{-5} m^2/s.

1.1 Well Completion Details

The water well is located at 01-27-091-19 W4M at UTM easting 380630.5 and northing 6309673.6 (NAD 83).

The well was drilled to a vertical depth of 35.05 metres below ground surface (mbgs) and was completed with a 5 inch outer diameter (OD) casing screened between 28.65 and 30.18 mbgs in a sand and gravel unit within the Undifferentiated Overburden Aqufer/Aquitard. The initial head measurement was 5.49 mbgs.

1.2 Theis Recovery Analysis

The transmissivity (T) of a sand and gravel unit within the Undifferentiated Overburden Aquifer/Aquitard was determined using the Theis method (1935; Equation D1) for the recovery portion of the test (Figure D1).

Equation D1.

$$T = \frac{2.3Q}{4\pi\Delta s'}$$

Where:

Q = pumping rate (98.19 m^3/d)

$\Delta s'$ = drawdown within one log interval (16.25 m)

therefore,

T = 1.1 m^2/d = 1.3 x 10^{-5} m^2/s

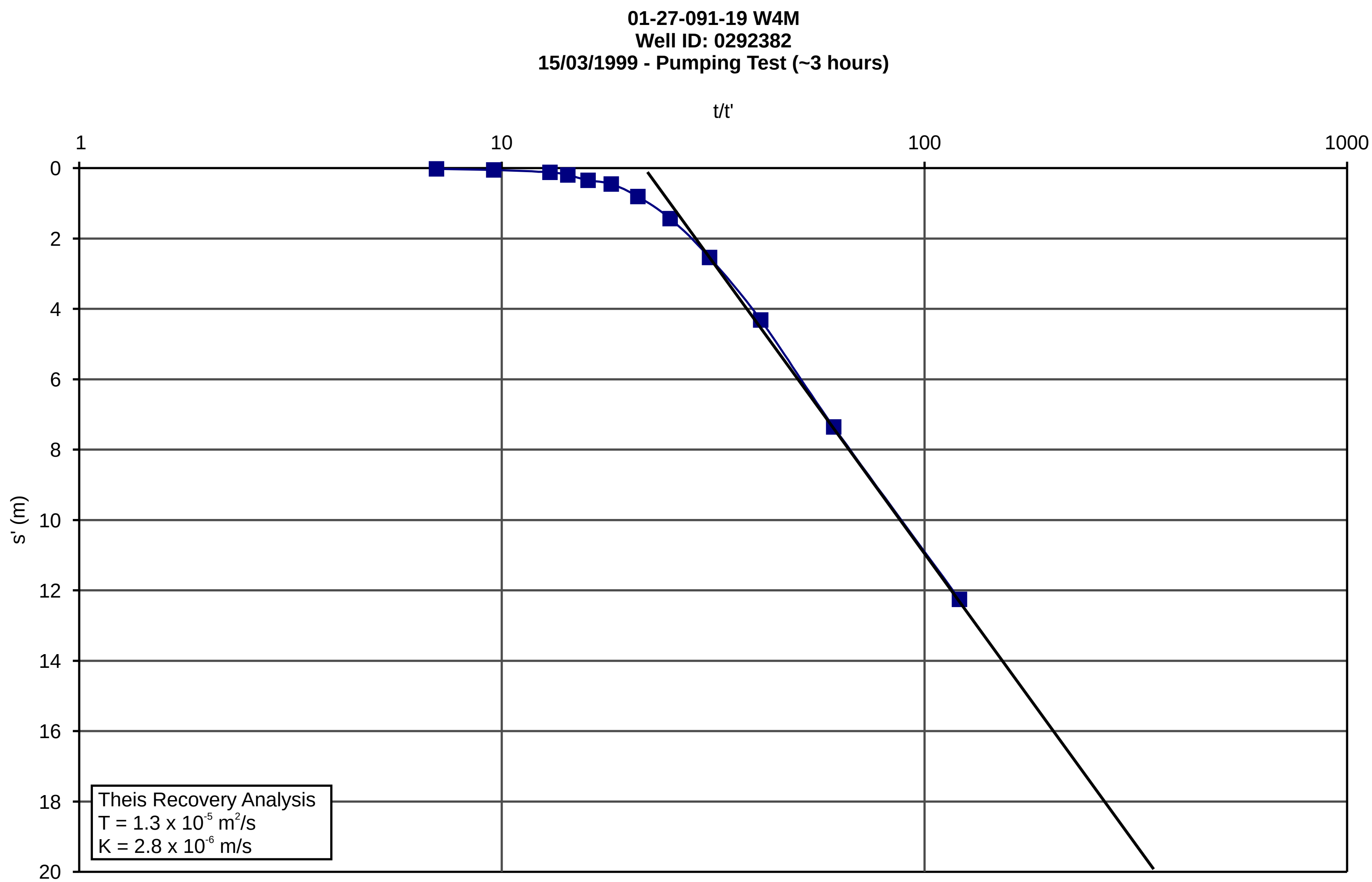
and,

K = 0.24 m/d = 2.8 x 10^{-6} m/s

REFERENCES

Theis, C.V., 1935. "The Relation between the Lowering of the Piezometric Surface and the Rate and Duration of Discharge of a Well Using Groundwater Storage." American Geophysical Union.

Schwartz, F.W. and H. Zhang, 2003. "Fundamentals of Groundwater". John Wiley and Sons, Inc., New York, USA.



Matrix Solutions Inc.
ENVIRONMENT & ENGINEERING

ATHABASCA OIL SANDS CORP.

THEIS RECOVERY ANALYSIS
UNDIFFERENTIATED OVERBURDEN
AQUIFER / AQUITARD - 01-27-091-19 W4M

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-Graph-08	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE D1

ATTACHMENT D.2

2.0 10-29-092-17 W4M HYDRAULIC TEST SUMMARY

A 270 minute pumping test at 10-29-092-17W4/00 (Well ID 0243283) was completed on March 9, 1981. The well was pumped at a constant rate of 341 L/min. Using the Theis Recovery method (1935), the transmissivity of the Lower Grand Rapids Aquifer at this location is estimated to be 2.6 x 10^{-4} m^2/s.

2.1 Well Completion Details

The water well is located at 10-29-092-17W4/00 at UTM easting 396891.7 and northing 6319748.15 (NAD 27).

The well was drilled to a vertical depth of 102.7 m below ground surface (m bgs) and was completed with a 7 inch outer diameter (OD) casing screened between 80.8 and 100.6 m bgs. The initial head measurement was 13 mbgs.

2.2 Theis Recovery Analysis

The transmissivity (T) of the Lower Grand Rapids Aquifer was determined using the Theis method (1935; Equation D1) for the recovery portion of the test (Figure D2).

Where:

$T = 22.5\ m^2/d = 2.6 \times 10^{-4}\ m^2/s$

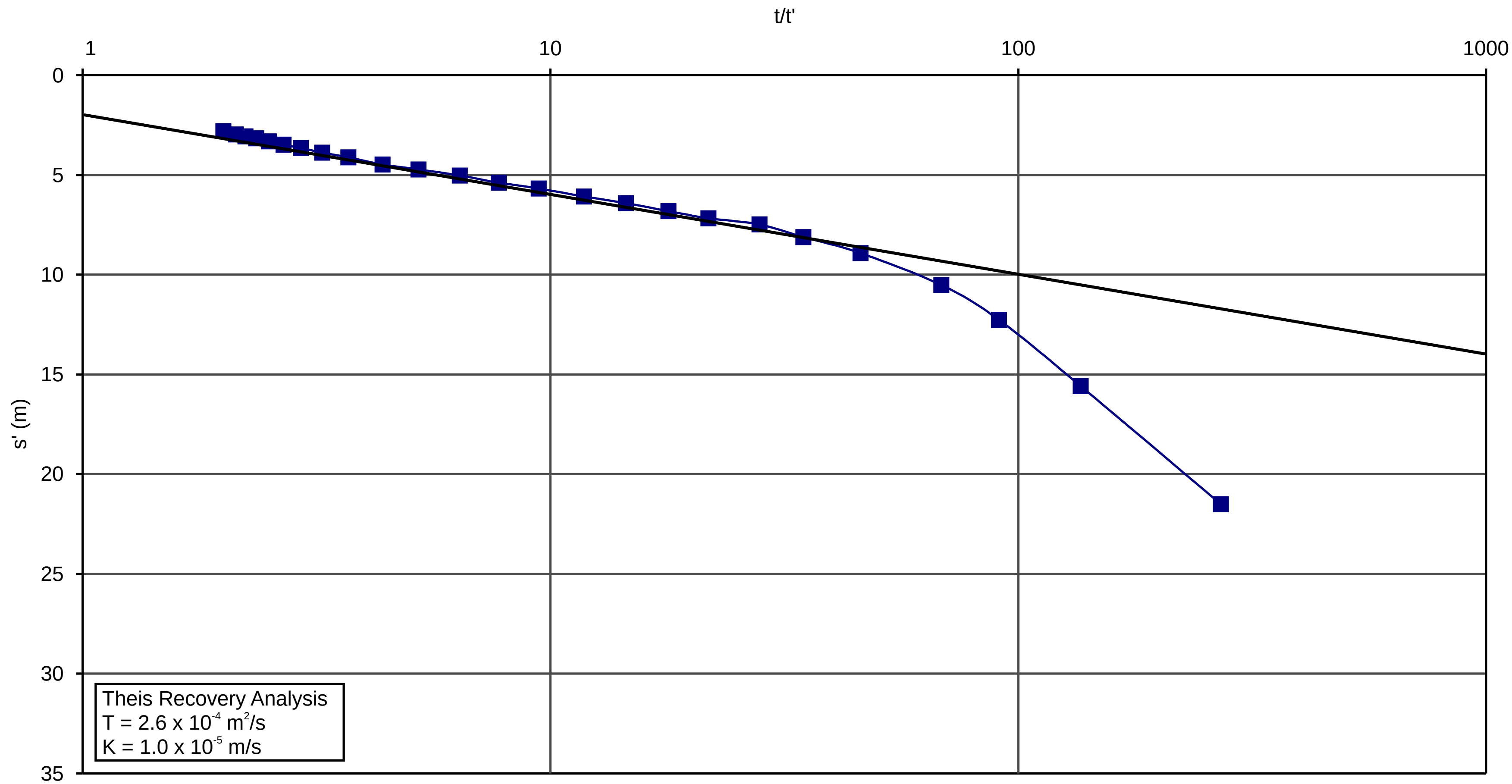
therefore,

$K = 0.86\ m/d = 1.0 \times 10^{-5}\ m/s$

REFERENCES

Theis, C.V., 1935. "The Relation between the Lowering of the Piezometric Surface and the Rate and Duration of Discharge of a Well Using Groundwater Storage." American Geophysical Union

10-29-092-17 W4M
Well ID: 0243283
03/09/1981 - Pumping Test (4.5 hours)



Matrix Solutions Inc.
ENVIRONMENT & ENGINEERING

ATHABASCA OIL SANDS CORP.

THEIS RECOVERY ANALYSIS
LOWER GRAND RAPIDS AQUIFER
10-29-092-17 W4M

DATE:	FILE:	DESIGN:	DRAWN:	CHECK:
MAY 2008	7349-Graph-08	ED	ZS	SR

DOVER CENTRAL PILOT PROJECT

FIGURE D2

ATTACHMENT D.3

3.0 01-23-093-17 W4M HYDRAULIC TEST SUMMARY

A water well was drilled under the supervision of Matrix from March 4 to March 8, 2008, at 01-23-093-17W4M/00 and a 4.0 hour pumping test was completed on March 11, 2008, by Matrix personnel. The well was pumped at a rate of 322 L/min. Using the Theis Recovery method (1935), the transmissivity of the Lower Grand Rapids Aquifer at this location is estimated to be 1.7×10^{-4} m/s.

3.1 Well Completion Details

The test well is located at 01-23-093-17W4/00 at UTM easting 402284.5 and northing 6327106.9 (NAD 83).

The well was drilled to a vertical depth of 100.72 metres below ground surface (mbgs) and was completed with a 7 inch outer diameter (OD) casing screened between 77.5 and 99.5 mbgs. The initial head measurement was 16.2 mbgs.

3.2 Theis Recovery Analysis

Analysis of the data was facilitated by Waterloo Hydrogeologic Inc.'s software, Aquifer Test Pro 3.5. The transmissivity of the Lower Grand Rapids Aquifer was determined using the Theis method (1935; Equation D1) for the recovery portion of the test (Figure D3).

Where:

$T = 15.0 \text{ m}^2/\text{d} = 1.7 \times 10^{-4} \text{ m}^2/\text{s}$

therefore,

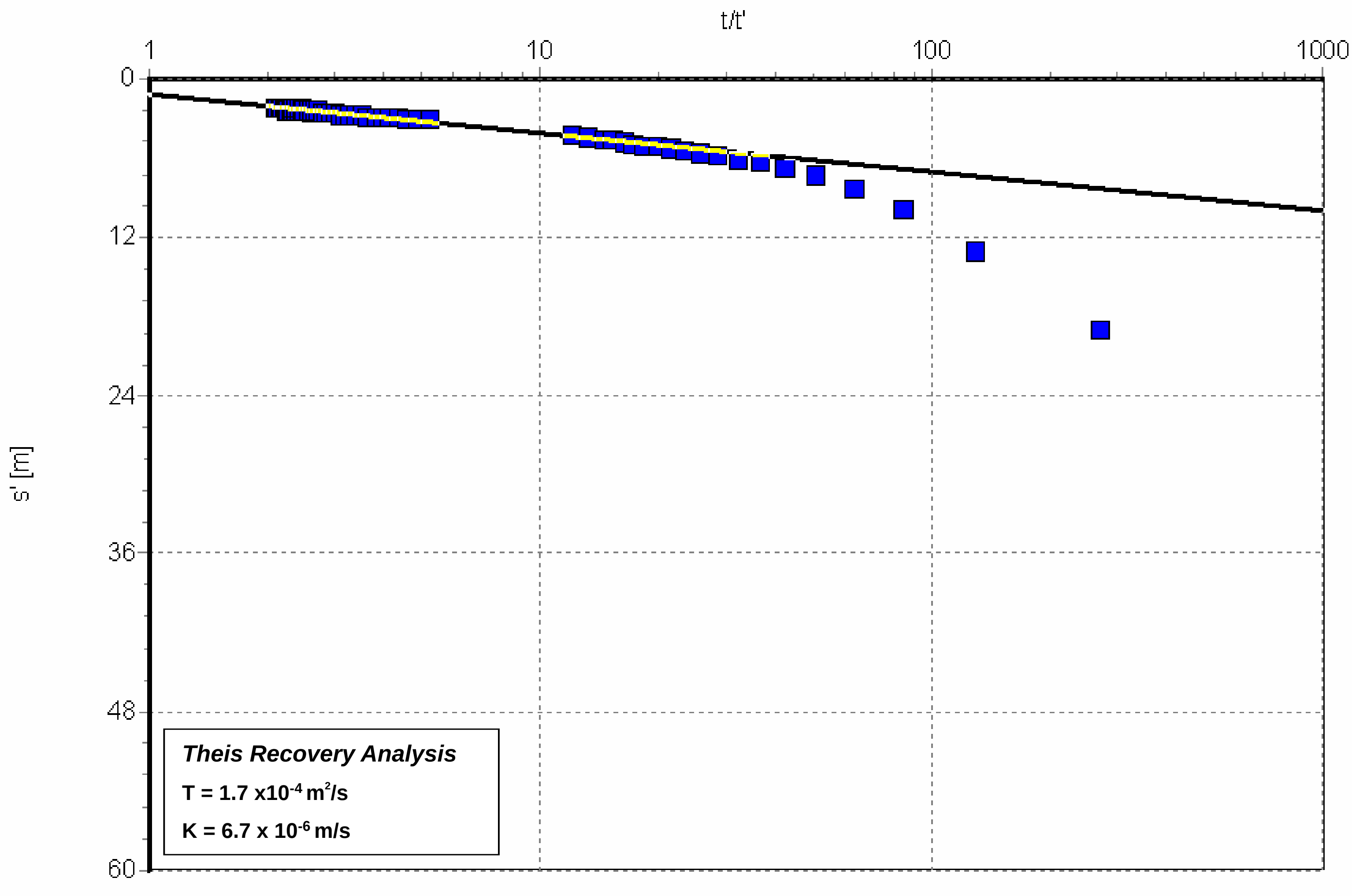
$K = 0.58 \text{ m/d} = 6.7 \times 10^{-6} \text{ m/s}$

REFERENCES

Theis, C.V., 1935. "The Relation between the Lowering of the Piezometric Surface and the Rate and Duration of Discharge of a Well Using Groundwater Storage." American Geophysical Union.

Waterloo Hydrogeologic Inc., 2002. "Aquifer Test Pro 3.5 – Graphical Analysis and Reporting of Pumping Test and Slug Test Data." Waterloo, Ontario. www.waterloohydrogeologic.com

01-23-093-17 W4M
11/03/2008 - Pumping Test (4 hours)



Matrix Solutions Inc. ENVIRONMENT & ENGINEERING					ATHABASCA OIL SANDS CORP.
					THEIS RECOVERY ANALYSIS LOWER GRAND RAPIDS AQUIFER 01-23-093-17 W4M
DATE: MAY 2008	FILE: 7349-Graph-08	DESIGN: ED	DRAWN: ZS	CHECK: SR	DOVER CENTRAL PILOT PROJECT — **FIGURE D3**

Note: Throughout the remainder of this document Athabasca Oil Sands Corp. will be referred to as the "Company".

SECTION 12.0: FORMS

SECTION 13.0: APPENDIX

FINAL REPORT

AIR QUALITY ASSESSMENT
ATHABASCA OIL SANDS CORP.
DOVER CENTRAL PILOT PROJECT

Project Number: #W08-1106A **May 21, 2008**

RWDI

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A. AIR QUALITY

The Athabasca Oil Sands Corp. (AOSC) Dover Central Pilot Project (Pilot) will discharge gaseous emissions to the atmosphere from various processes. It is important that air quality changes associated with these emissions meet the respective ambient air quality objectives. This section of the report identifies and quantifies expected emissions from the plant and surrounding emission sources, describes the terrain and meteorology, details the predictive modelling approach, and summarizes the air quality changes due to the plant emissions. These changes are then compared to background values and to ambient quality objectives. In addition, cumulative impacts due to the Pilot and other sources are evaluated and compared to background values and to ambient quality objectives. Finally, total GHG emissions for the Pilot were estimated and compared to the total Alberta and Canadian GHG estimates for 2005.

A.1 Emission Sources

Figure A-1 is a plot plan showing the relative location of the emission sources and buildings at the Pilot. The primary buildings include: a steam generation building, a glycol building, exchange building, tank farm pump building, evaporator building, storage building and control room/office. Table A-3 provides the stack parameters and emission rates associated with each emission source at the Central Plant, except for the flare stack which is detailed in Table A-2.

A.1.1 HP Steam Boiler Stack

One stack will serve the HP steam boiler, which is fired by mixed fuel gas composed of field produced gas, pipeline make-up fuel gas, and recovered gas from the Vapour Recovery Unit (VRU) system. The fuel gas composition is provided in Table A-1. Emissions from the steam generator are assumed to be continuous and include trace amounts of sulphur dioxide (SO_2), oxides of nitrogen (NO_X), carbon monoxide (CO) and particulate matter less than 2.5 µm in diameter ($PM_{2.5}$).

A.1.2 Gas Generators

Two stacks will service two gas fired electrical generators. Emissions from the gas generators are assumed to be continuous and include trace amounts of NO_X and CO.

A.1.3 Diesel Generator

One stack will serve the diesel fired electrical generator. Emissions from the diesel generator are assumed to be intermittent (i.e. for emergency power generation only) and include trace amounts of NO_X and CO.

A.1.4 Start-up Boiler

A start-up boiler will be applied only to the start up of the evaporator, and /or hold it on hot standby. It will run approximately 12 times per year for approximately 24 hours. Emissions from the start-up boiler are assumed to be intermittent and include trace amounts of NO_X, CO and $PM_{2.5}$.

A.1.5 Glycol Heater

A glycol heater will supply building heat in case of plant shut down. Typically, the glycol heater will be operated 1 to 5 times per year for approximately 24 hours during emergency service. Emissions from the glycol heater will be intermittent, and include trace amounts of NO_X, CO and $PM_{2.5}$.

A.1.6 Compressors

Two compressors will be required for the pilot. Two separate stacks with identical design parameters will serve the compressors. Emissions from the compressors include trace amounts of NO_X and CO.

A.1.7 Vapour Recovery Unit

A Vapour Recovery Unit (VRU) will be installed to recover hydrocarbon vapours and sweep blanketed natural gas from all tanks (storage tanks and water tanks) in order to eliminate fugitive emissions. Normally, VRU recovered gas is routed to the HP Steam Boiler for combustion. When VRU is shut down or upset, built-up vent gas will be directed to the flare stack (Upset Scenario 1). The gas composition associated with VRU shut-down (Upset Scenario 1) is listed in Table A-1.

A.1.8 Flare Stack

During normal operations, the flare stack will have a continuous pilot fuelled by sweet gas. The composition of the sweet flare gas is provided in Table A-1. Emissions will consist of trace amounts of NO_X, CO and $PM_{2.5}$ which are listed in Table A-2.

In the event of any plant upsets, the plant will go into emergency shutdown. During this situation, all other emission sources will cease, and the recovered gas from the storage tanks and water tanks is diverted to flare. The flare stack will be the only source of emissions (Upset Scenario 2). The gas composition during this emergency shutdown is presented in the Table A-1.

Dispersion models require a pseudo-stack height, a pseudo-temperature and a pseudo-diameter (effective stack parameters) for evaluating flares since they do not address flare stacks explicitly. The pseudo-parameters account for the flame length in determining the effective release height and account for heat release by calculating an effective diameter based on the 25 percent radiation loss. An H_2S-to-SO_2 conversion efficiency of 98% was assumed. These are consistent with the EUB Directive 60 – *Upstream Petroleum Industry Flaring, Incinerating and Venting*. Therefore, the EUBflare_v0101.xls (2006 version) was used to create the pseudo-parameters for CALPUFF model inputs. Table A-2 provides the emission rates and pseudo-parameters for the flare stacks during normal and upset conditions.

A.1.9 Baseline Emissions in the Study Area

The Alberta Environment (AENV) Code of Practice (AENV 2007a) for compressor stations and sweet gas processing plants, and the EUB Directive 56 (EUB 2007) both indicate that significant NO_X emission sources within 0.5 km of a proposed facility must be identified and included in the dispersion modelling assessment. In addition, the AENV (2003a) air quality model guideline indicates that nearby sources within 5 km of a proposed facility should be considered in a dispersion modelling assessment.

For this assessment, other sources of SO_2, NO_X, CO and $PM_{2.5}$ emissions were considered within a 50 km by 50 km study area centered on the Pilot. Searching other operating, approved, designed and proposed emission sources identified two compressor stations and one sour gas plant (Paramount Legend) within the model domain. Another sour gas plant (CNRL Liege) was found just outside the modelling domain to the southwest. As conservatism, this facility was also considered in the modelling. The source locations relative to the Pilot are shown in Figure A-2. Table A-4 summarizes the emission parameters for these four other facilities.

A.2 Terrain

Elevated terrain can have adverse and beneficial effects on dispersion. Adverse effects result in ground-level concentrations that would be larger than those expected for flat terrain conditions. Specifically, there is an increased potential for plume centerlines to more closely approach elevated terrain features under stable conditions than would be expected over flat terrain. There are also terrain-related factors that can lead to reduced concentrations. For example, increased turbulence due to terrain features results in greater dispersion and a dilution of plume centerline values. The overall effect of terrain on ambient air quality relative to that for flat terrain depends on competing adverse and beneficial effects. For the most part, dispersion models tend to be biased by only incorporating the adverse components to be conservative.

Figure A-3 shows the terrain contours for the 50 km by 50 km study area centred on the facility. For the most part, the terrain is comprised of low rolling hills interspersed with wetlands. The Pilot is located on a relatively flat region at an elevation of about 530 m above sea level (masl). Within the modelled area, the terrain rises to an elevation of approximately 726 masl (196 m above facility base) about 45 km to the northwest.

A.3 Meteorology

Meteorological parameters such as wind direction, wind speed and atmospheric stability control the transport and dispersion of stack emissions. There are a few potential sources of meteorological data in the region that include:

- The Environment Canada meteorological station at Fort Chipewyan Airport located approximately 200 km to the northeast of the Pilot area;
- The Environment Canada meteorological station at Fort McMurray Airport located approximately 105 km to the southeast of the Pilot area; and
- The meteorological station at Mildred Lake located approximately 70 km to the east of the Pilot area.

Figure A-4 compares the joint frequency distribution of wind direction and wind speed in a "wind rose" format collected at the previously described locations. A wind rose format is a histogram in a polar format, which indicates the frequencies that the wind blows from, based on a 16-point compass. In the comparing of the wind rose information, the following comments can be made:

- The Fort Chipewyan Airport data are influenced by the east-west orientation of the nearby Athabasca Lake. For example, winds from the east and west occur about 25 percent of the time;
- The Fort McMurray Airport data are influenced by the east-west orientation of the nearby Clearwater River. For example, winds from the east and west occur about 20 percent of the time;

- The Mildred Lake data shows a more uniform distribution of winds from most directions relative to the other sites. However, there are significantly higher frequencies of wind from the northwesterly quadrant than for the other sites; and
- While airport data are collected over open runway areas away from local influences; the Mildred Lake data can be subject to micro-scale influences (e.g., nearby tree canopies).

Given the limitations with selecting a single surface station as the basis for the meteorological input, the CALMET model was used to provide three-dimensionally varying wind, temperature, and turbulence fields for use by the CALPUFF dispersion model. The CALMET model results are based on:

- MM5 wind and temperature profiles generated on a 12 km grid for the year of 2002. None of the stations mentioned above were physically located close enough to be included in the modeling;
- Regional terrain elevations and spatially varying land-use information; and
- Allowing the surface cover to vary during the year on a seasonal basis.

Figure A-4 displays the joint frequency distribution of wind direction and wind speed in a "wind rose" format based on the CALMET predictions at the Pilot. The following comments can be made to the predicted wind roses:

- The predicted winds occur primarily from the southwest to northwest sector;
- The predicted winds occur least frequently from the east to south-southwest sectors; and
- The predicted winds were viewed as sufficient to describe the airflow in the region and were used for dispersion modelling purposes.

A.4 Ambient Air Quality Objectives

AENV (2007b) has established Ambient Air Quality Objectives (AAAQO) for the Province of Alberta. These objectives can be used in a number of ways, one of which includes assessing compliance near major industrial air emission sources. The ambient objectives refer specifically to ambient concentrations, and they can be expressed in units of "$\mu g/m^3$" and "ppb". The objectives also represent a range of averaging periods that address potential short-term exposure responses (i.e., 1-h) and longer-term chronic exposures (i.e., annual). In 2007, AENV added the 1-h and 24-h averaged $PM_{2.5}$ objectives, which are based on the Canada Wide Standard (CWS). However, the 1-h $PM_{2.5}$ objective is not meant to be applied to regulatory applications only ambient monitoring, and therefore, is not used for assessing modelled predictions. The ambient objectives of relevance to this Pilot are provided in Table A-5.

A.4.1 Background Air Quality

The Pilot is located to the northwest of Fort McMurray. In this area, much of the regional monitoring needs are addressed through the multi-stakeholder Wood Buffalo Environmental Association (WBEA). WBEA conducts extensive monitoring in the oil sands operating area with 15 ambient air quality monitoring stations; however, all of these stations are outside of the modelling domain. The Fort Chipewyan monitoring station, which represents background air quality conditions, is about 240 km northeast of Fort McMurray. Therefore, ambient air quality monitoring data in the vicinity of the Pilot are assumed to be similar to the Fort Chipewyan monitoring station. Maximum 1-h, 24-h and annual concentrations over the period, January 2003 to December 2007 are presented in Table A-6.

A.4.2 Monitoring Data

Five years of ambient monitoring data from the Fort Chipewyan monitoring station between 2003 and 2007 are shown in Table A-6 and can be summarized as:

- The maximum hourly SO_2 concentration was 52.3 μg/m^3, and the maximum daily SO_2 concentration was 26.8 μg/m^3. These measurements are lower than their AAAQOs of 450 μg/m^3 and 150 μg/m^3, respectively. The measured annual average was 0.9 μg/m^3;
- The maximum hourly NO_2 concentration was 58.3 μg/m^3, and the maximum daily NO_2 concentration was 40.6 μg/m^3. These measurements are lower than their AAAQOs of 400 μg/m^3 and 200 μg/m^3, respectively. The measured annual average was 2.0 μg/m^3;
- The maximum 24-h $PM_{2.5}$ concentration was 101.5 μg/m^3. This value is greater than the AAAQO of 30 μg/m^3. The measured annual average $PM_{2.5}$ concentration was 2.4 μg/m^3; and
- Hourly and daily CO concentration data were not available at the Fort Chipewyan monitoring station.

A.4.3 Background Values Selection in the Pilot Area

Background values were selected to be representative of background concentrations in the vicinity of the Pilot. Even though ambient concentrations are expected to vary, representative values based on annual averages were extracted from the 5-year Fort Chipewyan dataset. These values are summarized in Table A-7.

A.5 Model Application

A.5.1 Modelling Objectives

The CALPUFF dispersion model was applied to predict the ambient air quality concentrations due to the Pilot under normal operation and upset conditions. In addition, the cumulative impacts due to the Pilot and other sources within the 50 km by 50 km study domain were also assessed.

A.5.2 Transport and Dispersion

Air quality simulation (or dispersion) models provide a scientific means of relating industrial emissions to air quality changes through the use of mathematical equations that simulate transport, dispersion, transformation, and deposition processes. Dispersion models can address a range of spatial scales (100's of m to 1000's of km) and temporal scales (minutes to years).

Regulatory agencies have relied on dispersion model predictions to address air quality management issues as part of the approval process. Numerous models are available for the air quality predictions and the appropriate selection depends on Pilot-specific needs. In response to the regulatory use of these models, formal objectives regarding the selection and application of these models have been developed (e.g. AENV 2003a, AENV 2003b, U.S. EPA 2005).

The following summarizes the modelling approach for this assessment:

- The CALPUFF model was applied with the meteorological fields predicted by CALMET to address overlapping effects of multiple sources, and predict hourly, daily and annual averaged ground-level concentrations. The model is a U.S. EPA approved multi-layer, multi-species puff dispersion model;

- The CALPUFF model can account for building wake effects. The U.S. EPA (1995b) Building Profile Input Program for PRIME (BPIPPRM) was used to process the building information and prepare the data for input into CALPUFF. Building effects were only considered for the Pilot sources;
- The CALMET model was used to provide three-dimensionally varying wind, temperature, and turbulence fields for use by the CALPUFF dispersion model. MM5 wind and temperature profiles generated on a 12 km grid for the year of 2002 were used as input data to the CALMET model;
- Hourly ambient O_3 concentrations observed in Fort Chipewyan during 2002 were used for the chemistry calculations;
- Terrain elevation data were obtained for a 50 km by 50 km area approximately centered on the Pilot;
- Multiple Cartesian receptor grids with a variable spacing ranging from 20 m around the plant footprint, to 1,000 m beyond 5 km from the facility were selected. A total of 3,789 receptors were selected;
- As recommended by AENV, the eight highest predicted hourly average concentrations in a year were considered to be outliers and disregarded. The ninth-highest values (equivalent to the 99.9th percentile) are therefore used as the basis for determining compliance with the hourly average ambient objectives. For this assessment, the 99.9th percentile hourly predictions are referred to as the 'maximum' values in the assessment figures and tables provided;
- Background ambient values (annual average measurements from 2003 to 2007) from the Fort Chipewyan station were added to the model predictions to account for natural emission sources, nearby sources, and other more distant sources; and
- Concentrations at or beyond the plant property footprint only were compared to the ambient criteria.

A.5.3 Building Effects

For cases where the stack height is relatively short in comparison to an adjacent building structure, there is the potential for a plume from the stack to be influenced by the presence of the building wake. The CALPUFF model can account for building wake effects. The U.S. EPA (1995b) Building Profile Input Program for PRIME (BPIPPRM) was used to process the building information and prepare the data for input into CALPUFF. Building effects were only considered for the Pilot sources. The dimension parameters for buildings and tanks are shown in Tables A-8 and A-9, respectively.

A.5.4 NO to NO_2 Chemistry

While the CALPUFF model can predict ambient NO and NO_2 concentrations, the calculation has been shown to overestimate ambient NO_2 concentrations. For this assessment, the ozone limiting method (OLM) was applied. The OLM assumes that the conversion of NO to NO_2 in the atmosphere can be limited by the ambient ozone (O_3) concentration in the atmosphere. The approach assumes that 10% (on a volume basis) of the NO is converted to NO_2 prior to discharge into the atmosphere. For the remaining NO, the following is adopted:

- If 0.9 [NO_x] is greater than the ambient O_3 concentration then NO_2 = 0.1 [NO_x] + [O_3]. For this case the conversion is not complete; and
- If 0.9 [NO_x] is less than the ambient O_3 concentration then NO_2 = 0.1 [NO_x] + 0.9 [NO_x] = NO_x. This is equivalent to the total conversion approach, since there is sufficient ozone to effect the complete conversion.

In the application of the OLM, the above relationships are calculated on a ppb basis, with the appropriate conversions for concentrations given in units of $\mu g/m^3$. Alberta Environment (2003a) has recommended ambient ozone concentrations to be used for 1-h, 24-h and annual averaging periods (i.e., 50, 40 and 35 ppb for rural areas, and 50, 35 and 20 ppb for urban areas). Alternately, hourly ambient ozone data can be used to calculate the NO to NO_2 conversion on an hourly basis. For consistency, the hourly ozone data should coincide with the meteorological data used in the modelling. For this assessment, the OLM approach based on hourly ozone data from Fort Chipewyan for 2002 was used to estimate hourly NO_2 concentrations.

A.6 CALPUFF Modelling Results

A.6.1 Pilot Project Only

The CALPUFF model was used to predict maximum concentrations for the averaging periods that correspond to the AAAQOs. The evaluation presented in this section considers effects due to the Pilot sources only.

A.6.1.1 Maximum Predicted NO_2 Concentrations

Table A-10 summarizes the maximum predicted NO_2 concentrations. The maximum predicted hourly, daily and annual averaged concentrations, calculated using the OLM, are less than their respective AAAQOs.

When the dispersion model was applied to the 50 km by 50 km region depicted in Figure A-2, the maximum concentrations tend to occur within the AOSC facility property. For the purposes of illustration, the maximum NO_2 concentration plots are provided for a nominal 4 km by 4 km area centred on the Pilot. Figures A-5, A-6 and A-7 show the maximum predicted NO_2 concentrations for the 1-h (9th-highest), 24-h and annual averaging periods, respectively. The figures indicate that the maximum NO_2 concentrations are predicted to occur at the property boundary and concentrations decrease moving from the source.

When the background concentration is added to the downwind predictions, the conclusions remain unchanged (i.e., maximum predicted values are less than their respective AAAQOs).

A.6.1.2 Maximum Predicted SO_2 Concentrations

Table A-10 summarizes the maximum predicted SO_2 concentrations. The maximum hourly, daily and annual averaged SO_2 concentrations are predicted to be less than their respective AAAQOs.

The maximum SO_2 concentration plots are provided for a nominal 4 km by 4 km area centred on the Pilot. Figures A-8, A-9 and A-10 show the maximum predicted SO_2 concentrations for the 1-h (9^{th}-highest), 24-h and annual averaging periods, respectively. The figures indicate that the maximum SO_2 concentrations are predicted to occur on the property boundary.

When the background concentration is added to the predictions, the conclusions remain unchanged (i.e., maximum predicted values are less than their respective AAAQOs).

A.6.1.3 Maximum Predicted CO Concentrations

Table A-10 summarizes the maximum predicted CO concentrations. The maximum hourly and 8-h averaged CO concentrations are predicted to be less than their respective AAAQOs.

No background CO measurements were available from the Fort Chipewyan Station.

A.6.1.4 Maximum Predicted $PM_{2.5}$ Concentrations

Table A-10 summarizes the maximum predicted $PM_{2.5}$ concentrations. The maximum 24-h average $PM_{2.5}$ concentration is predicted to be less than the AAAQO.

The maximum $PM_{2.5}$ concentration plot is provided for a nominal 4 km by 4 km area centred on the Pilot. Figure A-11 shows the maximum predicted 24-h average $PM_{2.5}$ concentration. The figure indicates that the maximum $PM_{2.5}$ concentrations are predicted to occur on the property boundary.

When a background concentration is added to the predictions, the conclusion remain unchanged (i.e., maximum predicted value is less than the 24-h AAAQO).

A.6.2 Dover Central Pilot, Other Existing and Other Proposed Sources

Modelling was undertaken to predict the cumulative effect of emissions from the Pilot and other sources in the area. Those sources are shown in Figure A-2 and the emissions are summarized in Table A-4. Even though the "CNRL - Liege Sour gas plant" was just outside our modelling domain, this source was included in the modelling as a conservatism.

A.6.2.1 Cumulative NO_2 Concentrations

Table A-11 summarizes the cumulative maximum predicted NO_2 concentrations. The maximum predicted hourly, daily and annual concentrations, calculated using the OLM, are less than their respective AAAQOs.

While the dispersion model was applied to the 50 km by 50 km region depicted in Figure A-2, the maximum concentrations tend to occur within the facility property. Figures A-12, A-13 and A-14 show the maximum predicted cumulative NO_2 concentrations for the 1-h (9^{th} highest), 24-h and annual averaging periods, respectively. The figures indicate that the maximum cumulative NO_2 concentrations are predicted on the AOSC property boundary and concentrations decrease downwind from the source.

When background concentration is added to the cumulative predictions, the conclusions remain unchanged (i.e., maximum predicted values are less than their respective AAAQO).

A.6.2.2 Cumulative SO_2 Concentrations

Table A-11 summarizes the cumulative maximum predicted SO_2 concentrations. The maximum hourly (9th highest), daily and annual average SO_2 concentrations are predicted to be less than their respective AAAQOs.

Figures A-15, A-16 and A-17 show the maximum predicted cumulative SO_2 concentrations for the 1-h (9th-highest), 24-h and annual averaging periods, respectively. The figures indicate that the maximum cumulative SO_2 concentrations are predicted at the property boundary.

When background concentration is added to the cumulative predictions, the conclusions remain unchanged (i.e., maximum predicted values are less than their respective AAAQOs).

A.6.2.3 Cumulative CO Concentrations

Table A-11 summarizes the cumulative maximum predicted CO concentrations. The maximum hourly and 8-h average CO concentrations are predicted to be less than their respective AAAQOs.

Because there was no available background concentration for CO, an evaluation with background added was not assessed.

A.6.2.4 Cumulative $PM_{2.5}$ Concentrations

Table A-11 summarizes the cumulative maximum predicted $PM_{2.5}$ concentrations. The predicted maximum 24-h concentration is predicted to be less than the AAAQO of 30 $\mu g/m^3$.

Figures A-18 shows the predicted maximum cumulative 24-h $PM_{2.5}$ concentration. The figure indicates that the maximum cumulative $PM_{2.5}$ concentrations are predicted at the property boundary.

When the background concentration is added to the predictions, the conclusion remains unchanged (i.e., maximum predicted values is less than the 24-h AAAQO).

A.6.3 Dover Central Pilot Upset Cases

There are several possible upset scenarios during facility failures including fuel gas (FG) regulator failure, degasser inlet block flow, and purge gas (PG) flaring, VRU shutdown, and plant shutdown. Of these upset scenarios, only VRU shutdown and plant shutdown involve combustion of sour fuels. As such, only these scenarios are considered in this assessment. These scenarios were modelled individually and included emissions from the tow sour gas plants.

A.6.3.1 Maximum Predicted SO_2 Concentrations due to Vapour Recovery Unit Shutdown

When VRU shut down (Upset Scenario 1) occurs, a total volume of 150 m^3 sour gas with a concentration of 0.09% H_2S will be directed to the flare stack. This volume of gas will be flared for a maximum duration of 30 minutes. The total gas composition for this Upset Scenario is presented in Table A-1.

Table A-12 summarizes the maximum predicted 1-h SO_2 concentrations due to VRU shutdown. The predicted maximum hourly (9th highest) average SO_2 concentration of 191$\mu g/m^3$ is less than the AAAQO of 450 $\mu g/m^3$.

When the background concentration is added, the conclusion remains unchanged (i.e., maximum predicted value is less than the 1-h AAAQO).

The two sour gas plants in the study area, emit relatively small amounts of SO_2. As a result, the predicted maximum concentration due to cumulative impact will be same as the results for the VRU shutdown.

A.6.3.2 Maximum Predicted SO_2 Concentrations due to Plant Shutdown

During emergency plant shutdown, a total volume of 343 m^3 of processed gases with a concentration of 1.26% H_2S will be directed to the flare. This gas stream will be flared for a maximum duration of 4 hours. The gas composition for this upset scenario is presented in Table A-1.

Table A-12 summarizes the maximum predicted 1-h SO_2 concentrations due to plant shutdown (Upset Scenario 2). The predicted maximum hourly (9^{th} highest) average SO_2 concentration of 220 $\mu g/m^3$ is less than the AAAQO of 450 $\mu g/m^3$.

When the background concentration is added, the conclusion remains unchanged (i.e., maximum predicted value is less than the 1-h AAAQO).

The two sour gas plants in the study area emits a relatively small amount of SO_2. As a result, the predicted maximum concentration due to cumulative impact will be same as the results for the Plant shutdown.

A.6.4 Summary of CALPUFF Predictions

The CALPUFF model predictions indicate that:

- All maximum predicted SO_2, NO_2 and $PM_{2.5}$ values due to the Pilot during normal operational conditions are less than their applicable AAAQOs, with or without the background values;
- When the cumulative effects of four additional facilities are considered, all maximum predicted SO_2, NO_2 and $PM_{2.5}$ values are less than their applicable AAAQOs, with or without the background values;
- When a VRU emergency shutdown occurs, the maximum predicted SO_2 concentration is less than the 1-h AAAQO; and

- When the plant undergoes emergency shutdown in the event of any upsets, the maximum SO_2 is predicted to be less than the 1-h AAAQO, with or without the background values.

A.7 GHG EMISSIONS AND IMPACTS

A.7.1 Introduction

When operating, the Pilot will result in GHG emissions of CO_2, CH_4 and N_2O from the combustion of fossil fuels. For the equipment proposed at the Pilot, natural gas will be combusted and it was assumed that the equipment was operating everyday, regardless if the source runs only intermittently (with the exception of the emergency diesel generator). Based on Environment Canada (2007), emission factors (Table A-13), GHGs were calculated for the Pilot. GHG emissions are expressed in carbon dioxide equivalents (CO_2E). Factors for global-warming potential used in generating the GHG estimates are 1 for CO_2, 21 for CH_4 and 310 for N_2O emissions, based on a 100 year time horizon. The GHG emissions from the Pilot were estimated and compared to total Alberta and total Canada GHG emissions.

The GHG emission total for the Pilot is estimated to be 0.11 Mt/y CO_2E. Table A-14 compares this estimate to the total Alberta and Canadian GHG estimates for 2005. Pilot operations are estimated to contribute 0.05% and 0.02% to the 2005 provincial and 2005 national totals, respectively. It is important to note that the Pilot GHG emissions are not expected to occur until 2011 or 2012. By this time, total GHG emissions in Alberta and Canada will have changed and the corresponding percentages shown in Table A-14 will change.

A.8 Monitoring

While this assessment has indicated that ambient concentrations of all expected emissions are predicted to meet ambient air quality objectives, the predicted SO_2 and NO_2 concentrations are above the background levels. As such, an ambient monitoring program comprised of passive SO_2 and NO_2 samplers will be deployed at the predicted "hot spots" and at more remote locations.

A.9 Summary

The Pilot will discharge gaseous and particulate emissions to the atmosphere. The primary emission sources include:

- A high pressure steam boiler that continually emits SO_2, NO_x, CO and $PM_{2.5}$;
- Two gas generators that continually emit NO_x and $PM_{2.5}$;
- A diesel generator that intermittently emits NO_x and CO;
- A glycol heater that intermittently emit NO_X, CO and $PM_{2.5}$;
- Two compressors that continuously emit NO_X and CO;
- A flare stack, which will continuously emit NO_X and CO;
- During VRU shutdown upset, which is assumed to be infrequent and of short duration, built-up recovered gas with 0.09% (900 ppm), H_2S will be emitted from the flare stack for 30 minutes. This will result in emissions of SO_2; and
- During plant shutdown upset conditions, which are assumed to be infrequent and of short duration (i.e., 240 minutes), processed gas containing 1.26% H_2S will be diverted to the flare stack. This will result in emissions of SO_2.

The CALPUFF dispersion model was used to estimate maximum ground-level concentrations due to the operation of the Pilot for averaging periods that correspond to the respective AENV ambient air quality objectives. The model approach accounts for building downwash, terrain effects and chemical transformation. In addition, the CALPUFF model was used to predict cumulative ground-level concentrations due to the operation of other facilities within the 50 km by 50 km study area. The CALMET model was used to represent meteorological fields required by CALPUFF for the study area.

Based on the assessment of the Pilot sources, the CALPUFF model predicted that ambient NO_2, SO_2, CO and $PM_{2.5}$ concentrations will be less than their respective AAAQOs, with and without background values. A cumulative assessment of emissions, including four other facilities within a 50 km by 50 km area surrounding the Pilot, indicated that the ambient NO_2, SO_2, CO and $PM_{2.5}$ concentrations will meet their respective AAAQOs, both with and without background values. Finally, for two upset flaring scenarios, the maximum predicted 1-h SO_2 concentrations (including two sour gas plant emissions) were less than the 1-h AAAQO.

Total GHG emissions for the Pilot were estimated and compared to the total Alberta and Canadian GHG estimates for 2005. The Pilot operations were estimated to contribute 0.05% and 0.02% to the 2005 provincial and 2005 national totals, respectively.

In conclusion, emissions from the operation of the Pilot meet the relevant ambient air quality objectives.

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TABLES

Table A-1: Composition of the Gas Streams at Normal Conditions and Upset Conditions (in %)

Compound	Mixed Gas (Mole Fraction)	Flare Purge Gas (Mole Fraction)	Upset Scenario 1 (Mole Fraction)	Upset Scenario 2 (Mole Fraction)
H_2	0.02	0.02	0.00	0.00
He	0.00	0.00	0.00	0.00
H_2O	0.00	0.00	0.1794	0.0402
N_2	0.79	0.79	0.0039	0.00
CO_2	0.60	0.60	0.0272	0.4879
H_2S	0.00	0.00	0.0009	0.0126
CH_4	98.01	98.01	0.4705	0.4241
C_2H_6	0.51	0.51	0.0024	0.00
C_3H_8	0.05	0.05	0.0210	0.0017
iC_4H_{10}	0.01	0.01	0.0755	0.0064
nC_4H_{10}	0.01	0.01	0.00	0.0018
iC_5H_{12}	0.00	0.00	0.1803	0.0116
nC_5H_{12}	0.00	0.00	0.0390	0.0103
C_6H_{14}	0.00	0.00	0.00	0.003
C7+	0.00	0.00	0.00	0.0004

Table A-2: Emissions and Pseudo-Parameters Associated with the Flare Stack

Type	Flare Stack		
	Normal	**Upset Scenario 1**	**Upset Scenario 2**
Operation Status	**Continuous**	**Intermittent**	**Intermittent**
Stack Coordinates (m E) [(a)]	395036	395036	395036
Stack Coordinates (m N) [(a)]	6332259	6332259	6332259
Stack Height (m)	30.48	30.48	30.48
Pseudo-Stack Height (m)	30.77	31.144	30.23
Stack Diameter (m)	0.219	0.219	0.219
Pseudo-Stack Diameter (m)	2.077	8.777	2.63
Stack Gas Pseudo-Temperature (°C)	1000	2548.06	2233.76
(K)	1273	2821.16	2560.76
Sour Gas Flow Rate[(b)] (10^3 m^3/d)	0.065	7.2	2.065
Sweet Gas Flow Rate[(b)] (10^3 m^3/d)	0.000	0.000	0.000
Total Flow Rate[(b)] (10^3 m^3/d)	0.065	7.2	2.065
Stack Gas Velocity (m/s)	0.020	0.199	0.176
SO_2 Emission Rate (g/s)	-	0.55	1.0
(t/d)	-	4.75×10^{-2}	8.64×10^{-2}
NO_X Emission Rate[(d)] (g/s)	0.0007	-	-
(t/d)	6.05×10^{-5}	-	-
CO Emission Rate[(d)] (g/s)	0.0040	-	-
(t/d)	3.46×10^{-4}	-	-
$PM_{2.5}$ Emission Rate[(e)] (g/s)	-	-	-
(t/d)	-	-	-

Notes:
(a) UTM Coordinates (NAD 83) of stack, based on plot plan information provided by AOSC
(b) Flow rates referenced to 15°C and 101.325 kPa
(d) Emissions estimated from AP-42 emission factors (U.S. EPA)
(e) A dash (-) indicates that the parameter is not applicable

Table A-3: Parameters and Emissions Associated with the AOSC Central Plant Site Stacks (Excluding Flare Stacks)

Type	HP Steam Boiler H-4100	Gas Generators		Diesel Generator	Start-up Boiler	Glycol Heater	Compressors (2)
Operation Status	**Continuous**	**Continuous Z-8000**	**Continuous Z-8050**	**Intermittent H-3500**	**Intermittent H-9450**	**Continuous Z-5000**	**Continuous Z-5010**
Power Rating (kW)	38390	1500	1500	2340	2340	448	448
Stack Coordinates[a] (m E)	394950	394958	394960	394983	394993	394969	394972
Stack Coordinates[a] (m N)	6331420	6332406	6332406	6332393	6332423	6332438	6332436
Stack Height (m)	30.48	3	3	6.07	7.62	3.66	3.66
Stack Diameter (m)	1.524	0.254	0.254	0.303	0.457	0.154	0.154
Stack Gas Velocity (m/s)	11.7	15.45	15.45	19.7	8.7	19.7	18.8
Stack Gas Temperature (°C)	174	503	503	174	174	40	25
Stack Gas Temperature (K)	447	776	776	447	447	313	298
SO_2 Emission Rate[c] (g/s)	0.7639	-	-	-	-	-	-
(t/d)	0.066	-	-	-	-	-	-
NO_X Emission Rate[d] (g/s)	0.3009	0.6481	0.6481	0.0231	0.0231	0.0347	0.0347
(t/d)	0.026	0.056	0.056	0.002	0.002	0.003	0.003
CO Emission Rate [e] (g/s)	0.7639	1.9676	1.9676	0.0463	0.0463	7.5	7.5
(t/d)	0.066	0.17	0.17	0.004	0.004	0.648	0.648
$PM_{2.5}$ Emission Rate [e] (g/s)	0.1620	-	-	0.0116	00116	-	-
(t/d)	0.014	-	-	0.001	0.001	-	-

Notes:
[a] UTM Coordinates (NAD 83) of stack, based on plot plan information provided by AOSC
[b] Building dimensions based on plot plan information provided by AOSC
[c] SO_2, NO_X, CO and $PM_{2.5}$ emission rates provided by AOSC
[d] A dash (-) indicates that the parameter is not applicable
[e] Glycol heater emissions were based on 67% load

Table A-4: Summary of Emissions from the other Facilities within the Modelling Domain of the Project

Unit	UTM X	UTM Y	Elevation (m ASL)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)	$PM_{2.5}$ (g/s)
CNRL, Liege Sour Gas Plant, 03-29-92-20 W4M											
2 x1230 kw reboiler	367056	6319999	527	9.75	0.50	6.47	728	0.0000	0.0026	0.0022	0.0002
351 kw heater	367056	6319999	527	4.27	0.50	1.83	728	0.0000	0.0004	0.0003	0.0000
2 x 243 kw heater	367056	6319999	527	4.57	0.50	1.27	728	0.0000	0.0006	0.0004	0.0000
220 kw dehydrator reboiler	367056	6319999	527	6.71	0.50	1.17	728	0.0000	0.0002	0.0002	0.0000
2 x 73 kw heater	367056	6319999	527	5.49	0.50	0.41	728	0.0000	0.0002	0.0002	0.0000
2 x 29 kw heater	367056	6319999	527	10.00	0.50	15.00	773	0.1479	0.0000	0.0000	0.0000
Amine Stack	367056	6319999	527	26.72	0.50	15.00	773	0.0000	2.1600	3.3200	0.0400
2 x1102 kw compressors	367056	6319999	527	19.81	0.50	15.00	773	0.0000	3.6000	5.5600	0.0800
4 x 919 kw compressors	367056	6319999	527	5.34	0.50	15.00	773	0.0000	0.6200	0.9600	0.0200
2 x 317 kw compressors	367056	6319999	527	2.64	0.50	15.00	773	0.0000	0.2400	0.3800	0.0000
2 x 125 kw compressors	367056	6319999	527	9.75	0.50	6.47	728	0.0000	0.0026	0.0022	0.0002
Paramount, Legend Sour Gas Plant, 12-31-94-18 W4M											
1465 kw reboiler	385186	6341325	636	2.60	0.50	7.74	728	0.0000	0.0016	0.0013	0.0001
2 x 103 kw reboiler	385186	6341325	636	3.70	0.50	0.56	728	0.0000	0.0002	0.0002	0.0000
1640 kw heater	385186	6341325	636	3.70	0.50	8.66	728	0.0000	0.0018	0.0015	0.0001
996 kw heater	385186	6341325	636	3.7	0.50	5.25	728	0.0000	0.0011	0.0009	0.0001
137 kw waste incinerator	385186	6341325	636	3.7	0.50	3.36	728	0.1088	0.0007	0.0006	0.0001
1976 kw compressor	385186	6341325	636	15.4	0.50	15.00	773	0.0000	1.9300	2.9800	0.0300
1491 kw compressor	385186	6341325	636	13.4	0.50	15.00	773	0.0000	1.4600	2.2500	0.0200
4 x 1230 kw compressor	385186	6341325	636	22.0	0.50	15.00	773	0.0000	4.8000	7.4400	0.0800
2 x 298 kw compressor	385186	6341325	636	3.7	0.50	15.00	773	0.0000	0.5800	0.9000	0.0000
AltaGas, Compressor Station, 04-23-95-16 W4M											
Compressor	411786	6343504	599	6.8	0.50	15.00	773	0.0000	1.3772	1.4000	0.0200
Paramount, Liege Compressor Station, 01-30-92-19 W4M											
Compressor	376021	6319721	531	10.0	0.50	15.00	773	0.0000	2.0900	3.2300	0.0400

Table A-5: Alberta Ambient Air Quality Objectives for Project Air Emissions

Air Quality Parameter	Averaging Period	Objective	
		($\mu g/m^3$)	(ppb)
Sulphur dioxide (SO_2)	1-h	450	172
	24-h	150	57
	Annual arithmetic mean	30	11
Nitrogen dioxide (NO_2)	1-h	400	212
	24-h	200	106
	Annual arithmetic mean	60	32
Respirable particulate matter ($PM_{2.5}$)	1-h	80[(a)]	-
	24-h	30	-
Carbon monoxide (CO)	1-h	15,000	13,000
	8-h	6000	5,000

Notes: **"-"**indicates no specified values
Sources: Alberta Ambient Air Quality Objectives (AENV, 2007)
(a) 1-h $PM_{2.5}$ objective is not meant for regulatory application, only ambient monitoring

Table A-6: Summary of Ambient Air Quality measurements at the Fort Chipewyan Monitoring Station for the Period, January 2003 to December 2007

Parameter	Maximum 1-h Concentration ($\mu g/m^3$)	Maximum 24-h Concentration ($\mu g/m^3$)	Average Annual Concentration ($\mu g/m^3$)
SO_2	52.3	26.8	0.9
NO_2	58.3	40.6	2.0
$PM_{2.5}$	214.4	101.5	2.4
CO	-	-	-

Note: These values were obtained online from the Clear Air Strategic Alliance website http;//www.casadata.org/Reports/Select/Category.asp

Table A-7: Representative Average Background Air Concentrations at the Project

Parameter	Annual Average Concentration ($\mu g/m^3$)
NO_2	0.9
SO_2	2.0
$PM_{2.5}$	2.4
CO	-

Table A-8: Dimensions of Significant Buildings at the Project Facility

Buildings List	Tag Number	Height (m)	Width (m)	Length (m)
MCC Building	BU-0401	18.00	5.70	4.16
Glycol Building	BU-0101	16.5	6.70	4.00
Steam Generation Building	BU-0301	21.5	6.70	5.00
Gas Building	BU-0502	6.90	4.00	3.05
Tank Farm Pump Building	BU-0601	27.15	6.70	4.00
Exchanger Building	BU-0602	36.0	6.50	4.00
Sales Oil Pump Building	BU-0603	7.05	4.05	3.05
Control Room/Office	BU-0605	21.95	6.35	3.05
Storage Building	BU-0606	18.00	6.35	3.05
Portable washroom	BU-0607	6.10	3.00	3.05
FWKO/Treater Building	V-1100	15.24	4.50	4.25
Test Separator	Z-0200	4.30	2.50	2.80
Evaporator Building	Z-3100	28.00	13.40	5.00
VRU Package	Z-9700	6.00	5.00	4.00

Table A-9: Dimensions of Significant Tanks at the Project Facility

Buildings List	Tag Number	Height (m)	Tank Diameter (m)
Skim Tank	T-2000	10.35	6.5
Backwash Tank	T-2300	10.35	5.25
Slop Oil Tank	T-2400	7.9	5.25
De-Oiled Water Tank	T-3000	12.8	7.8
Disposal Tank	T-3800	10.35	5.25
Excess Water Disposal Tank	T-3810	12.8	7.8
BFW Tank	T-4000	12.8	7.8
BFW Tank	T-4010	12.8	7.8
Sales Oil Tank	T-7000	12.8	7.8
Sales Oil Tank	T-7010	12.8	7.8
Diluent Tank	T-7100	7.9	6.5

Table A-10: Maximum Predicted NO_2, SO_2, CO and $PM_{2.5}$ Concentrations due to the Project (in µg/m^3)

Averaging Period		Pilot	Background Concentration	Total Concentration[a] (Pilot Plus Background)	Ambient Air Quality Objective
NO_2 (OLM)	1-h (highest)	170	0.9	171	-
	1-h (9th)	136		137	400
	24-h	114		115	200
	Annual	17.9		18.8	60
SO_2	1-h (highest)	42	2.0	44	-
	1-h (9th)	31		33	450
	24-h	10		12	150
	Annual	0.5		2.5	30
CO	1-h (highest)	9154	-	9154	-
	1-h (9th)	6295	-	6295	15,000
	8-h	4284	-	4284	6,000
$PM_{2.5}$	24-h	3	2.4	5	30

Note: [a] The total is based on the Overall Maximum

Table A-11: Maximum Predicted NO_2, SO_2, CO and $PM_{2.5}$ Concentrations due to the Project and Other Sources (in µg/m³)

Averaging Period		Maximum Cumulative Concentration	Background Concentration	Total Cumulative Concentration[(a)] (Pilot Plus Background)	Ambient Air Quality Objective
NO_2 (OLM)	1-h (highest)	170	0.9	171	-
	1-h (9th)	136		135	400
	24-h	114		115	200
	Annual	18.0		18.9	60
SO_2	1-h (highest)	42	2.0	44	-
	1-h (9th)	31		33	450
	24-h	10		12	150
	Annual	0.5		2.5	30
CO	1-h (highest)	9155	-	9155	-
	1-h (9th)	6297	-	6297	15,000
	8-h	4284	-	4284	6,000
$PM_{2.5}$	24-h	3	2.4	5	30

Note: [(a)] The total is based on the Overall Maximum
Bold values are predicted to exceed the respective objective

Table A-12: Maximum Predicted SO_2 Concentrations due to the Upset Operations of the Project and Two Sour Gas Plants (in µg/m^3)

Averaging Period	Upset 1 (Vapor Recovery Unit Shutdown) Maximum Concentration	Upset 2 (Plant Shutdown) Maximum Concentration	Background Concentration	Total Concentration (Upset 1 plus background)	Total Concentration (Upset 2 plus background)	Ambient Air Quality Objective
1-h (highest) 1-h (9^{th})	437 191	442 220	2.0	439 193	444 222	- 450

Table A-13: Emission Factors (Environment Canada, 2007)

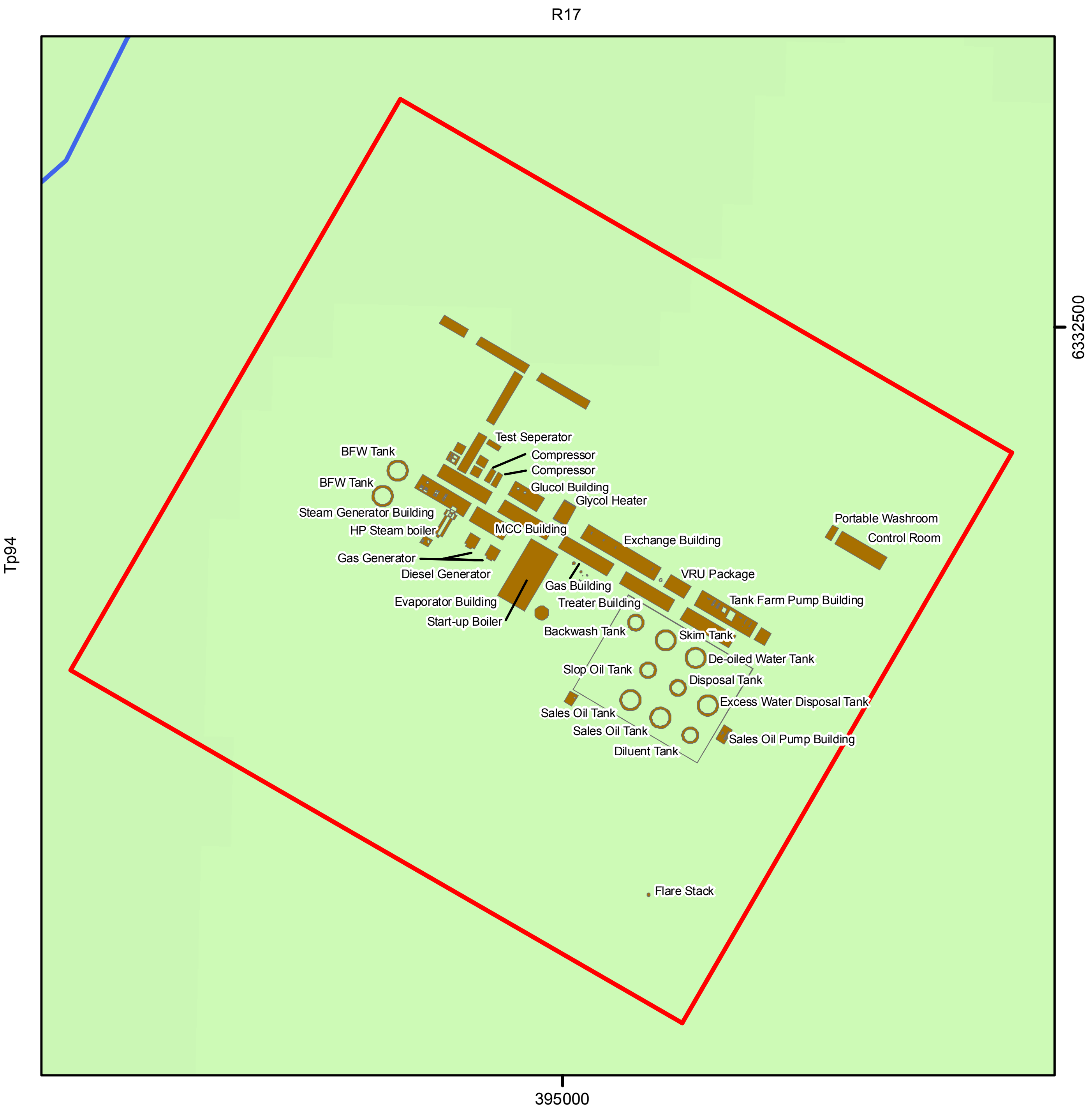
Species	Emission Factor (g/m^3)
CO_2	2389
CH_4	6.5
N_2O	0.06

Table A-14: Comparison of Project GHG Emissions

Source	Total GHG Emissions (Mt/y CO_2E)
Alberta's GHG Emissions (2005)	233
Canada's GHG Emissions (2005)	747
AOSC Dover Central Pilot Estimated GHG Emissions	0.11
AOSC Dover Central Pilot GHG Emissions as a Percentage of:	**Percent of Total GHG Emissions (%)**
Alberta Total	0.05
Canada Total	0.02

Notes: CO_2E = global warming equivalent that includes CO_2, CH_4, and N_2O
Source: Alberta and Canada totals are from Environment Canada (2007)

FIGURES



0 0.02 0.04 0.06 0.08 0.1 Kilometres

1:2,500

N

Legend

River

Buildings

Fenceline

Terrain (m ASL)

High : 757

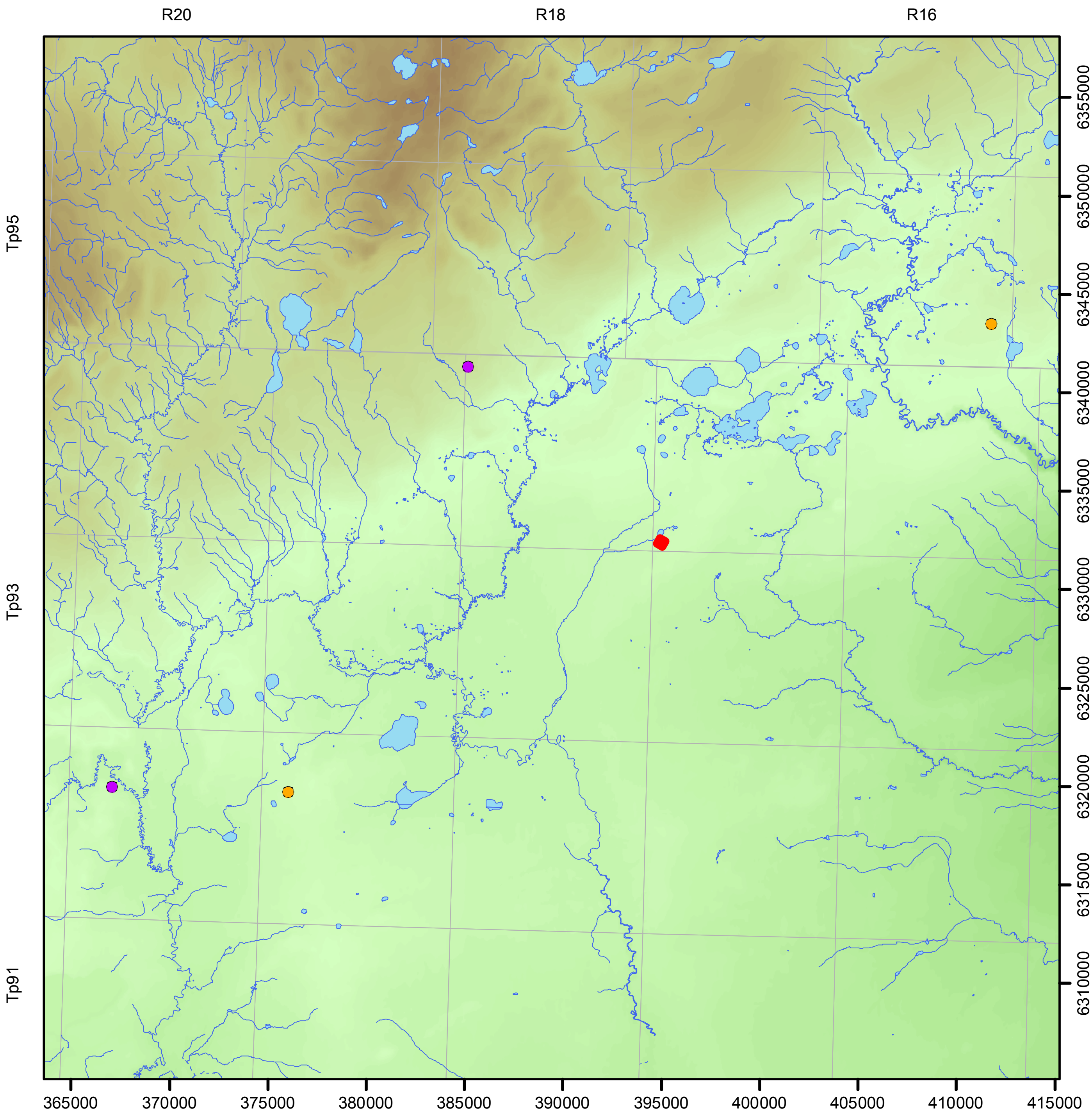
Low : 47

PROJECT		
AOSC Dover Central Pilot Project		
TITLE		
Central Plant Plot Plan Emission Sources and Buildings		
DRAWN	NS	05/22/2008
CHECKED	KAO	05/22/2008
REVIEWED	DSC	05/22/2008
PROJECT	W08-1106A	

Figure A-1

Focus Area

UTM ZONE 12 NAD83



0 3 6 9 12 15 Kilometres

1:300,000

N

Legend

- Compressor
- Sour Gas Plant
- River
- Lake
- Fenceline
- Township

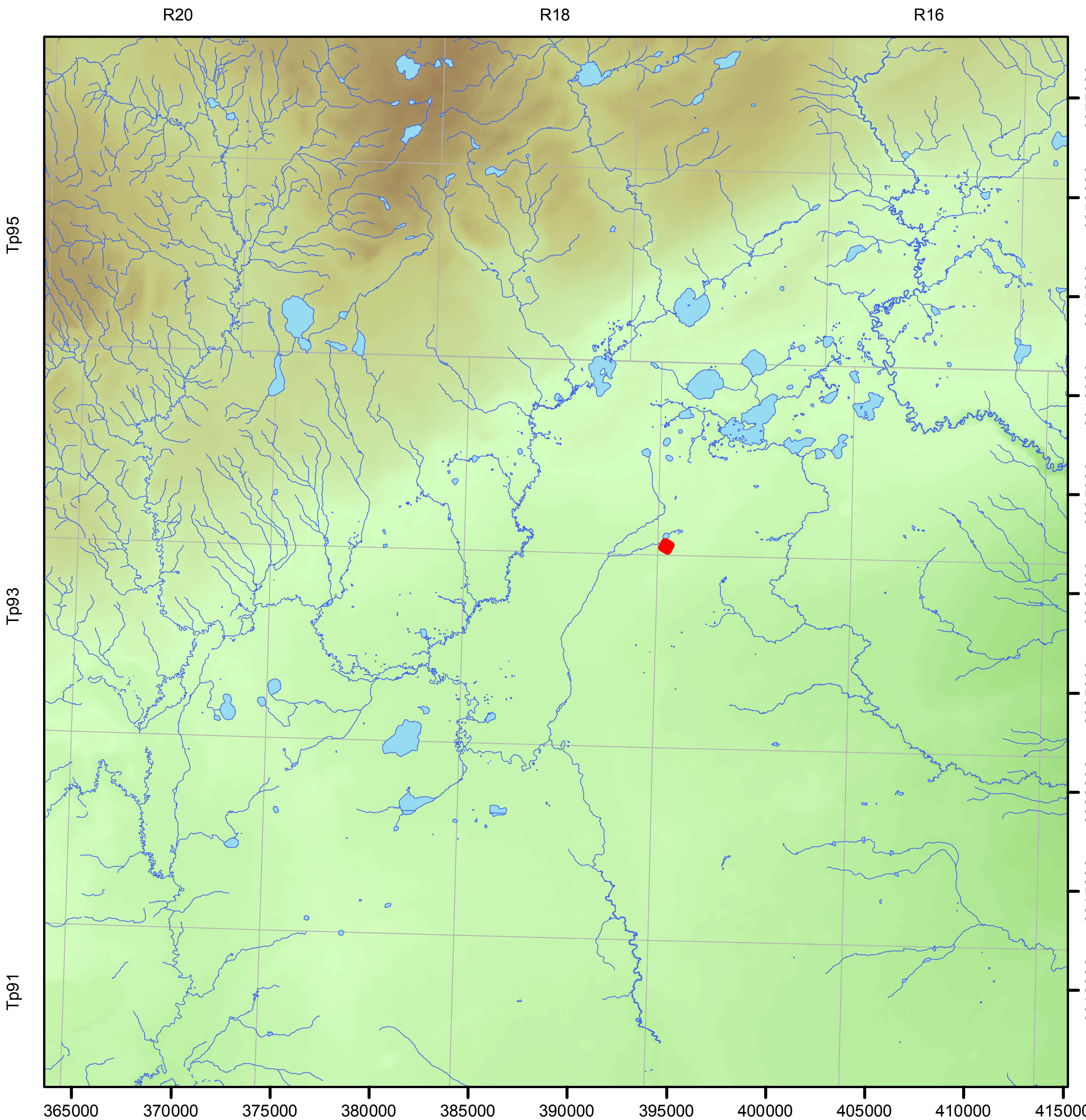
Terrain (m ASL)

High : 757

Low : 47

PROJECT			
AOSC Dover Central Pilot Project			
TITLE			
Cumulative Emissions Sources within the Study Area			
DRAWN	NS	05/22/2008	Figure A-2
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



0 3 6 9 12 15 Kilometres

1:300,000

N

Legend

River

Lake

Fenceline

Township

Terrain (m ASL)

High : 757

Low : 47

PROJECT

AOSC Dover Central Pilot Project

TITLE

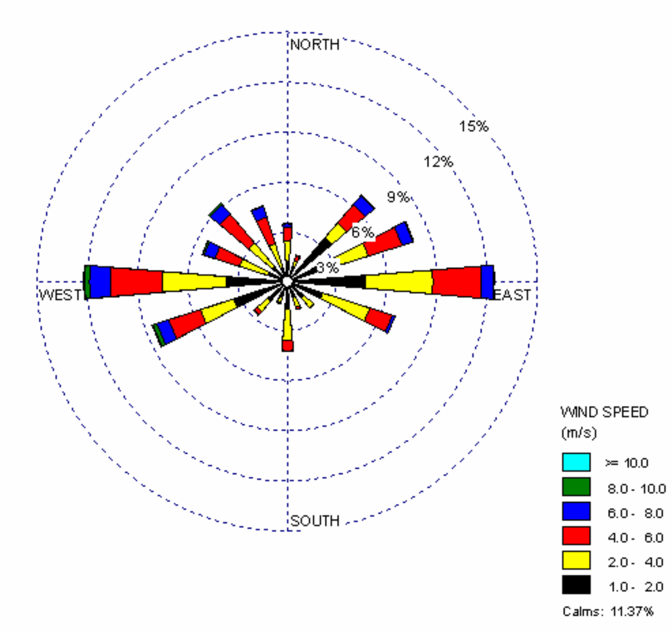
Topography within the Study Area

DRAWN	NS	05/22/2008
CHECKED	KAO	05/22/2008
REVIEWED	DSC	05/22/2008
PROJECT	W08-1106A	

Figure A-3

UTM ZONE 12 NAD83

Fort Chipewyan



Fort McMurray

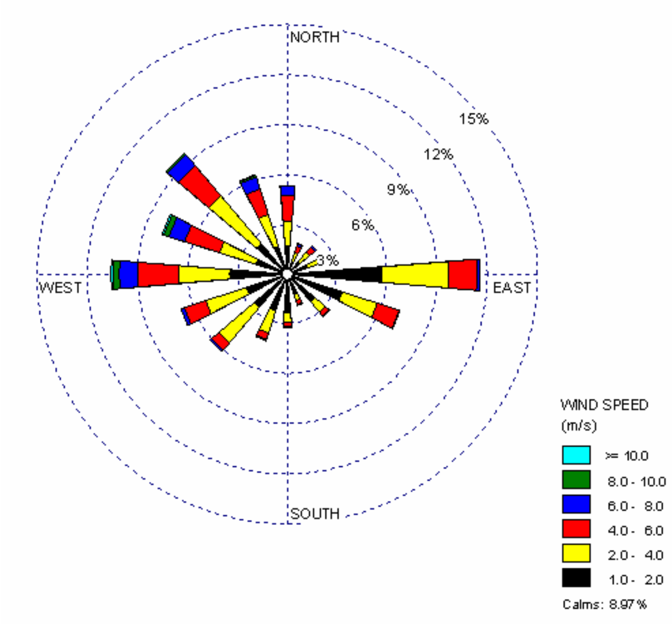
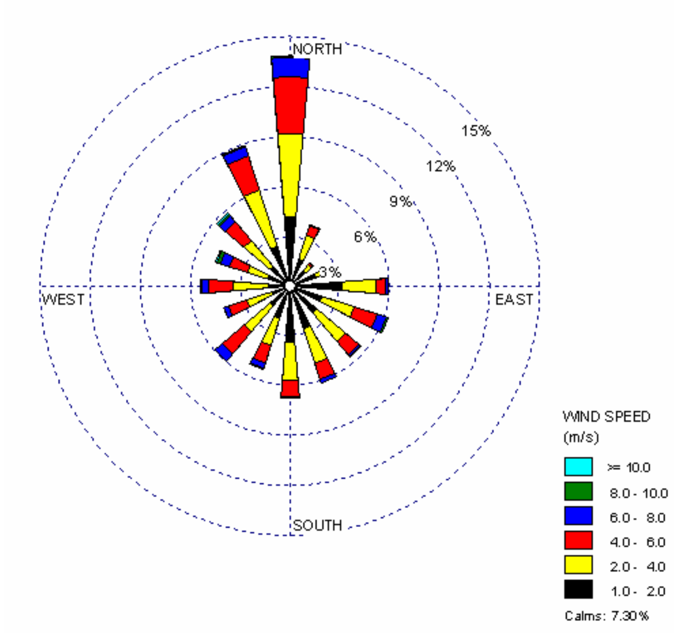


Figure A-4: Comparison of Surface Wind Roses at Selected Locations

Mildred Lake



CALMET Prediction at AOSC Central Plant Site

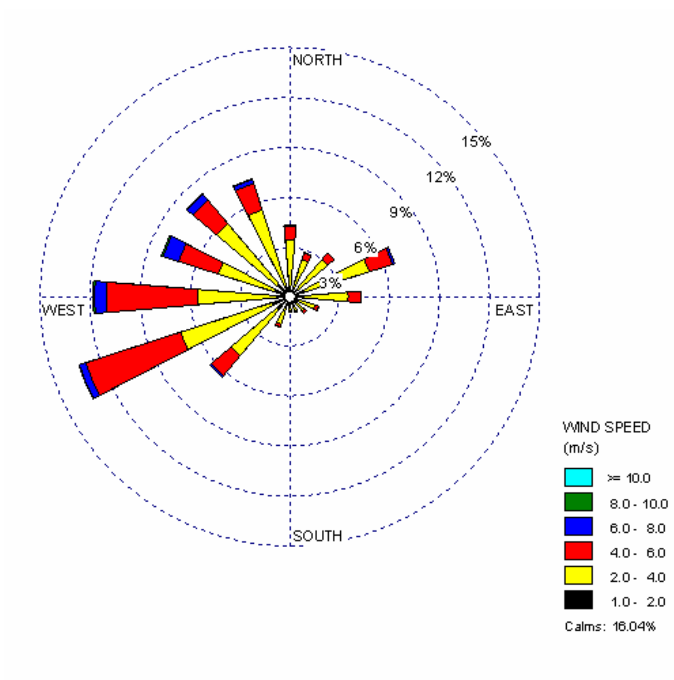
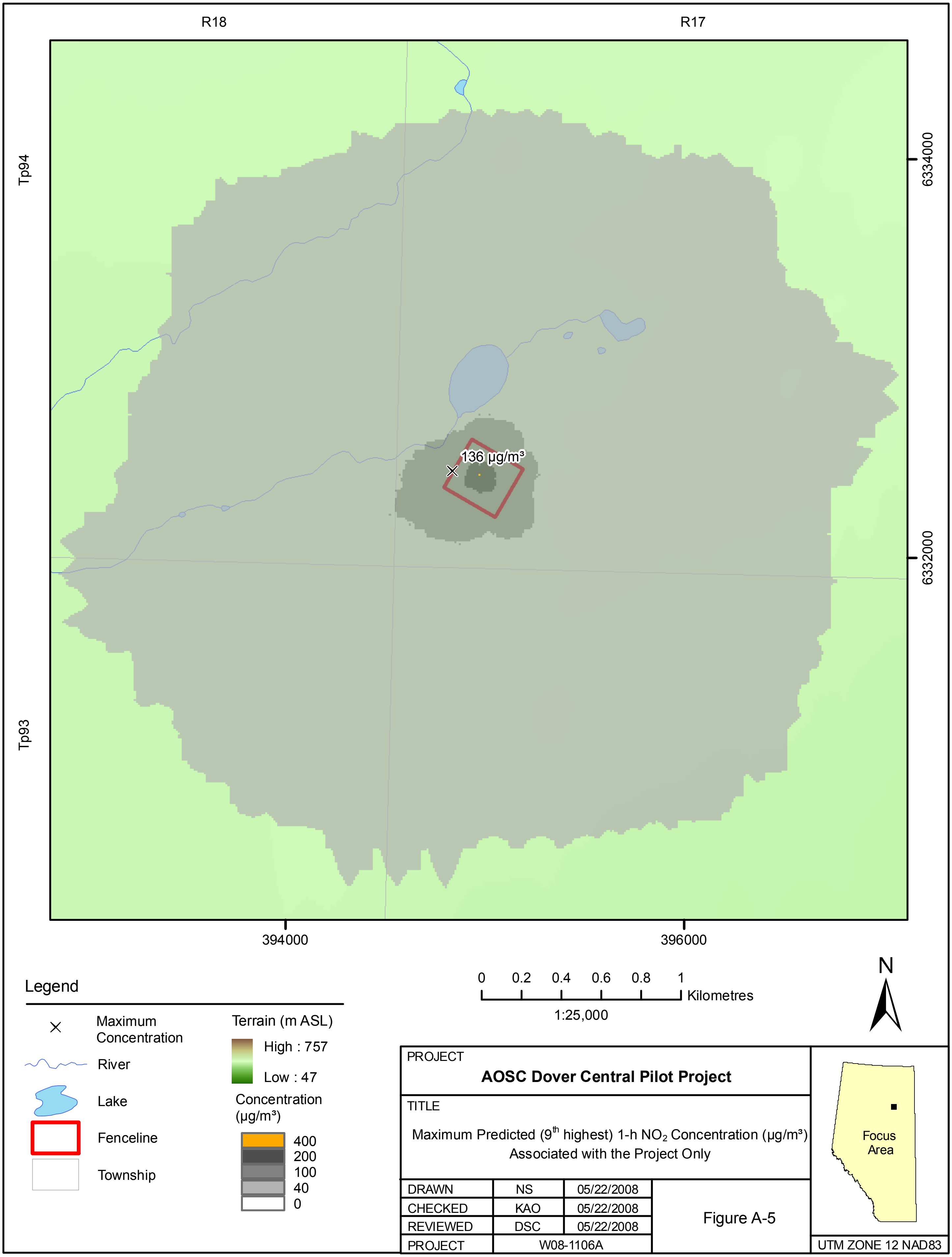
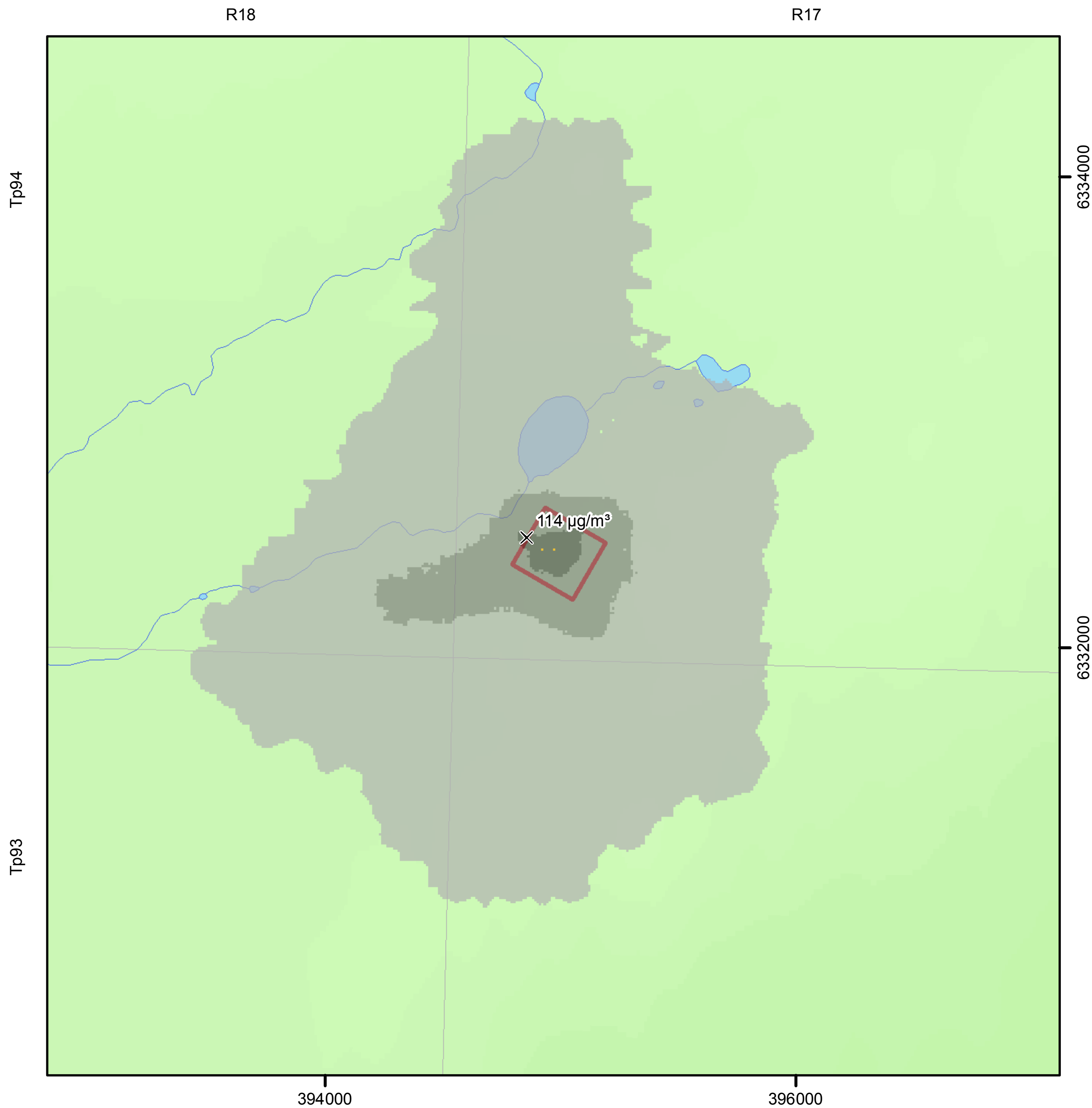


Figure A-4 (cont'd): Comparison of Surface Wind Roses at Selected Locations


R18
R17
Tp94
Tp93
6334000
6332000
394000
396000
136 µg/m³
0 0.2 0.4 0.6 0.8 1 Kilometres
1:25,000
N
Legend
Maximum Concentration
River
Lake
Fenceline
Township
Terrain (m ASL)
High : 757
Low : 47
Concentration (µg/m³)
400
200
100
40
0
PROJECT
AOSC Dover Central Pilot Project
TITLE
Maximum Predicted (9th highest) 1-h NO2 Concentration (µg/m³)
Associated with the Project Only
DRAWN NS 05/22/2008
CHECKED KAO 05/22/2008
REVIEWED DSC 05/22/2008
PROJECT W08-1106A
Figure A-5
Focus Area
UTM ZONE 12 NAD83



0 0.2 0.4 0.6 0.8 1 Kilometres

1:25,000

N

Legend

×	Maximum Concentration
	River
	Lake
	Fenceline
	Township

Terrain (m ASL)

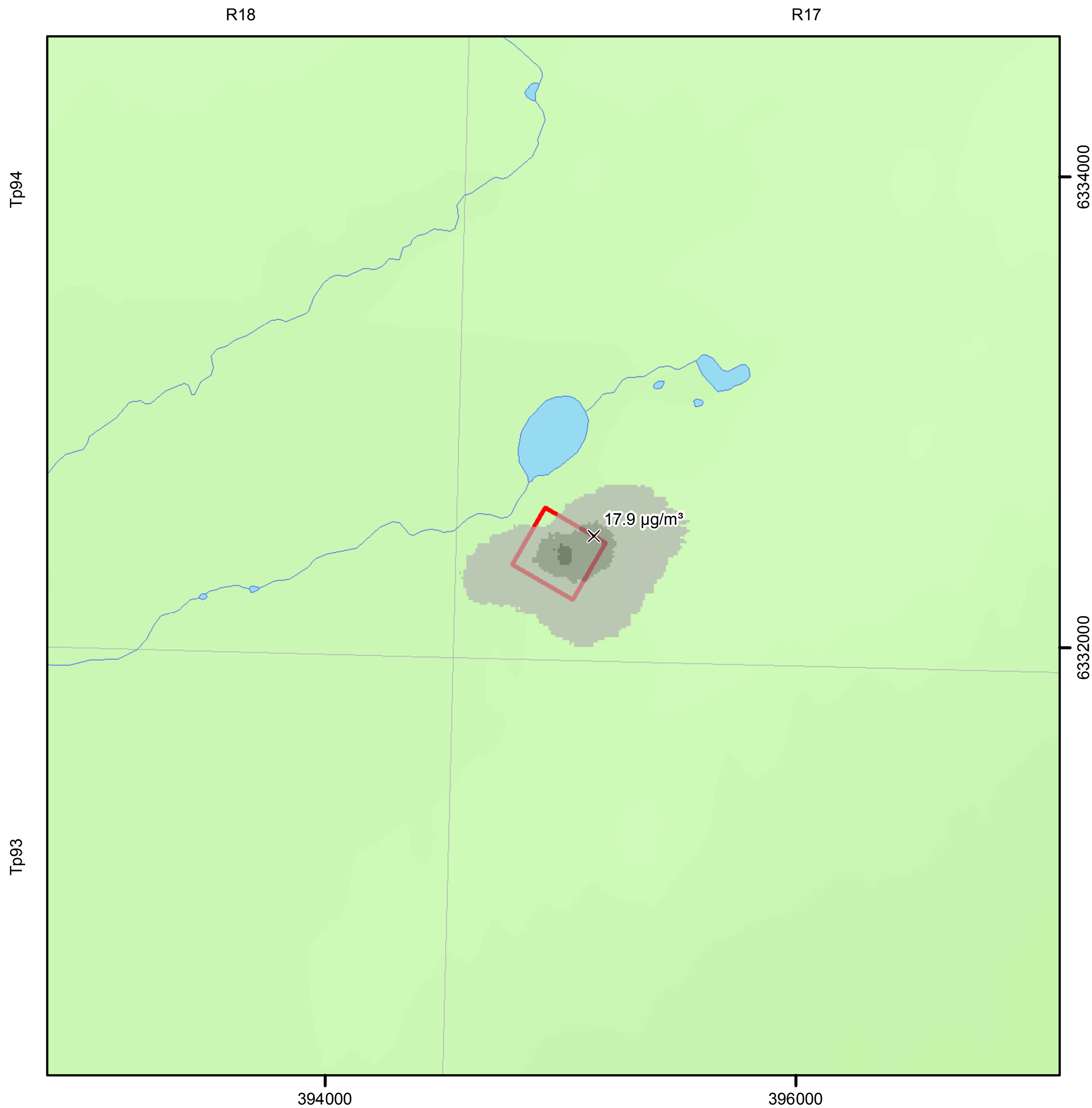
- High : 757
- Low : 47

Concentration (µg/m³)

- 200
- 100
- 50
- 20
- 0

PROJECT	**AOSC Dover Central Pilot Project**		
TITLE	Maximum Predicted 24-h NO_2 Concentration (µg/m³) Associated with the Project Only		
DRAWN	NS	05/22/2008	Figure A-6
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



Legend

×	Maximum Concentration
	River
	Lake
	Fenceline
	Township

Terrain (m ASL)

High : 757

Low : 47

Concentration (µg/m³)

60
30
15
6
0

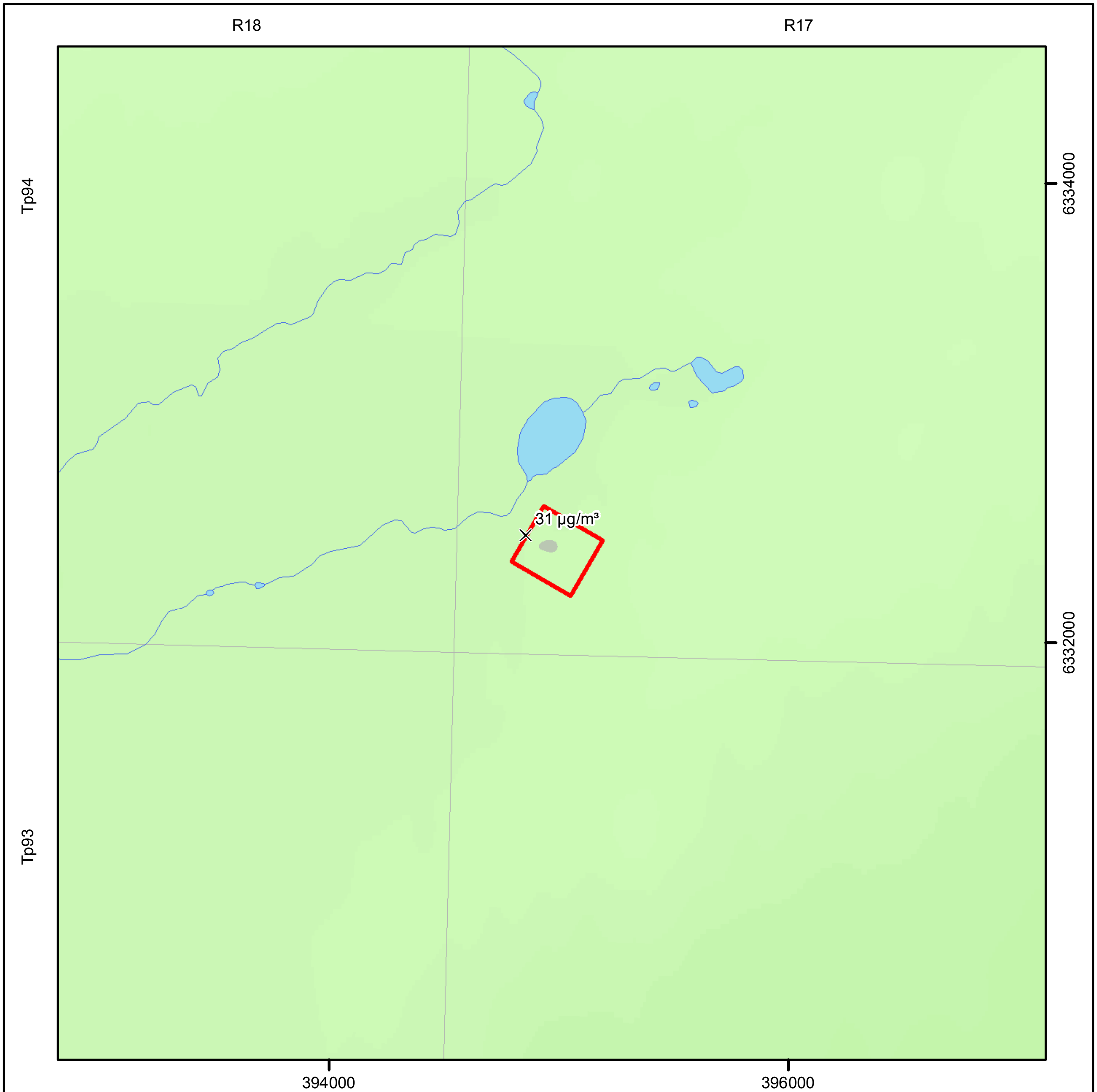
0 0.2 0.4 0.6 0.8 1 Kilometres

1:25,000

N

PROJECT			
AOSC Dover Central Pilot Project			
TITLE			
Maximum Predicted Annual NO_2 Concentration (µg/m³) Associated with the Project Only			
DRAWN	NS	05/22/2008	Figure A-7
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



Legend

	Terrain (m ASL)
Maximum Concentration	High : 757
River	Low : 47
Lake	Concentration (µg/m³)
Fenceline	450 200 100 45 0
Township	

0 0.2 0.4 0.6 0.8 1 Kilometres

1:25,000

N

PROJECT

AOSC Dover Central Pilot Project

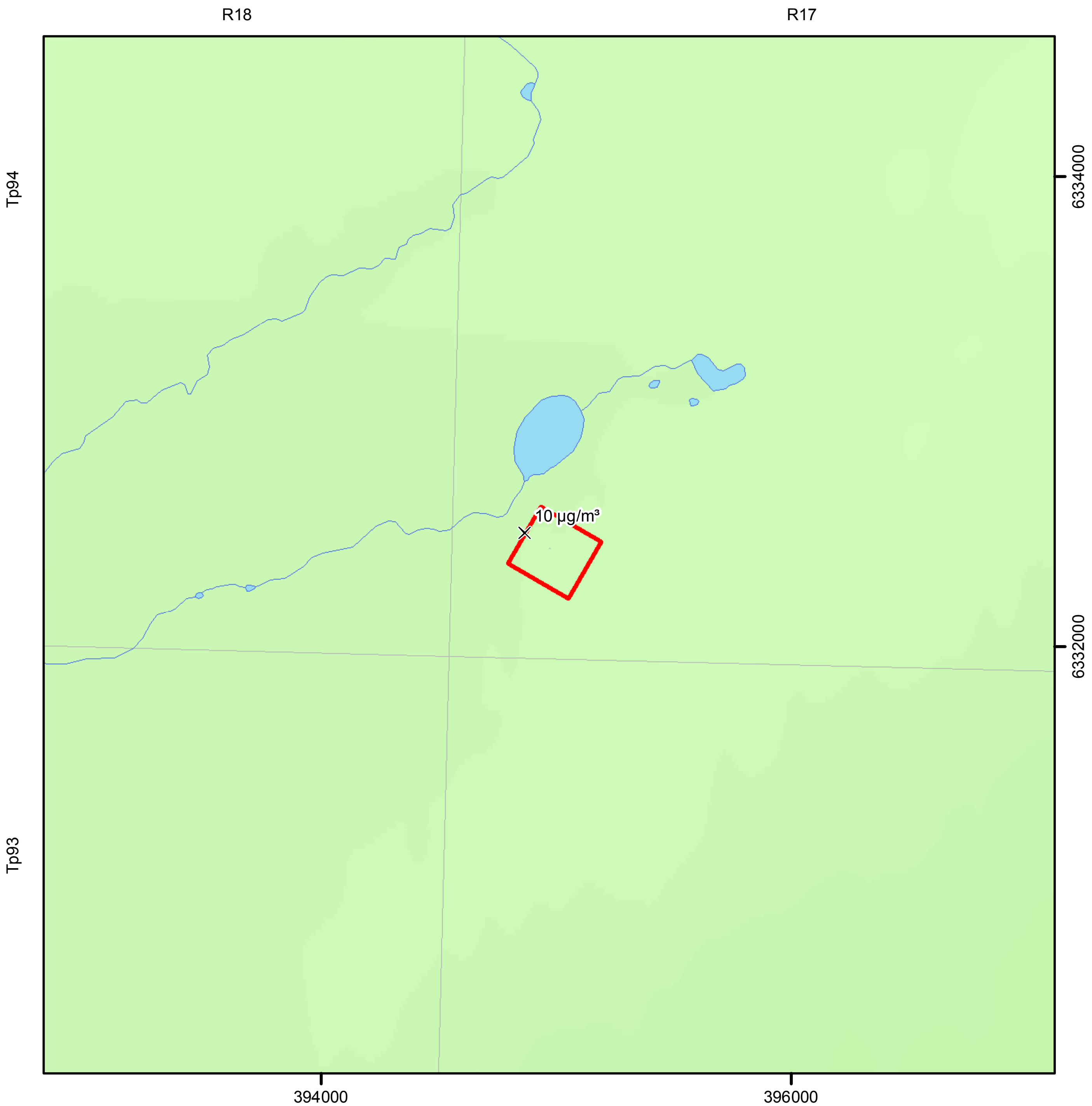
TITLE

Maximum Predicted (9th highest) 1-h SO_2 Concentration (µg/m³) Associated with the Project Only

DRAWN	NS	05/22/2008
CHECKED	KAO	05/22/2008
REVIEWED	DSC	05/22/2008
PROJECT	W08-1106A	

Figure A-8

UTM ZONE 12 NAD83



0 0.2 0.4 0.6 0.8 1 Kilometres

1:25,000

N

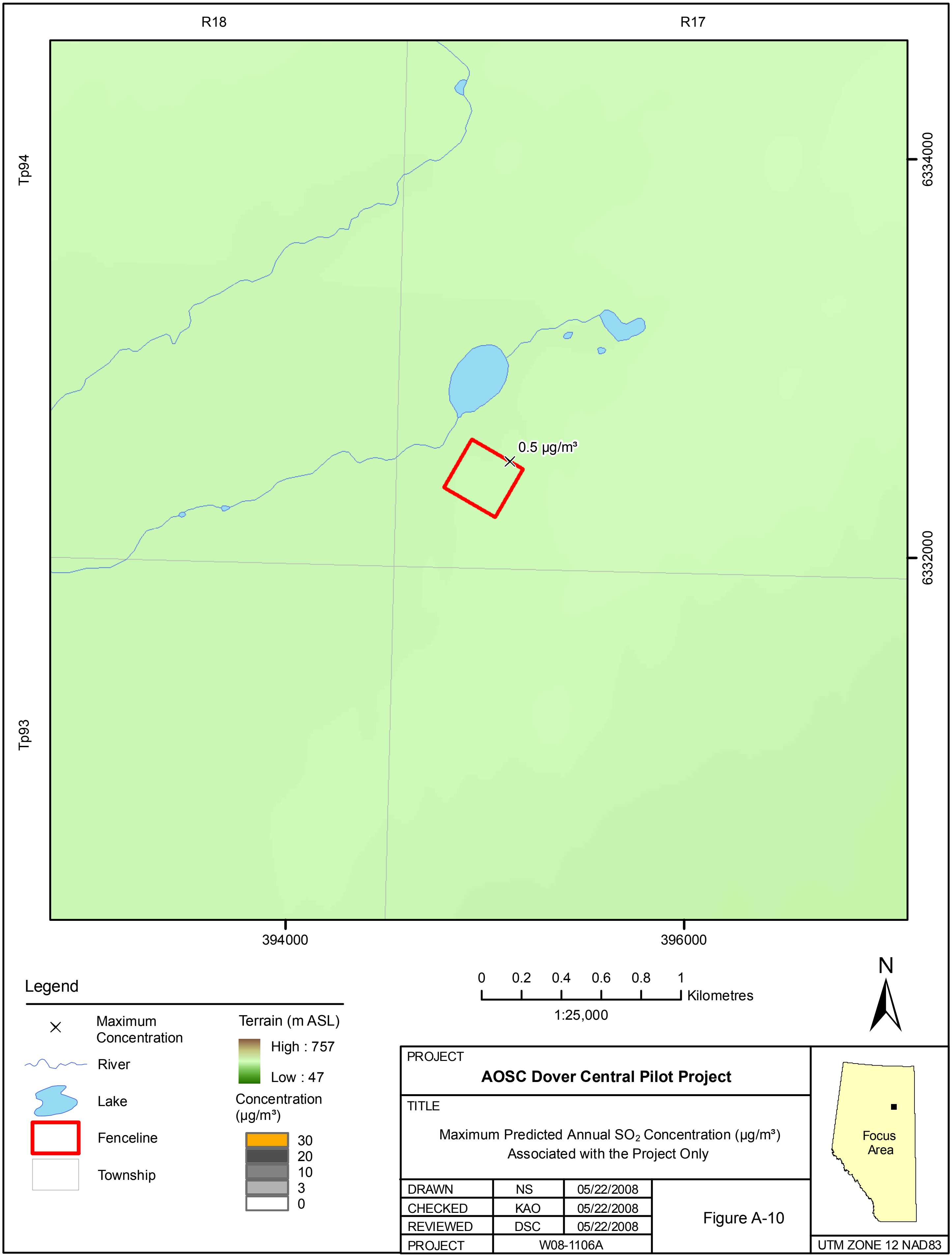
Legend

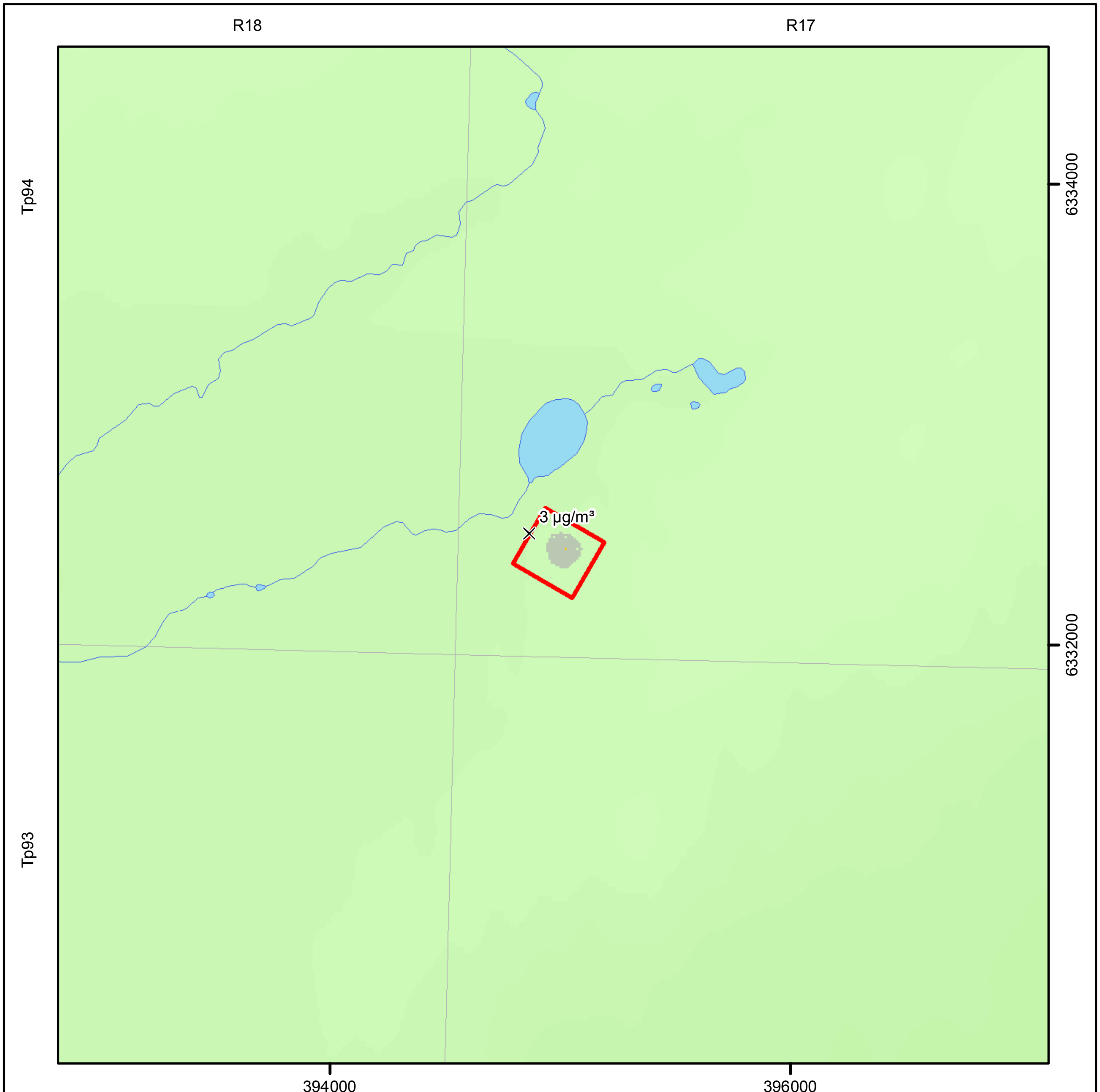
		Terrain (m ASL)
×	Maximum Concentration	High : 757
	River	Low : 47
	Lake	Concentration (µg/m³)
	Fenceline	150, 100, 50, 15, 0
	Township	

PROJECT	**AOSC Dover Central Pilot Project**	
TITLE	Maximum Predicted 24-h SO_2 Concentration (µg/m³) Associated with the Project Only	

DRAWN	NS	05/22/2008	Figure A-9
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83


R18
R17
Tp94
Tp93
6334000
6332000
394000
396000
0.5 µg/m³
0 0.2 0.4 0.6 0.8 1 Kilometres
1:25,000
N
Legend
Maximum Concentration
River
Lake
Fenceline
Township
Terrain (m ASL)
High : 757
Low : 47
Concentration (µg/m³)
30
20
10
3
0
PROJECT
AOSC Dover Central Pilot Project
TITLE
Maximum Predicted Annual SO_2 Concentration (µg/m³) Associated with the Project Only
DRAWN NS 05/22/2008
CHECKED KAO 05/22/2008
REVIEWED DSC 05/22/2008
PROJECT W08-1106A
Figure A-10
Focus Area
UTM ZONE 12 NAD83



Legend

Maximum Concentration	
River	
Lake	
Fenceline	
Township	

Terrain (m ASL)

High : 757

Low : 47

Concentration (µg/m³)

30
20
10
3
0

0 0.2 0.4 0.6 0.8 1 Kilometres

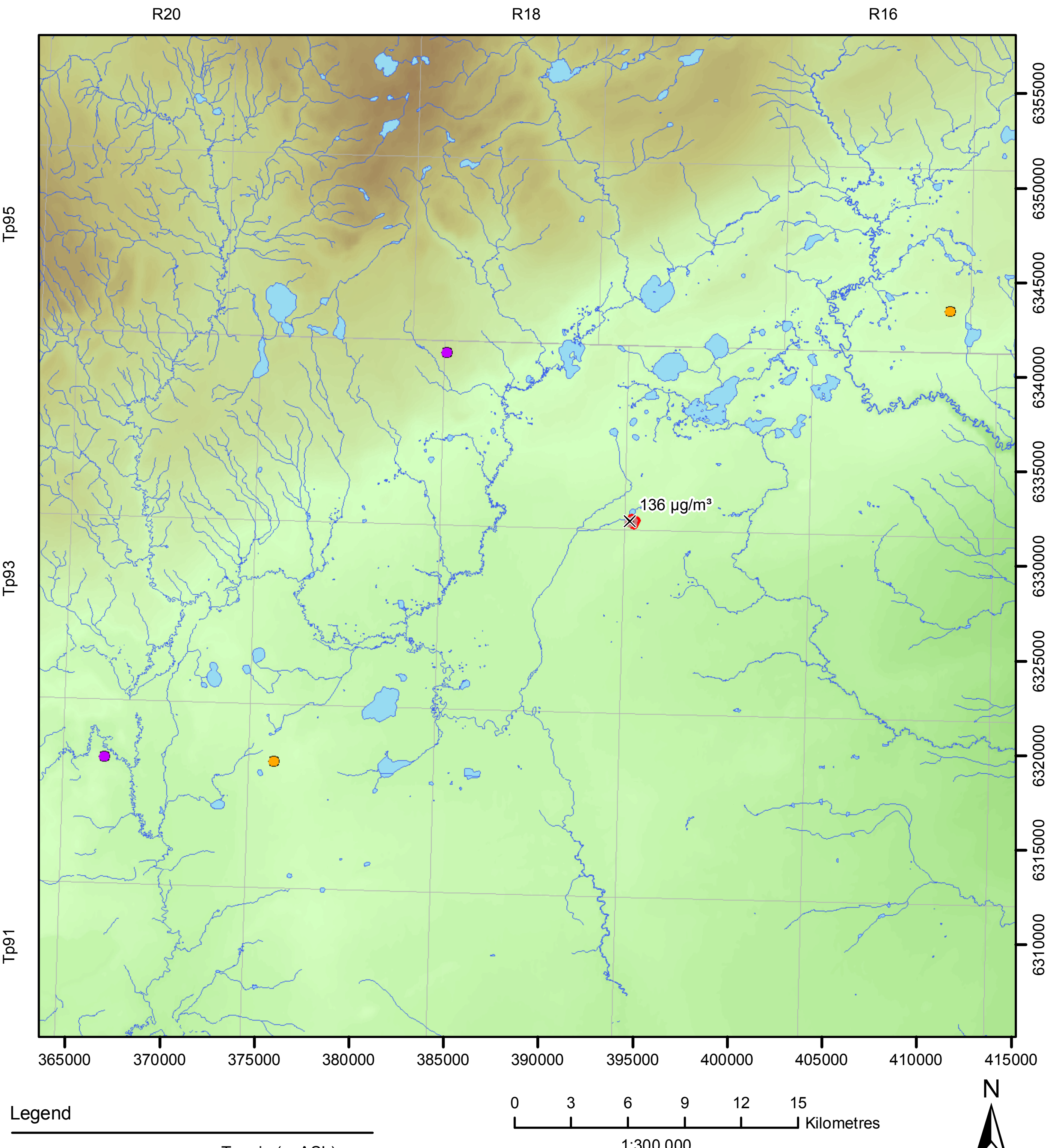
1:25,000

N

PROJECT **AOSC Dover Central Pilot Project**			
TITLE Maximum Predicted 24-h $PM_{2.5}$ Concentration (µg/m³) Associated with the Project Only			
DRAWN	NS	05/22/2008	Figure A-11
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

Focus Area

UTM ZONE 12 NAD83



Legend

×	Maximum Concentration
●	Compressor
●	Sour Gas Plant
	River
	Lake
	Fenceline
	Township

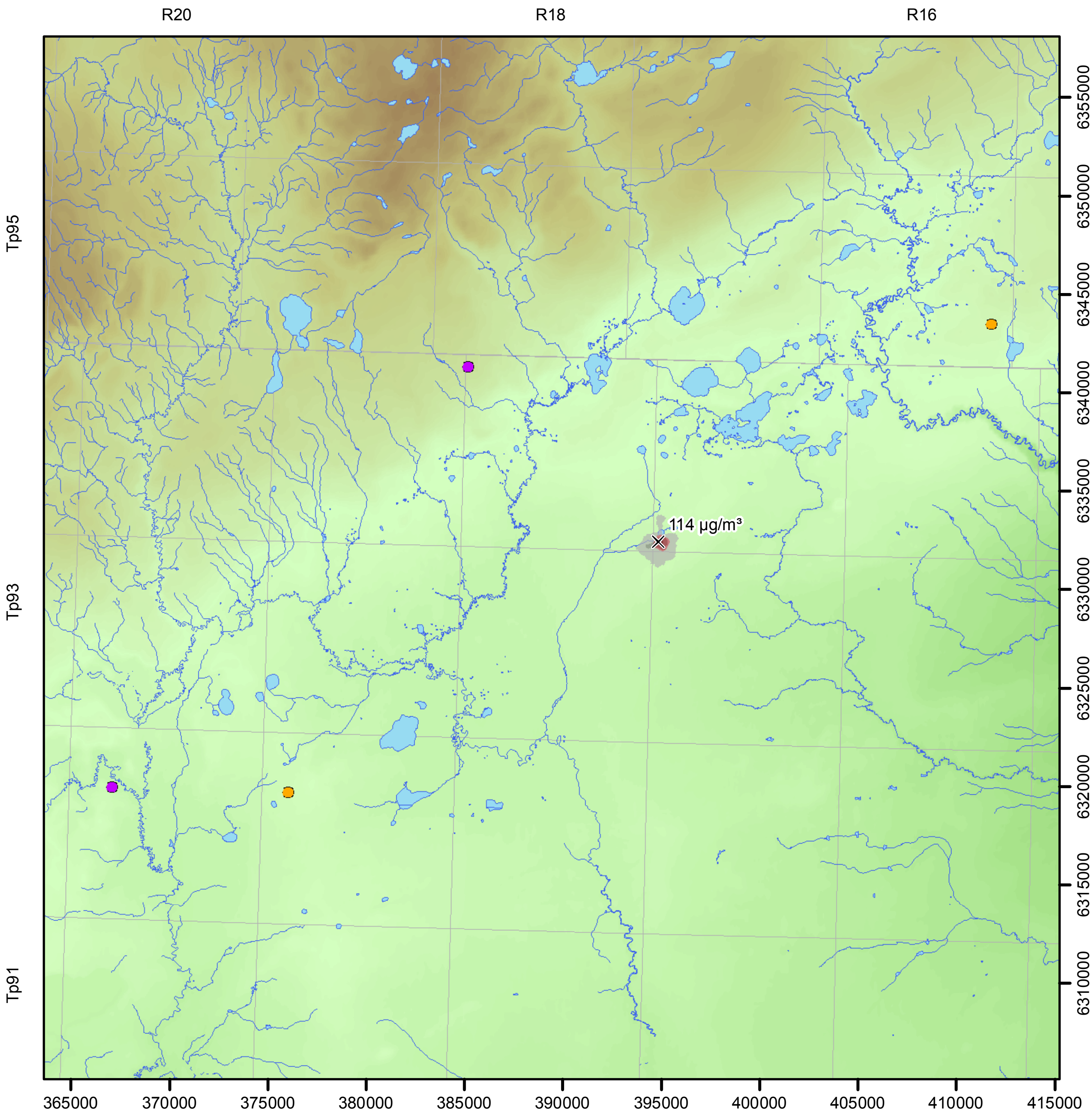
Terrain (m ASL)
High : 757
Low : 47

Concentration (µg/m³)
400
200
150
100
0

PROJECT		
AOSC Dover Central Pilot Project		
TITLE		
Maximum Predicted (9th highest) 1-h NO_2 Concentration (µg/m³) Associated with the Cumulative Emissions		
DRAWN	NS	05/22/2008
CHECKED	KAO	05/22/2008
REVIEWED	DSC	05/22/2008
PROJECT	W08-1106A	

Figure A-12

UTM ZONE 12 NAD83



0 3 6 9 12 15 Kilometres

1:300,000

N

Legend

×	Maximum Concentration
●	Compressor
●	Sour Gas Plant
	River
	Lake
	Fenceline
	Township

Terrain (m ASL)

High : 757

Low : 47

Concentration (µg/m³)

200
100
50
25
0

PROJECT

AOSC Dover Central Pilot Project

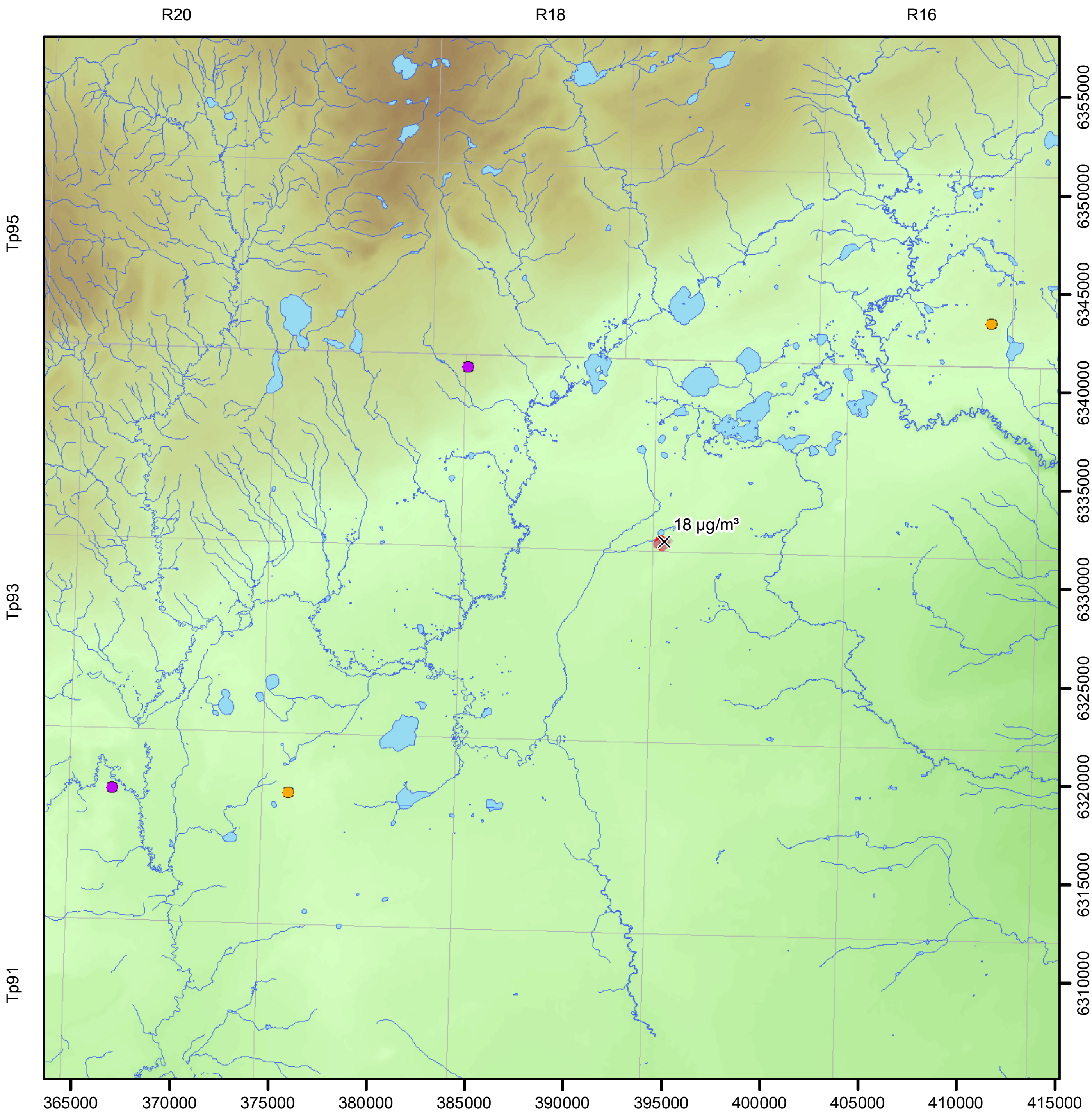
TITLE

Maximum Predicted 24-h NO_2 Concentration (µg/m³) Associated with the Cumulative Emissions

DRAWN	NS	05/22/2008
CHECKED	KAO	05/22/2008
REVIEWED	DSC	05/22/2008
PROJECT	W08-1106A	

Figure A-13

UTM ZONE 12 NAD83



0 3 6 9 12 15 Kilometres

1:300,000

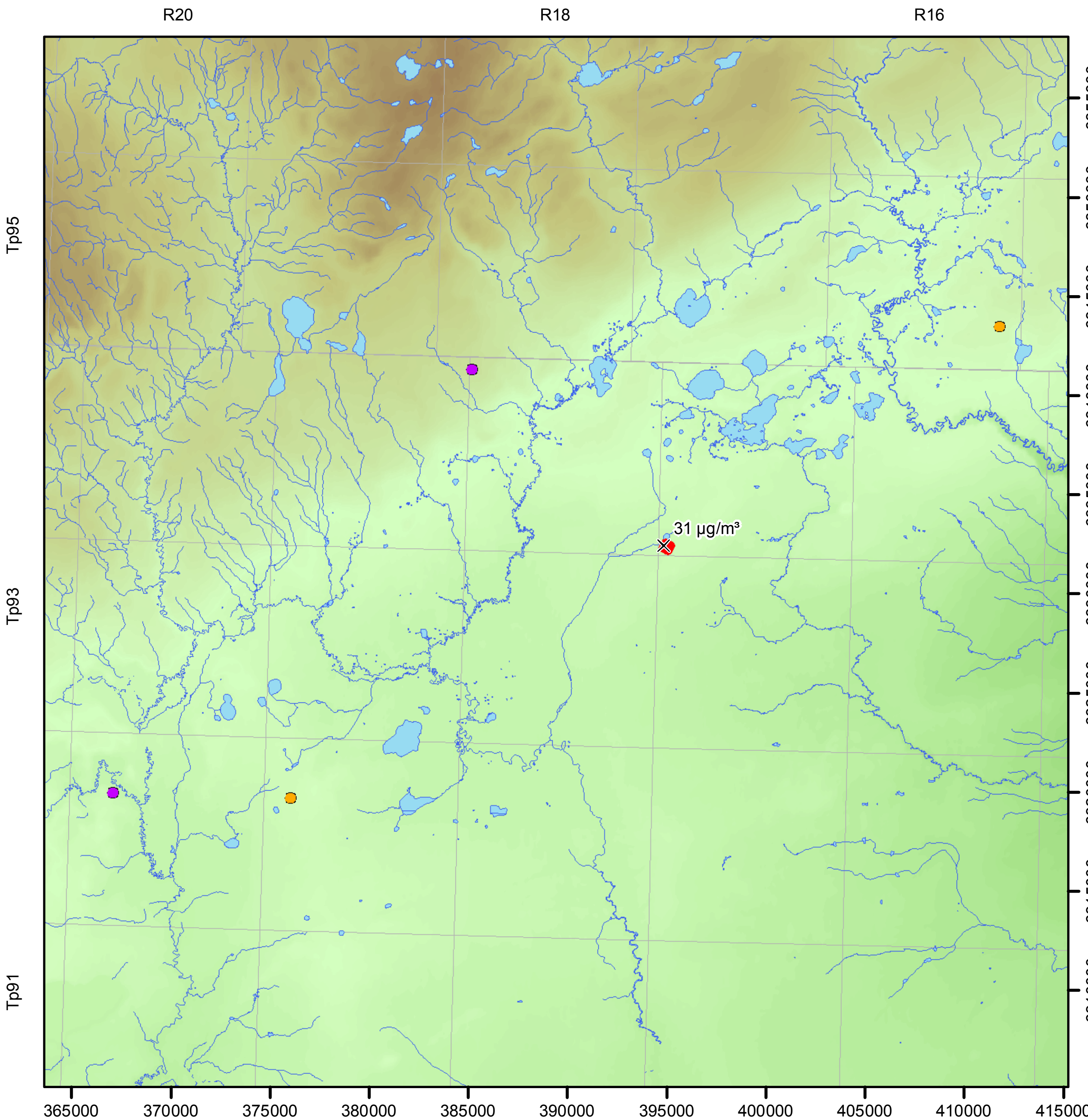
N

Legend

×	Maximum Concentration	Terrain (m ASL)	High : 757
●	Compressor		Low : 47
●	Sour Gas Plant	Concentration (µg/m³)	60
	River		30
	Lake		15
	Fenceline		6
	Township		0

PROJECT	**AOSC Dover Central Pilot Project**		
TITLE	Maximum Predicted Annual NO_2 Concentration (µg/m³) Associated with the Cumulative Emissions		
DRAWN	NS	05/22/2008	Figure A-14
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



0 3 6 9 12 15 Kilometres

1:300,000

N

Legend

- × Maximum Concentration
- Compressor
- Sour Gas Plant
- River
- Lake
- Fenceline
- Township

Terrain (m ASL)

High : 757

Low : 47

Concentration (µg/m³)

450

200

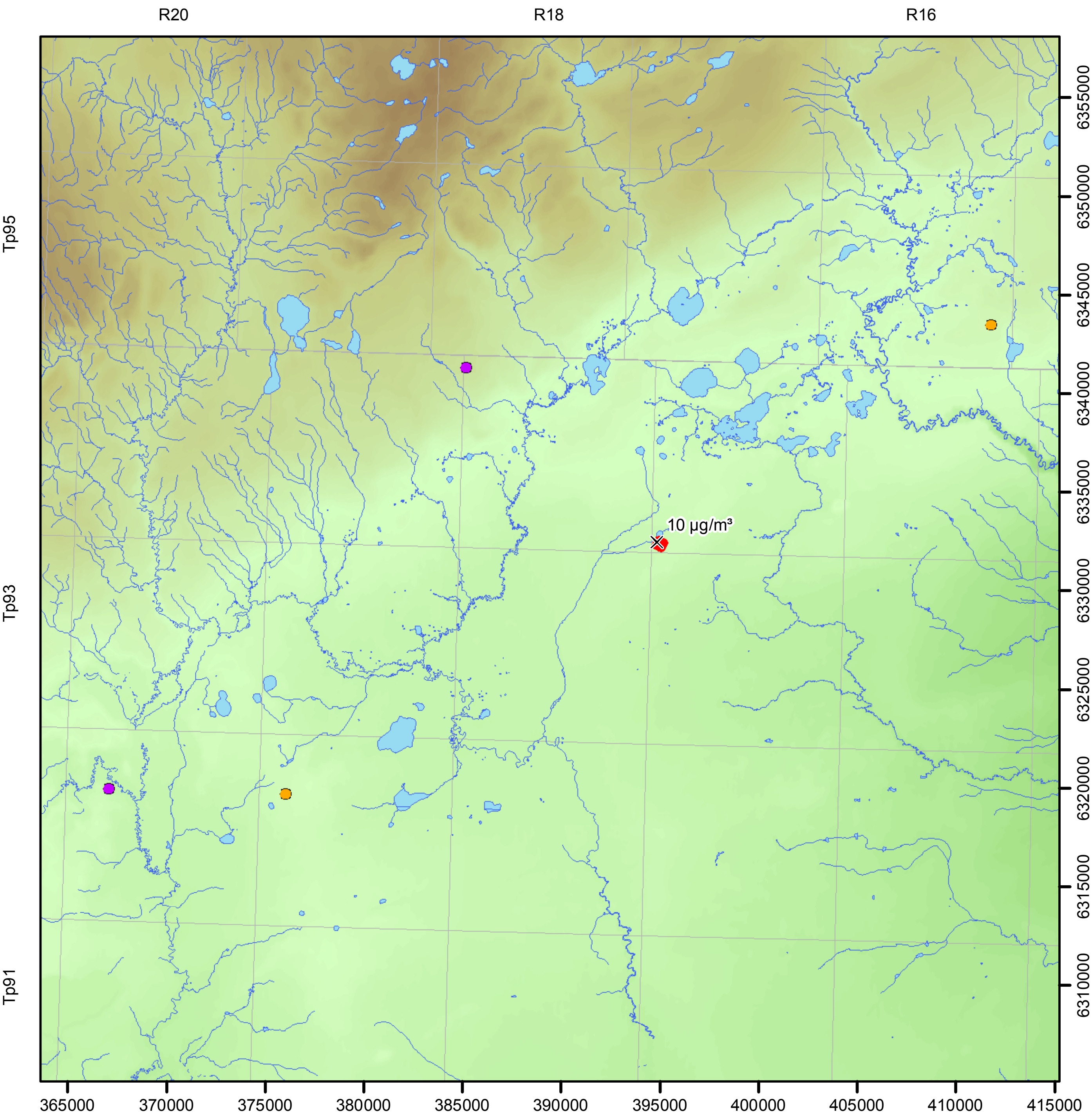
100

45

0

PROJECT			
AOSC Dover Central Pilot Project			
TITLE Maximum Predicted (9th highest) 1-h SO_2 Concentration (µg/m³) Associated with the Cumulative Emissions			
DRAWN	NS	05/22/2008	Figure A-15
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



Legend

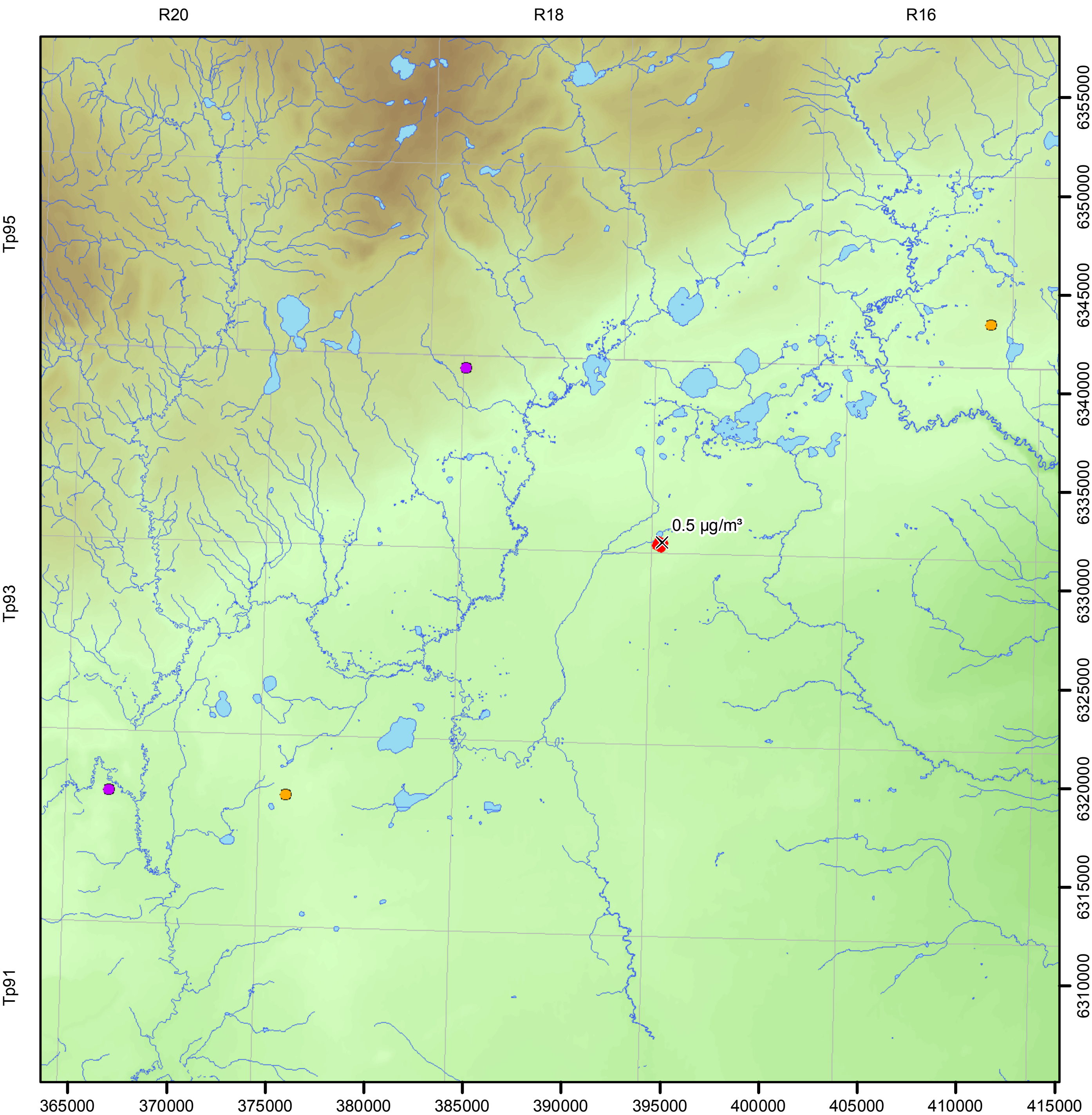
×	Maximum Concentration
●	Compressor
●	Sour Gas Plant
	River
	Lake
	Fenceline
	Township

Terrain (m ASL)
High : 757
Low : 47

Concentration (µg/m³)
150
100
50
15
0

PROJECT **AOSC Dover Central Pilot Project**			
TITLE Maximum Predicted 24-h SO_2 Concentration (µg/m³) Associated with the Cumulative Emissions			
DRAWN	NS	05/22/2008	Figure A-16
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



Legend

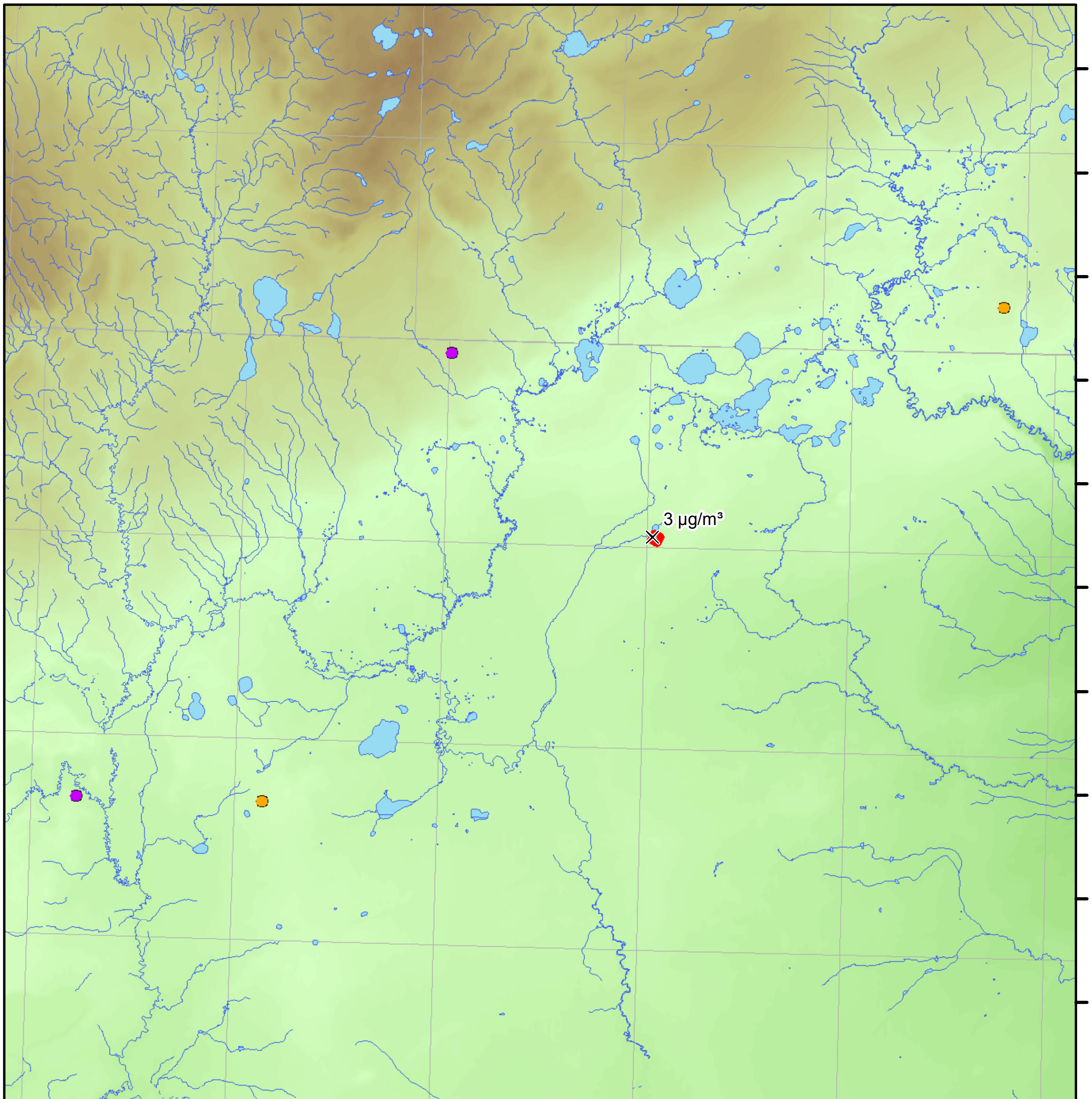
×	Maximum Concentration
●	Compressor
●	Sour Gas Plant
	River
	Lake
	Fenceline
	Township

Terrain (m ASL)
High : 757
Low : 47

Concentration ($\mu g/m^3$)
30
20
10
3
0

PROJECT	**AOSC Dover Central Pilot Project**		
TITLE	Maximum Predicted Annual SO_2 Concentration ($\mu g/m^3$) Associated with the Cumulative Emissions		
DRAWN	NS	05/22/2008	Figure A-17
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83



Legend

- Maximum Concentration
- Compressor
- Sour Gas Plant
- River
- Lake
- Fenceline
- Township

Terrain (m ASL)

High : 757

Low : 47

Concentration (µg/m³)

30
20
10
3
0

PROJECT			
AOSC Dover Central Pilot Project			
TITLE Maximum Predicted 24-h $PM_{2.5}$ Concentration (µg/m³) Associated with the Cumulative Emissions			
DRAWN	NS	05/22/2008	Figure A-18
CHECKED	KAO	05/22/2008	
REVIEWED	DSC	05/22/2008	
PROJECT	W08-1106A		

UTM ZONE 12 NAD83