POTENTIAL OF EOR IN ALBERTA OIL POOLS

PHASE 1 REPORT

FOR

ENERGY RESOURCES CONSERVATION BOARD (ERCB)

(June 2011)

Sproule

Copies:	Energy Resources Conservation Board (ERCB) (1 copy) Sproule International Limited (1 copy) Electronic (1 copy)
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Introduction

Sproule Associates Limited ("Sproule") has been contracted to conduct a study titled "Identification of Enhanced Oil Recovery Potential in Alberta" at the request of the Energy Resources Conservation Board (ERCB). The study is being prepared during the period March 2011 to March 2012. The study is being conducted in two phases. This report presents the results of Phase 1.

Project Objectives

The primary objectives of the study "Identification of Enhanced Oil Recovery Potential in Alberta" are as follows:

1.0 Phase 1

- Retrieve information on all EOR schemes in Alberta from the ERCB's Reserves Report and other ERCB and public databases/files
- Create an inventory of EOR scheme information organized by pertinent characteristics such as geographic area, pool, formation, reservoir properties, scheme type (e.g. CO_2, alkali surfactant polymer (ASP)), and recoveries
- Analyze the inventory of EOR scheme information focussing on successful EOR operations, existing and emerging trends, and likely short-term EOR prospects
- Assess the associated potential success factors
- Preliminary report on EOR in Alberta oil pools: lessons learned/preliminary findings
- Inventory of existing EOR schemes in Alberta organized by pertinent characteristics
- Initial assessment of potential success factors

2.0 Phase 2

- Apply knowledge gained from Phase 1, along with information from literature searches, and possible industry interviews, to fully develop criteria for the screening of potential future EOR prospects, having consideration for the various types of possible EOR schemes and technologies
- Apply screening criteria to all oil pools in Alberta
- Assess and compile potential incremental recoverable volumes for all oil pools under various EOR technologies
- Provide progress update on preliminary findings and adjust study as necessary

- Prepare a report on the total findings on existing and future potential EOR in Alberta in written, tabular, and graphical formats. Report to include, but is not limited to, the following information:
    a. field and pool name
    b. formation
    c. EOR type
    d. fluid properties
    e. reservoir parameters
    f. geographic location
    g. primary recovery
    h. current incremental recovery

This study considers only the technical factors associated with EOR. For any individual project, the economics are important, however, since the economic factors are variable and highly dependent on the current oil price (and the expectation of future oil prices), these factors are not addressed in this study.

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Certification

Report Preparation

The report entitled, "Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)" was prepared by the following Sproule personnel:

Original Signed by Chris M.F. Galas, Ph.D., P.Eng.

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Chris M.F. Galas, Ph.D., P.Eng.
Project Leader;
Manager, Reservoir Studies and Associate
10/06/2011 dd/mm/yr

Original Signed by Oluyemisi Jeje, P.Eng.

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Oluyemisi Jeje, P.Eng.
Petroleum Engineer
10/06/2011 dd/mm/yr

Original Signed by Elden Jaafar, P.Eng.

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Original Signed by Adela Clements, P.Eng.

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Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

Original Signed by Harry J. Helwerda, P.Eng., FEC

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Harry J. Helwerda, P.Eng., FEC
Executive Vice-President and Director
10/06/2011 dd/mm/yr

Permit to Practice

Sproule International Limited is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and our permit number is P6151.

Certificate

Chris M.F. Galas, Ph.D., P.Eng.

I, Chris Galas, Manager, Reservoir Studies, and Associate of Sproule, 900, 140 Fourth Ave. SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
    a. B.A. Natural Sciences (1971), Cambridge University, United Kingdom
    b. M.A. Natural Sciences (1975), Cambridge University, United Kingdom
    c. M.Sc. Nuclear and Elementary Particle Physics (1975), London University, United Kingdom
    d. Ph.D. X-Ray Astronomy (1980), University of Calgary, Calgary, Alberta, Canada

2. I am a registered professional:
    a. Professional Engineer (P.Eng.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
    a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
    b. Society of Petroleum Engineers (SPE)

4. My contribution to the report entitled “Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board (ERCB).

Original Signed by Chris M.F. Galas, P.Eng.

Chris M.F. Galas, P.Eng.

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Oluyemisi O. Jeje, P.Eng.

I, Oluyemisi O. Jeje, Petroleum Engineer of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
    a. B.Sc. Petroleum Engineering (2000), University of Calgary, Calgary, AB, Canada

2. I am a registered Professional:
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    a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
    b. Society of Petroleum Engineers (SPE)

4. My contribution to the report entitled “Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board (ERCB).

Original Signed by Oluyemisi O. Jeje, P.Eng.

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Elden Jaafar, Ph.D., P.Eng.

I, Elden Jaafar, Senior Petroleum Engineer of Sproule International Limited, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. Ph.D. Petroleum Engineering (1989), Heriot-Watt University, Edinburgh, United Kingdom

2. I am a registered professional:
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3. I am a member of the following professional organizations:
   a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
   b. Society of Petroleum Engineers (SPE)

4. My contribution to the report entitled “Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board (ERCB).

Original Signed by Elden Jaafar, P.Eng.

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Adela M. Clements, B.Sc., P.Eng.

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1. I hold the following degree:
   a. B.Sc., Civil Engineering (1983), University of Manitoba, Winnipeg, Manitoba

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   a. Professional Engineer (P.Eng.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
   b. Society of Petroleum Engineers (SPE)
   c. Canadian Heavy Oil Association (CHOA)

4. My contribution to the report entitled “Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board.

Original Signed by Adela M. Clements, P.Eng.

Adela M. Clements, P.Eng.

Certificate

Harry J. Helwerda, B.Sc., P.Eng., FEC

I, Harry J. Helwerda, Executive Vice-President, and Director of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc. Civil Engineering (1978) University of Calgary, Calgary AB, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.) Province of Alberta, Canada

3. I have been bestowed with the designation Fellow Engineers Canada (FEC)

4. I am a member of the following professional organizations:
   a. Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
   b. Society of Petroleum Engineers (SPE)
   c. Society of Petroleum Evaluation Engineers (SPEE)

5. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

6. My contribution to the report entitled "Potential of EOR In Alberta Oil Pools – Phase 1 Report For The Energy Resources Conservation Board (ERCB) (June 2011)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

7. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of the Energy Resources Conservation Board.

Original Signed by Harry J. Helwerda, P.Eng., FEC

Harry J. Helwerda, P.Eng., FEC

Summary

This report is a summary of Phase 1 of the project “Identification of Enhanced Oil Recovery (EOR) Potential in Alberta” (June 2011).

The tasks undertaken for Phase 1 are:

- Database Development and Literature Searches (collection of data and organizing it into a useful form)
- Binary Screening Criteria (Parameters for successful EOR projects)
- Summary of EOR in Alberta (including grouping of projects into different categories and examining the ranges of parameters)
- Preliminary Screening of Alberta oil pools for EOR (based on existing screening criteria)
- Preliminary Findings

Three principal sources of data were used:

ERCB Oil Reserves Report (2010)
ERCB Oil and Gas Experimental Projects Report
ERCB Oilsands Schemes Report

These were put into a relational database. This task required considerable cleaning of the data and manipulation to put it into a useable form and to relate each report to the others (this work is continuing in Phase 2).

In addition, a set of binary screening criteria were put into the database.

A brief review of the principal EOR techniques is included in the report.

Preliminary screening of Alberta oil pools for EOR potential resulted in a large number of potential EOR opportunities for evaluation. The data for EOR screening parameters is limited and additional work is being done in this area. The ERCB reports provide only a limited number of parameters that can be used. However, this provides a starting point, to look further in the analysis of EOR potential.

Included in this report is a literature search to find relevant publications to help assess the success or failure of each project and to identify the “key learnings” of each project. The initial searches were restricted to petroleum engineering technical publications. The search for information available in the public domain will be continued in Phase 2.

The major EOR processes are miscible flooding, chemical flooding and thermal recovery. Preliminary findings for each are discussed under the headings “Alberta Experience”, “Observations”, and “Potential Success Factors”.

Discussion

1.0 Overview

This report summarizes the results of the work carried out for Phase 1 of the study. For this phase, only data from ERCB summaries was used and Sproule's in-house EOR screening criteria were applied.

This report is focused on EOR projects in the "conventional" oil areas of Alberta and excludes the "oilsands" areas. However, since there is information from the oilsands that is relevant (or potentially relevant) to conventional oil, some data on oilsands pilot schemes is included. Conventional oil includes light, medium and heavy oil. Bitumen is defined as oil with an in-situ viscosity greater than 10,000 mPa.s. The oilsands areas contain both bitumen and heavy oil and some of the developments for heavy oil in the oilsands areas can be applied to heavy oil in the conventional oil areas.

The tasks undertaken for Phase 1 that will be described in the following sections are:

- Database Development and Literature Searches (collection of data and organizing it into a useful form)
- Binary Screening Criteria (Parameters for successful EOR projects)
- Summary of EOR in Alberta (including grouping of projects into different categories and examining the ranges of parameters)
- Preliminary Screening of Alberta oil pools for EOR (based on existing screening criteria)
- Preliminary Findings

2.0 Database

The database is the location where all the information gathered over the course of the project is stored. The responsibility of the database development team is to efficiently store large quantities of data in an easy to access system. This requires careful design, large amounts of data validation and creation of an intuitive software interface.

Critical to the database development is the assignment of the data sources for the database.

Three sources of data were assessed and used in the initial development of the database:

- ERCB Annual Oil Reserves Report
- ERCB ST58: Oil and Gas Experimental Schemes Quarterly Edition

- ERCB ST44: Active Oilsands Schemes Quarterly Edition.

In addition, the Sproule EOR Binary Screening Criteria were used to develop the screening tool in the database.

The database was developed by:

- importing the Oil Reserves spreadsheet into a SQL Server relational database
- designing the EOR search program and database
- cleaning up the ST58 and ST44 ERCB reports to be imported into the same relational SQL database
- integrating the binary screening tool into the database

The database design is preliminary and will be modified and improved during Phase 2. The development of the database was complicated by the following factors:

- inconsistent data entry within the reports, including the following categories: Operator Name, Recovery Method, Field Name, Pool Name
- errors within the supplied spreadsheets (such as dates entered in Field Name column)
- within the "Terminated Project" tab in the ST58 report, there was no indication what fluid is associated with each entity (oil or gas)

All of the available data were pulled into the database and set up to allow queries and searching. In Phase 2, additional data and references to technical documents will be added. User-friendly interfaces will also be added to give users the ability to retrieve accurate data efficiently.

The basic data available from the ERCB to analyze consists of three reports in spreadsheet format:

Alberta Oil Reserves Report

This contains a list of all the pools in Alberta along with the following data:

- Field and Pool
- Field and Pool Codes
- Crude Classification
- Oil In Place
- Recovery Factor - Primary
- Recovery Factor - Enhanced
- Initial Established Reserves
- Cumulative Production

- Remaining Established Reserves
- Reservoir Parameters
  - Area
  - Average Pay Thickness
  - Porosity
  - Water Saturation
  - Shrinkage
  - Initial Solution GOR
  - Density
  - Temperature
  - Initial Pressure
- Other Pool Information
  - Datum Depth
  - Mean Formation Depth
  - Discovery Year
  - Date Last Reviewed
  - Remarks

ERCB Oil & Gas Experimental Schemes Report

This report contains tables with “Active Oil Experimental Schemes” and “Terminated Approvals”

The columns in the tables contain the following data:

- Approval No.
- Operator
- Field
- Location
- Active Period
- Recovery Method

In order to incorporate these tables into the database, there must be columns which are common to all tables. The field specification alone is inadequate for the task – there must be a pool specification as well.

The “Location” column provides a means to identify the pool, but in many cases there are multiple pools at each location. Identification of the appropriate pool for each project was carried out. Pool identifiers for most projects were found, however, in some cases, the final identification will have to be carried out in Phase 2, where the details of each EOR project will be examined.

ERCB Oil Sands Schemes Report

This report contains worksheets with in-situ projects, mining projects and “terminated” projects. The mining data are not relevant to this study. The other two worksheets were incorporated into the database, but no linking to locations was carried out.

The data for the Active Insitu projects consists of:

- Approval Number
- Operator
- Issue Date
- Expiry Date
- Scheme Name
- Field
- Deposit
- Location
- Recovery Method
- Deposits

The data for the Terminated Approvals consists of:

- Approval Number
- Operator
- Area
- Location
- Active Period
- Recovery Method
- Remarks

Note that there is no reservoir data associated with these reports.

3.0 EOR Screening

3.1 Review of Process - Solvent Floods

The key to solvent floods is to achieve miscibility between the solvent and the reservoir oil. This can be as a first contact miscible system or a multiple contact miscible system. Multiple contact floods can be either vaporising or condensing gas drives. In a miscible flood, the reservoir oil becomes increasingly solvent rich and so the residual oil phase has less oil component i.e. more of the reservoir oil can be displaced. The solvent also increases the reservoir pressure, swells the oil phase and reduces the oil viscosity – all of these aid in increasing the oil recovery.

A major difficulty with most solvent floods is early solvent breakthrough due to the unfavourable mobility ratio of any gas flood. This leads to the solvent being re-cycled through the reservoir. The most common method of mitigating this is to inject water and gas in alternating slugs, hence “water-alternating-gas” (WAG) flooding.

The solvent can be of several types:

- Ethane, propane or butane (or mixtures of these)
- Enriched hydrocarbon gas
- Lean natural gas
- High pressure lean gas
- Nitrogen
- Carbon Dioxide

The selection is usually based on miscibility pressure, reservoir pressure and cost. The order of the solvents in the above list is roughly in the order of the miscibility pressure, with the exception of carbon dioxide.

Carbon dioxide can be multiple contact miscible at fairly low pressures. It is of particular interest since miscible flooding can also serve to sequester carbon dioxide in the reservoir and hence reduce the amount of carbon dioxide released into the atmosphere.

A principal costs for a solvent flood are the cost of the solvent itself, injection facilities, processing facilities and the cost of transportation of the solvent to the EOR site. As a result, there are considerable economies of scale and larger projects tend to be much more economic than small projects.

3.2 Review of Process - Chemical Floods

The key to chemical floods is to improve the mobility ratio of a waterflood and/or to reduce the residual oil saturation. Polymer flooding can also improve the vertical conformance of a waterflood. All of these mechanisms can improve the oil recovery factor.

There are a number of different types of chemical floods:

- Polymer
- Alkali
- Alkali-polymer
- Surfactant

- Alkali-surfactant-polymer (ASP)
- Micellar

In polymer floods, a polymer, most commonly a polyacrylamide, is added to the injection water where it increases the viscosity of the water. This increase in viscosity improves the mobility ratio of the flood. Since the mobility ratio is of most concern in more viscous oil reservoirs, polymer flooding is most often applied to medium and heavy oil pools. The oil-water relative permeability end-points are not changed by the polymer, so in a sense, there is no incremental oil recovery. However, this is only true if the waterflood is carried out to completion. If there is a maximum watercut limit applied, then the polymer flood results in considerable incremental reserves. There is also an acceleration component i.e. time for the oil recovery for a given volume of water injected is greatly increased. In a heavy oil waterflood there is usually a long production period (often decades or even centuries) where the watercut is over 95%. For reserves purposes, only 50 years of production can be claimed as reserves so a polymer flood can increase the reserves by producing more oil in 50 years. Fractional flow theory predicts that a polymer flood will have a "plateau" period where water has broken through to a well and the well produces for a period at a constant watercut. Eventually, the waterflood front breaks through to the well and the well continues to produce as if it was under a simple waterflood. Plotting the water-oil ratio against cumulative oil production shows a sideways shift of the plot when the polymer is injected into a mature waterflood. The size of this shift can be interpreted as the incremental oil due to the polymer flood.

One of the features of polymer flooding is that the polymer is adsorbed to the rock. This leads to a loss of polymer and determines the amount of polymer solution that is needed to flood the reservoir and hence the cost of the flood. The adsorption also results in a reduction of the permeability of the reservoir. In a heterogeneous reservoir, the injected fluids tend to flow preferentially in the highest permeability reservoir so the permeability reduction is greatest there. This leads to more of the injected fluids going into the less permeable layers, improving the vertical sweep efficiency of the flood. The very successful polymer floods in the Minnelusa trend in Wyoming use this mechanism to improve the recovery of light oil.

In surfactant and micellar floods a surfactant is added to the injected water. The role of the surfactant is to reduce the interfacial tension between the oil and the water. The reduction of the interfacial tension, if great enough, can reduce the residual oil saturation, thereby increasing the oil displacement efficiency and hence the oil recovery factor.

Like polymer, surfactants tend to adsorb onto the reservoir rock. In order to adequately flood the reservoir, the concentration of the surfactant must be quite high. Surfactants are relatively expensive so the cost of a surfactant flood is high.

Alkalis such as sodium hydroxide, sodium carbonate, sodium orthosilicate are used instead of surfactants due to their lower costs. The alkali can react with acids in the oil to create in-situ surfactants, which then act in the same way as the injected surfactants. However, it is usually difficult to get sufficient lowering of the interfacial tension to reduce the residual oil saturation significantly.

Both surfactants and alkalis are often used together with polymers for better mobility control.

Combining alkali, surfactant and polymer together ("ASP flood") has the added advantage that there is a synergy between the alkali and the surfactant and the adsorption of the surfactant is significantly reduced while lowering the residual oil saturation to very low levels. In the laboratory, ASP floods can reduce the residual oil saturation to less than 3%.

3.3 Review of Process - Thermal Recovery

The key to thermal recovery is the use of heat to lower the viscosity of oil and hence make it possible to produce (in the case of bitumen) or to increase the productivity/recovery (in the case of medium/heavy oil).

There are several major thermal processes in use today:

- Cyclic steam stimulation (CSS)
- Steam Flood
- Steam-Assisted Gravity Drainage (SAGD)
- In-situ combustion (ISC)

Other processes, which are not as widely implemented are:

- Electrical/Electromagnetic heating
- Hot water flooding

In cyclic steam stimulation, a pre-determined volume of steam is injected into a well, the well is allowed to “soak” for a period and then the well is brought on production. Typically, the injection period is one month, the soak lasts for a week or two and the production lasts for several months. The injection/soak/production cycles are repeated until they become uneconomic.

A steam flood is exactly like a waterflood, except that steam replaces water as the injection fluid.

In SAGD, two long horizontal wells are used. The production well is located near the base of the reservoir. A second horizontal well is placed directly above the production well and is used for steam injection. A key to the process is that the injection/production rates are sufficiently low that the process is dominated by gravity forces. In this situation, the steam rises to the top of the formation, forming a “steam chamber”, and the heated oil drains down to the producer.

In in-situ combustion, air or oxygen is injected into the reservoir and ignited. The heat pyrolyses the oil, resulting in part of the oil reduced to a solid “coke”. The coke is the primary fuel for the combustion and the rest of the oil is displaced ahead of the combustion front. Water is often injected as well to improve the flow of heat ahead of the front. In many cases, the process can be viewed as a steam flood with in-situ steam generation.

3.4 Review of Process – Other EOR

Other EOR schemes that have been proposed in the literature or tested in the field include:

- Microbial recovery
- Foam flooding
- Fresh water flood
- Immiscible gas vertical floods
- VAPEX
- THAI

None of these has been extensively tested and so will not be considered here. For further description of the methods, references are provided.

3.5 Sproule EOR Screening Criteria

The following table lists the potential EOR processes screened for using the Sproule Binary Screening Criteria. Processes applicable principally to oil sands have been not been excluded to investigate their potential of the process to lighter oils.

Sproule EOR Screening Processes
Alkaline
Carbon Dioxide
High Pressure Lean Gas
LPG/Enriched Gas
Miscible Nitrogen
Polymer
Surfactant
Steam
Vapex
SAGD
InSitu Combustion

The following table is a list of the property criteria used to evaluate the potential EOR process.

Sproule Binary Screening Criteria	Units
Depth	(m) metres
Net Pay Thickness	(m) metres
Net/Gross Ratio	fraction
Average Permeability	(mD) millidarcies
Pressure	(kPa) kilopascals
Temperature	(C) degrees Celsius
Oil Density	(kg/m^3) kilograms/cubic metre
Oil Viscosity	(mPa-s) millipascal second
Salinity of Formation Water	(ppm) parts per million
Divalent Ion Content	(ppm) parts per million
Remaining Oil Saturation	(%PV) percent pore volume
Mobile Oil Saturation	(%PV) percent pore volume
Actual Oil Content	(m^3/ha-m) cubic metre/hectare-metre
Transmissivity	(mD*m/mPa-s) millidarcy metre/millipascal second
Preferred Lithology	Sandstone or carbonate or other
Dip Angle	Degrees
Intergranular Clay Content	Less than 5% = Low
Presence of Natural Fractures	Detected in core (Yes or No)
Presence of Gas Cap	Less than 0.1 m

Table 1 identifies the parameters which are useful as screening criteria for each process. Not all parameters are relevant for all of the processes.

Table 2 provides the upper and lower limits of each applicable parameter for each individual EOR process.

Part of this study is to adjust and update these criteria to conditions specific to Alberta, incorporating the learnings from the existing EOR projects, both commercial and experimental.

4.0 Alberta EOR Projects

Alberta EOR projects are contained in the three ERCB reports:

1. Alberta Oil Reserves report contains information on commercial EOR projects
2. ERCB Oil & Gas Experimental Schemes contains information on experimental EOR projects
3. ERCB Active Oil Sands Schemes Quarterly Edition contains information on oilsands active and terminated projects.

These are discussed in sections 4.1 to 4.3.

4.1 Alberta Oil Reserves Report

The first data source evaluated for potential EOR processes in Alberta used the data from the reserves report provided by the ERCB. The reserves report identified 12,993 unique field and pool combinations; 91 had some form of EOR scheme; leaving 12,902 pools left to determine if they have potential for an EOR scheme.

The issue encountered with this method was that the reserves report only contained a limited sample of the data required to analyze a reservoir for EOR Potential using the Binary Screening Criteria. This analysis only yields 6 properties that matched this screening parameters.

Those matching properties are:

Depth
Net Pay Thickness
Oil Density

Temperature
Initial Oil saturation
Pressure

The reserves report only identified 4 existing EOR processes. The EOR processes identified are broken down into the following EOR schemes:

Existing EOR Process Identified	**# of EOR Processes Identified in the Public Data Base**
ASP Flood	5
Gas Flood	18
Polymer Flood	7
Solvent Flood	61
Sub Total	**91**

In this evaluation, water flood is considered a secondary scheme and not an EOR scheme. Gas flood is also not considered an EOR scheme; however, it is not possible to differentiate the injected gas between a true gas flood (secondary scheme) or if the gas was an enriched (EOR scheme).

Figure 1 is a histogram of the EOR processes identified in the reserves data base.

Figures 2 to 5 are location maps showing ASP Floods, gas floods, polymer floods and solvent floods in Alberta identified by Field/Pool. Figures 6 to 9 show the same data but with the outline of the field for each project.

The ASP and Polymer floods are all in the Mannville group of formations (with one exception). The solvent floods are predominantly in the Nisku, Keg River, Beaverhill Lake and Cardium. Note that in this report, there is no distinction made between hydrocarbon solvent and CO_2. The floods in the Cardium are predominantly CO_2, while the others are hydrocarbon solvents.

Parameter Range of Commercial EOR Projects in Alberta

The parameters of the pools with commercial EOR projects were examined and the minimum and maximum values are listed in Table 3. These provide data for fine-tuning the screening criteria for each process and will be further evaluated in Phase 2.

4.2 ERCB Oil & Gas Experimental Schemes Report

The "Active Oil Experimental Schemes" and "Terminated Oil Experimental Schemes" spreadsheets were evaluated to determine if they provide additional EOR information to the Reserves Report.

The report provides different detail on the EOR processes. However, it does not provide additional reservoir data. The locations of the projects are identified by Township and Range, but the Field/Pool designations were not provided and were determined by other means.

Figures 10 and 11 show the locations of the EOR processes for the "Light to Medium Oil" and the "Heavy Oil".

In general, the experimental projects are carried out on a part of the pool. The Reserves Report does not specify which pools have experimental projects. In some cases, there may be more than one experimental project in a single pool.

No information is available on the experimental database producing formations. To identify these, the pool and field of the project must be identified.

The experimental schemes fall into the following categories (the number in brackets indicates the number of projects in that category):

- Alkaline Flood (2)
- Polymer Flood (3)
- Polymer/Alkaline Flood (3)
- Alkali/Surfactant/Polymer (1)
- Nitrogen Injection (2)
- Solvent Injection (3)
- Sour Gas Injection (2)
- Natural Gas Injection (1)
- Cyclic Injection (1)
- CO_2 Flood (12)
- Foamed CO_2 (1)
- Coalbed Methane (20)
- Combustion (2)
- Hot-water Injection (1)
- Anti-water Coning (3)
- Bulk Sample Pit (1)

- Enhanced Gas Recovery (1)
- Flue gas injection into gas above bitumen (1)
- Partial Pressure Maintenance (1)
- Horizontal Drainhole (2)
- Horizontal Well (31)

Some of the projects are clearly not related to EOR (Coalbed Methane, Horizontal Well). Others are too poorly defined to provide an indication if they are EOR related or not ("Bulk Sample Pit"). The EOR schemes can be grouped as:

- Chemical flood (9 projects)
- Miscible flood - Solvent/N2/Sour gas (9 projects)
- Miscible flood - CO_2 (13 projects)
- Thermal Recovery (3 projects)

All of the chemical flood experimental projects are in sandstones of the Mannville group. The miscible floods are mainly in the Nisku (D2) and Leduc (D3) formations, though two are in the Mannville group. The CO_2 floods are in the Viking, Cardium and Mannville group formations.

4.3 ERCB Oil Sands Schemes Report

The "Active Oil Sands Schemes" and "Terminated Approvals" spreadsheets were evaluated to determine if they provide additional EOR information to the Reserves Report.

In the "active schemes", there are 6 cyclic steam stimulation (CSS) projects, and 25 "steam-assisted gravity drainage" (SAGD) projects. All of these are considered commercial. In the "terminated approvals" there are:

- 16 in-situ combustion (ISC)
- 14 steamfloods
- 169 CSS
- 13 SAGD
- 6 Combination Thermal Drive (CTD)
- 7 Electrical/electromagnetic heating
- 6 single well SAGD (SWSAGD)
- 13 VAPEX/Gas Injection
- 1 emulsion flood
- Jet Leaching

There are also a number of "primary" and "water injection" schemes. The water injection schemes may include polymer injection.

Although a detailed discussion of these is outside the scope of this project, they are mentioned here to allow the reader to follow-up on developments which may be applicable to heavy and medium oils in the “conventional oil” areas.

5.0 Preliminary Screening of Alberta Oil Pools for EOR Potential

The Reserves Report was compared to the binary screening criteria. Limited data was available for the screening.

Table 4 identifies the binary screening parameters available in the ERCB Reserves Report vs. the data for binary screening.

Table 5 identifies the screening data available with the high-low ranges of the data for the specific EOR processes.

Figure 12 is a graph showing a comparison of the binary screening criteria for the different EOR processes vs. the data available in the Reserves Report.

Figure 13 shows the percentage of binary screening data available in the Reserves Report by EOR process.

Note that Oilsands Processes are included in the comparison.

Table 6 summarizes the binary screening criteria that matched from the Reserves Report by EOR scheme. For the individual processes there appear to be significant EOR potential opportunities, however, this is based on very limited criteria to determine the potential of an EOR process as shown in Figures 10 and 11.

The EOR screening of the Reserves Report resulted in a large number of potential EOR opportunities for evaluation. The data for EOR screening parameters is limited and additional work is being done in this area. The screening criteria available only consider approximately 30% of the required parameters. However, this provides a starting point, to look further in the analysis of EOR potential. This is discussed further in section 7.

Included in Table 6 are the total OOIP, Initial Established Reserves and Remaining Reserves for all the pools which satisfied the criteria. Table 7 and Table 9 identify the recovery factors for the solvent and chemical floods in Alberta. If the average incremental factors for each process are applied to these volumes, the potential incremental reserves for Alberta can be estimated. The results are clearly extreme and will be reduced by the following factors:

- Some criteria need to be added e.g. minimum reservoir pressure from all miscible floods (enriched gas, nitrogen and CO_2)
- Minimum economic size of project (e.g. facilities and solvent transport systems have considerable economies of scale, so small projects are not economic)
- No distinction made between secondary or tertiary projects – the success of EOR is often increased if the EOR scheme is started early in the depletion of the pool. In many cases, EOR is started after secondary (waterflood) recovery is started but before the waterflood has been completed
- Estimates of additional parameter eg. oil viscosity based on the available date

The producing formations were identified using the IHS database linking it to the Reserves Report. This provides information on potential geological trends for the different EOR processes.

6.0 Literature Searches

Listings of the EOR projects and oil pools in Alberta are readily available. However, to assess the success or failure of each project and to identify the "key learnings" for each, additional sources of information are required. Some of this information is available in the industry literature. This task is aimed at locating this information.

A literature search is a method of systematically researching and collecting all the data available on a given topic. In this case, there are two main avenues being pursued in the research:

- Information on all projects in Alberta that are related to enhanced oil recovery
- Data and analyses of EOR data that directly present or can be used to determine binary search criteria

The literature search covered the following sources:

API - includes: "classic petroleum papers from the *API Drilling & Production Practices* and *Secondary Recovery of Oil in the United States*. Coverage (1934-1985)

ARMA -includes: papers from its annual conferences (1956-57, 1959, 1969-70, 1972, 1976-77, 1980-81, 1983-1990, 1992, 1993 (partial), 1996, 1999, 2001, 2004, 2005, 2006, 2008 and 2009)

ASSE - includes: papers from its annual conferences (1999-2007)

ISRM - includes: papers from its annual conferences which includes: SINOROCK (2009), ARMS 5 (2008), The 11th CONGRESS (2007), EUROCK (2005), The 10th CONGRESS (2003), ARMS 2 (2001), The 9th CONGRESS (1999), EUROCK (1996), and The 8th CONGRESS (1995)

NACE - includes: both journal and meeting papers; NACE's annual conference papers are included from 1996-2008

NETL - includes: Access to the National Energy Technology Laboratory database portal that provides access to content from dozens of CDs and DVDs relating to oil and natural gas research that FE's National Energy Technology Laboratory has published over the years. (more than 9,000 files) **NETL citation exportable information is limited*

OTC - includes: “All papers presented at the Offshore Technology Conference from 1969 to present”

PETSOC - includes: “All papers from The Petroleum Society of CIM. This includes meeting and journal papers extending back to 1962.”

SPE - includes: “all papers from SPE's eLibrary are included in OnePetro. This includes meeting and journal papers extending back to 1927. SPE also includes some presentations from Distinguished Lecturers and panel/plenary sessions at their meetings.”

SPEE - includes: “all journal articles from 1968-1971 (13 total)”

SPWLA - includes “both journal and meeting papers. SPWLA's meeting papers are included from 1960 to the present. The SPWLA journal *The Log Analyst* is included from 1964-2000. The SPWLA journal *PetroPhysics* is available beginning in 2000.”

SUT - includes “all the volumes of *Advances In Underwater Technology Ocean Science And Offshore Engineering* as well as numerous other conference proceedings.”

WPC - includes: “all documents presented at past World Petroleum Congresses from 1933-2002. Papers presented at the 2008 World Petroleum Congress are currently available only as complete proceedings”

The following search criteria were applied:

Chemical flooding / Chemical injection

- Alkaline flooding
- Micellar-polymer flooding / surfactant flooding
- Alkali-Polymer
- Alkali-surfactant-polymer (ASP)

Miscible displacement / miscible gas drive / miscible flood

- Carbon dioxide injection / CO_2 injection / cyclic carbon dioxide stimulation
- Inert gas flood / nitrogen flooding
- Hydrocarbon injection / LPG injection
- Solvent
- Vapex

Thermal Recovery

- Steamflood
- In-situ combustion / fire flooding
- CSS / Cyclic Steam Stimulation
- SAGD / Steam assisted gravity drainage

Microbial Injection / Microbial Flooding / Cyclic Microbial Recovery

Binary Screening / EOR Screening / EOR Criteria

The literature search identified 1085 papers. These were screened manually and irrelevant papers were excluded.

The initial searches were restricted to petroleum engineering technical publications. Therefore, the results do not include geological and petrophysical publications (AAPG, CSPG) and/or AOSTRA papers and other perspectives.

The search for information available in the public domain will be continued in Phase 2. Owing to papers and information being continuously supplied into the public domain, this task will likely continue for the duration of the project in some capacity.

Literature Search Result Filtering

After the literature search was been completed, the lists of papers were reviewed to remove unnecessary documents. This required a brief technical analysis to assess the relevancy and applicability of each document. The original 1085 technical papers, articles, and presentations were filtered down to 219 relevant documents pertaining to specific EOR projects in Alberta.

The filter criteria were:

- Location
- At least one EOR method described
- Emphasis on operating projects and pilots rather than laboratory results.

To allow for easy linking to the database, tags and field codes were attached to 80 of the papers, where the title and/or abstract had the data. For the remaining papers, either the location mentioned in the paper was too ambiguous or the information did not appear in the code listings.

Owing to papers and information being continuously supplied into the public domain, this task will likely continue for the duration of the project in some capacity.

7.0 Preliminary Findings

In this section, each of the major EOR processes will be discussed under three sub-headings:

- Alberta Experience
- Observations
- Potential Success Factors

Microbial, foam flooding and other EOR processes are not evaluated since there are too few projects for a valid sample to draw general conclusions and the processes are not established worldwide.

7.1 Solvent Floods

<u>Alberta Experience</u>

Hydrocarbon miscible floods have been very successful in selected reservoirs in Alberta. Table 7 lists the commercial solvents floods in Alberta. In particular, the Pembina Nisku and Rainbow Keg River reefs have been successful. The average incremental recovery factor (IRF) for hydrocarbon miscible floods is 28%, with a range from 2 to 48%, with primary recovery in the 30-40% range. The average IRF for Pembina Nisku reefs is 43%, while for Rainbow Keg River, Simonette, Swan Hills and Virginia Hills it is 21-23%. Zama Keg River floods appear to be unsuccessful with an IRF of only 3%, though the sample consists of only three pools. The initial oil-in-place (OOIP) for the Rainbow and Pembina reefs ranges from

1.1 x 10^6 m^3 for the Rainbow Keg River D pool to 46.8 x 10^6 m^3 for the Rainbow Keg River B pool, indicating that such floods can be successful with relatively small pools.

Table 8 lists the experimental solvent floods. Large D2 and D3 reefs, such as Leduc and Redwater, were tested in the mid-1980's but were not made commercial. Whether this is due to poor performance or low oil prices at the time is not immediately apparent.

Carbon dioxide floods in the Viking formation at Joffre and Chigwell also appear successful, with an average IRF of 19%. Pilot projects have also been carried out in the Pembina Cardium but are not yet commercial. The Cardium formation is relatively tight, and, if the pilots are successful, can greatly expand the range of applicability of CO_2 flooding. The use of horizontal wells would be partly responsible for that.

<u>Observations</u>

The Keg River and Nisku miscible floods are believed to be vertically stable floods that were implemented early in the life of the pools. Many of the potential pools for miscible flooding either have limited relief or have been extensively depleted already, or both. This may explain why they are not commercial (though the Viking CO_2 floods are also "areal" floods).
A large number of pools satisfied the screening criteria. This should not be accepted at face value since many of the criteria need to be tightened and additional data acquired for the pools. Note that many pools satisfied the criteria for several miscible processes. The preferred solvent must be chosen taking into account reservoir properties, solvent availability and economics.

Carbon dioxide flooding has environmental benefits in sequestering the CO_2. However, in most cases, the volume that can be sequestered in an oil pool is limited. Due to early breakthrough, much of the CO_2 requirement can be met by recycling. This, of course, means that very little of the CO_2 actually escapes into the atmosphere (contrary to some people's beliefs).

For better screening, the formations and lithology for each pool should be added into the database.

<u>Potential Success Factors</u>

For hydrocarbon miscible floods, a high initial pressure and low oil gravity are key factors. Vertical floods seem to work well. Another factor which may be critical is the permeability (both vertical and horizontal).

Carbon dioxide floods also require a low oil gravity, though the initial pressure is not as great a concern, largely because multiple contact miscibility can be achieved at relatively low pressures.

7.2 Chemical Floods

Alberta Experience

All of the chemical flood projects, whether experimental or commercial, have been implemented in reservoirs in the cretaceous Mannville Group, with the exception of the Edgerton Woodbend A pool which is in the Upper Devonian Woodbend group.

There are currently eight commercial “polymer floods” listed in the Alberta Oil Reserves report. The eight projects are listed in Table 9.

There are also five ASP floods; these are included in Table 9.

As previously noted, the Edgerton polymer flood is an exception. It also has the lowest incremental recovery factor of only 3%. The primary recovery is also low, at 6%.

There is currently only one active experimental polymer flood in the Viking-Kinsella Sparky JJ pool. There are also 8 terminated experimental projects:

- 3 polymer floods
- 2 alkali floods
- 3 alkali/polymer floods
- 1 ASP flood

These are listed in Table 10.

Assessment of the success of each project requires a detailed review of the literature and the progress reports submitted to the ERCB. Most of the experimental projects were terminated in the early 1990’s, when low oil prices reduced interest in EOR. The two recent pilots are the Countess Upper Mannville H alkali-polymer pilot and the Suffield Upper Mannville UU ASP pilot (both of these operated by EnCana Corporation).

In the oilsands areas, two projects in the Wabiskaw formation in the Wabasca area are using polymer flooding on heavy oil. Most screening criteria put the maximum viscosity for a polymer flood at 200 mPa.s. The Wabasca polymer floods are in reservoirs with much higher oil viscosities, 500 mPa.s and higher. This is the result of merging polymer flooding with horizontal well technology. Research carried out at Sproule suggests that the upper limit for the oil viscosity for a chemical flood may be 10,000 mPa.s, i.e. if the oil can be produced without the addition of heat, it can be polymer flooded.

Observations

The experimental chemical floods appear to have been the victims of low oil prices at the time. The current high oil prices should enable many of the technical successes to be converted into commercial successes.

The Wabasca polymer floods have extended the range of applicability of chemical flooding from medium oils to heavy oils. The Chauvin Sparky E polymer flood extended the applicability of polymer flooding to reservoirs with higher water salinity through the use of a biopolymer. The more detailed look at the experimental projects in Phase 2 should reveal additional learnings and expand the applicability of chemical flooding.

There does not appear to have been any attempt in Alberta at using polymers for vertical conformance improvement. This needs to be confirmed in Phase 2. This may be an area which should be examined in future developments.

For better screening, the oil viscosity, water salinity, formation and lithology for each pool should be added in the database. The oil viscosity is not generally available, but it can be estimated from the oil density and reservoir temperature. The water salinity can be calculated from the water resisitivity and reservoir temperature.

Potential Success Factors

Chemical floods appear to be very successful in providing incremental oil recovery in Cretaceous reservoirs. For the most part, these have high permeability, high porosity, relatively low salinity water and oil in the medium/heavy range.

The only chemical flood in a carbonate reservoir appears to have limited success.

7.3 Thermal Recovery

Alberta Experience

There are only three experimental projects in the conventional oil areas where thermal recovery was tested (Table 11). In two projects (in the Countess and Shekilie fields) in-situ combustion was tested. At Suffield, AEC tested hot-water injection. There are no commercial thermal projects at present.

In the Oilsands areas, there have been numerous projects. Currently licensed commercial projects include:

- Commercial CSS (6)
- Commercial SAGD (25)

- “Commercial” (5)
- Primary (143)
- “Experimental” (13)
- “Enhanced Recovery” (8)

The ERCB Oilsands report does not specify what is classed as “Commercial”, “Experimental” and “Enhanced Recovery”.

In addition, there have been 401 terminated approvals. These include:

- CSS (169)
- SAGD (13)
- Combustion (16)
- Solvent injection/VAPEX (13)
- Electromagnetic (7)
- Single Well SAGD (SWSAGD) (6)
- Jet Leaching
- Steam Drive (14)

A detailed discussion of these is outside the scope of this study. However, some of the projects will have application to heavy and medium oil in the conventional oil areas. These include:

- Extension of polymer flooding to more viscous oil
- CSS in horizontal wells in heavy oil
- SAGD in heavy oil

Observations

Due to the size of Alberta’s oilsands resources, it is only to be expected that thermal recovery would be tested much more extensively in the oilsands areas than in the conventional areas. Note that some of the “oilsands” projects are in areas now designated as “conventional oil and gas”, for example, SAGD in Provost, CSS in Atlee-Buffalo and Chauvin South and ISC at Viking-Kinsella, Suffield, Joarcam and others. Table 12 lists the "oilsands" experimental projects south of Township 52.

SAGD has clearly been very successful in bitumen, but has only recently been applied to heavy oil in Alberta and Saskatchewan.

In-situ combustion is applicable to very many reservoirs. However, it should be borne in mind that it is a very complex process and very difficult to operate. Safety is obviously a major concern with the possibility of oxygen reaching the producing wells. Operating difficulties include high sulphate levels due to the high sulphur content of heavy oils and bitumen, which can lead to high levels of corrosion and scaling.

A variation of in-situ combustion, the "THAI" process (Toe to Heel Air Injection) is currently being tested at several locations, but performance data are not yet available.

For better screening, the oil viscosity, reservoir permeability, formations and lithology for each pool should be added into the database. The reservoir permeability may be estimated from the porosity - this shall be investigated in Phase 2.

Potential Success Factors

Thermal recovery is applicable to many medium and heavy oils. As such, there is competition with primary recovery, waterflood and chemical floods. In general, thermal recovery is costly and so is not the preferred choice for EOR except for bitumen where it is the only option.

Nevertheless, thermal recovery can result in very high recovery factors and may compete on those grounds.

Due to the high capital and operating cost for steam generation, there are significant economies of scale, so the size of the resource is a key factor for success.

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Table 1

BINARY SCREENING PARAMETERS FOR EOR RECOVERY PROCESSES

Property	InSitu Combustion	Steam	SAGD	Vapex	Polymer	Surfactant	Alkaline	Carbon Dioxide	LPG/Enriched Gas	Miscible Nitrogen	High Pressure Lean Gas
Depth (m)	X	X	X	X	X	X	X	X	X	X	X
Net Pay Thickness (m)	X	X	X	X		X		X	X	X	X
Net/Gross Ratio	X	X			X	X	X			X	
Average Permeability (mD)	X	X	X	X	X	X	X		X		X
Pressure (kPa)		X	X						X	X	X
Temperature (C)	X				X	X	X				
Oil Density (kg/m^3)	X	X	X	X	X	X	X	X	X	X	X
Oil Viscosity (mPa-s)	X	X	X	X	X	X	X	X	X	X	X
Salinity of Formation Water (ppm)					X	X	X				
Divalent Ion Content (ppm)							X				
Remaining Oil Saturation (% PV)	X	X	X	X	X	X	X	X	X	X	X
Mobile Oil Saturation (%PV)					X						
Actual Oil Content (m^3/ha-m)	X	X	X	X							
Transmissivity (mD*m/mPa-sec)	X	X	X	X							
Preferred Lithology	X	X	X	X	X	X	X				
Dip Angle (degree)									X	X	X
Intergranular Clay Content (<5% = Low)		X	X		X	X	X				
Presence of Natural Fractures (detected in core)	X	X	X	X	X	X	X	X	X	X	X
Presence of Gas Cap (< 0.1 m = None or Small)	X	X	X	X				X	X		X

X = Reservoir Property Required For Binary Screening

Table 2

BINARY SCREENING PARAMETER RANGES FOR EOR PROCESSES

Property	InSitu Combustion	Steam	SAGD	Vapex	Polymer	Surfactant	Alkaline	Carbon Dioxide	LPG/Enriched Gas	Miscible Nitrogen	High Pressure Lean Gas
Property	**Binary Screening Parameters for Recovery Processes (Low Values)**										
Depth (m)	3	3	3	3	3	3	0	762	610	1829	1524
Net Pay Thickness (m)	3.05	6.10	6.10	6.10	N/A	3.05	NC	0.30	0.30	0.30	0.30
Net/Gross Ratio	0.75	0.75	N/A	N/A	0.75	0.75	0.75	N/A	N/A	0.6	N/A
Average Permeability (mD)	50	200	1000	1000	10	20	20	NC	10	NC	10
Pressure (kPa)	N/A	69	69	N/A	N/A	N/A	N/A	NC	10342	20684	20684
Temperature (C)	38	NC	NC	NC	0	0	-17	NC	NC	NC	NC
Oil Density (kg/m^3)	1000	1014	1014	1014	966	904	934	922	916	850	916
Oil Viscosity (mPa-s)	0.1	20	20	20	10	0.1	1	0.1	0.1	0.1	0.1
Salinity of Formation Water (ppm)	N/A	N/A	N/A	N/A	1	1	1	N/A	N/A	N/A	N/A
Divalent Ion Content (ppm)	N/A	N/A	N/A	N/A	N/A	N/A	1	N/A	N/A	N/A	N/A
Remaining Oil Saturation (% PV)	50	40	40	40	50	30	30	20	30	40	30
Mobile Oil Saturation (%PV)	N/A	N/A	N/A	N/A	10	N/A	N/A	N/A	N/A	N/A	N/A
Actual Oil Content (m^3/ha-m)	644	644	644	644	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transmissivity (mD*m/mPa-sec)	6.1	30.5	15.2	15.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Preferred Lithology	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	N/A	N/A	N/A	N/A
Dip Angle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0	0	0
Intergranular Clay Content (<5% = Low)	N/A	Low	Low	N/A	Low	Low	Low	N/A	N/A	N/A	N/A
Presence of Natural Fractures (detected in core)	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small
Presence of Gas Cap (<0.1m = none or small)	None or Small	None or Small	None or Small	None or Small	N/A	N/A	N/A	None or Small	None or Small	N/A	None or Small
Property	**Binary Screening Parameters for Recovery Processes (High Values)**										
Depth (m)	3505	914	914	914	2743	2438	2743	4877	4877	4877	4877
Net Pay Thickness (m)	1524	1524	1524	1524	N/A	1524	NC	30	30	30	30
Net/Gross Ratio	1	1	N/A	N/A	1	1	1	N/A	N/A	1	N/A
Average Permeability (md)	100000	100000	100000	100000	100000	100000	100000	NC	100000	NC	100000
Pressure (kPa)	N/A	13790	13790	N/A	N/A	N/A	N/A	NC	110316	110316	110316
Temperature (C)	538	NC	NC	NC	93	79	93	NC	NC	NC	NC
Oil Density (kg/m^3)	780	855	855	780	780	780	780	780	780	780	780
Oil Viscosity (mPa-s)	5000	200000	1000000	200000	10000	40	90	10	3	10	3
Salinity of Formation Water (ppm)	N/A	N/A	N/A	N/A	200000	200000	200000	N/A	N/A	N/A	N/A
Divalent Ion Content (ppm)	N/A	N/A	N/A	N/A	N/A	N/A	200	N/A	N/A	N/A	N/A
Remaining Oil Saturation (% PV)	100	100	100	100	100	100	100	100	100	100	100
Mobile Oil Saturation (%PV)	N/A	N/A	N/A	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A
Actual Oil Content (m^3/ha-m)	12885	128855	128855	128855	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transmissivity (mD*m/mPa-sec)	3048.0	30480.0	30480.0	30480.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Preferred Lithology	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	N/A	N/A	N/A	N/A
Dip Angle (degree)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	90	90	90
Intergranular Clay Content (<5% = Low)	N/A	Low	Low	N/A	Low	Low	Low	N/A	N/A	N/A	N/A
Presence of Natural Fractures (detected in core)	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small	None or Small
Presence of Gas Cap (<0.1m = none or small)	None or Small	None or Small	None or Small	None or Small	N/A	N/A	N/A	None or Small	None or Small	N/A	None or Small

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Table 3

RANGES OF RESERVOIR DATA OF COMMERCIAL EOR PROJECTS IN ALBERTA

Units	Property	Enhanced_Type	Min	Max	# Recovery Processes In Reserves Database
ha	Area	ASP FLOOD	139	1057	5
m	Average_Pay	ASP FLOOD	1.9	7.05	5
fraction	Porosity	ASP FLOOD	0.16	0.3	5
fraction	Water_Saturation	ASP FLOOD	0.15	0.31	5
fraction	Shrinkage	ASP FLOOD	0.79	0.97	5
m^3m^3	Initial_Solution_GOR	ASP FLOOD	2	118	5
kg/m^3	Density	ASP FLOOD	855	972	5
°C	Temperature	ASP FLOOD	20	53	5
kPa	Initial_Pressure	ASP FLOOD	5485	13645	5
m MSL	Datum_Depth	ASP FLOOD	-833.4	-52.3	5
m KB	Mean_Formation_Depth	ASP FLOOD	907.7	1782.8	5
ha	Area	GAS FLOOD	57	10841	18
m	Average_Pay	GAS FLOOD	0.83	135.71	18
fraction	Porosity	GAS FLOOD	0.042	0.23	18
fraction	Water_Saturation	GAS FLOOD	0.11	0.42	18
fraction	Shrinkage	GAS FLOOD	0.51	0.89	18
m^3m^3	Initial_Solution_GOR	GAS FLOOD	45	295	18
kg/m^3	Density	GAS FLOOD	765	898	18
°C	Temperature	GAS FLOOD	32	101	18
kPa	Initial_Pressure	GAS FLOOD	3588	26629	18
m MSL	Datum_Depth	GAS FLOOD	-1861.3	-72.6	18
m KB	Mean_Formation_Depth	GAS FLOOD	1022.2	2677.6	18
ha	Area	POLYMER FLOOD	99	1252	7
m	Average_Pay	POLYMER FLOOD	2.92	8.54	7
fraction	Porosity	POLYMER FLOOD	0.21	0.3	7
fraction	Water_Saturation	POLYMER FLOOD	0.18	0.32	7
fraction	Shrinkage	POLYMER FLOOD	0.89	0.98	7
m^3m^3	Initial_Solution_GOR	POLYMER FLOOD	10	50	7
kg/m^3	Density	POLYMER FLOOD	898	951	7
°C	Temperature	POLYMER FLOOD	21	32	7
kPa	Initial_Pressure	POLYMER FLOOD	3672	10703	7
m MSL	Datum_Depth	POLYMER FLOOD	-299.3	-0.5	7
m KB	Mean_Formation_Depth	POLYMER FLOOD	569.7	1062.5	7

Sproule

Table 3 (continued)

RANGES OF RESERVOIR DATA OF COMMERCIAL EOR PROJECTS IN ALBERTA

Units	Property	Enhanced_Type	Min	Max	# Recovery Processes In Reserves Database
ha	Area	SOLVENT FLOOD	17	17500	61
m	Average_Pay	SOLVENT FLOOD	1.96	90.35	61
fraction	Porosity	SOLVENT FLOOD	0.06	0.15	61
fraction	Water_Saturation	SOLVENT FLOOD	0.07	0.39	61
fraction	Shrinkage	SOLVENT FLOOD	0.38	0.91	61
m^3m^3	Initial_Solution_GOR	SOLVENT FLOOD	34	552	61
kg/m^3	Density	SOLVENT FLOOD	798	898	61
°C	Temperature	SOLVENT FLOOD	35	108	61
kPa	Initial_Pressure	SOLVENT FLOOD	6616	46019	61
m MSL	Datum_Depth	SOLVENT FLOOD	-2657.8	-556.7	61
m KB	Mean_Formation_Depth	SOLVENT FLOOD	1320.6	3542	61
ha	Area	WATER FLOOD	3	140992	812
m	Average_Pay	WATER FLOOD	0.79	109.56	812
fraction	Porosity	WATER FLOOD	0.01	0.32	812
fraction	Water_Saturation	WATER FLOOD	0.07	0.61	812
fraction	Shrinkage	WATER FLOOD	0.26	0.99	812
m^3m^3	Initial_Solution_GOR	WATER FLOOD	2	672	812
kg/m^3	Density	WATER FLOOD	775	995	812
°C	Temperature	WATER FLOOD	11	112	812
kPa	Initial_Pressure	WATER FLOOD	1283	40808	812
m MSL	Datum_Depth	WATER FLOOD	-2941.6	408.1	812
m KB	Mean_Formation_Depth	WATER FLOOD	221.8	3890.6	812

Table 4

RESERVOIR DATA IN ERCB RESERVES REPORT
VS
BINARY SCREENING PARAMETERS

Property	InSitu Combustion	Steam	SAGD	Vapex	Polymer	Surfactant	Alkaline	Carbon Dioxide	LPG/Enriched Gas	Miscible Nitrogen	High Pressure Lean Gas
Depth (m)	X	X	X	X	X	X	X	X	X	X	X
Net Pay Thickness (m)	X	X	X	X		X		X	X	X	X
Net/Gross Ratio	X	X			X	X	X			X	
Average Permeability (mD)	X	X	X	X	X	X	X		X		X
Pressure (kPa)		X	X						X	X	X
Temperature (C)	X				X	X	X				
Oil Density (kg/m^3)	X	X	X	X	X	X	X	X	X	X	X
Oil Viscosity (mPa-s)	X	X	X	X	X	X	X	X	X	X	X
Salinity of Formation Water (ppm)					X	X	X				
Divalent Ion Content (ppm)							X				
Remaining Oil Saturation (% PV)	X	X	X	X	X	X	X	X	X	X	X
Mobile Oil Saturation (%PV)					X						
Actual Oil Content (m^3/ha-m)	X	X	X	X							
Transmissivity (mD*m/mPa-sec)	X	X	X	X							
Preferred Lithology	X	X	X	X	X	X	X				
Dip Angle (degree)									X	X	X
Intergranular Clay Content (<5% = Low)		X	X		X	X	X				
Presence of Natural Fractures (detected in core)	X	X	X	X	X	X	X	X	X	X	X
Presence of Gas Cap (<0.1m = none or small)	X	X	X	X				X	X		X

Data Available In ERCB Reserves Report

Table 5

RANGES OF BINARY SCREENING CRITERIA FOR AVAILABLE RESERVOIR DATA

Property	InSitu Combustion		Steam		SAGD		Vapex	
Criteria Range - Low High	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Depth (m)	3.0	3505.2	3.0	914.4	3.0	914.4	3.0	914.4
Net Pay Thickness (m)	3.0	1524.0	6.1	1524.0	6.1	1524.0	6.1	1524.0
Net/Gross Ratio								
Average Permeability (mD)								
Pressure (kPa)	N/A	N/A	69	13790	69	13790	N/A	N/A
Temperature (C)	38	538	NC	NC	NC	NC	NC	NC
Oil Density (kg/m^3)	1000	780	1014	855	1014	855	1014	780
Oil Viscosity (mPa-s)								
Salinity of Formation Water (ppm)								
Divalent Ion Content (ppm)								
Remaining Oil Saturation (% PV)								
Mobile Oil Saturation (%PV)								
Actual Oil Content (m^3/ha-m)								
Transmissivity (mD*m/mPa-sec)								
Preferred Lithology								
Dip Angle (Degrees)								
Intergranular Clay Content (<5% = Low)								
Presence of Natural Fractures (detected in core)								
Presence of Gas Cap (<0.1m = none or small)								

Property	Polymer		Surfactant		Alkaline		Carbon Dioxide	
Criteria Range - Low High	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
Depth (m)	3.0	2743.2	3.0	2438.4	0.3	2743.2	762.0	4876.8
Net Pay Thickness (m)	N/A	N/A	3.0	1524.0	NC	NC	0.3	30.5
Net/Gross Ratio								
Average Permeability (mD)								
Pressure (kPa)	N/A	N/A	N/A	N/A	N/A	N/A	NC	NC
Temperature (C)	0	93	0	79	-17	93	NC	NC
Oil Density (kg/m^3)	966	780	904	780	934	780	922	780
Oil Viscosity (mPa-s)								
Salinity of Formation Water (ppm)								
Divalent Ion Content (ppm)								
Remaining Oil Saturation (% PV)								
Mobile Oil Saturation (%PV)								
Actual Oil Content (m^3/ha-m)								
Transmissivity (mD*m/mPa-sec)								
Preferred Lithology								
Dip Angle (Degrees)								
Intergranular Clay Content (<5% = Low)								
Presence of Natural Fractures (detected in core)								
Presence of Gas Cap (<0.1m = none or small)								

Sproule

Table 5 (continued)

RANGES OF BINARY SCREENING CRITERIA FOR AVAILABLE RESERVOIR DATA

Property	LPG/Enriched Gas		Miscible Nitrogen		High Pressure Lean Gas	
Criteria Range - Low High	**Low**	**High**	**Low**	**High**	**Low**	**High**
Depth (m)	609.6	4876.8	1828.8	4876.8	1524.0	4876.8
Net Pay Thickness (m)	0.3	30.5	0.3	30.5	0.3	30.5
Net/Gross Ratio						
Average Permeability (mD)						
Pressure (kPa)	10342	110316	20684	110316	20684	110316
Temperature (C)	NC	NC	NC	NC	NC	NC
Oil Density (kg/m^3)	916	780	850	780	916	780
Oil Viscosity (mPa-s)						
Salinity of Formation Water (ppm)						
Divalent Ion Content (ppm)						
Remaining Oil Saturation (% PV)						
Mobile Oil Saturation (%PV)						
Actual Oil Content (m^3/ha-m)						
Transmissivity (md*m/mPa-sec)						
Preferred Lithology						
Dip Angle (Degrees)						
Intergranular Clay Content (<5% = Low)						
Presence of Natural Fractures (detected in core)						
Presence of Gas Cap (<0.1m = none or small)						

Table 6

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
Alkaline	Average Pay	No			
	Mean Formation Depth	Yes	11,794		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	Yes	11,899		# Meeting the Temperature Criteria
	Density	Yes	9,592		# Meeting the Density Criteria
	Criteria Available		3		# Criteria Available
	Total		9,244		# Meeting the Mean Formation Depth, Temperature and Density Criteria
	Total without Heavy		8,177		# Light to Medium Oil Meeting the Mean Formation Depth, Temperature and Density Criteria
	Oil In Place (OOIP)			1,931,493	Total Light/Medium/Heavy
	Initial Established Reserves Primary			267,487	Total Light/Medium/Heavy
	Remaining Established Reserves			39,096	Total Light/Medium/Heavy
Carbon Dioxide	Average Pay	Yes	10,689		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	11,154		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	No			
	Density	Yes	9,364		# Meeting the Density Criteria
	Criteria Available		3		# Criteria Available
	Total		8,039		# Meeting the Average Pay, Mean Formation Depth and the Density Criteria
	Total without Heavy		7,281		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth and the Density Criteria
	Oil In Place (OOIP)			1,785,891	Total Light/Medium/Heavy
	Initial Established Reserves Primary			252,136	Total Light/Medium/Heavy
	Remaining Established Reserves			37,200	Total Light/Medium/Heavy

Sproule

Table 6 (continued)

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
High Pressure Lean Gas	Average Pay	Yes	**10,689**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**5,149**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	Yes	**788**		# Meeting the Initial Pressure Criteria
	Temperature	No			
	Density	Yes	**9,170**		# Meeting the Density Criteria
	Criteria Available		**4**		# Criteria Available
	Total		**610**		# Meeting the Average Pay, Mean Formation Depth, Initial Pressure and the Density Criteria
	Total without Heavy		**607**		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth, Initial Pressure and the Density Criteria
	Oil In Place (OOIP)			**131,390**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**16,540**	Total Light/Medium/Heavy
	Remaining Established Reserves			**2,203**	Total Light/Medium/Heavy
LPG Enriched Gas	Average Pay	Yes	**10,689**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**11,607**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	Yes	**6,108**		# Meeting the Initial Pressure Criteria
	Temperature	No			
	Density	Yes	**9,170**		# Meeting the Density Criteria
	Criteria Available		**4**		# Criteria Available
	Total		**4,408**		# Meeting the Average Pay, Mean Formation Depth, Initial Pressure Criteria and Density Criteria
	Total without Heavy		**4,277**		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth, Initial Pressure Criteria and Density Criteria
	Oil In Place (OOIP)			**971,980**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**136,352**	Total Light/Medium/Heavy
	Remaining Established Reserves			**17,914**	Total Light/Medium/Heavy

Sproule

Table 6 (continued)

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
Miscible Nitrogen	Average Pay	Yes	**10,689**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**2,975**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	Yes	**788**		# Meeting the Initial Pressure Criteria
	Temperature	No			
	Density	Yes	**5,213**		# Meeting the Density Criteria
	Criteria Available		**4**		# Criteria Available
	Total		**541**		# Meeting the Average Pay, Mean Formation Depth, Initial Pressure Criteria and Density Criteria
	Total without Heavy		**541**		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth, Initial Pressure Criteria and Density Criteria
	Oil In Place (OOIP)			**102,593**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**13,792**	Total Light/Medium/Heavy
	Remaining Established Reserves			**1,982**	Total Light/Medium/Heavy
Polymer	Average Pay	No			
	Mean Formation Depth	Yes	**11,794**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	Yes	**11,835**		# Meeting the Temperature Criteria
	Density	Yes	**10,287**		# Meeting the Density Criteria
	Criteria Available		**3**		# Criteria Available
	Total		**9,937**		# Meeting the Mean Formation Depth, Temperature and Density Criteria
	Total without Heavy		**8,177**		# Light to Medium Oil Meeting the Mean Formation Depth, Temperature and Density Criteria
	Oil In Place (OOIP)			**2,172,421**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**294,108**	Total Light/Medium/Heavy
	Remaining Established Reserves			**43,677**	Total Light/Medium/Heavy

Sproule

Table 6 (continued)

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
Surfactant	Average Pay	Yes	6,799		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	11,396		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	Yes	10,883		# Meeting the Temperature Criteria
	Density	Yes	8,706		# Meeting the Density Criteria
	Criteria Available		4		# Criteria Available
	Total		4,077		# Meeting the Average Pay, Mean Formation Depth, Temperature and Density Criteria Criteria
	Total without Heavy		3,979		# Light to Medium Oil Meeting both the Average Pay, Mean Formation Depth and TemperatureCriteria
	Oil In Place (OOIP)			1,165,730	Total Light/Medium/Heavy
	Initial Established Reserves Primary			155,002	Total Light/Medium/Heavy
	Remaining Established Reserves			23,261	Total Light/Medium/Heavy
Steam	Average Pay	Yes	3,296		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	1,620		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	Yes	7,742		# Meeting the Initial Pressure Criteria
	Temperature	No			
	Density	Yes	5,210		# Meeting the Density Criteria
	Criteria Available		4		# Criteria Available
	Total		145		# Meeting the Average Pay, Mean Formation Depth and Density Criteria
	Total without Heavy		18		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth and Density Criteria
	Oil In Place (OOIP)			285,517	Total Light/Medium/Heavy
	Initial Established Reserves Primary			25,424	Total Light/Medium/Heavy
	Remaining Established Reserves			3,499	Total Light/Medium/Heavy

Sproule

Table 6 (continued)

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
Vapex	Average Pay	Yes	**3,296**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**1,620**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	No			
	Density	Yes	**10,832**		# Meeting the Density Criteria
	Criteria Available		**3**		# Criteria Available
	Total		**170**		# Meeting the Average Pay,Mean Formation Depth and Density Criteria
	Total without Heavy		**32**		# Light to Medium Oil Meeting the Average Pay,Mean Formation Depth and Density Criteria
	Oil In Place (OOIP)			**295,928**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**26,241**	Total Light/Medium/Heavy
	Remaining Established Reserves			**3,946**	Total Light/Medium/Heavy
SAGD	Average Pay	Yes	**3,296**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**1,620**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	Yes	**7,742**		# Meeting the Initial Pressure Criteria
	Temperature	No			
	Density	Yes	**5,210**		# Meeting the Density Criteria
	Criteria Available		**4**		# Criteria Available
	Total		**145**		# Meeting the Average Pay, Mean Formation Depth, Initial Pressure and Density Criteria
	Total without Heavy		**18**		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth, Initial Pressure and Density Criteria
	Oil In Place (OOIP)			**285,517**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**25,424**	Total Light/Medium/Heavy
	Remaining Established Reserves			**3,499**	Total Light/Medium/Heavy

Table 6 (continued)

BINARY SCREENING OF OIL POOLS - RESULTS WITH CURRENT CRITERIA

Scheme	Properties	Applicable	Final Count	10^3m^3	Description
InSitu Combustion	Average Pay	Yes	**6,799**		# Meeting the Average Pay Criteria
	Mean Formation Depth	Yes	**11,989**		# Meeting the Mean Formation Depth Criteria
	Initial Pressure	No			
	Temperature	Yes	**8,237**		# Meeting the Temperature Criteria
	Density	Yes	**10,832**		# Meeting the Density Criteria
	Criteria Available		**4**		# Criteria Available
	Total		**4,210**		# Meeting the Average Pay, Mean Formation Depth, Temperature and Density Criteria
	Total without Heavy		**3,971**		# Light to Medium Oil Meeting the Average Pay, Mean Formation Depth, Temperature and Density Criteria
	Oil In Place (OOIP)			**1,144,159**	Total Light/Medium/Heavy
	Initial Established Reserves Primary			**135,909**	Total Light/Medium/Heavy
	Remaining Established Reserves			**20,725**	Total Light/Medium/Heavy

*** Based on 12108 potential field and pool combinations left with no EOR schemes currently running**

*** Numbers are contained in the Original-Binary-Comparison.xls spreadsheet**

Table 7

SOLVENT FLOODS IN ALBERTA

Field Code	Field Name	Pool Code	Pool Name	Producing Formation	Recovery Factor Primary	Recovery Factor Enhanced	Type
AB0009	ACHESON	AB00090720001	LEDUC A	LEDUC	54.0%	31.0%	Solvent Flood
AB0126	BIGORAY	AB01260696002	NISKU B	NISKU	31.0%	35.8%	Solvent Flood
AB0126	BIGORAY	AB01260696006	NISKU F	NISKU	40.0%	47.5%	Solvent Flood
AB0168	BRAZEAU RIVER	AB01680696001	NISKU A	NISKU	40.5%	41.5%	Solvent Flood
AB0168	BRAZEAU RIVER	AB01680696004	NISKU D	NISKU	50.0%	15.0%	Solvent Flood
AB0168	BRAZEAU RIVER	AB01680696005	NISKU E	NISKU	45.0%	40.0%	Solvent Flood
AB0194	CAROLINE	AB01940176005	CARDIUM E	CARDIUM SAND	9.0%	21.0%	Solvent Flood
AB0214	CHIGWELL	AB02140218009	VIKING I	VIKING	8.0%	12.0%	Solvent Flood
AB0336	ENCHANT	AB03360800560	CMG POOL 005 - ARCS F,G	NISKU	22.0%	17.0%	Solvent Flood
AB0336	ENCHANT	AB03360801760	CMG POOL 017 - ARCS A,B	NISKU	25.0%	23.0%	Solvent Flood
AB0425	GOOSE RIVER	AB04250744001	BEAVERHILL LAKE A	BEAVERHILL LAKE	16.0%	30.0%	Solvent Flood
AB0505	JOFFRE	AB05050720002	LEDUC B	LEDUC	33.0%	24.0%	Solvent Flood
AB0505	JOFFRE	AB05050218000	VIKING	VIKING	16.0%	44.0%	Solvent Flood
AB0509	JUDY CREEK	AB05090744001	BEAVERHILL LAKE A	BEAVERHILL LAKE	16.0%	34.0%	Solvent Flood
AB0509	JUDY CREEK	AB05090744002	BEAVERHILL LAKE B	BEAVERHILL LAKE	20.0%	29.0%	Solvent Flood
AB0513	KAYBOB	AB05130744001	BEAVERHILL LAKE A	BEAVERHILL LAKE	16.0%	30.5%	Solvent Flood
AB0514	KAYBOB SOUTH	AB05140500001	TRIASSIC A	MONTNEY	15.0%	30.0%	Solvent Flood
AB0615	MITSUE	AB06150765501	GILWOOD A	GILWOOD	25.0%	37.0%	Solvent Flood
AB0644	NIPISI	AB06440765501	GILWOOD A	GILWOOD	26.0%	28.4%	Solvent Flood
AB0685	PEMBINA	AB06850696001	NISKU A	NISKU	40.5%	42.0%	Solvent Flood
AB0685	PEMBINA	AB06850696004	NISKU D	NISKU	35.0%	35.0%	Solvent Flood
AB0685	PEMBINA	AB06850696006	NISKU F	NISKU	35.0%	45.0%	Solvent Flood
AB0685	PEMBINA	AB06850696833	NISKU G2G	NISKU	35.0%	28.0%	Solvent Flood
AB0685	PEMBINA	AB06850696007	NISKU G	NISKU	40.8%	50.0%	Solvent Flood
AB0685	PEMBINA	AB06850696834	NISKU H2H	NISKU	40.0%	47.0%	Solvent Flood
AB0685	PEMBINA	AB06850696011	NISKU K	NISKU	40.0%	48.0%	Solvent Flood
AB0685	PEMBINA	AB06850696012	NISKU L	NISKU	25.0%	63.0%	Solvent Flood
AB0685	PEMBINA	AB06850696013	NISKU M	NISKU	40.0%	45.0%	Solvent Flood
AB0685	PEMBINA	AB06850696015	NISKU O	NISKU	40.0%	40.0%	Solvent Flood
AB0685	PEMBINA	AB06850696842	NISKU P2P	NISKU	40.0%	45.0%	Solvent Flood
AB0685	PEMBINA	AB06850696016	NISKU P	NISKU	35.0%	45.0%	Solvent Flood
AB0685	PEMBINA	AB06850696017	NISKU Q	NISKU	40.0%	29.0%	Solvent Flood
AB0753	RAINBOW	AB07530772101	KEG RIVER A	RAINBOW MEMBER	50.0%	25.0%	Solvent Flood
AB0753	RAINBOW	AB07530772102	KEG RIVER B	KEG RIVER UPPER	40.0%	23.0%	Solvent Flood
AB0753	RAINBOW	AB07530772104	KEG RIVER D	KEG RIVER	40.0%	28.0%	Solvent Flood
AB0753	RAINBOW	AB07530772105	KEG RIVER E	KEG RIVER	29.1%	20.0%	Solvent Flood
AB0753	RAINBOW	AB07530772205	KEG RIVER EEE	KEG RIVER	39.9%	9.8%	Solvent Flood
AB0753	RAINBOW	AB07530772106	KEG RIVER F	KEG RIVER	38.0%	15.0%	Solvent Flood
AB0753	RAINBOW	AB07530772132	KEG RIVER FF	KEG RIVER	21.0%	15.0%	Solvent Flood

Table 7 (continued)

SOLVENT FLOODS IN ALBERTA

Field Code	Field Name	Pool Code	Pool Name	Producing Formation	Recovery Factor Primary	Recovery Factor Enhanced	Type
AB0753	RAINBOW	AB07530772107	KEG RIVER G	KEG RIVER	43.4%	41.8%	Solvent Flood
AB0753	RAINBOW	AB07530772108	KEG RIVER H	KEG RIVER	39.2%	20.0%	Solvent Flood
AB0753	RAINBOW	AB07530772135	KEG RIVER II	KEG RIVER	45.0%	15.5%	Solvent Flood
AB0753	RAINBOW	AB07530772115	KEG RIVER O	KEG RIVER	40.0%	27.7%	Solvent Flood
AB0753	RAINBOW	AB07530772126	KEG RIVER Z	KEG RIVER	32.0%	33.0%	Solvent Flood
AB0753	RAINBOW	AB07530772127	KEG RIVER AA	KEG RIVER	45.0%	22.3%	Solvent Flood
AB0754	RAINBOW SOUTH	AB07540772102	KEG RIVER B	KEG RIVER	44.0%	21.0%	Solvent Flood
AB0754	RAINBOW SOUTH	AB07540772105	KEG RIVER E	KEG RIVER UPPER	26.0%	10.0%	Solvent Flood
AB0754	RAINBOW SOUTH	AB07540772107	KEG RIVER G	KEG RIVER	20.0%	12.0%	Solvent Flood
AB0844	SIMONETTE	AB08440720000	LEDUC	LEDUC	40.0%	6.0%	Solvent Flood
AB0887	SWAN HILLS	AB08870800160	CMG POOL 001 - BEAVERHILL LAKE A,B	SWAN HILLS	17.0%	36.0%	Solvent Flood
AB0889	SWAN HILLS SOUTH	AB08890800160	CMG POOL 001 - BEAVERHILL LAKE A,B	SWAN HILLS	17.0%	28.0%	Solvent Flood
AB0925	VIRGINIA HILLS	AB09250744000	BEAVERHILL LAKE	SWAN HILLS	23.0%	22.0%	Solvent Flood
AB0942	WESTPEM	AB09420696004	NISKU D	NISKU	40.0%	40.0%	Solvent Flood
AB0985	WIZARD LAKE	AB09850720001	LEDUC A	LEDUC	66.0%	19.0%	Solvent Flood
AB0997	ZAMA	AB09970772106	KEG RIVER F	KEG RIVER	33.1%	5.0%	Solvent Flood
AB0997	ZAMA	AB09970772233	KEG RIVER G2G	KEG RIVER	22.5%	4.0%	Solvent Flood
AB0997	ZAMA	AB09970772214	KEG RIVER NNN	KEG RIVER	30.0%	5.0%	Solvent Flood
AB0997	ZAMA	AB09970772218	KEG RIVER RRR	KEG RIVER	25.0%	5.0%	Solvent Flood
AB0997	ZAMA	AB09970768512	MUSKEG L	MUSKEG	20.0%	5.0%	Solvent Flood

Table 8

EXPERIMENTAL SOLVENT FLOODS IN ALBERTA

APPROVAL_NO	OPERATOR	FIELD	POOL	RECOVERY METHOD	Start Year	End Year
5229	Gulf	Fenn - Big Valley	Nisku A	Nitrogen Injection[1]	1987	1989
4674A/B	Esso	Leduc-Woodbend		Solvent/Chase Gas/Water Inject	1985	1988
6098	Petro-Canada	Provost	Cummings I	Gas Injection	1989	1991
4309E	Esso	Redwater	Leduc A	Solvent/Chase Gas/Water Inject	1984	1991
7809	Gulf	Rich	Leduc A	Sour Gas Injection	1995	1996
5023	AEC	Suffield	Upper Mannville N	Cyclic Injection	1986	1988
9540B	EnCana	Suffield	Upper Mannville N	Solvent Injection	2003	2005
TVU 4	Talisman	Turner Valley	Rundle	Nitrogen Injection	2001	2005
7939	Pennzoil	Zama		Sour Gas Injection	1996	1998

Table 9

CHEMICAL FLOODS IN ALBERTA

Field Code	Field Name	Pool Code	Pool Name	Producing Formation	Recovery Factor Primary	Recovery Factor Enhanced	Type
AB0339	ENTICE	AB03390310002	LOWER MANNVILLE B	ELLERSLIE	10.0%	25.0%	ASP Flood
AB0902	MOONEY	AB09020304001	BLUESKY A	BLUESKY	7.0%	12.0%	ASP Flood
AB0877	SUFFIELD	AB08770250047	UPPER MANNVILLE UU	GLAUCONITIC	10.0%	25.0%	ASP Flood
AB0893	TABER	AB08930300011	GLAUCONITE K	GLAUCONITIC	18.0%	38.0%	ASP Flood
AB0895	TABER SOUTH	AB08950248002	MANNVILLE B	MANNVILLE GRP	10.0%	42.0%	ASP Flood
AB0259	COUNTESS	AB02590250008	UPPER MANNVILLE H	GLAUCONITIC	10.5%	36.0%	Polymer Flood
AB0318	EDGERTON	AB03180294018	WOODBEND A	WOODBEND	6.0%	3.0%	Polymer Flood
AB0750	PROVOST	AB07500250001	UPPER MANNVILLE A	MANNVILLE UPPER	3.0%	12.0%	Polymer Flood
AB0877	SUFFIELD	AB08770250021	UPPER MANNVILLE U	MANNVILLE UPPER	15.0%	20.0%	Polymer Flood
AB0923	VIKING-KINSELLA	AB09230278002	WAINWRIGHT B	WAINWRIGHT	14.0%	35.0%	Polymer Flood
AB0963	WILDMERE	AB09630800360	CMG POOL 003 - SPARKY E,LLOYDMINSTER A	LLOYDMINSTER SS/SPARKY	11.0%	12.0%	Polymer Flood
AB0992	WRENTHAM	AB09920310002	LOWER MANNVILLE B	SUNBURST SS	15.0%	30.0%	Polymer Flood
AB0992	WRENTHAM	AB09920310003	LOWER MANNVILLE C	MANNVILLE LOWER	15.0%	30.0%	Polymer Flood

Table 10

EXPERIMENTAL CHEMICAL FLOODS IN ALBERTA

APPROVAL_NO	OPERATOR	FIELD	POOL	RECOVERY METHOD	Start Year	End Year
3884	Dome	Viking-Kinsella	Wainwright B	Alkaline Flood[2]	1983	
4357A/3692A	Amoco	Cessford	Mannville C	Alkaline Flood[2]	1982	1992
4065	PanCanadian	Horsefly Lake		Water/Polymer/Alkaline Flood[2]	1984	1987
10640	EnCana	Countess	Upper Mannville H	Water, Alkaline, and Polymer Injection[2]	2006	2008
5353F/4263	Amoco	Provost	Lloydminster	Polymer/Alkaline Flood[2]	1984	1992
10626B	EnCana	Upper Mannville UU	Upper Mannville UU	Water, Alkaline, Polymer, and Surfactant	2006	2008
5379	BP	Chauvin South	Sparky E	Polymer Flood[2]	1987	1993
6097	Petro-Canada	Provost	Cummings I	Polymerized Water[2]	1989	1991
5078C	Chevron	Taber		Water/Polymer[2]	1986	1993

Table 11

EXPERIMENTAL THERMAL RECOVERY PROJECTS IN ALBERTA (NON OILSANDS DESIGNATION)

APPROVAL NO	OPERATOR	FIELD	LOCATION	RECOVERY METHOD	ACTIVE PERIOD
6373 (5789)	AEC	Suffield	3-20-8 W4M	Hot-water Injection	1988-1991
3537E	PanCanadian	Countess	9-19-16 W4M	Combustion	1982-1995
7156	Petro Canada	Shekilie	5-5-118-08 W6M	Combustion	1993-1996

Table 12

OILSANDS EXPERIMENTAL PROJECTS IN "CONVENTIONAL OIL" AREAS OF ALBERTA

APPROVAL NO.	OPERATOR	FIELD	LOCATION	RECOVERY METHOD	ACTIVE PERIOD
4632C	CNRL	Lindbergh	13-55-6-W4M	Central Processing Facility	1985-2003
3105D	Amoco	Morgan	35-51-4 W4M	CTD/Steam Stimulation	1980-1992
788	Husky	Lloydminster	20/28/29-50-1 W4M	Steam Flood	1965-1970
805	Forgotson & Burk	Wizard Lake	11,13 & 14-48-28 W4M	Injection Program Various Fluids	1965-1966
840	Husky	Wainwright	20 & 21 46-6 W4M	Steam Stimulation	1965-1966
845	Husky	Lloydminster	14A-35-49-2 W4M	Steam Stimulation	1966-1967
847	Kodiak Petroleums Ltd.	Lloydminster	11/14-50-2 W4M	Steam Stimulation	1966-1967
1316	Canadian Hidrogas	Lloydminster	12-50-2 W4M	Combustion	1970-1975
2145	Tesoro	Provost	19-37-1 W4M	Steam Stimulation	1975-1976
2707	Tesoro	Provost	32-36-1 W4M	Steam Stimulation	1978-1979
3086	AEC	Suffield	10-20-08 W4M	Fireflood Combustion	1980-1985
3341	Dome	Chauvin South	26-42-3 W4M	Steam Stimulation	1981-1982
3342	Dome	Hayter	26-40-1 W4M	Steam Stimulation	1981-1982
3374	Esso	Joarcam	6/7-48-20 W4M	Combustion	1979-1984
3402	Hudson's Bay	Lloydminster	23-49-1 W4M	Steam Stimulation	1981-1982
3417	Dome	Rivercourse	36-47-1 W4M	Steam Stimulation	1981-1984
3424	Husky	Lloydminster	13-50-3 W4M	Steam Stimulation	1982
3635	Koch	Wildmere	23-47-5 W4M	Combination Thermal Drive	1982-1987
3646	Husky	Wainwright	32-45-6 W4M	Steam Stimulation	1982-1984
3720	Dome	Atlee-Buffalo	18-21-5 W4M	Combination Thermal Drive	1982-1987
3991	Koch	Wildmere	13/14-47-5 W4M	Steam Stimulation	1983-1984
4561	Dome	Morgan	35-51-4 W4M	Steam Stimulation	1985-1986
4567	Canadian Occidental	Morgan	34-51-4 W4M	Combustion	1985-1990
4780	AEC	Suffield	10-20-8 W4M	Combustion	1980-1990
4943	Can. N.W. Energy	Wildmere	4-30-48-4 W4M	Electrical Stimulation	1986-1990
5802	PanCanadian	Medicine Hat	35-12-5 W4M	Steam Stimulation	1988-1991
7173	Koch	Wildmere	9-23-47-5 W4M	Electromagnetic Stimulation	1993-1994
7516	Probe Exploration	Lloydminster	2-51-2 W4M	Steam Assisted Gravity Drainage	1994-1997
7810	ELAN	Provost	33-36-1W4M	Steam Assisted Gravity Drainage	1995-1998
7919	Norcen	Provost	20-37-1W4M	Single Well Steam Assisted Gravity Drainage	1996-1999
8040	ELAN	Fort Kent	13&14-62-4W4M	Single Well Steam Assisted Gravity Drainage	1996-1999
8059	PanCanadian	Provost	4-21-38-1 W4M	Water & Gas Injection	1996-1997
2531B	Husky	Lloydminster	30-50-1 W4M	Steam Stimulation	1977-1981
2768D	Petro-Canada	Viking-Kinsella	30-48-8 W4M	Fireflood	1978-1985
3002A	Dome	Morgan	35-51-4 W4M	Steam Injection	1980

Table 12 (continued)

OILSANDS EXPERIMENTAL PROJECTS IN "CONVENTIONAL OIL" AREAS OF ALBERTA

APPROVAL NO.	OPERATOR	FIELD	LOCATION	RECOVERY METHOD	ACTIVE PERIOD
3250G	Home	Lloydminster	2-51-2 W4M	Steam Stimulation/Flood	1981-1992
3293A	Mobil-GC	Morgan	27-51-4 W4M	Steam Stimulation	1981-1982
3418B (2057,3132)	Norcen	Provost	17-37-1 W4M	Combustion	1981-1987
3638A	Husky	Lloydminster	13-50-3 W4M	Steam Stimulation	1982
3918B	Petro-Canada	Viking-Kinsella	24-48-9 W4M	Combustion	1983-1987
4414C	Norcen	Provost	20-37-1 W4M	Steam Stimulation/Drive	1984-1995
4449A	Mobil	Morgan	36-51-4 W4M	Steam Stimulation	1984-1986
4459 (2144)	Mobil	Lloydminster	18-51-2 W4M	Steam Stimulation	1975-1988
4460B (3229, 2142)	Mobil	Lloydminster	12-49-1 W4M	Combination Thermal Drive	1975-1987
5844B	PanCanadian	Provost	21-38-1 W4M	Steam Stimulation	1988-1991
6010B (5387, 4686,11X, 15X)	Canada Energy N.W.	Atlee-Buffalo	19-21-5 W4M	Steam Stimulation	1985-1992
6968A (3105D)	CNRL	Morgan	35-51-4 W4M	CTD/Steam Stimulation	1980-1995
6975A	PanCanadian	Provost	4-21-38-1 W4M	Horizontal Well/Steam Flood	1992-1995
8006D	AEC	Fisher	21&22-70-4-W4M	Steam Assisted Gravity Drainage	1996-2002

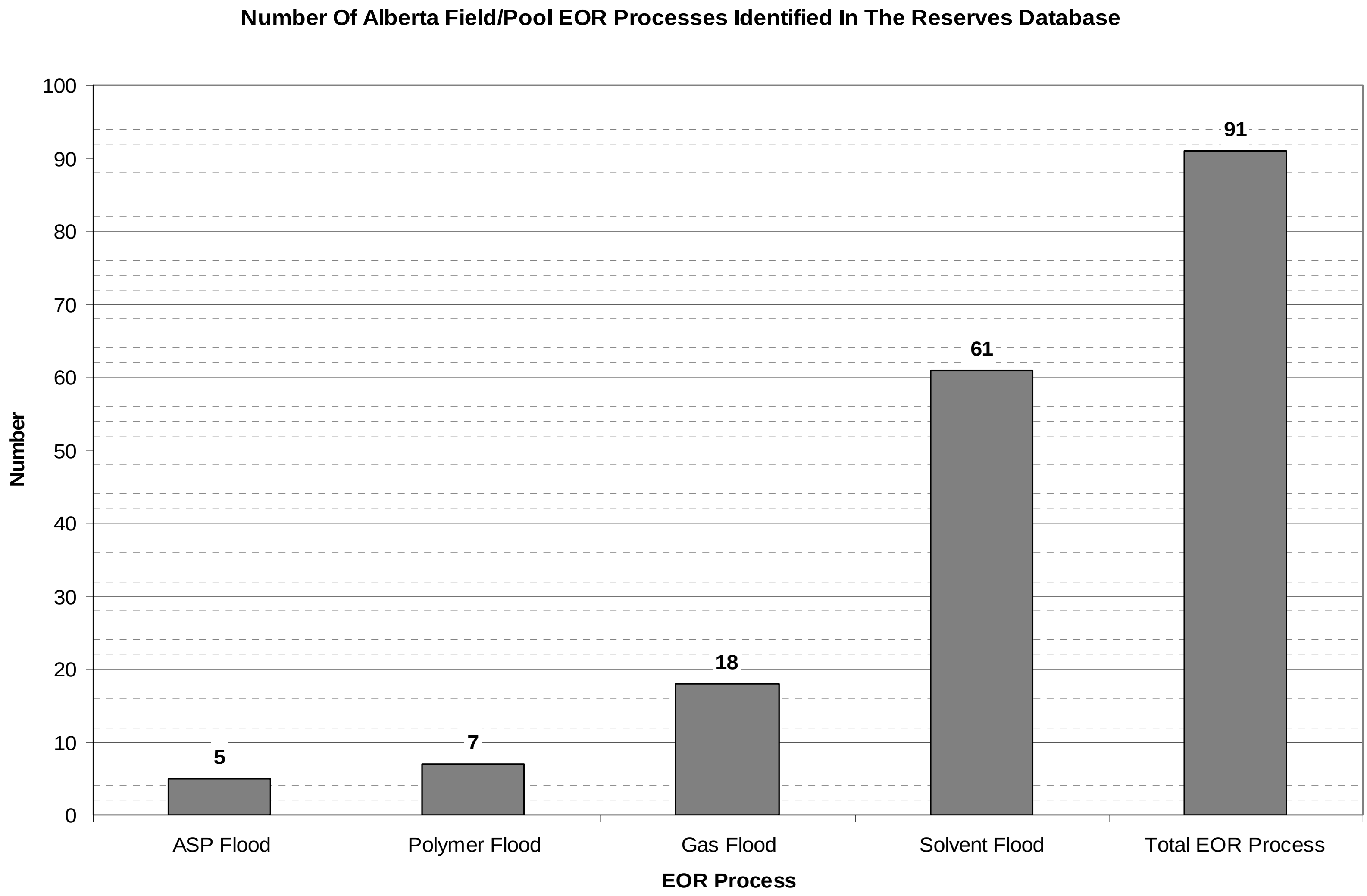
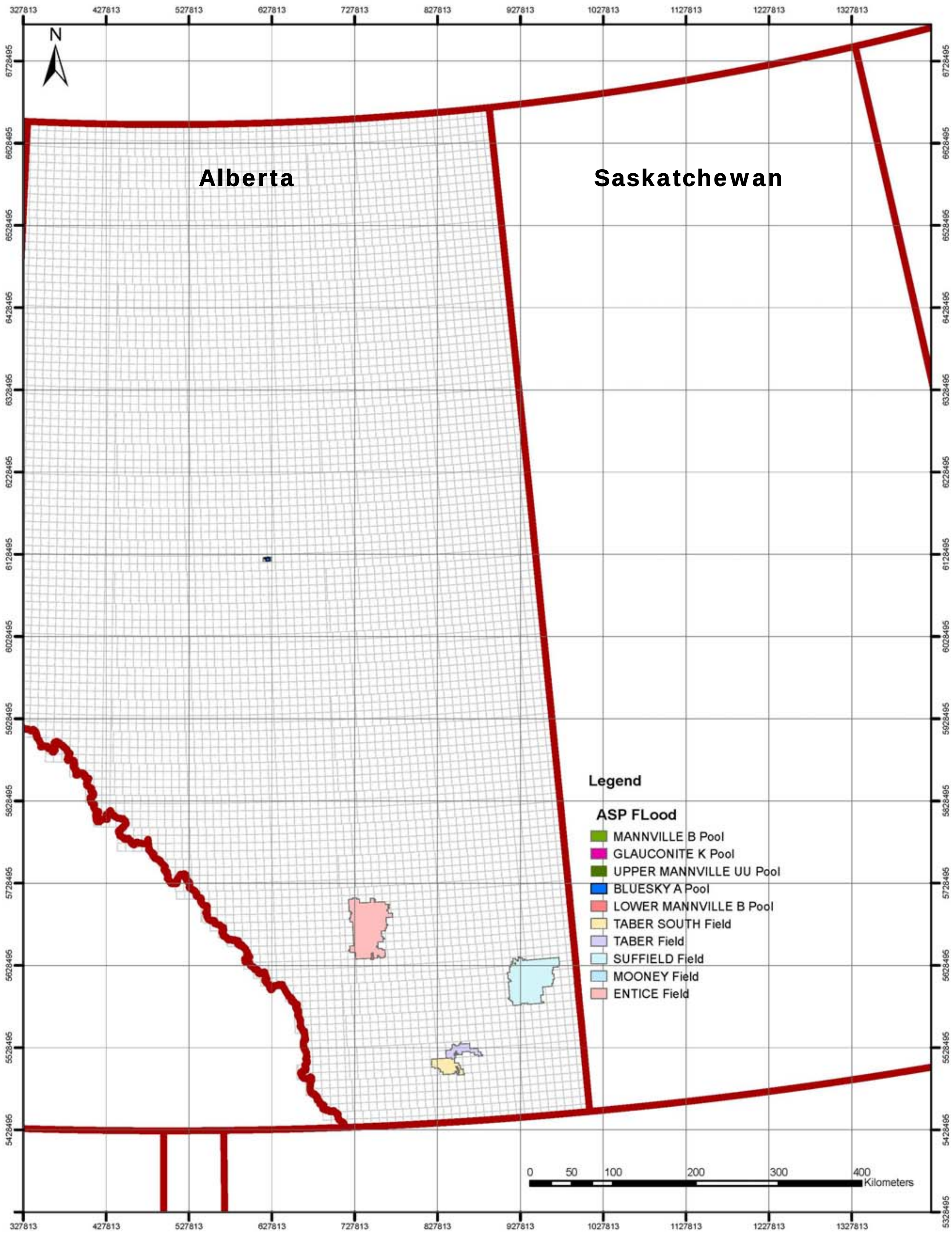
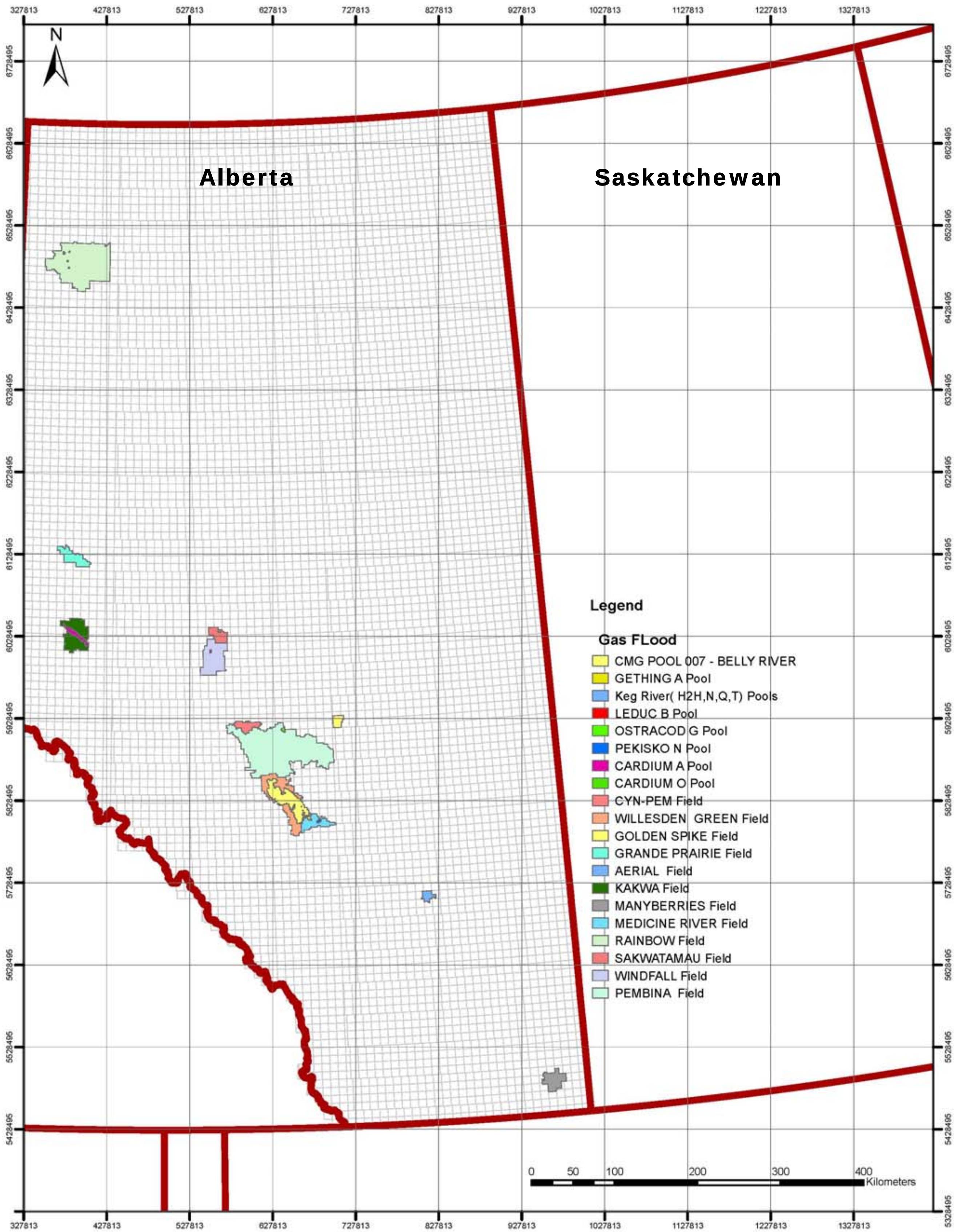


Figure 1

Sproule

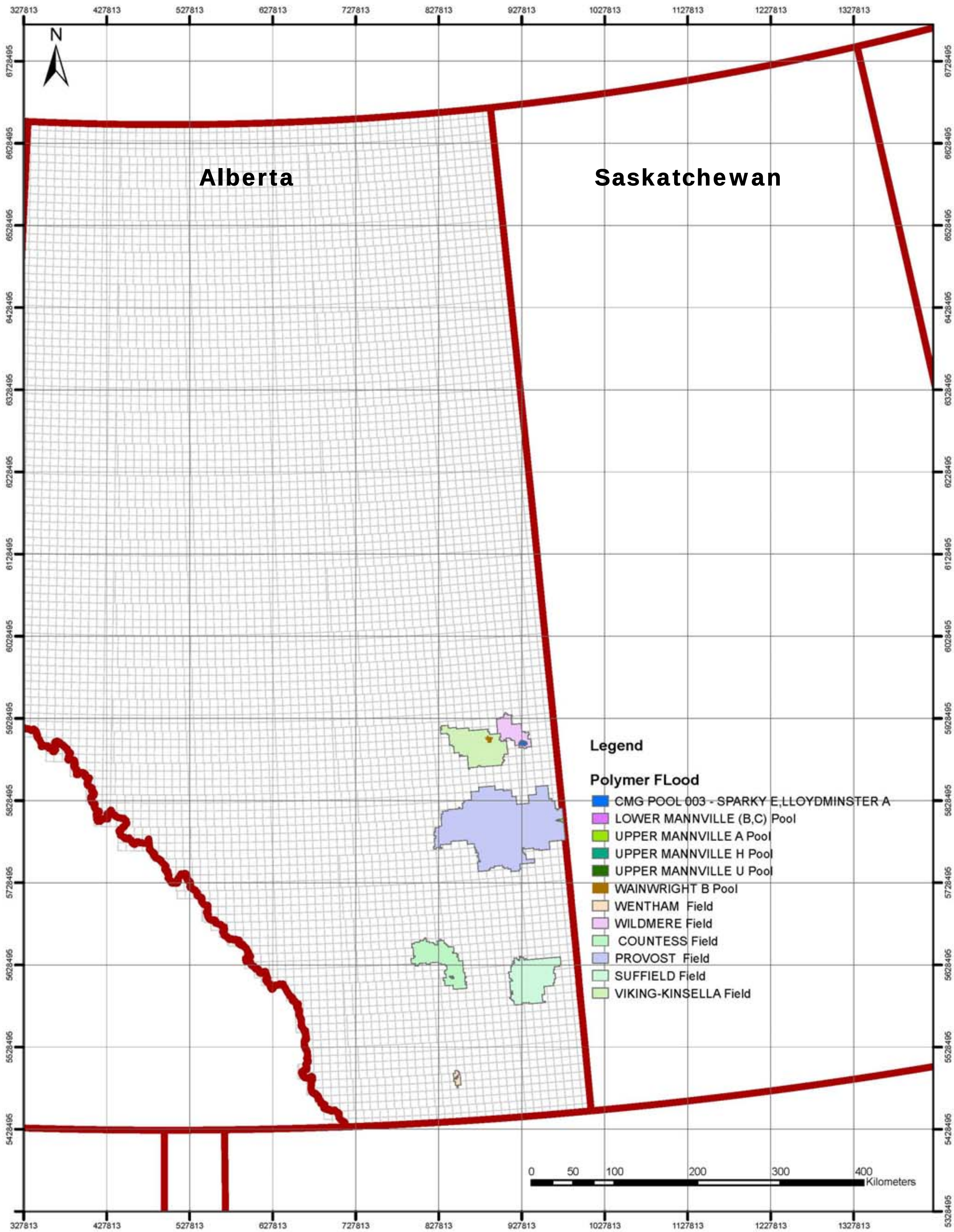


Alberta EOR Process – ASP Flood – By Field / Pool

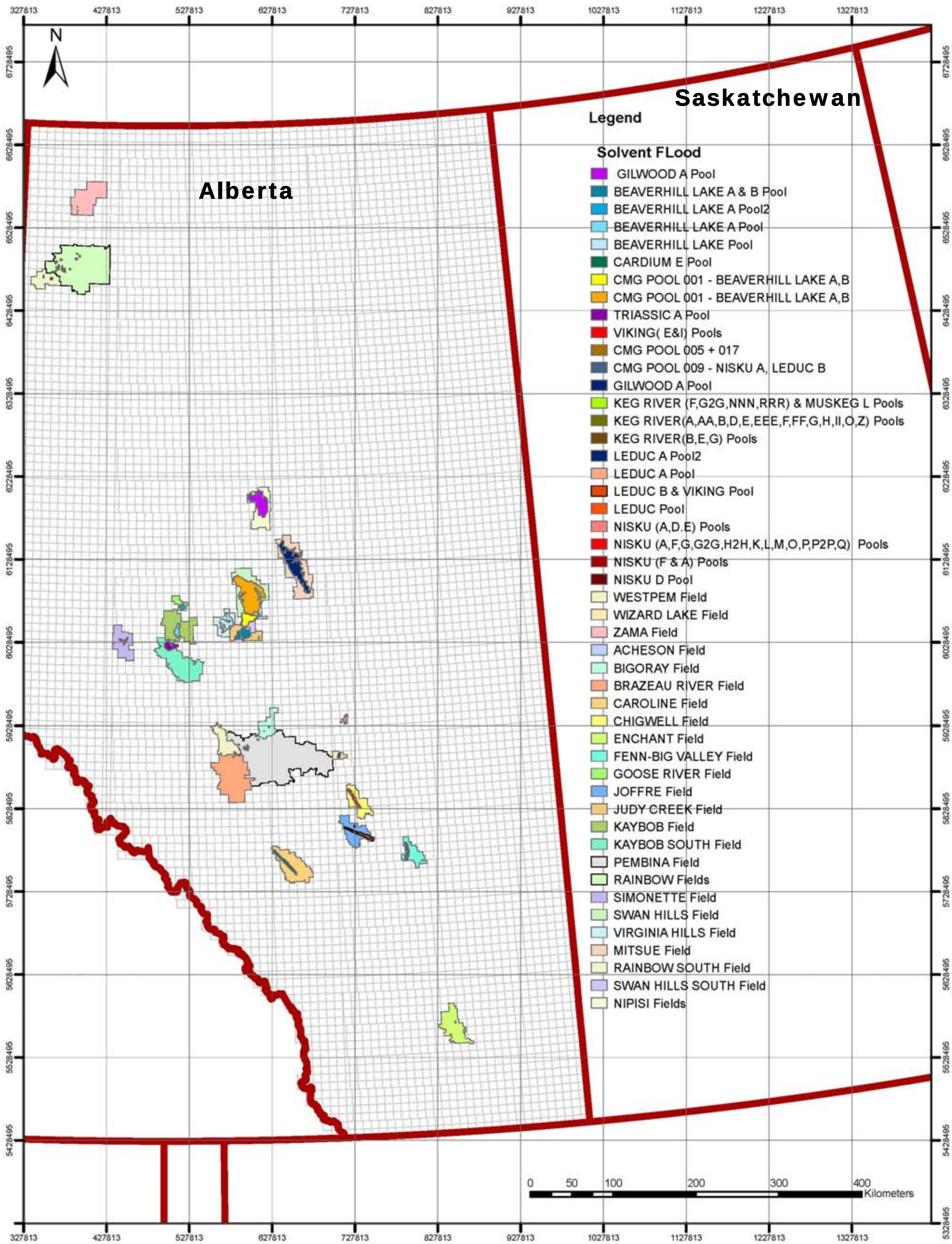


Alberta EOR Process – Gas Flood – By Field / Pool

Sproule



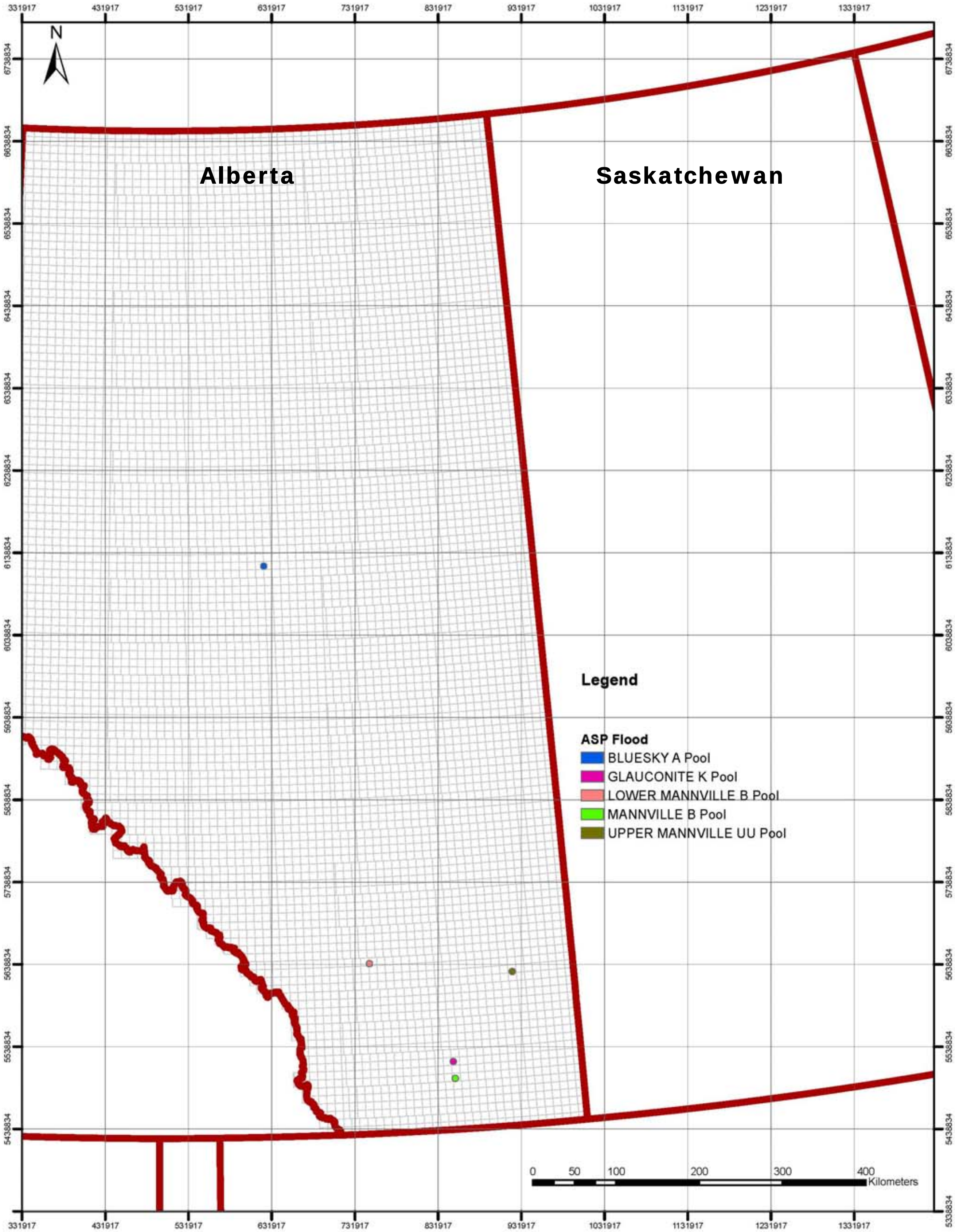
Alberta EOR Process – Polymer Flood – By Field / Pool



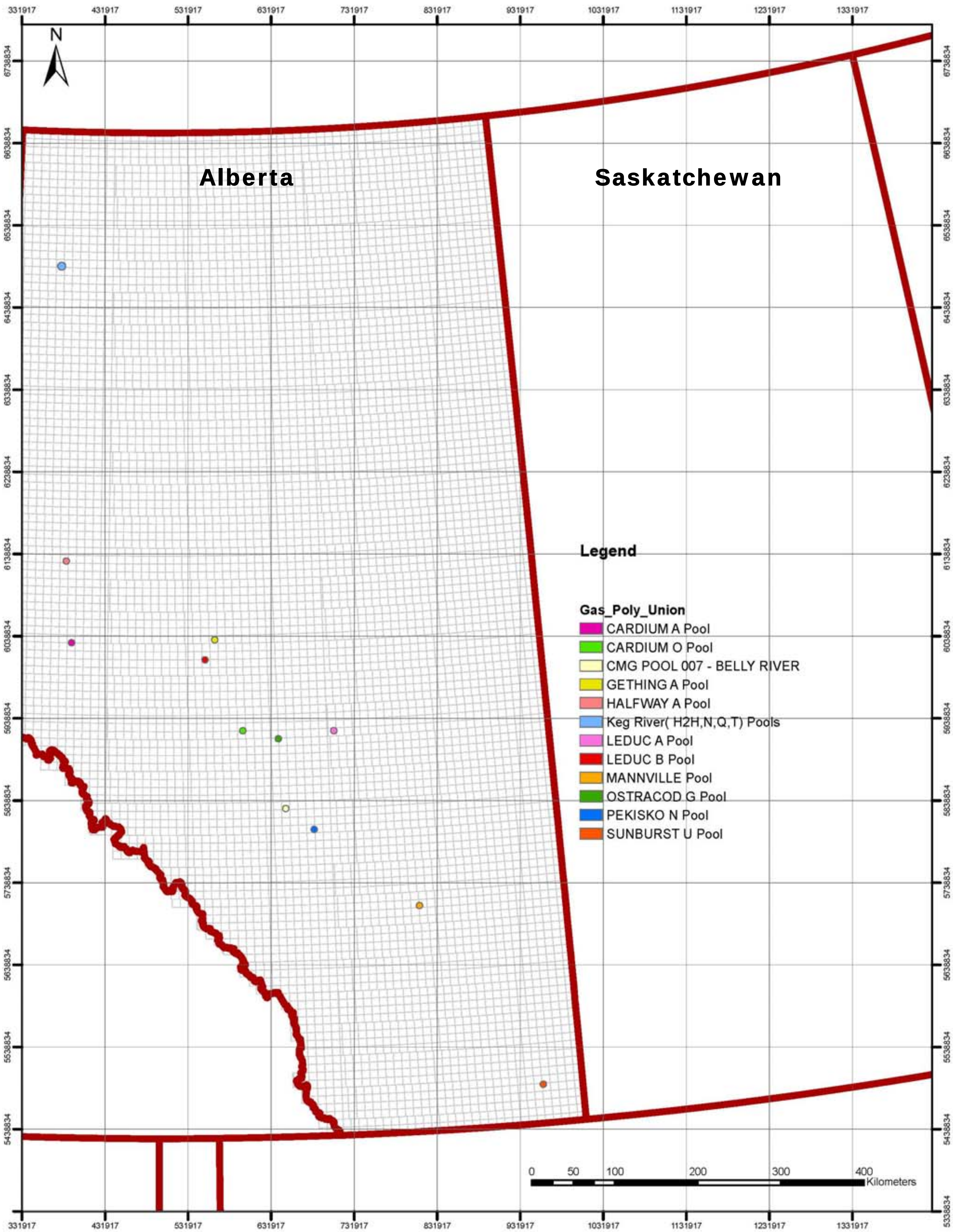
Alberta EOR Process – Solvent Flood – By Field / Pool

Sproule

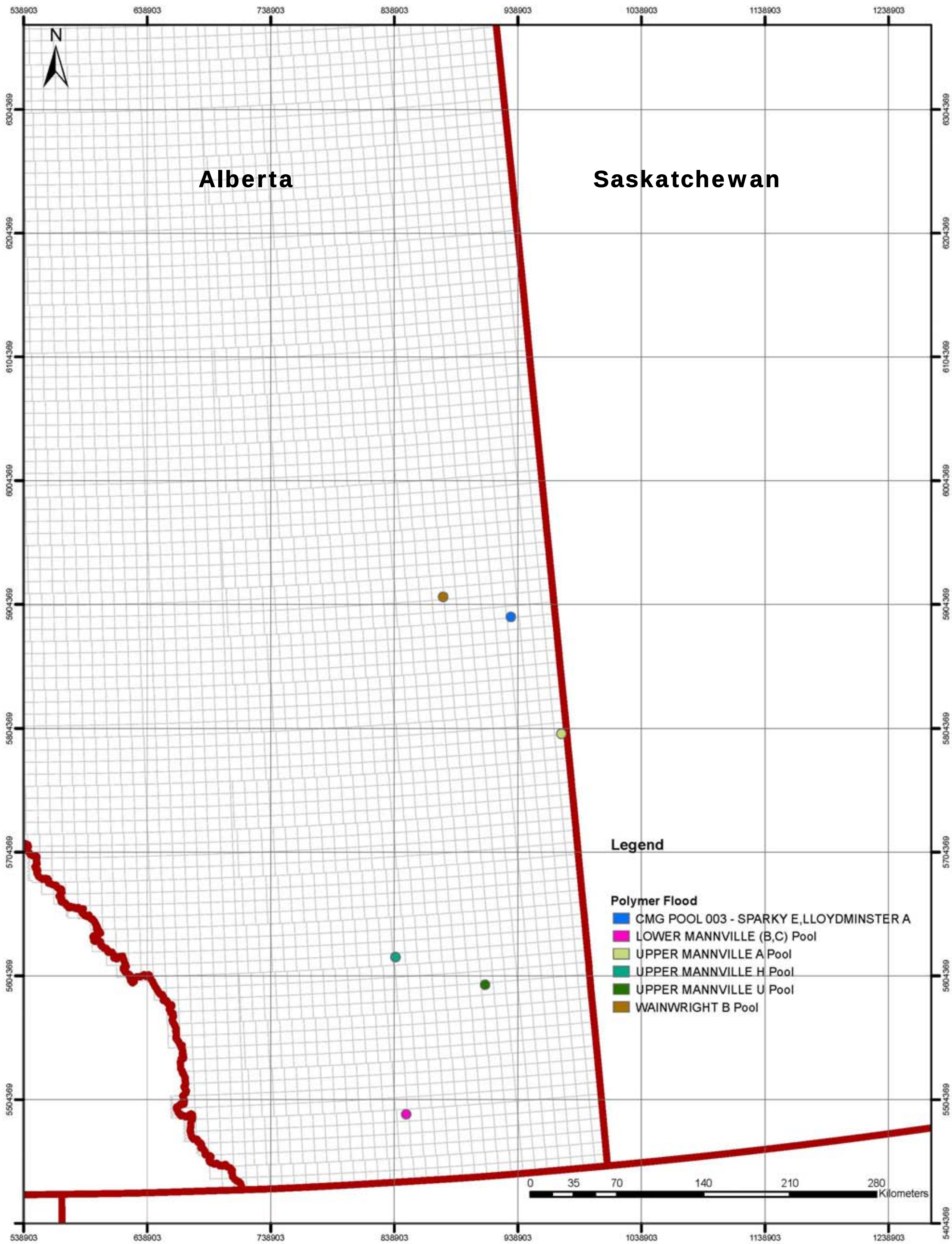
Figure 6



Alberta EOR Process – ASP Flood – By Pool

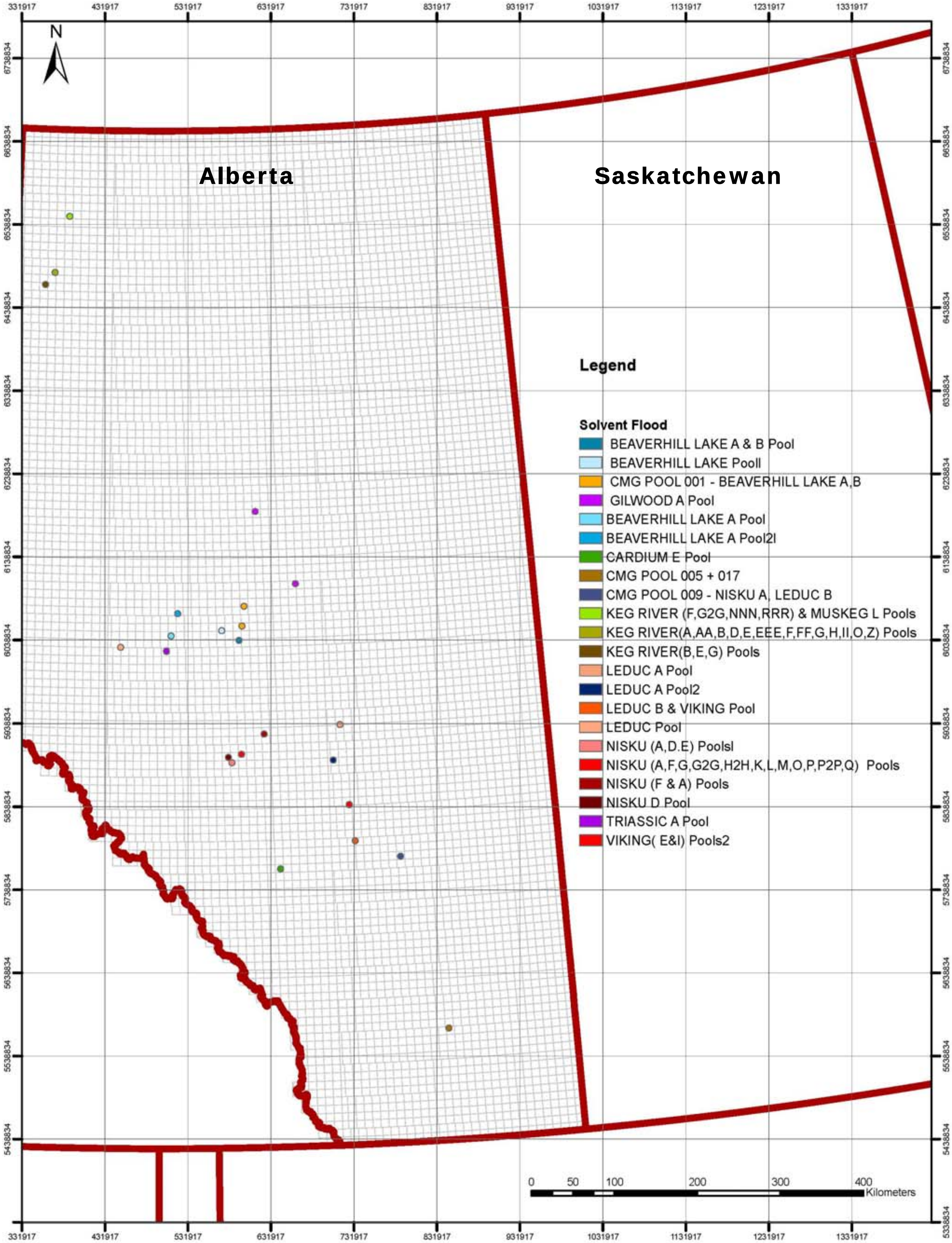


Alberta EOR Process – Gas Flood – By Pool



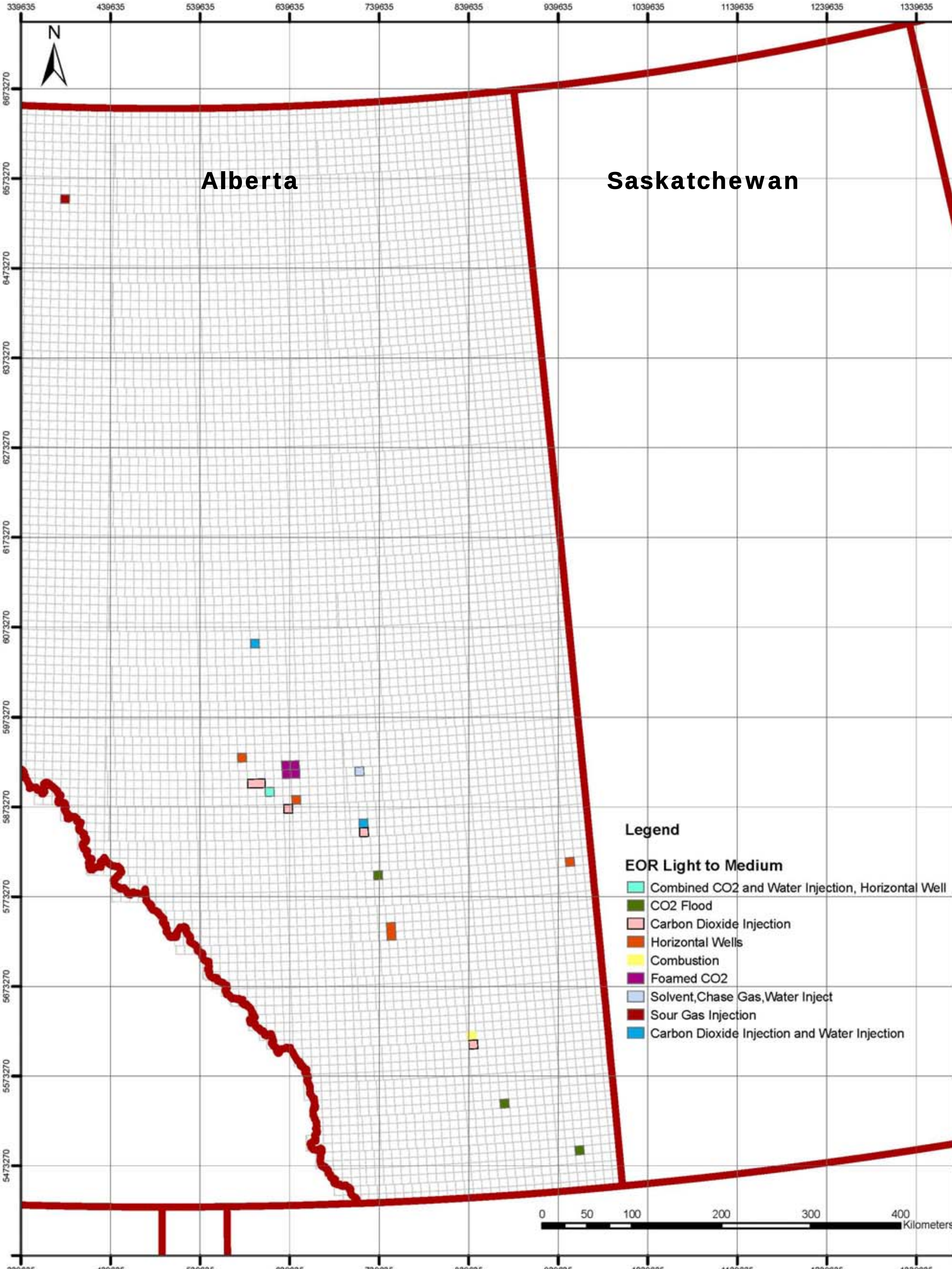
Alberta EOR Process – Polymer Flood – By Pool

Sproule

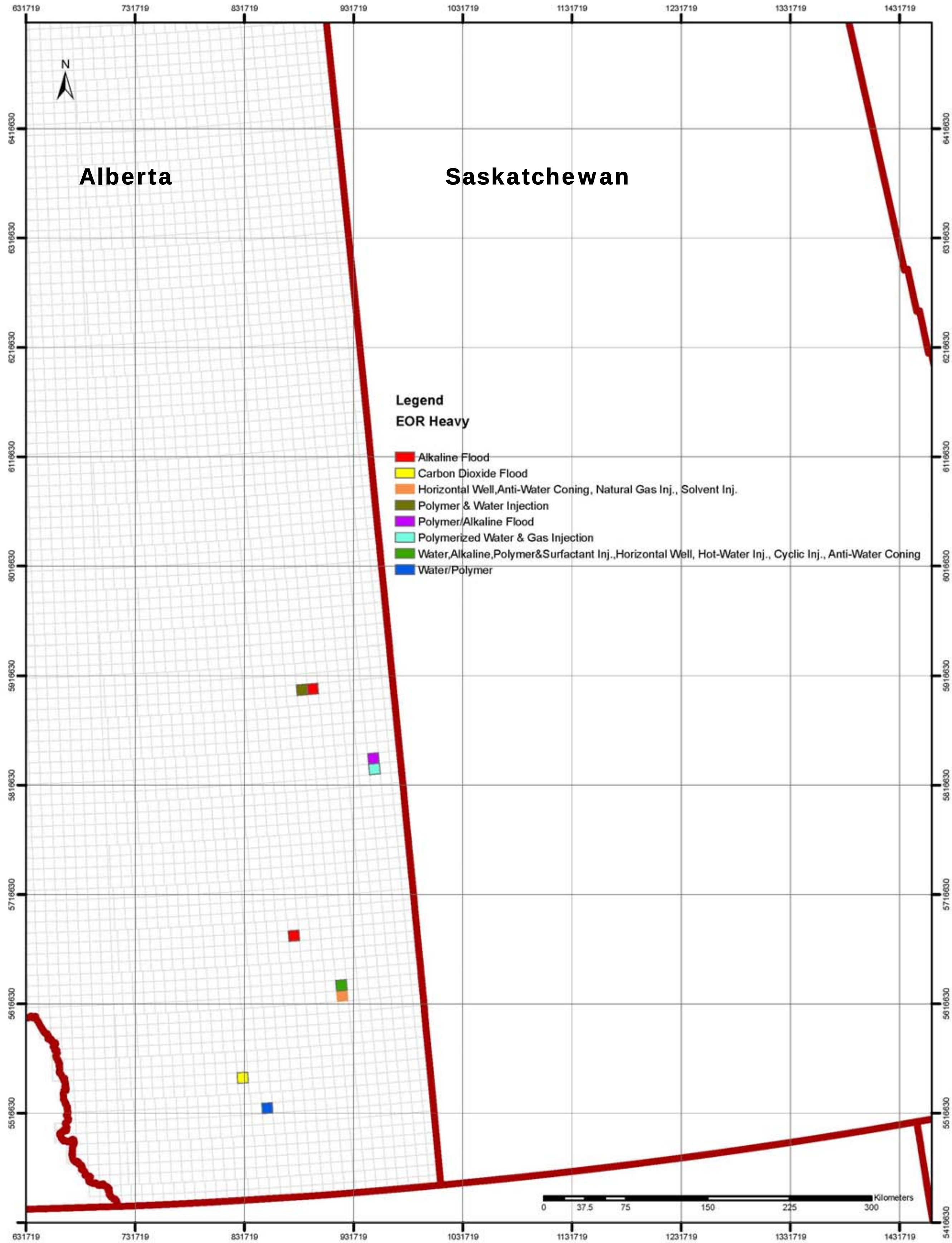


Alberta EOR Process – Solvent Flood – By Pool

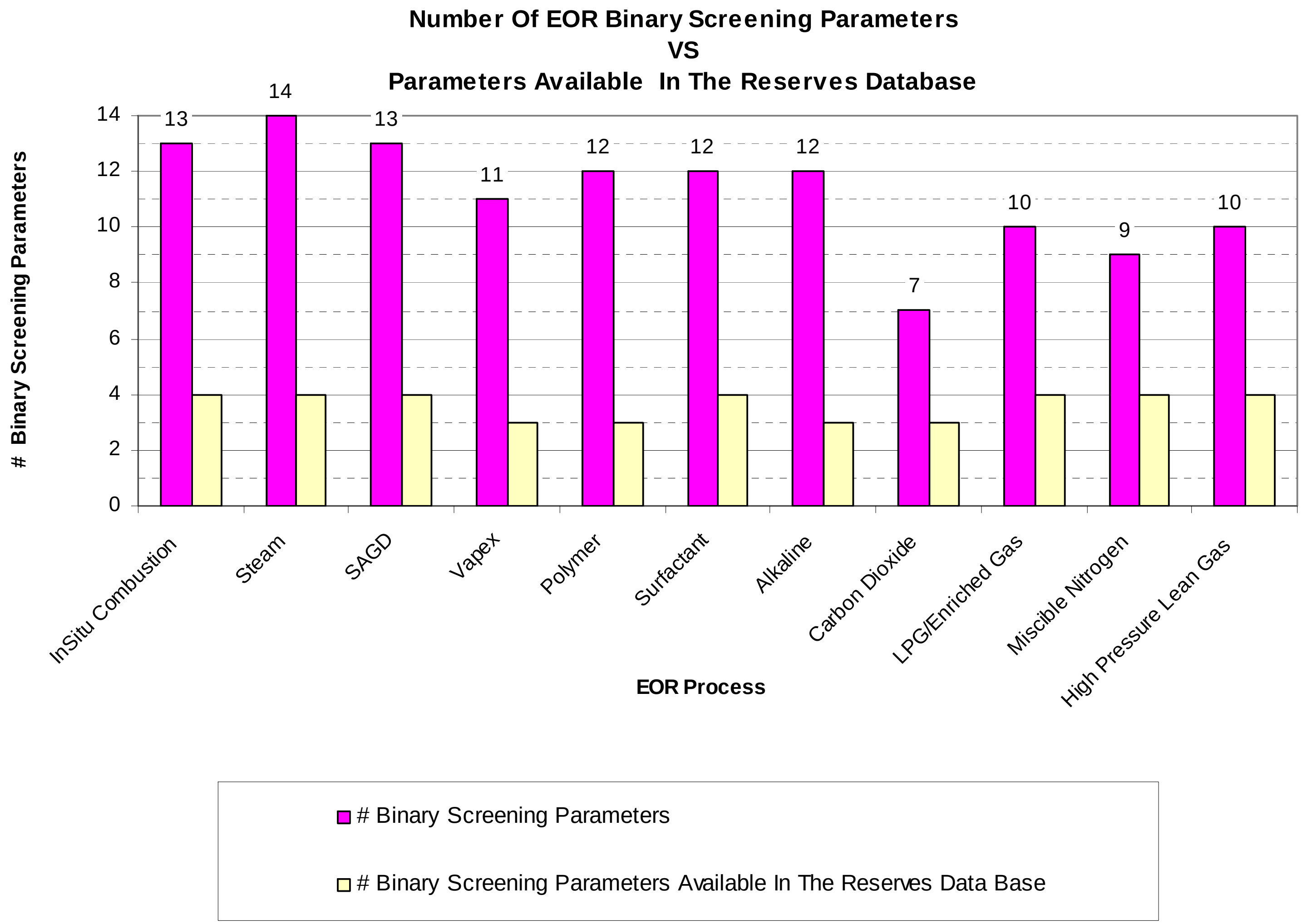
Sproule



Alberta Experimental Light to Medium Oil Terminated EOR Processes – Identified By Township



Alberta Experimental Heavy Oil Terminated EOR Processes – Identified By Township



Number Of EOR Binary Screening Parameters
VS
Parameters Available In The Reserves Database
Binary Screening Parameters
EOR Process
InSitu Combustion
Steam
SAGD
Vapex
Polymer
Surfactant
Alkaline
Carbon Dioxide
LPG/Enriched Gas
Miscible Nitrogen
High Pressure Lean Gas
13
14
13
11
12
12
12
7
10
9
10
0
2
4
6
8
10
12
14
Binary Screening Parameters
Binary Screening Parameters Available In The Reserves Data Base

Figure 12

Percent Binary Screening Data Available In The Reserves Database By EOR Process

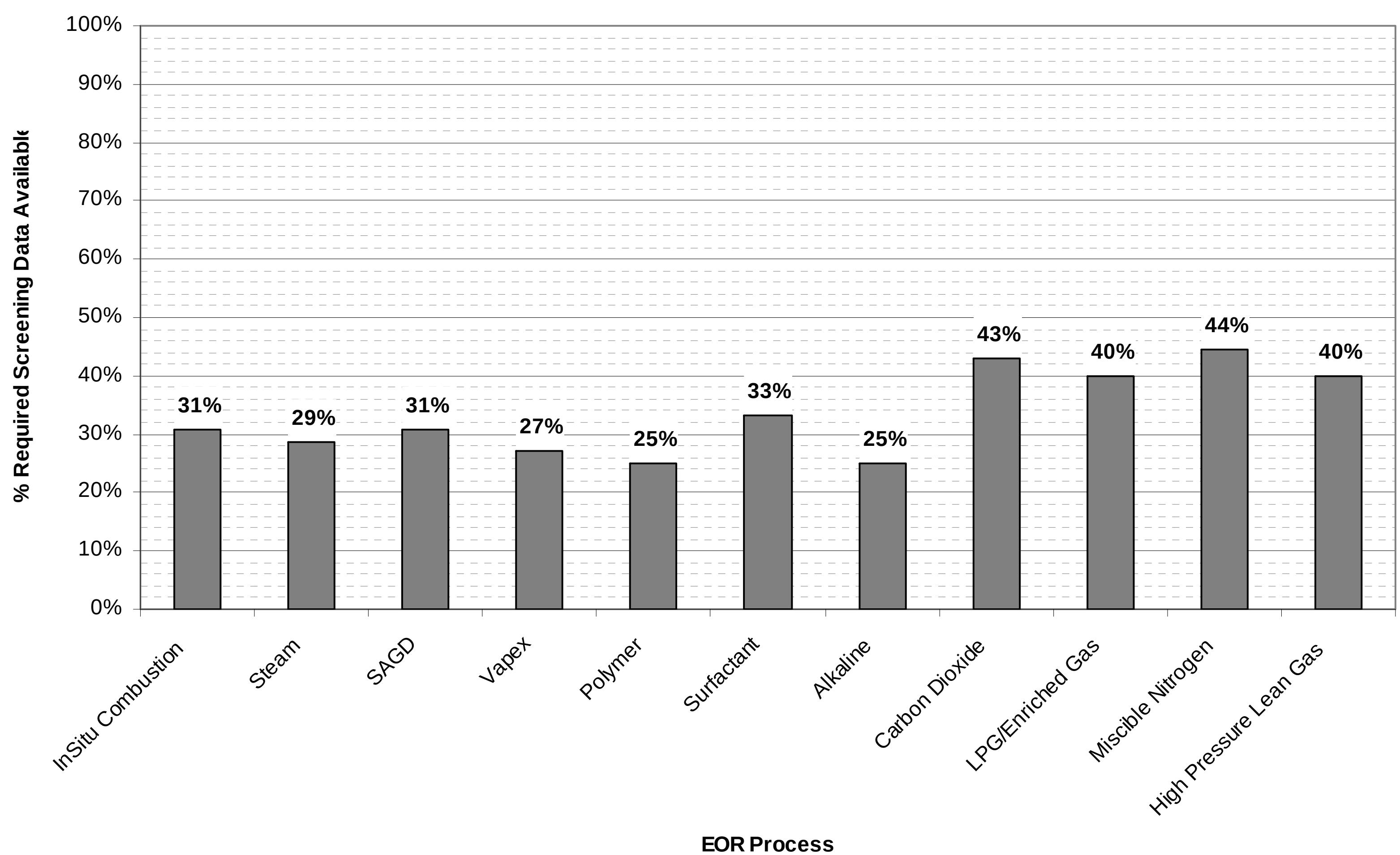


Figure 13

Sproule

APPENDIX A

ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Appendix A — Abbreviations, Units and Conversion Factors

This appendix contains a list of abbreviations found in Sproule reports, a table comparing Imperial and Metric units, and conversion tables used to prepare this report.

Abbreviations

AFE	authority for expenditure
AOF	absolute open flow
APO	after pay out
ASP	alkaline surfactant polymer
B_g	gas formation volume factor
B_o	oil formation volume factor
bopd	barrels of oil per day
bfpd	barrels of fluid per day
BPO	before pay out
BS&W	basic sediment and water
BTU	British thermal unit
bwpd	barrels of water per day
CF	casing flange
CGR	condensate gas ratio
CSS	cyclic steam stimulation
CTD	combination thermal drive
D&A	dry and abandoned
DCQ	daily contract quantity
DSU	drilling spacing unit
DST	drill stem test
EOR	enhanced oil recovery
EPSA	exploration and production sharing agreement
FVF	formation volume factor
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water-contact
HCPV	hydrocarbon pore volume
HPAI	high pressure air injection
ID	inside diameter
IOR	improved oil recovery
IPR	inflow performance relationship
IRF	incremental recovery factor
IRR	internal rate of return

ISC	in-situ combustion
k	permeability
KB	kelly bushing
LKH	lowest known hydrocarbons
LNG	liquefied natural gas
LPG	liquefied petroleum gas
md	millidarcies
MDT	modular formation dynamics tester
MEOR	microbial enhanced oil recovery
MPR	maximum permissive rate
MRL	maximum rate limitation
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
NPV	net present value
OD	outside diameter
OGIP	original gas in place
OOIP	original oil in place
ORRI	overriding royalty interest
OWC	oil-water-contact
P1	proved
P2	probable
P3	possible
P&NG	petroleum and natural gas
PI	productivity index
ppm	parts per million
PSU	production spacing unit
PSA	production sharing agreement
PSC	production sharing contract
PVT	pressure-volume-temperature
Rf	recovery factor
RFT	repeat formation tester
RT	rotary table
SAGD	steam assisted gravity drainage
SCAL	special core analysis
SS	subsea
THAI	toe to heel air injection
TVD	true vertical depth
WGR	water gas ratio
WI	working interest
WOR	water oil ratio

2D two-dimensional
3D three-dimensional
4D four-dimensional
1P proved
2P proved plus probable
3P proved plus probable plus possible
^{o}API degrees API (American Petroleum Institute)

Imperial and Metric Units

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	Million		M (10^6)	million
B (10^9)	one billion		T (10^{12})	one billion
T (10^{12})	one trillion		E (10^{18})	one trillion
			G (10^9)	one milliard
in.	Inches	**Length**	cm	centimetres
ft	Feet		m	metres
mi	Mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	Acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	Standard cubic feet			
gal	Gallons		L	litres
Mcf	Thousand cubic feet			
Mcfpd	Thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	Barrels		m^3	cubic metre
Mbbl	Thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
bbl/mo	barrels per month			
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			

Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Imperial and Metric Units (Cont'd)

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Tables

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$ (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$ (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)

Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Conversion Tables (Cont'd)

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F)	x 0.03743222	= megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $/$m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)

degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)