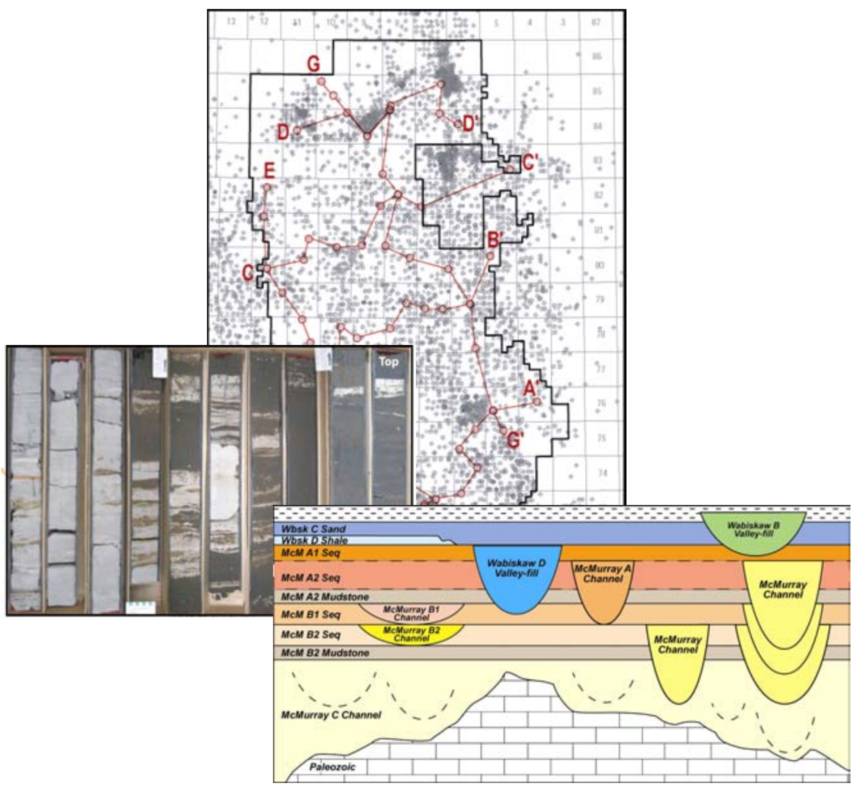
Report **2003-A**

Athabasca Wabiskaw-McMurray Regional Geological Study

December 31, 2003



Alberta Energy and Utilities Board

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Contents

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- Imperial Oil Resources Limited
- ISH Energy Limited
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Executive Summary

This study was initiated as part of the process the EUB established through *General Bulletin (GB) 2003-28.* The purpose of the study was to identify where gas pools are associated with bitumen within a part of the Athabasca Wabiskaw-McMurray deposit.

EUB staff and seconded staff from eleven companies were brought together in September 2003 to complete the study by the end of December 2003. Dr. Norman Wardlaw reviewed the study as it progressed and provided an assessment of the scope and approach, and opinion on data limitations and potential future data gathering and analysis.

The study covered two geographical areas where there is gas production from the area of concern outlined in *GB 2003-28*. The larger, main area lies south of Township 87, excluding the Surmont oil sands leases (~6 townships), which was the subject of *Decision 2000-22*. The north area is west of the surface mining area, between Townships 92 and 101 inclusive. The total area studied encompasses about 136 townships (almost 5000 square miles).

The study area contains about 5000 wellbores. Wells were drilled to explore for and produce natural gas and as oil sands delineation or production wells. Logs of suitable quality for geological analysis are available for the majority of the wells. The study identified and recorded stratigraphic unit picks on 3600 wells, and evaluated 3280 wells for the presence of gas and bitumen. Core was reviewed from 155 wells and correlated to the well logs to refine the stratigraphic models.

There were four primary components to the study. The first three were the development of a geological framework (including the identification of significant mudstones and shales), the evaluation and mapping of gas pools, and the evaluation and mapping of bitumen. The fourth component integrated the results from the first three components to provide an understanding of where gas is associated with bitumen.

The study concluded that:

- Regional stratigraphic units are present and correlatable throughout the study area but can be removed by subsequent erosion by channels.
- The existing well density is sufficient to identify regional channel trends, however it is insufficient to recognize local channel occurrences. Further, within the McMurray C Channel and McMurray Channel stratigraphic units, the lithology is also highly variable and difficult to predict.
- The McMurray C Channel / McMurray Channel sequence contains the bulk of the bitumen in the study area.
- Gas pools are nonassociated where the McMurray A2 or B2 Mudstones are preserved under the entire region of influence of the gas pool. The Wabiskaw A, C, and D Shales, where present, may provide local barriers between gas and bitumen.
- The quantity and quality of historical pressure data is limited. Therefore, the gas pooling was primarily based on the geological interpretation.

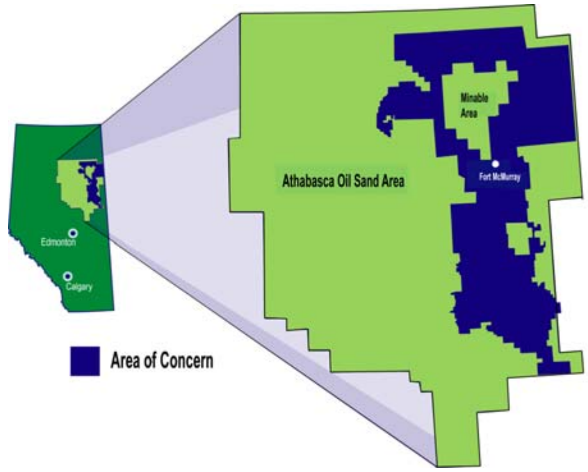
- There are seven cases, described in detail in Section 5 of the study, where gas can be associated with underlying bitumen. In all cases, gas is either associated through vertical connection to an underlying bitumen-bearing interval where regional mudstones or shales are absent, or is connected laterally to gas zones or water that are in vertical association.

- There are 464 associated and 313 nonassociated gas pools. These pools contain both producing and nonproducing wells.

The study provides a regional overview of the geological framework of the study area and identifies gas that is associated with bitumen. Continued review of existing and new data will enhance and refine the interpretations presented.

1 Introduction

1.1 Background



In late July 2003, the Alberta Energy and Utilities Board (EUB/Board) issued *General Bulletin (GB) 2003-28* announcing bitumen conservation requirements for gas production from part of the Wabiskaw-McMurray[1] in the Athabasca Oil Sands Area (Figure 1, right).

The Board stated in the GB that

- associated gas production presents an unacceptable risk to bitumen recovery using steam-assisted gravity drainage (SAGD), and
- the best available method to identify nonassociated gas production is through a regional geological study (RGS); the EUB recognizes that such a study is subject to change as new information becomes available.

The EUB announced its intention to conduct the RGS in the GB and provided an outline of the approach it intended to follow.

The study area is located within the area of concern defined earlier in *GB 2003-16*. Within this area the study was split into two separate geographic areas. The southern area, referred to in the report as the "main area," covers lands south of Township 87 except the Surmont oil sands leases, which were the subject of EUB *Decision 2000-22*. The second area, referred to as the "northern area," covers the northwest portion of the area of concern. The remaining areas within the area of concern were excluded because there is currently no gas production. The areas studied contain some of the thickest bitumen within the Athabasca Wabiskaw-McMurray, have a history of gas production, and encompass most existing and proposed SAGD projects within the Athabasca Oil Sands area.

1.2 Study Objective

The objective of the study is to identify which gas pools are in pressure communication with stratigraphic units that have the potential to contain bitumen exceeding 10 metres (m) in thickness.

1.3 Study Approach

An assessment of which gas is associated with underlying bitumen is essential to address the bitumen conservation risk. In some instances associated gas is obvious where well logs or core show continuous porosity from a gas zone into an underlying bitumen zone. Many well logs show the presence of intervals of mudstone between gas and bitumen-bearing zones. The lateral extent of these mudstones influences their ability to act as effective barriers to pressure communication, and is dependent upon the environment in which they were deposited and whether they were adequately preserved. Mudstones deposited in a fluvial or estuarine environment are laterally discontinuous and are not considered to be effective barriers. The Board arrived at this conclusion in the Chard-Leismer Decision (*Decision 2003-023*).

[1] The Wabiskaw Member of the Clearwater Formation and the McMurray Formation

Fundamental to the question of communication, therefore, is the identification of regional mudstones, their lateral extent, and the potential for the continuity of these units to be limited by erosional channelling. Individual wells provide site-specific data (well logs, core, and pressure and production data) that can be interpreted to develop a regional geological framework for this assessment.

As a starting point, the RGS adopted the geological conclusions from the Chard-Leismer decision and extended the analysis to the remainder of the study area. The key conclusions include the following:

- The occurrence of thick bitumen-saturated channel sands is extensive and randomly distributed throughout the study area.
- Wabiskaw-McMurray gas has the potential to be associated with underlying channel bitumen, either through direct vertical continuity or indirectly through lateral continuity of the gas and top water zones.
- Regionally correlatable mudstones and shales may exist throughout the study area and, where present, act as barriers to vertical pressure transmission between Wabiskaw-McMurray gas and underlying channel bitumen.

The study area was subdivided into six project areas, as shown in Figure 2. Separate teams were responsible for each project area but worked together to ensure consistency across project area boundaries.

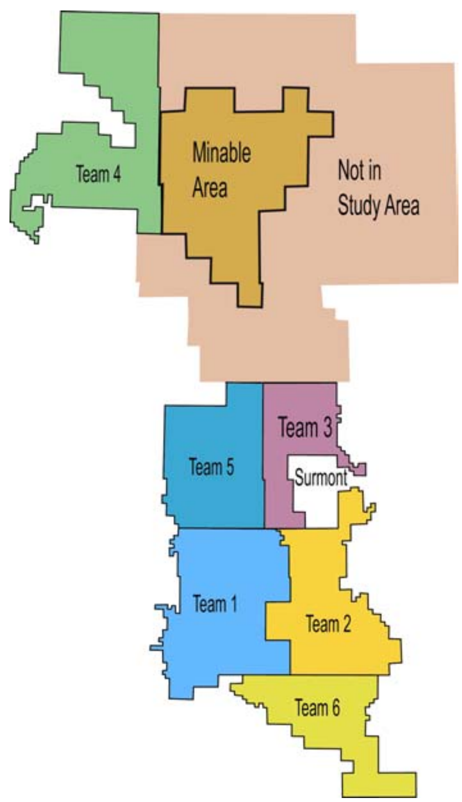


Figure 2 – Team Map

The work completed in the study progressed through a four-step process described briefly below. More detailed descriptions of the steps are provided in the body of the study.

Step 1: Develop a regional stratigraphic model to assist in understanding the geological complexity of the study area. The model formed a basis for subdividing the Wabiskaw-McMurray into discrete stratigraphic units. Theses units include both potential reservoir units (channel sequences and regional sands) containing gas, water, and/or bitumen and nonreservoir units (regional mudstones) that could act as barriers to vertical communication.

Step 2: Evaluate and map the lateral and vertical extent of gas pools and associated top water to establish the region of influence (ROI) of each gas accumulation.

Step 3: Evaluate and map bitumen within the defined stratigraphic units to assess its quality, thickness, and distribution.

Step 4: Integrate information from steps 1, 2, and 3 to provide a composite picture of where gas pools are in communication with underlying units that have the potential for bitumen pay in excess of 10 m.

To accomplish this work, a large volume of data, including well logs, core, and pressure and production data, was analyzed. There are approximately 5000 wells in the study area, but not all have sufficient data quality to be used. The following is a description of the data and analysis incorporated in the study.

- Stratigraphic picks were made on about 3600 wells, for a total of 28 700 picks.
- Cores were examined from 155 wells, for a total of approximately 6600 core boxes or 10 km of core.
- Pressure and production data from 83 gas pools were analyzed.
- 3280 wells were evaluated for the presence of gas or top water. Many wells had multiple gas zones in separate stratigraphic units. A total of 2958 stratigraphic units had gas pay in the 1816 wells found to contain gas.
- Detailed bitumen evaluations were made in 3265 wells.

Dr. Norman Wardlaw reviewed the study as it progressed and provided an assessment of the scope and approach, as well as opinion on data limitations and potential future data gathering and analysis. This report is attached as Appendix A.

A CD accompanies the report and includes

- cross-sections
- maps
- gas pool pressure reviews
- source data including all stratigraphic data, gas pool data, and bitumen data for all wells evaluated
- table identifying associated and nonassociated pools, wells, and licensees.

2 Geology

2.1 Method

The teams began the study by reviewing the available well logs for the non-confidential wells within their respective areas. This provided for a quick overview of the area to be studied, including a preliminary identification of stratigraphic units that appeared to be correlatable and deposited on a regional scale, identification of areas and units that are gas prone and/or have thick bitumen, and identification of those wells that have core cut over the zones of interest. Each team constructed a series of stratigraphic cross-sections over its area using wells that had both suitable log suites and core. Preliminary picks were made of any stratigraphic units that could be identified. These were verified and adjusted where necessary through core examination at the EUB's Core Research Centre. This iterative process continued until all teams had landed on a stratigraphic model for their areas and had ensured consistency across the team area boundaries. The teams established a consistent nomenclature to identify each of the stratigraphic units encountered. The top of these units and their corresponding log depths were picked in each available well and entered into a database. In areas of high well density (multiple wells per section) associated with oil sands projects, picks were made only in a representative number of wells.

Mapping software was used to produce structure and isopach thickness maps on all stratigraphic units by accessing the database of stratigraphic picks. These maps were reviewed for data errors and to understand regional trends. Errors were corrected and maps regenerated as required. Maps are included in the report with additional maps on the CD.

2.2 Main Study Area

2.2.1 Stratigraphic Model and Unit Descriptions

The stratigraphic datum for the main study area is the top of the Wabiskaw Member, Clearwater Formation. Figure 3 presents the Wabiskaw Marker structure map. The basal McMurray units in the main study area were deposited on the sub-Cretaceous unconformity developed on the Paleozoic carbonates in the region. Figure 4 presents the Wabiskaw Marker to the Paleozoic isopach, and Figure 5 the Paleozoic surface structure map.

Several units have been identified within the Wabiskaw-McMurray sequence in this area, with the thickest units occurring in the McMurray. The units are named, from bottom to top, McMurray C Channel, McMurray B2 Sequence, McMurray B1 Sequence, McMurray A2 Sequence, McMurray A1 Sequence, Wabiskaw D Valley-fill, Wabiskaw D Shale, Wabiskaw C Sand, and Wabiskaw B Valley-fill. Channels that cut through some of these sequences or occur at the same stratigraphic interval as some of these sequences have also been identified and named. The relationship of these stratigraphic units is depicted in a schematic cross-section shown in Figure 6. A series of strike and dip stratigraphic cross-sections are available on the CD, with the lines of section depicted in Figure 7. A dip cross-section (B-B') for the main study area is attached at the end of the report. With the exception of the McMurray A1 and the Wabiskaw B Valley-fill, all other stratigraphic units were previously interpreted and reported in the Chard-Leismer Decision.

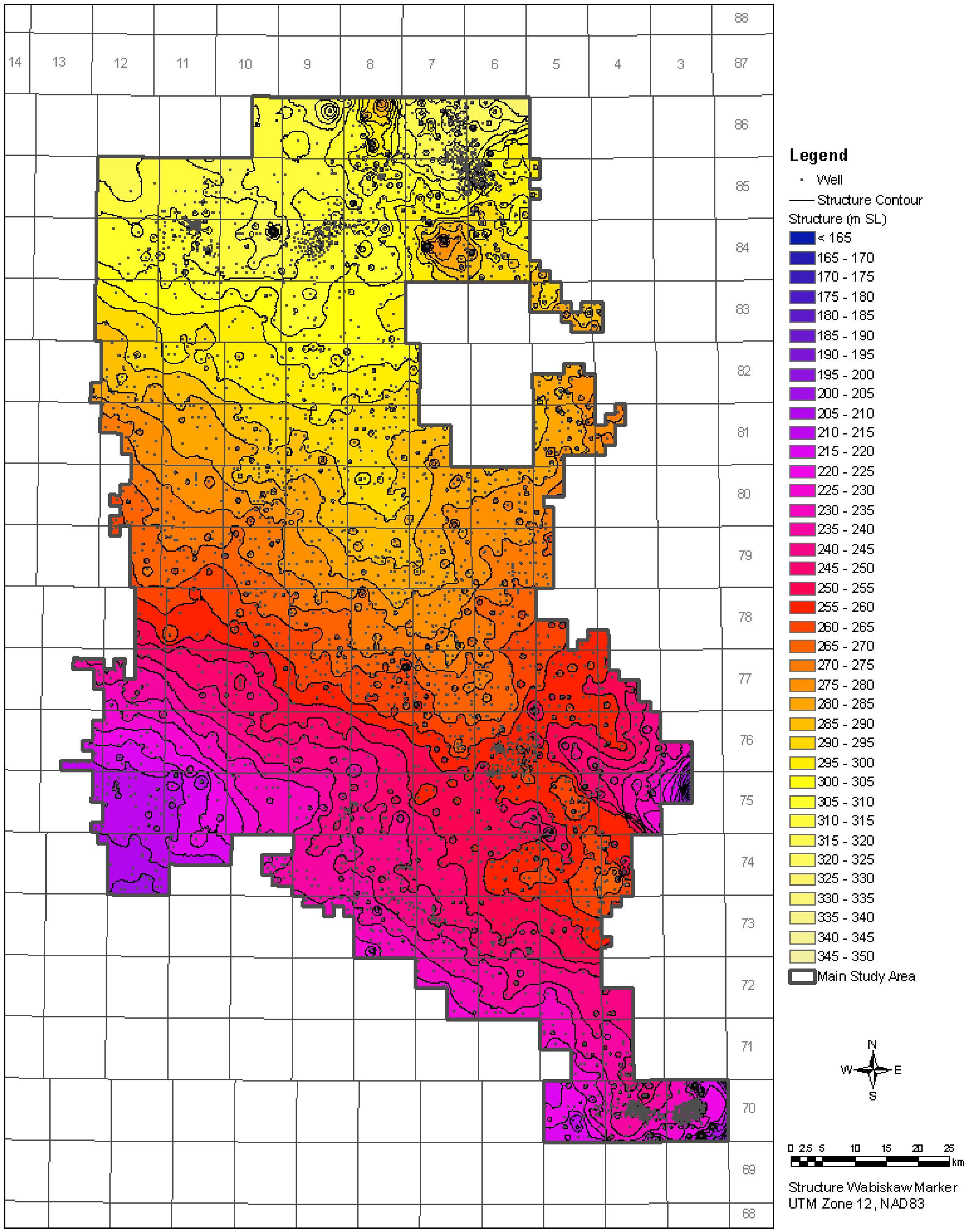


Figure 3 – Wabiskaw Marker Structure Map

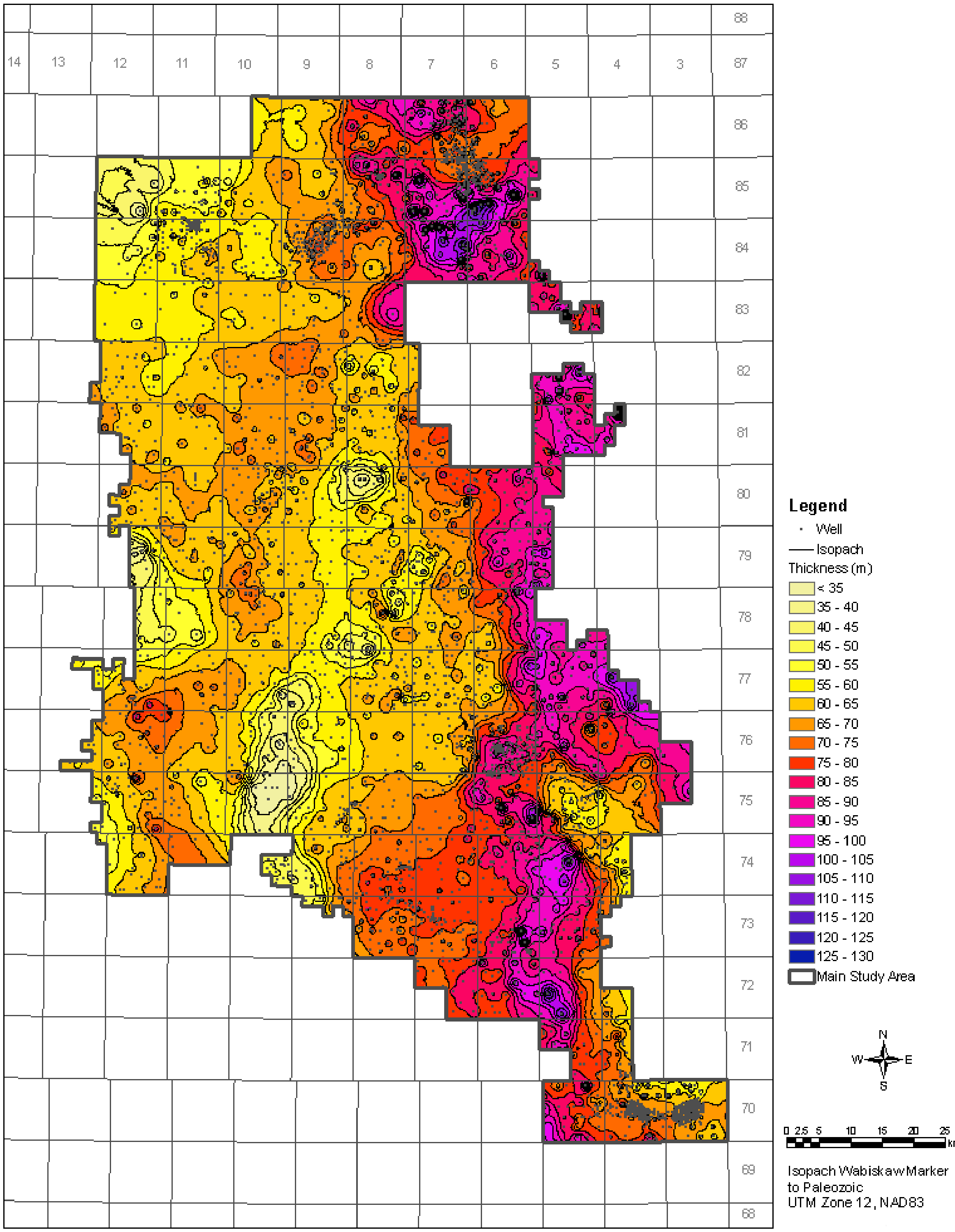


Figure 4 – Wabiskaw Marker to Paleozoic Isopach Map

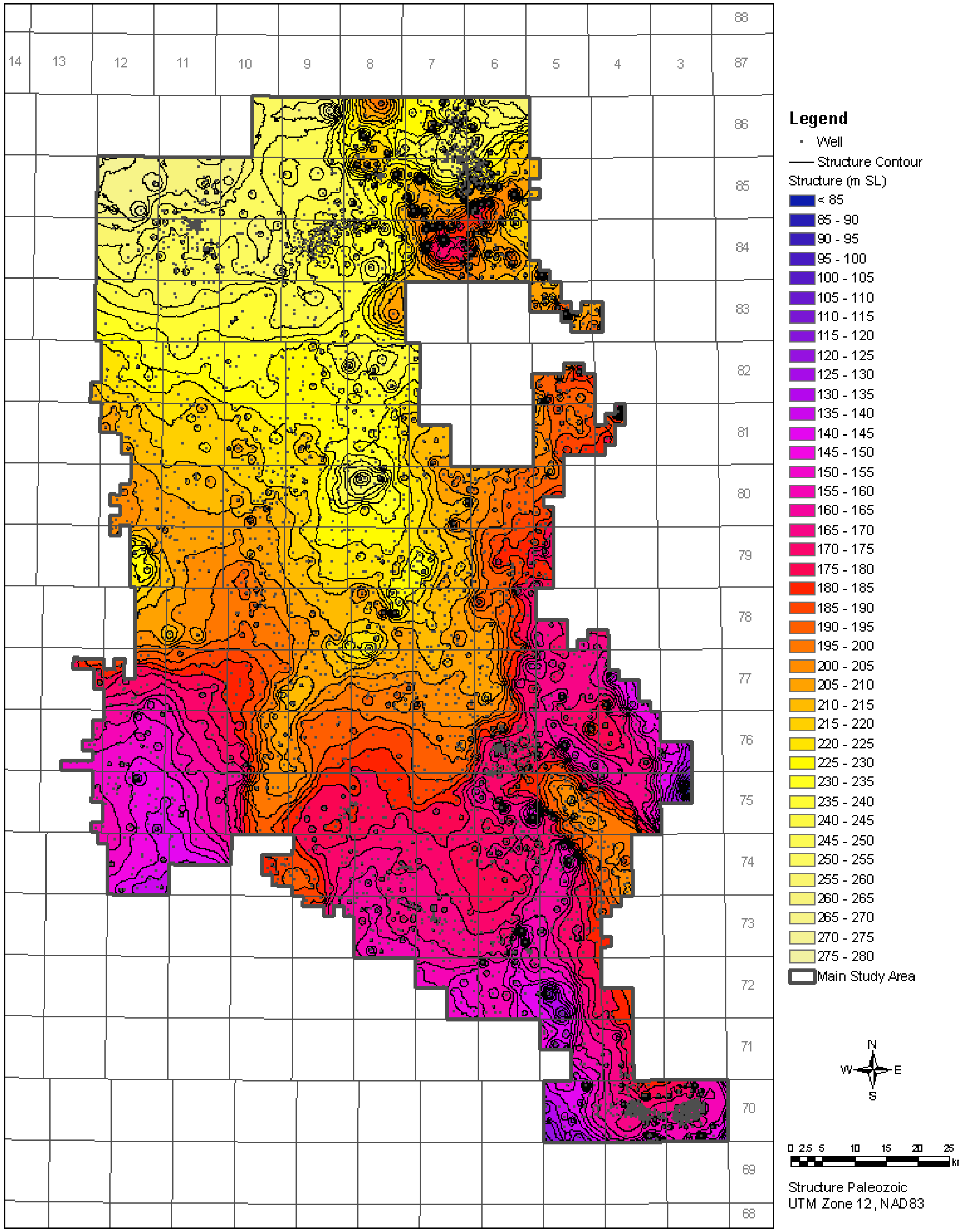


Figure 5 – Paleozoic Structure Map

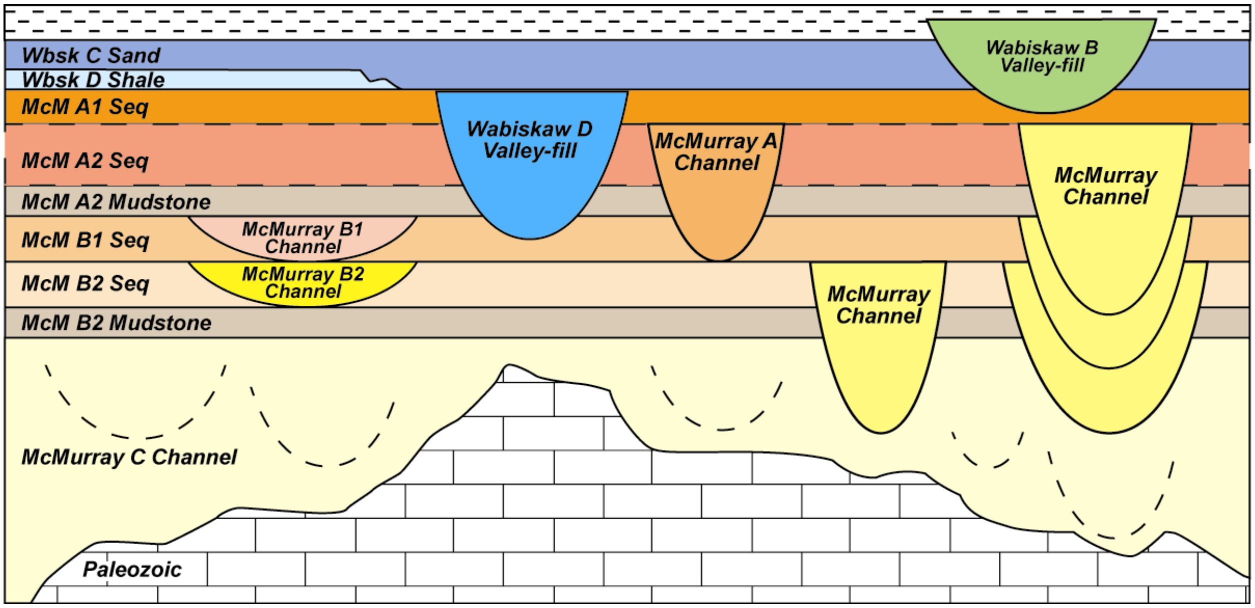


Figure 6 – Main Study Area Stratigraphic Model

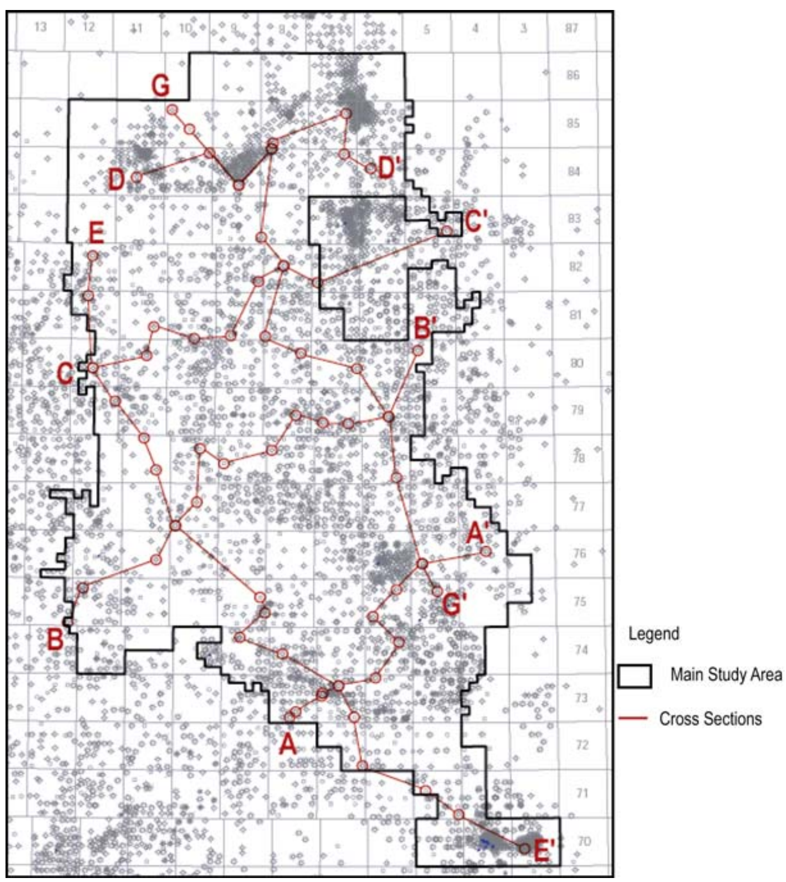


Figure 7 – Stratigraphic Cross Sections Across the Main Study Area

McMurray Channel / McMurray C Channel

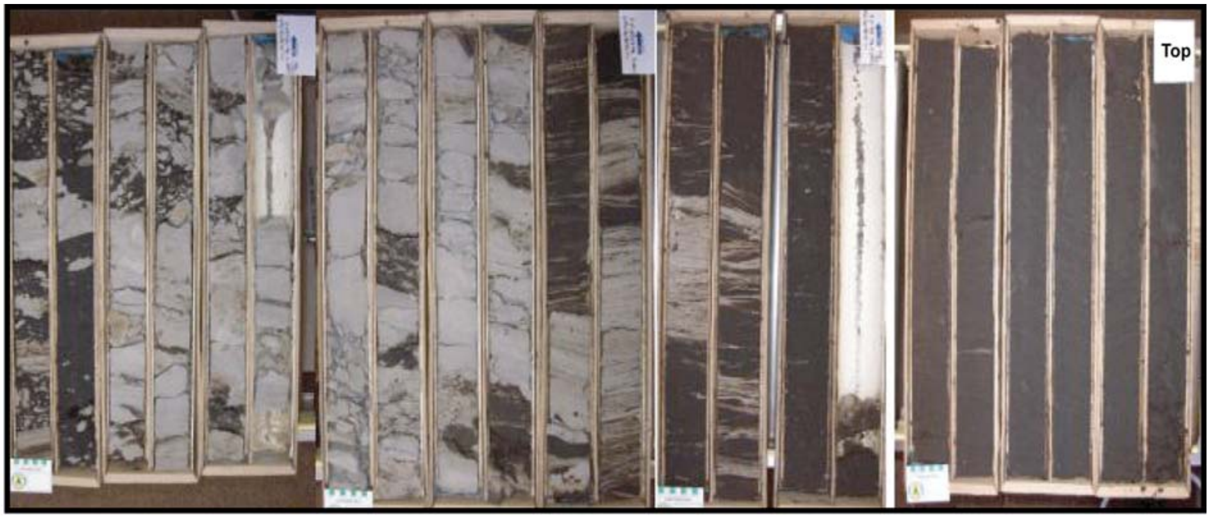
Unit Description

The stratigraphically lowest sediments in the McMurray Formation are channel deposits referred to as either McMurray Channel or McMurray C Channel. If the lowest recognizable regional mudstone, the B2 Mudstone, is present in a particular well, the underlying channel deposits are referred to as McMurray C Channel. Where the B2 Mudstone is not present, the channel deposits underlying the lowermost regional unit are called McMurray Channel. McMurray channels originate from more than one horizon and should not be considered a unique mappable unit.

Channel deposits have variable lithology, consisting of the following facies: clean blocky sands, sands with interbedded mudstone layers, muddy channel fill, and associated lateral facies. Channel deposits consist mainly of massive and trough cross-stratified quartz-rich sands, with occasional mudstone breccias or dispersed mudstone clasts grading up to inclined heterolithic strata (IHS) beds. Mudstone layers in IHS range from a few millimetres to several centimetres thick and are marked by numerous trace fossils indicative of a fluvial-estuarine environment. Monospecific assemblages of *Cylindrichnus* and *Gyrolithes* are common. Muddy channel fills are typically grey in colour, nonfissile, and without trace fossils. Channel packages range in thickness from 25 to 90 m, generally thicker near the eastern boundary of the main study area. McMurray channel deposits overlie Paleozoic carbonates and are themselves overlain by a variety of Wabiskaw-McMurray units, including the McMurray A1, A2, B1, and B2 Sequences and the various Wabiskaw units.

Log Characteristics

Channel deposits are heterogeneous units and their typical log responses vary considerably. Typical log signatures for clean sands include a Gamma Ray (GR) of 25 to 45 American Petroleum Institute (API) units in a blocky or bell shape. Resistivity is variable, and both neutron and density porosities are typically over 30 per cent. Several blocky or bell GR profiles may occur superimposed, reflecting more than one fining-upward package. Figure 8 presents an example of the McMurray Channel sequence and corresponding well log. This particular example illustrates an atypical GR profile that can be misleading if there is no core data to verify the interpretation.



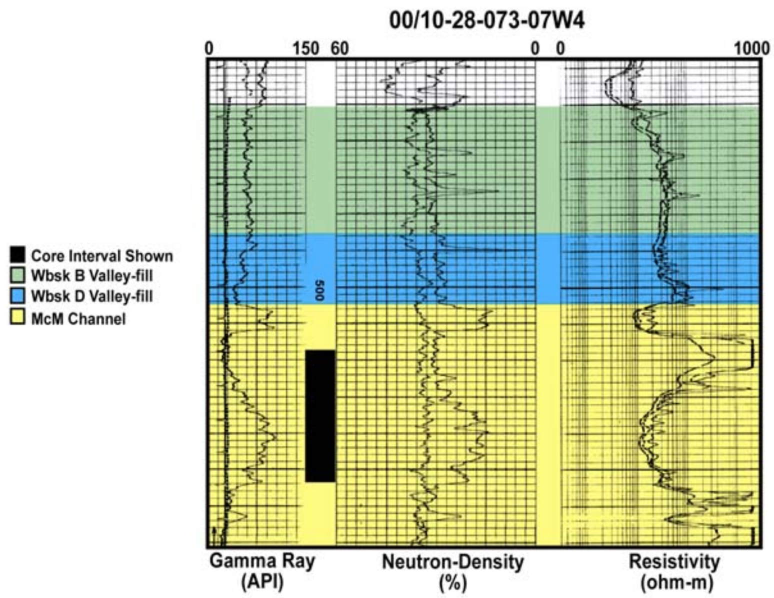


Figure 8 – McMurray Channel Core Photo and Well Log

McMurray B2 Sequence and B2 Channel

Unit Description

The lowest consistently recognizable regional package in the McMurray Formation is the B2 Sequence. It is a cleaning-upward package consisting of a light grey mudstone grading upward into silts and fine-grained quartz-dominated sands exhibiting wave ripple sedimentary structures. The mudstone at the base of the B2 is 1 to 2 m thick, is nonfissile, and exhibits abundant trace fossils, including *Planolites* and small *Teichichnus*. The interbedded mud layers show synaeresis cracks. Sands in the upper part of the sequence are moderately bioturbated. A thin coal occasionally caps the B2 Sequence. Total thickness of the sequence typically ranges from 5 to 10 m. The base of the B2 Mudstone occurs about 30 to 35 m below the Wabiskaw Marker, unless thick Wabiskaw B Valley-fill deposits are present in the region; in that case, the base of the B2 Mudstone can occur up to 58 m below the Wabiskaw Marker. Where present, the B2 Sequence overlies McMurray C Channel deposits. Figure 9 presents the Wabiskaw Marker to the base of the McMurray B2 Mudstone isopach map.

Localized channels can originate from the top of the B2 Sequence and erode the regional sands of the sequence. By definition, B2 Channels do not cut away the mudstone of the B2 Sequence; if channels cut away the B2 Mudstone, they are classified as McMurray Channels. The lithology and log characteristics of these B2 Channels are similar to the McMurray Channel deposits.

Log Characteristics

The mudstone at the base of the B2 Sequence displays GR values between 90 and 120 API units. GR values are 15 to 25 API units higher than the Wabiskaw shale baseline (shales between the Wabiskaw Marker and the Wabiskaw C Sand). Density and neutron porosity curves diverge through the B2 Mudstone, unlike Wabiskaw D Shales, in which the density porosity is typically unaffected. Typical neutron porosities of the mudstone are near 45 per cent, density porosities near 22 per cent, and resistivities range between 8 and 10 ohm-metres (ohm-m). Typical log signature of the upper sandy part of the sequence includes a GR of 30 to 45 API units, variable resistivity, and neutron and density porosities over 30 per cent. Porosities increase gradually from the base of the unit to the top in a funnel shape. Figure 10 presents a typical B2 Sequence and corresponding well log.

Where B2 Channels erode the upper sandy part of the B2 Sequence, the presence of the B2 Mudstone is difficult to discern on logs. However, it is assumed that the B2 Mudstone has been preserved if the mudstone exhibits the characteristic log responses and occurs at the expected stratigraphic position relative to the Wabiskaw Marker.

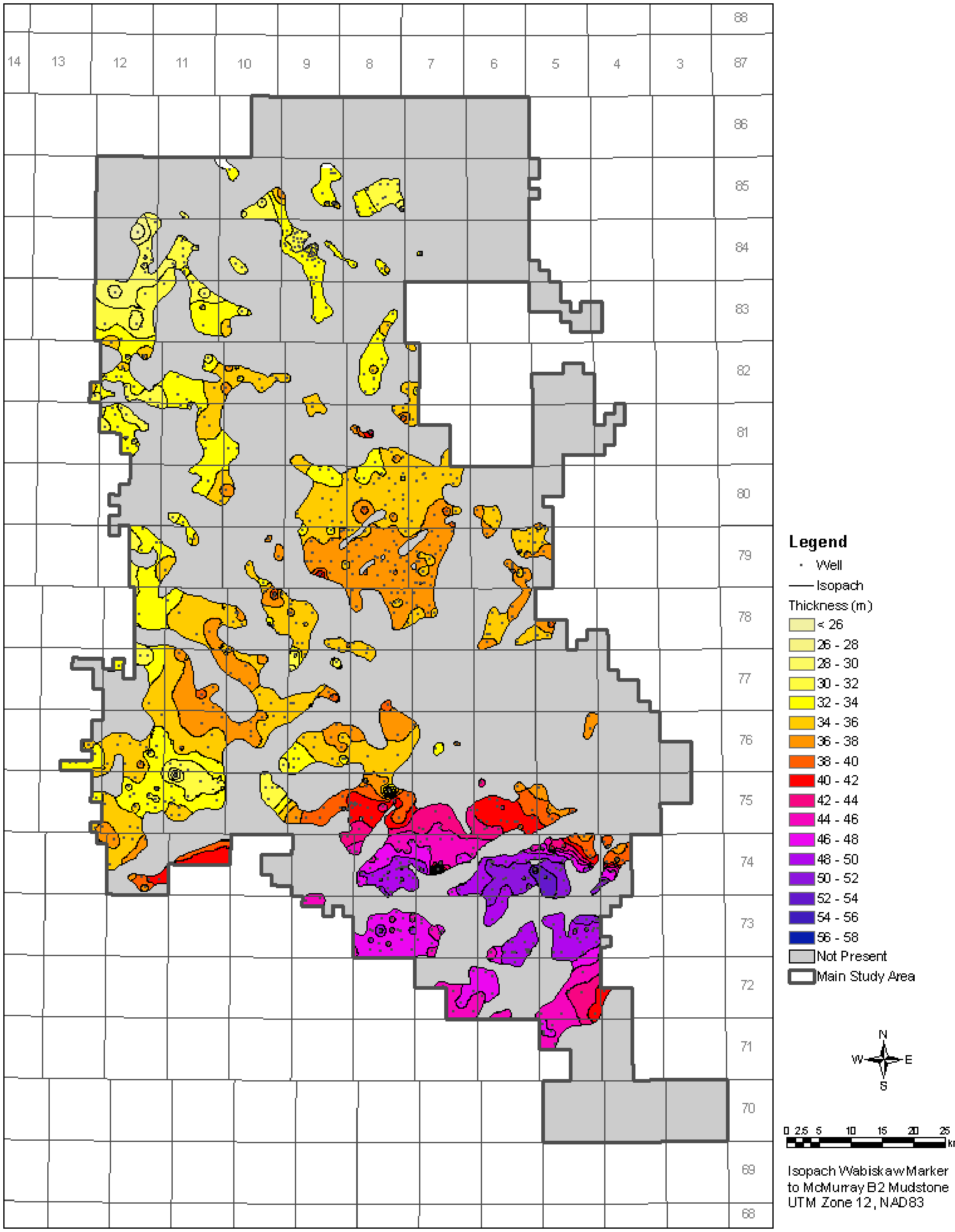


Figure 9 – Wabiskaw Marker to the Base of the McMurray B2 Mudstone Isopach Map

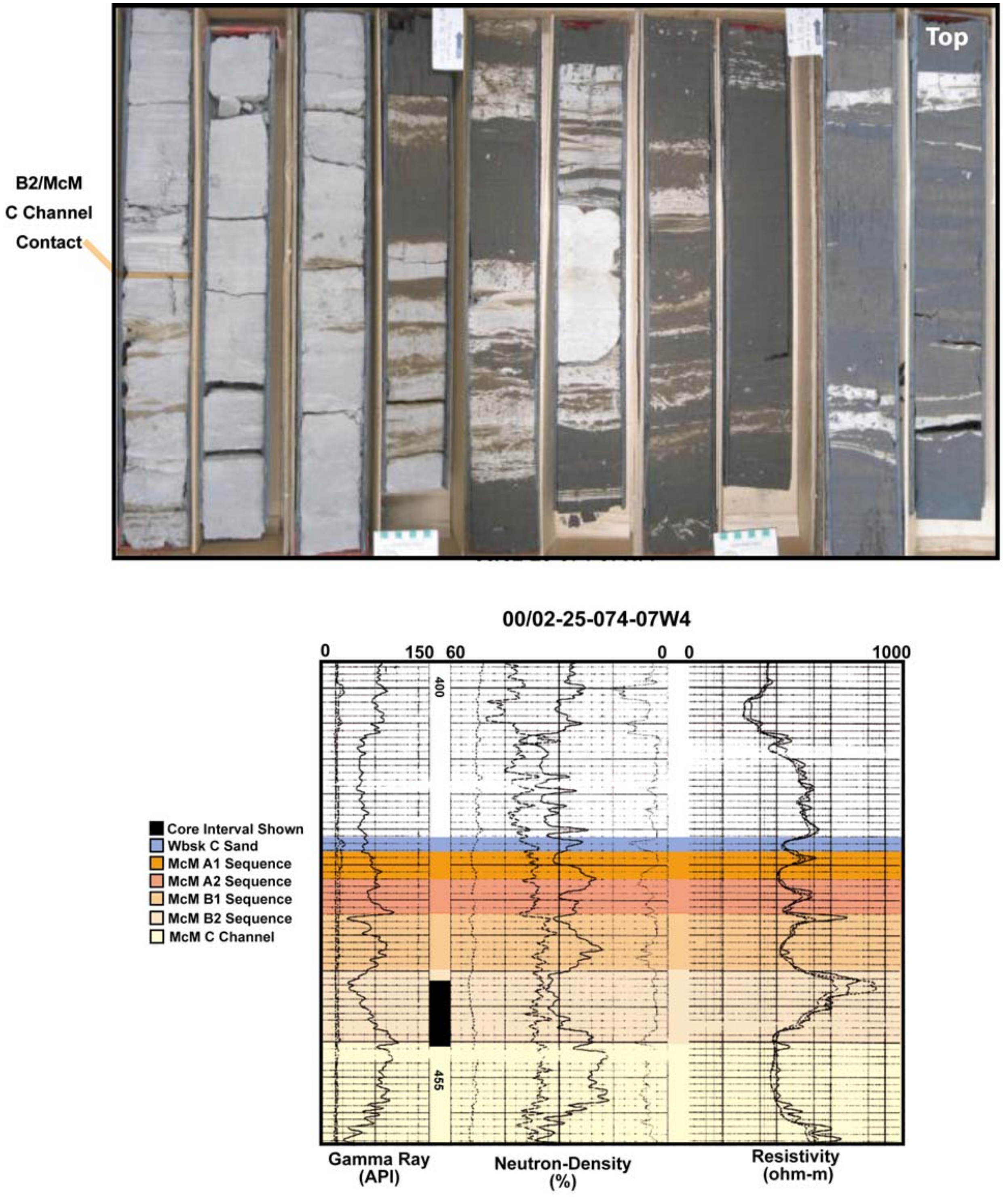


Figure 10 – McMurray B2 Sequence Core Photo and Well Log

McMurray B1 Sequence and B1 Channel

Unit Description

The B1 Sequence is a heavily bioturbated heterogeneous unit that is muddier than the B2 and A2 Sequences. It can consist of a single cleaning-upward package or two (or more) thinner cleaning-upward packages, but the unit does not clean upward in every instance and very clean sands are rare. When cleaning upward, each cycle consists of a variably developed (and sometimes absent) thin (5 to 40 cm) mudstone overlain by heavily burrowed silts and fine-grained quartz-dominated sands with wave ripples. Trace fossils are typically robust examples of *Cylindrichnus*, *Teichichnus*, *Skolithos*, and *Arenicolites*, and burrowing commonly destroys primary sedimentary structures in zones of alternating sands and mudstones. Thin, rooted zones and coals can occur at the top of each cleaning-upward cycle. Thickness of the sequence typically ranges from 5 to 10 m. Where present, the B1 Sequence overlies either the B2 Sequence or McMurray Channel deposits.

Localized channels can originate from the top of the B1 Sequence and erode the regional sands of the B1 Sequence and possibly the sands of the B2 Sequence. By definition, B1 Channels do not cut through the B2 Mudstone. The lithology and log characteristics of these B1 Channels are similar to the McMurray channel deposits.

Log Characteristics

The typical log signature of the upper part of the sequence includes a serrated GR curve that oscillates around 75 API units, variable resistivity, and density porosity between 20 and 30 per cent. Where lithologies alternate, the signature of most curves is serrated.

Due to its heterogeneous lithology, the B1 Sequence is best recognized on well logs if accompanied by the A2 Sequence above and the B2 Sequence below. The base of the sequence is often picked at the top of the B2 Sequence sands. In the absence of the B2 Sequence, the B1 Sequence is difficult to differentiate from the underlying McMurray Channel deposits. However, the B1 Sequence can be correlated locally based on GR log character from areas where the B2 Sequence is present to where it is absent. Figure 11 presents a typical B1 Sequence and corresponding well log.

Where B1 Channels erode the upper sandy part of the B2 Sequence, the presence of the B2 Mudstone is difficult to discern on logs. However, it is assumed that the B2 Mudstone has been preserved if the mudstone exhibits the characteristic log responses and occurs at the expected stratigraphic position relative to the Wabiskaw Marker.

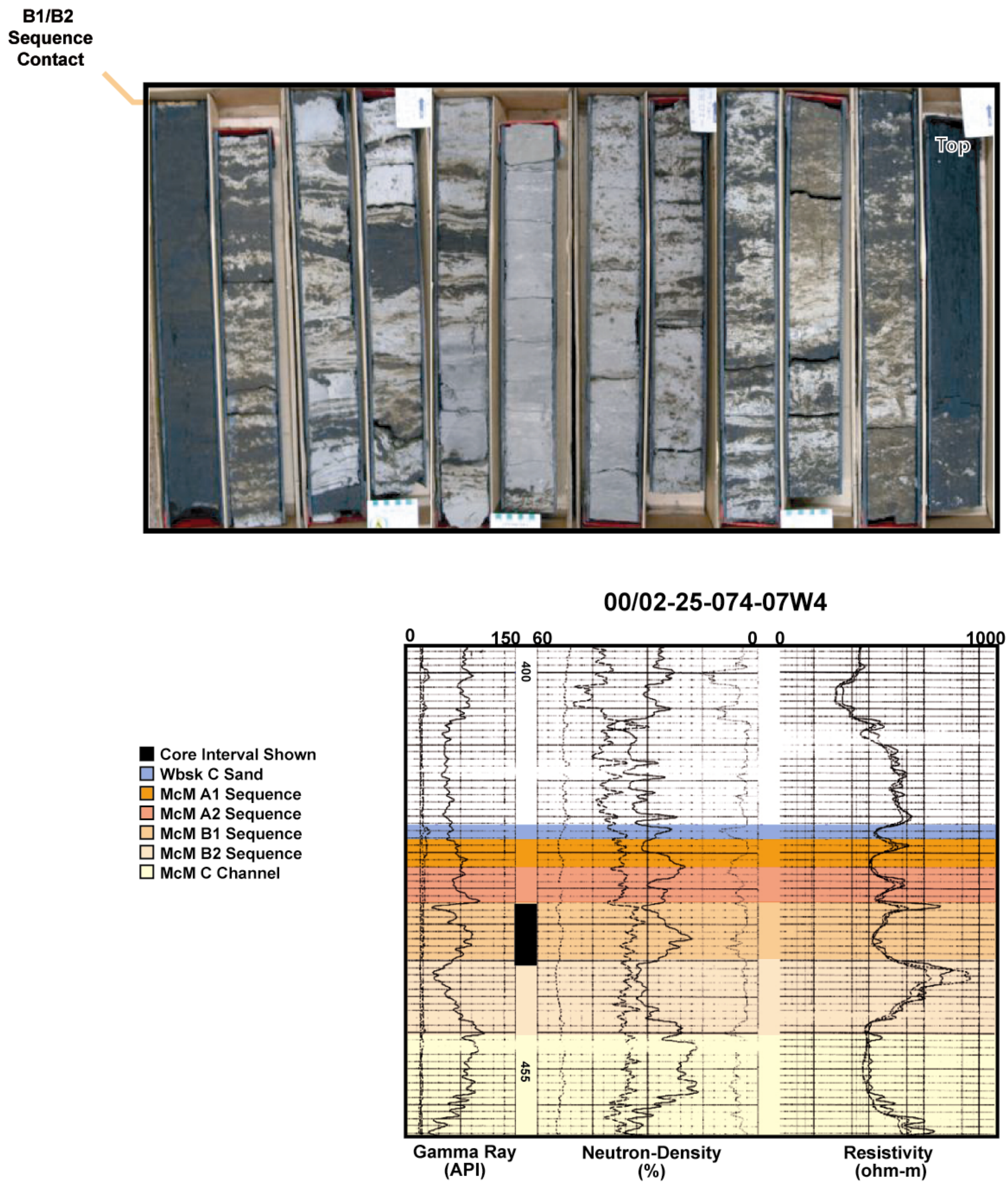


Figure 11 – McMurray B1 Sequence Core Photo and Well Log

McMurray A2 Sequence and A Channel

Unit Description

The A2 Sequence consists of a cleaning-upward package with light grey mudstone grading upward into silts and fine-grained wave-rippled quartz sands. It is similar in general description to the B2 Sequence, but the unit is not as bioturbated as either the B2 or B1 Sequence. The mudstone at the base of the A2 Sequence is 1 to 2 m thick. The base of the A2 Mudstone is characterized by a 5 to 20 centimetre (cm) thick condensed section of bitumen-stained sands and muds, which grade into a 1 to 2 m thick grey mudstone. Like that of the B2 Sequence, the mudstone is nonfissile and exhibits abundant trace fossils, including *Planolites* and small *Teichichnus*. Sands in the upper part of the sequence contain thin mudstone layers with synaeresis cracks, and mudstone layers are bioturbated with *Skolithos* and *Planolites*. The sequence ranges in thickness from about 3 to 9 m, although the unit may appear thicker if sediments of the A1 Sequence overlying the A2 Sequence are not separated from the A2 by a mudstone or muddy interval. The base of the A2 Mudstone occurs about 15 to 20 m below the Wabiskaw Marker, unless thick Wabiskaw B Valley-fill deposits are present in the region; in that case, the base of the A2 Mudstone can occur up to 30 m below the Wabiskaw Marker. Where present, the A2 Sequence overlies either the B1 Sequence or McMurray Channel deposits and can be eroded from above by Wabiskaw B and D Valley-fill deposits. Figure 12 presents the Wabiskaw Marker to the base of the A2 Mudstone isopach map.

McMurray A Channels are localized channels originating from the top of the A2 Sequence. They can erode the regional sands of the sequence and possibly the underlying units. By definition, A Channels do not cut away the mudstone of the B2 Sequence, although they can erode the mudstone of the A2 Sequence and all other units above the B2 Mudstone. The lithology and log characteristics of these A Channels are similar to the McMurray channel deposits. A Channels can be difficult to distinguish from Wabiskaw D Valley-fill deposits in the absence of mudstones or shales.

Log Characteristics

The mudstone at the base of the A2 Sequence has a consistent GR value near 120 API units. Similar to the associated B2 regional mudstones, the basal mudstone of the A2 is 15 to 25 API units higher than the Wabiskaw shale baseline (shales between the Wabiskaw Marker and the Wabiskaw C Sand). Density and neutron porosity curves diverge through the A2 Mudstone, unlike Wabiskaw shales, in which the density porosity is typically unaffected. Typical neutron porosities of the mudstone range from 36 to 45 per cent, density porosities near 22 per cent, and resistivities near 10 ohm-m. Typical log signatures of the upper sandy part of the sequence include a GR of 45 to 75 API units and neutron and density porosities ranging from 27 to 36 per cent. Porosities increase gradually from the base of unit to the top in a funnel shape, and resistivities are commonly greater than 10 ohm-m. Figure 13 presents a typical A2 Sequence and corresponding well log.

Where A Channels erode the upper sandy part of the A2 Sequence, the presence of the A2 Mudstone is difficult to discern on logs. However, it is assumed that the A2 Mudstone has been preserved if the mudstone exhibits the characteristic log responses and occurs at the expected stratigraphic position relative to the Wabiskaw Marker.

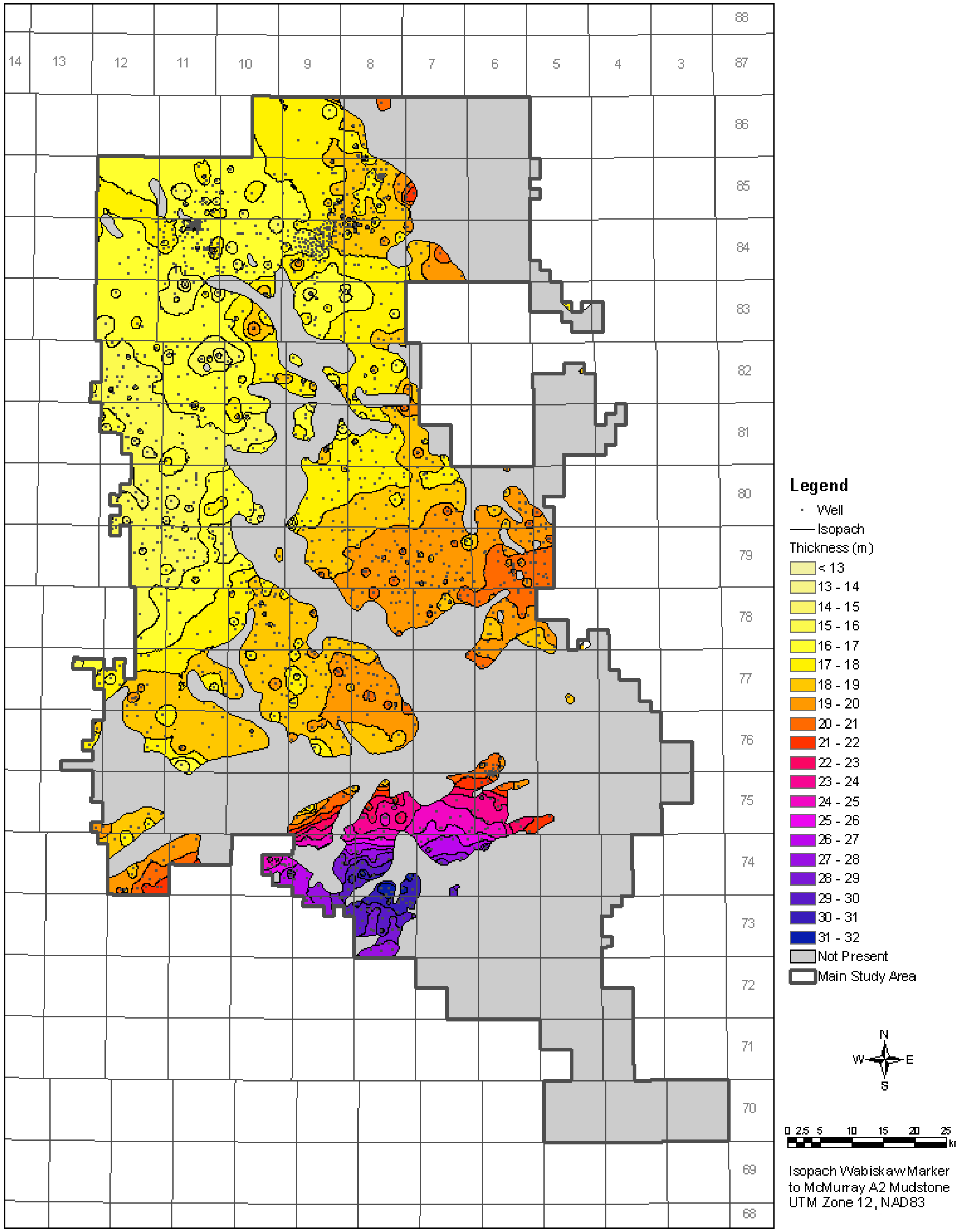


Figure 12 – Wabiskaw Marker to the Base of the McMurray A2 Mudstone Isopach Map

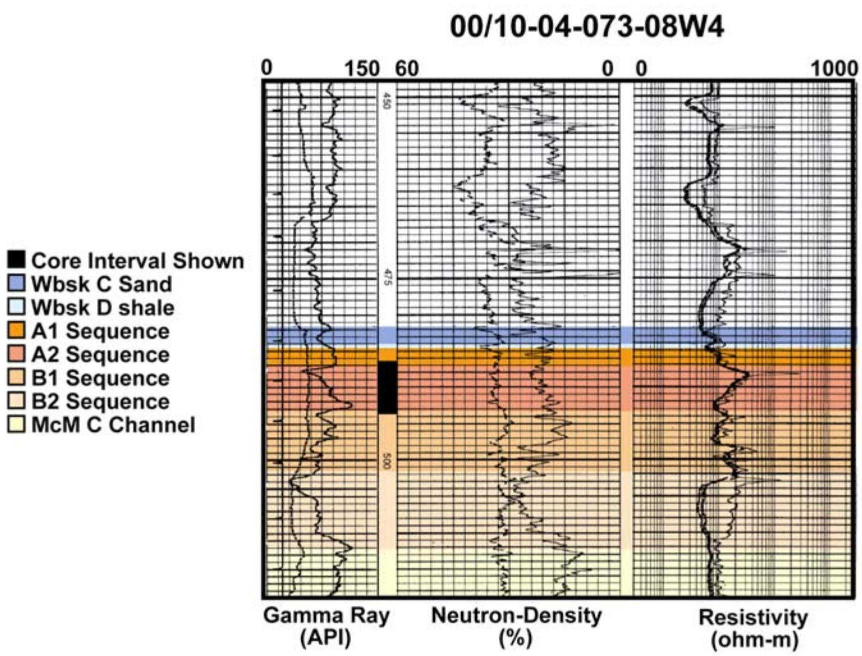


Figure 13 – McMurray A2 Sequence Core Photo and Well Log

McMurray A1 Sequence

Unit Description

The A1 Sequence is a unit of variable lithology, usually consisting of cleaning-upward fine-grained wave-rippled quartz sands (2 to 5 m) that often overlie a thin (10 to 30 cm) basal mudstone. In this most common form, the A1 resembles a thinner version of the A2 Sequence, but differs in that the basal mudstone of the A1 Sequence is variably present and does not contain abundant trace fossils typical of the A2 Mudstone. In some parts of the study area, where present above the A2 Sequence, the A1 can be the sandy top of an overall cleaning-upward A2 to A1 package, and it can be difficult to recognize if there is not a muddy interval at its base. When the A1 Sequence overlies McMurray Channel deposits, the unit is a sandy pulse at the top of the uppermost channel unit. Synaeresis cracks, soft sediment deformation, and trace fossils of *Cylindrichnus*, *Teichichnus*, and *Planolites* are variably present in sands with mud laminae.

In the northeast part of the main study area, the A1 differs in that it can grade downward into heavily bioturbated mudstones that grade farther downward into very dark grey to black organic-rich mudstone with minimal burrowing. There are no wave ripples present, and bedding varies from planar to low-angle bedding to chaotic bedding, with primary sedimentary structures rarely preserved. In-place and reworked burrows, as well as carbonaceous debris, are commonly found with the upper sand.

Log Characteristics

The basal mudstone of the A1 Sequence, where present, reads 20 to 25 API units lower than that of the A2 on the GR tool. The typical log signature of the upper sandy part of the sequence includes a GR of 60 to 75 API units and variable resistivity but generally greater than 20 ohm-m (higher than the Wabiskaw D Valley-fill of <10 ohm-m). Density porosity gradually increases from bottom to top. Where overlying the A2 Sequence, the A1 Sequence is usually separated from the A2 by a thin mudstone, resulting in an A1/A2 high resistivity doublet. Figure 14 presents a typical A1 Sequence and corresponding well log.

The A1 Sequence can overlie the A2 or B1 Sequences or McMurray Channel deposits and can be eroded from above by Wabiskaw B and D Valley-fill deposits. It can be difficult to distinguish from thinner Wabiskaw D Valley-fill on logs when overlying the A2 Sequence. Similarly it is difficult to differentiate from Wabiskaw C when no photo electric effect (PE) log is present.

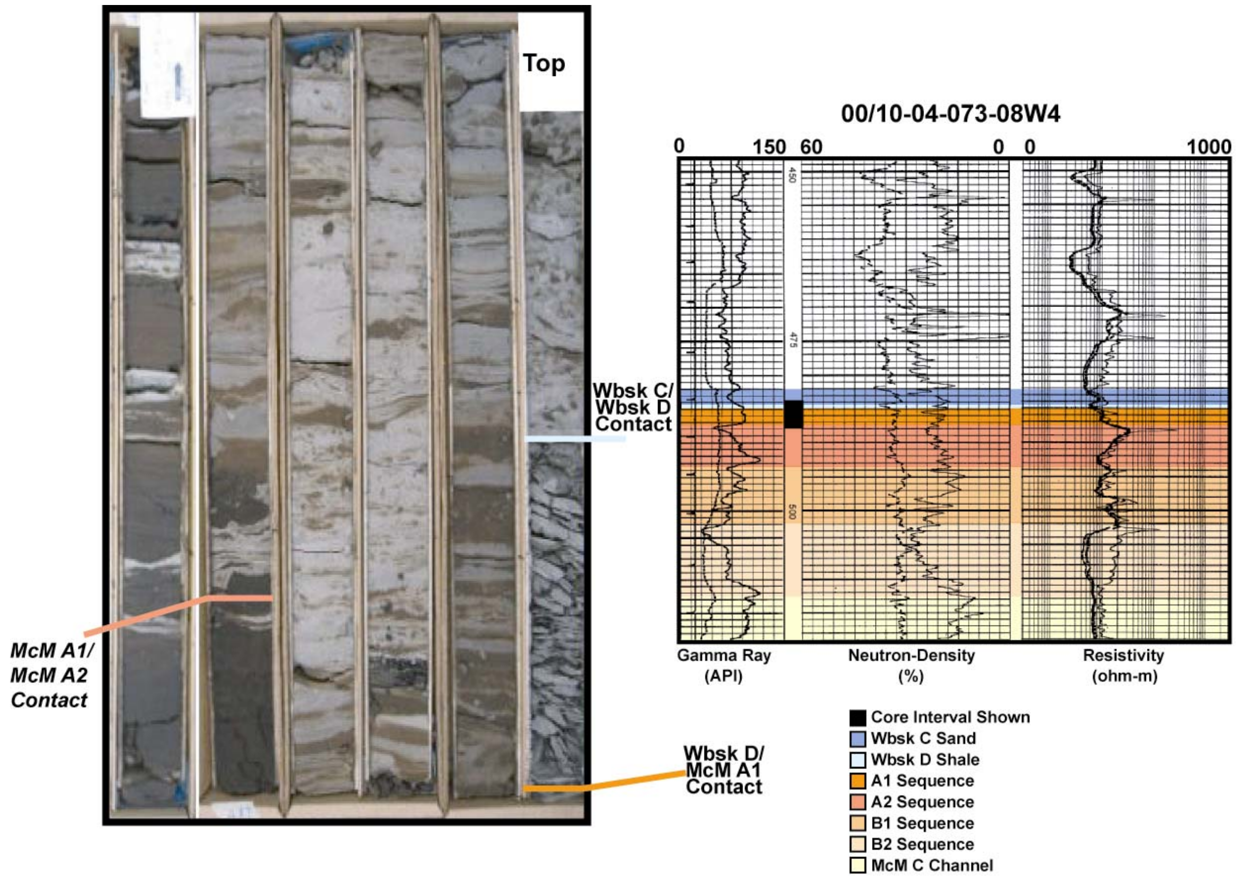


Figure 14 – McMurray A1 Sequence Core Photo and Well Log

Wabiskaw D Valley-fill

Unit Description

This is a variable unit consisting predominantly of fine-grained quartz-rich sand with interbedded dark blue-grey fissile shales similar to those of the Wabiskaw D Shale. Interbedded shales often drape wave-rippled sands. Shales can be brittle and are often broken during the coring process. Burrows in shales are rare, but can be larger than those typically seen in the McMurray Formation; in the south part of the main study area, the burrows are typically robust *Bergaueria*, *Thalassinoides*, *Teichichnus*, and *Planolites*. The Wabiskaw D Valley-fill unit can vary in thickness from 2 to 25 m, sometimes with thick reservoir-quality sands, but the unit is typically around 5 m thick. The Wabiskaw D Valley-fill can completely erode underlying units so that it sits directly above the lower regional units, such as the B1 or B2. Where the Wabiskaw D Valley-fill completely erodes the underlying A1 Sequence to lie directly above the A2 Sequence, it can be difficult to distinguish thin packages of Wabiskaw D Valley-fill from the A1 Sequence on logs.

Sands of the Wabiskaw D Valley-fill are derived from the erosion of the underlying McMurray Formation. When the diagnostic dark blue-grey shales are absent, it can be difficult to distinguish from McMurray channel sands in core.

Log Characteristics

The Wabiskaw D Valley-fill is typically represented on GR logs as a clean sand or interbedded sand and shale unit reading between 30 and 50 API units, with thin shale lenses having unique neutron-density porosity and resistivity log responses. The typical neutron porosity is greater than 30 per cent and is characterized by spikes of higher porosity than the surrounding sands. The density porosity of the shale is about 27 per cent, and overall porosity increases sharply at the base of the unit, rather than increasing gradually in a funnel shape. The interbedded shale causes resistivities below 10 ohm-m; otherwise the curve can spike due to thin interbedded sand/shale units. In the absence of interbedded shales, the Wabiskaw D Valley-fill is often difficult to distinguish from the underlying McMurray Channel deposits, as the two units share similar sand lithology. Figure 15 presents a typical Wabiskaw D Valley-fill sequence and corresponding well log.

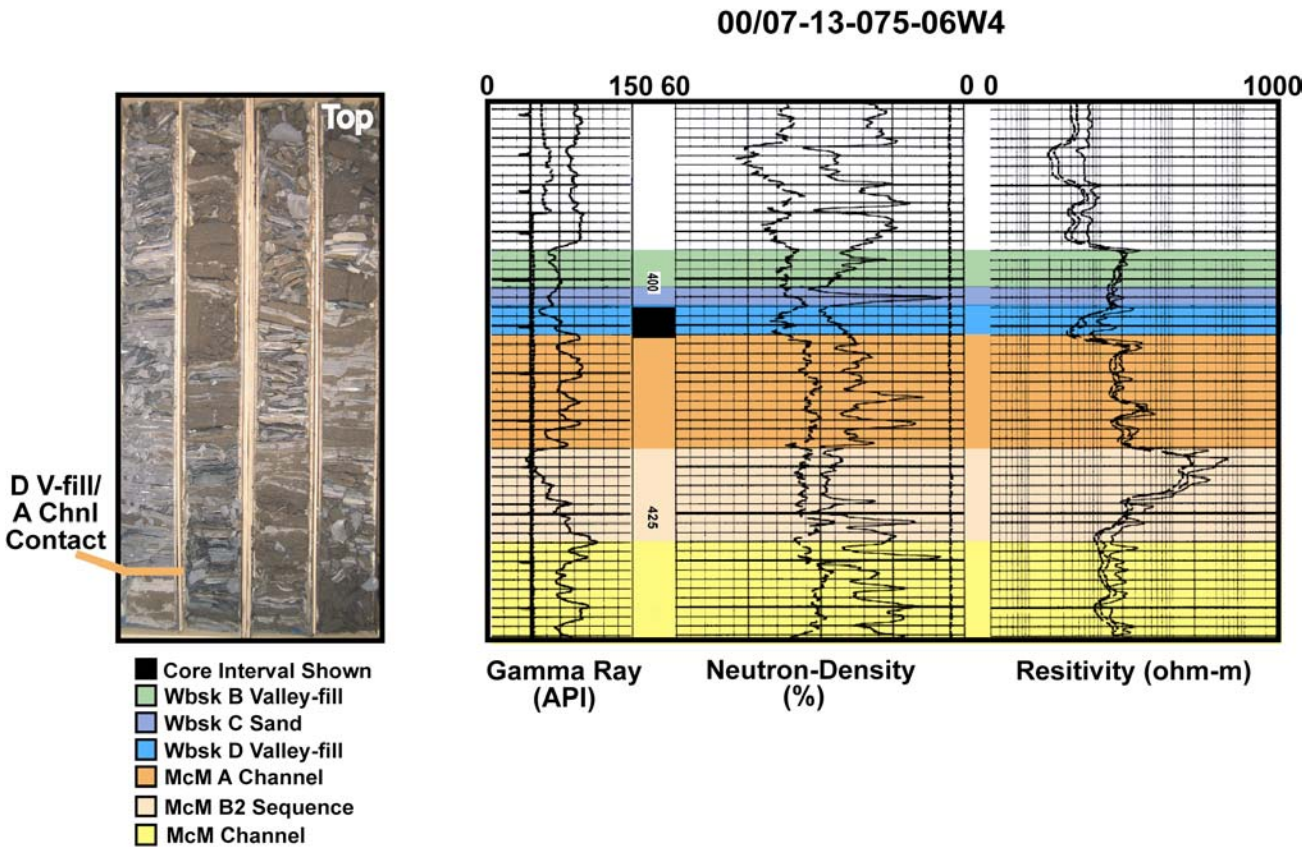


Figure 15 – Wabiskaw D Valley-fill Core Photo and Well Log

Wabiskaw D Shale

Unit Description

The Wabiskaw D Shale consists of true fissile shales, dark blue-grey in colour, commonly displaying platy fractures in core. Colour can also be charcoal grey, without the associated blue-grey. Trace fossils are typically absent, although small *Planolites* and *Chondrites* may be present. The D Shale varies in thickness from a few centimetres to 2 m but is commonly less than 1 m thick. It can be the basal Wabiskaw unit, unless eroded by younger Wabiskaw sands. Similar shales can also occur within the Wabiskaw D Valley-fill, but the Valley-fill shales tend to be sandier than the regional Wabiskaw D Shale.

Log Characteristics

The typical log signature includes a GR of 75 to 90 API units, increasing 10 to 15 API units relative to units above and below, and a neutron porosity spike greater than 30 per cent and sometimes greater than 45 per cent. Density porosity is variable, usually near 27 per cent, but it can deflect to lower values. The corresponding resistivity is commonly less than 10 ohm-m, and where the shale is thick and well developed, resistivity can be as low as 2 ohm-m. Identification is primarily based on a combination of high neutron porosity and low resistivity.

The Wabiskaw D Shale is a thin unit across the main study area, but the shallow-focused resistivity and neutron logs respond to shale intervals appearing thinner than 0.5 m. However, some logging tools may overestimate thickness of this unit as calibrated in core. Figure 16 presents a typical Wabiskaw D Shale sequence and corresponding well log.

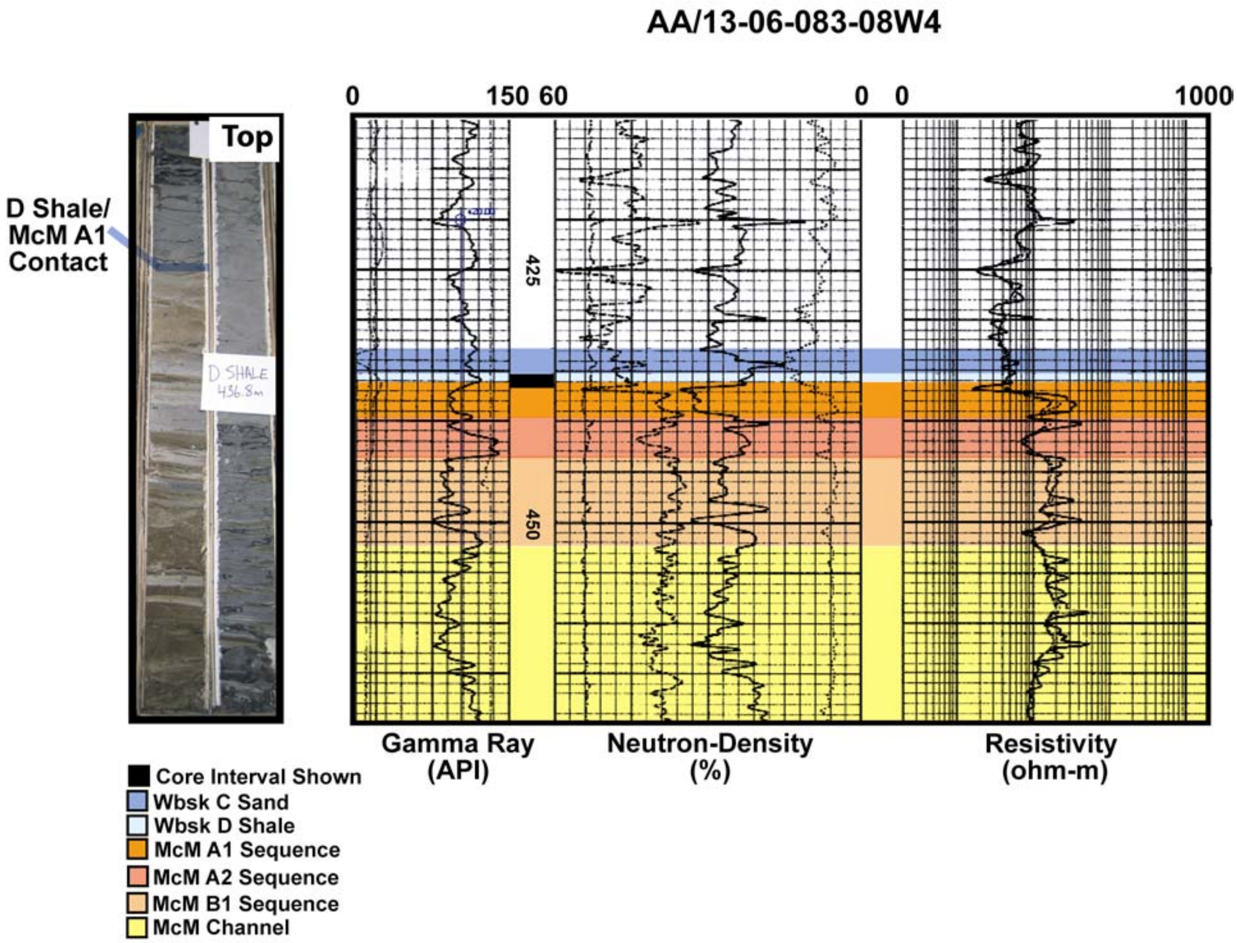


Figure 16 – Wabiskaw D Shale Core Photo and Well Log

Wabiskaw C Sand

Unit Description

The Wabiskaw C Sand is muddier than the McMurray sands and consists of glauconitic and lithic sandstone, fine- to medium-grained, sometimes alternating with finer-grained silts and mudstones. Sands are often heavily bioturbated with robust trace fossils of *Teichichnus*, *Asterosoma*, *Thalassinoides*, *Skolithos*, and *Diplocraterion*. The C Sand varies in thickness from a few tens of centimetres to over 10 m, with thicker sections present in the southeast part of the main study area. Thin siderite-cemented tight zones are common.

The Wabiskaw C Sand overlies a surface of erosion that is marked by the *Glossifungites* ichnofacies, resulting in glauconitic sand-filled vertical burrows penetrating the underlying units. The C Sand may overlie a variety of units, including the Wabiskaw D Shale, Wabiskaw D Valley-fill, McMurray A1 and A2 Sequences, and McMurray Channel deposits. Wabiskaw C Sands can be difficult to differentiate from sands of the overlying Wabiskaw B Valley-fill on logs when they share a sand-on-sand contact, but Wabiskaw C Sands typically have lower porosities.

Log Characteristics

The typical log signature of the Wabiskaw C Sand includes a GR of 60 to 90 API units, a weak to strong Spontaneous Potential (SP) deflection, and density and neutron porosities up to 30 per cent. Resistivity usually does not exceed 15 ohm-m, even when accompanied by gas effect. Wabiskaw C Sand density is higher than quartz sands of the McMurray, such that clean Wabiskaw C Sands show separation of the neutron and density porosity curves. The PE curve ranges from 2.5 to 3.5 barns/electron (b/e), which is slightly higher than the McMurray range of 1.8 to 2.5 b/e. The Wabiskaw C Sand is commonly recognized as the first sand underlying the Wabiskaw B Valley-fill or the thick shales of the Wabiskaw.

In the west-central part of the main study area, thin packages of Wabiskaw C Sand have been recognized in core but not resolved on accompanying well logs. The unit is difficult to resolve on well logs if its thickness is less than approximately 50 cm. Figure 17 presents a typical Wabiskaw C Sand sequence and corresponding well log.

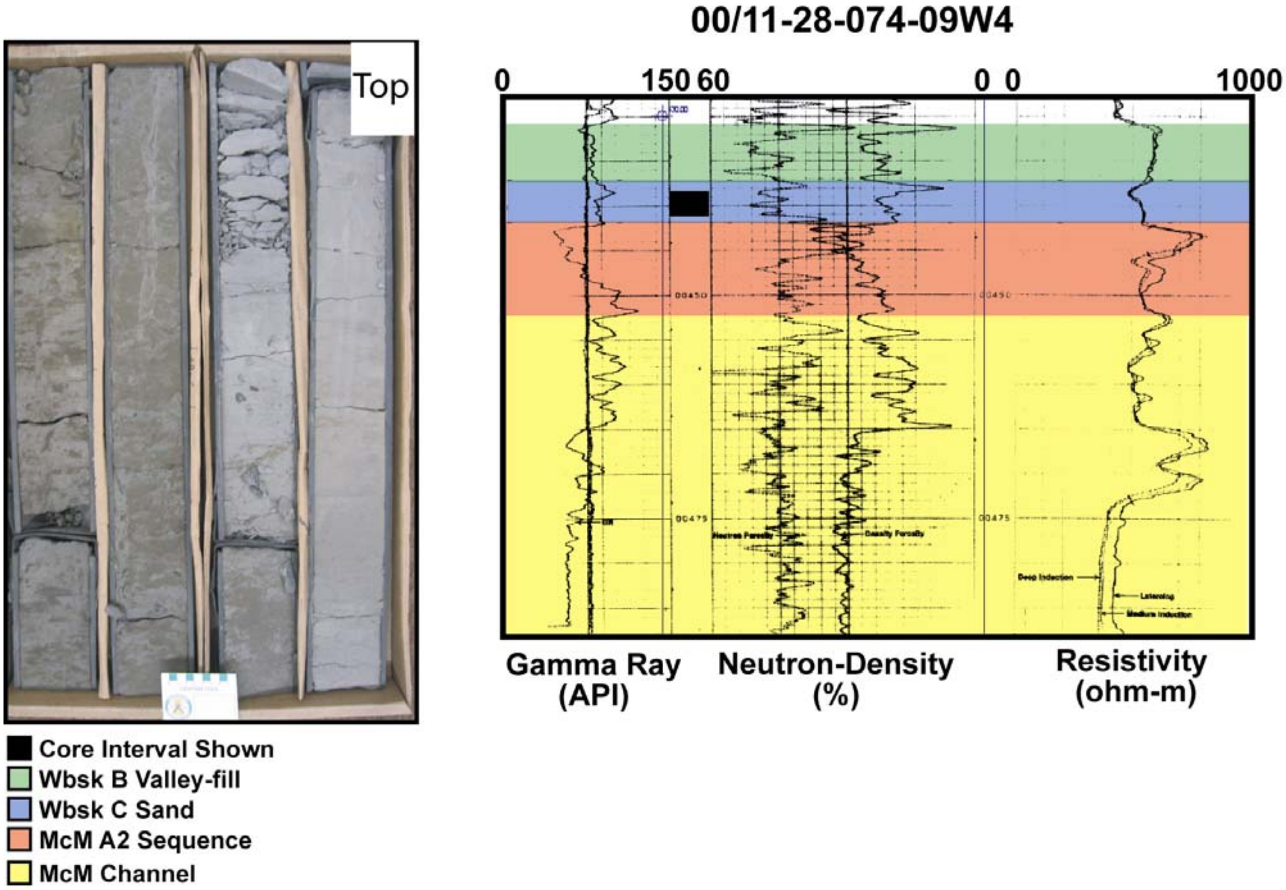


Figure 17 – Wabiskaw C Sand Core Photo and Well Log

Wabiskaw B Valley-fill

Unit Description

The Wabiskaw B Valley-fill consists mainly of massive litharenites, with mudstone lamina and mudstone breccia horizons and characteristic thin (< 1 m) carbonate-cemented tight streaks. Sands are very fine to fine grained, light grey in colour, with planar bedding as well as wave ripple and minor trough cross-bedding. The average thickness is 15 to 20 m, but the unit thickens rapidly to exceed 40 m in the eastern part of the main study area in Townships 73 and 74. The Wabiskaw B Valley-fill often overlies the Wabiskaw C Sand or the McMurray A1 or A2 Sequences, but can occasionally erode those units to overlie the B1 or B2 Sequence. The Wabiskaw B Valley-fill can be differentiated from the underlying Wabiskaw C Sand by the lack of glauconite and by the prominent calcium carbonate-cemented zones. The unit is well developed across most of its occurrence, and in these areas the top of the unit occurs within 2 to 4 m below the Wabiskaw Marker; where the unit is thinnest, it occurs about 10 m below the marker.

Where the Wabiskaw B Valley-fill is thickest, it appears to fill the accommodation space created by the apparent downward subsidence of the regional units. The underlying regional units can be preserved beneath the Wabiskaw B Valley-fill, not cut away by the valley, suggesting that subsidence of the regional units occurred prior to the deposition of the Wabiskaw B Valley-fill. When the Wabiskaw Marker later drapes all units, the resulting stratigraphy can lead to a range of thicknesses between the marker and regional units.

Log Characteristics

The typical log signature of the Wabiskaw B Valley-fill includes a GR between 60 and 75 API units and resistivity of about 20 to 30 ohm-m when saturated with bitumen (usually less than 8 ohm-m when wet). The characteristic thin (<1 m) carbonate-cemented tight sands have spikes of high resistivity and low porosity. Neutron porosity can achieve 45 per cent, density porosity about 30 per cent, and PE values typically equal to or greater than 2.5 b/e. Figure 18 presents a typical Wabiskaw B Valley-fill sequence and corresponding well log.

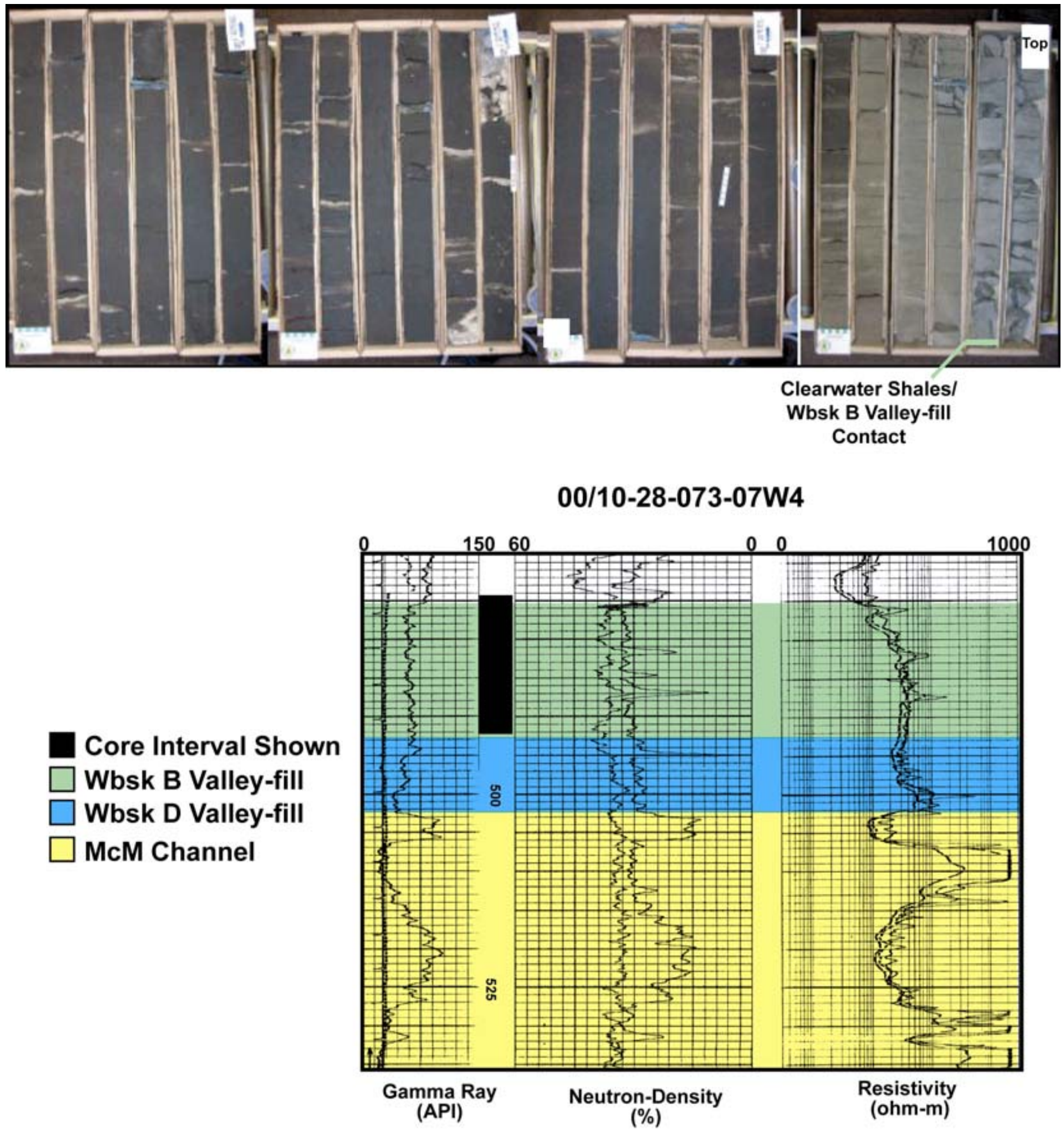


Figure 18 – Wabiskaw B Valley-fill Core Photo and Well Log

2.2.2 Distribution of Stratigraphic Units

McMurray Channel / McMurray C Channel

The McMurray Channel and McMurray C Channel deposits are ubiquitous in the main study area, as channel sands underlie all of the regional McMurray units (Figure 19). The study, however, makes a distinction between channel sands that were deposited prior to the McMurray B2 Sequence and channel sands that were deposited after the McMurray B2 Sequence, as stated in the previous section. McMurray C Channels are identified where the B2 mudstone is present and originate from the base of the B2 mudstone. McMurray Channel deposits erode the B2 mudstone and originate from any number of younger regional horizons; they are therefore stratigraphically higher in the section. These two units have been mapped as one unit.

The McMurray Channel and McMurray C Channel sediments are preferentially thickened within two linear Paleozoic lows (i.e., valley systems), both trending roughly northward. The main axis of McMurray channel deposition trends north-northwest along the eastern edge of the main study area, roughly linear from Township 75, Range 04, through to Township 86, Range 07. A secondary valley system trends northeast from Township 78, Range 10, joining the main valley system at a junction near Township 86, Range 08. Other narrower, less prominent, secondary valley systems are also present within the study area. While McMurray channel deposits are preferentially thickened within these main valleys, subsequent deposition is also influenced by these valley systems, and younger valleys and channels commonly occur along these trends.

Although broad channel deposition trends are recognizable, the existing well density is insufficient to recognize local channel occurrences in the study area. Further, within the McMurray C Channel and McMurray Channel stratigraphic units, the lithology is also highly variable and difficult to predict.

Channel thickness in the main valley trend along the eastern edge of the main study area commonly reaches 50 m and can exceed 100 m. Some of the thickest deposits are found in Township 85, Range 06; Township 84, Range 07; and Township 81, Range 04. Channel thicknesses in the secondary valleys and outlying areas commonly reach 30 m and can exceed 40 m.

Structure maps of this unit and the other defined units in this study are presented on the attached CD.

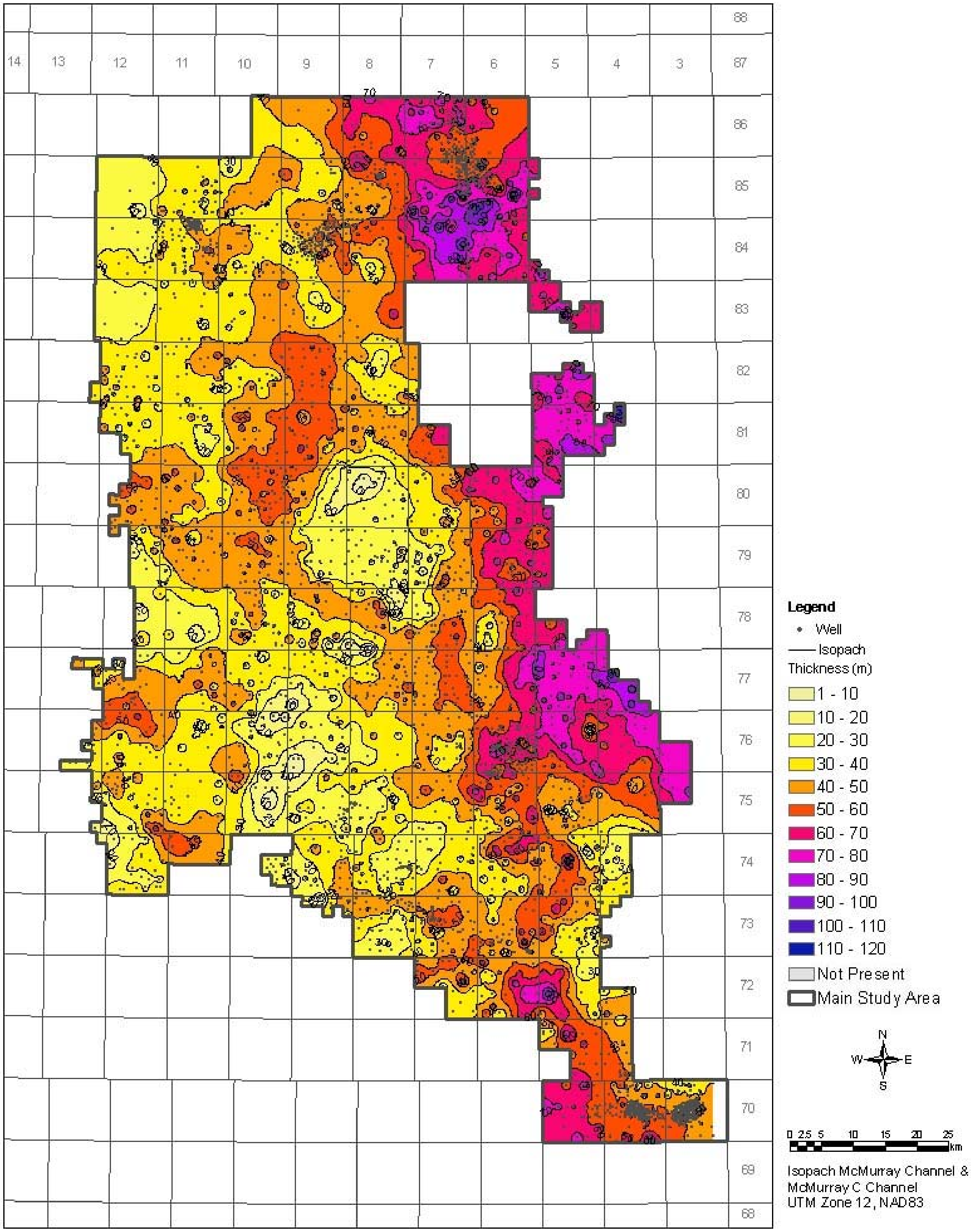


Figure 19 – McMurray Channel / McMurray C Channel Isopach Map

McMurray B2 Sequence and B2 Channel

The B2 Sequence is largely eroded across the main study area; in large areas, all that remains of the B2 are erosional remnants appearing as small island-like features (Figure 20). One region where the B2 Sequence is extensively preserved (about 4 townships in size) is in the south-central part of the main study area and contains the northern part of the Chard-Leismer area, centred in Township 79, Range 08. Several small patches of preserved B2 Sequence form a linear trend oriented east-southeast from Township 79, Range 12 to Township 73, Range 04.

When compared with the isopach map of the B1 Sequence, the two maps can be seen to share several similarities, but the B2 Sequence is more highly eroded and distinct erosion/preservation trends are more difficult to differentiate.

In the central part of the main study area, the B2 Sequence is most commonly between 5 and 10 m thick, with numerous patches slightly thicker than 10 m. Isopach maps of this unit do not display obvious trends in thickness.

Given that the McMurray B2 Mudstone defines the base of the McMurray B2 Sequence, its distribution is the same as that of the B2 Sequence. Figure 21 illustrates the distribution of the McMurray B2 Mudstone. This map is used later in the study to identify nonassociated gas pools.

McMurray B2 Channel deposits occur sporadically throughout the main study area but are rarely found to be correlatable between adjacent wells. The thickness of B2 Channels throughout the main study area ranges from 3 to 12 m. See Figure 22 for the isopach map of this unit.

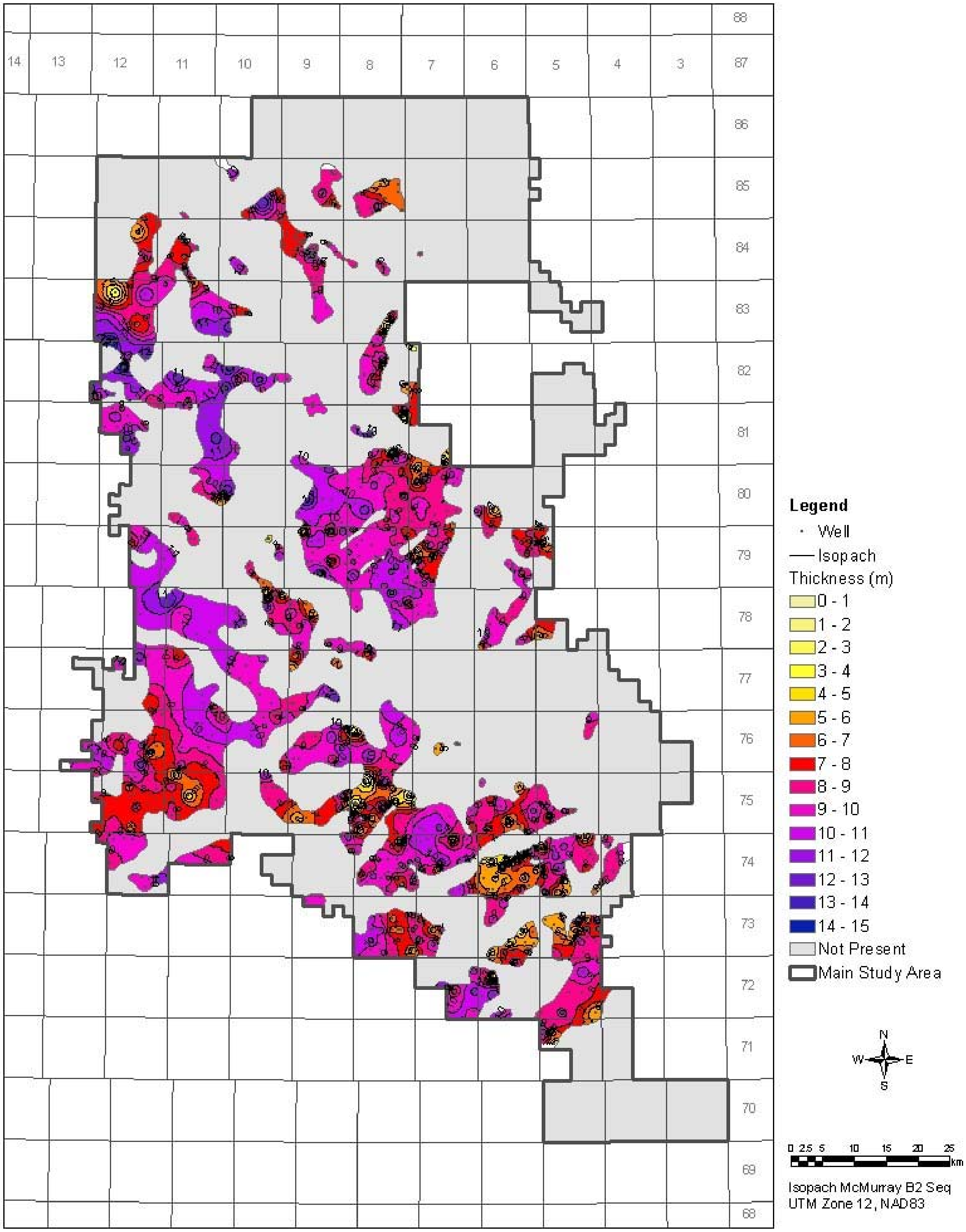


Figure 20 – McMurray B2 Sequence Isopach Map

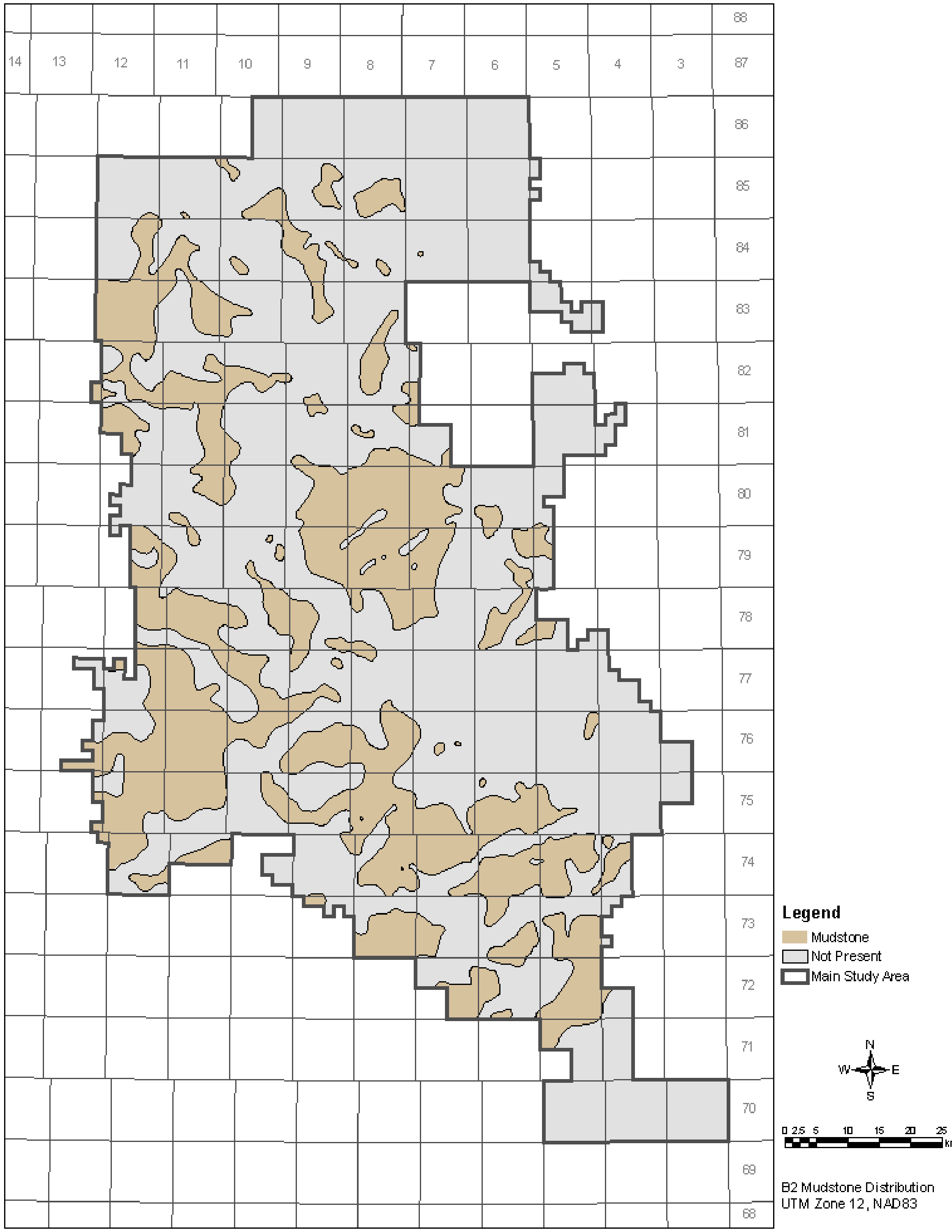


Figure 21 – McMurray B2 Mudstone Distribution

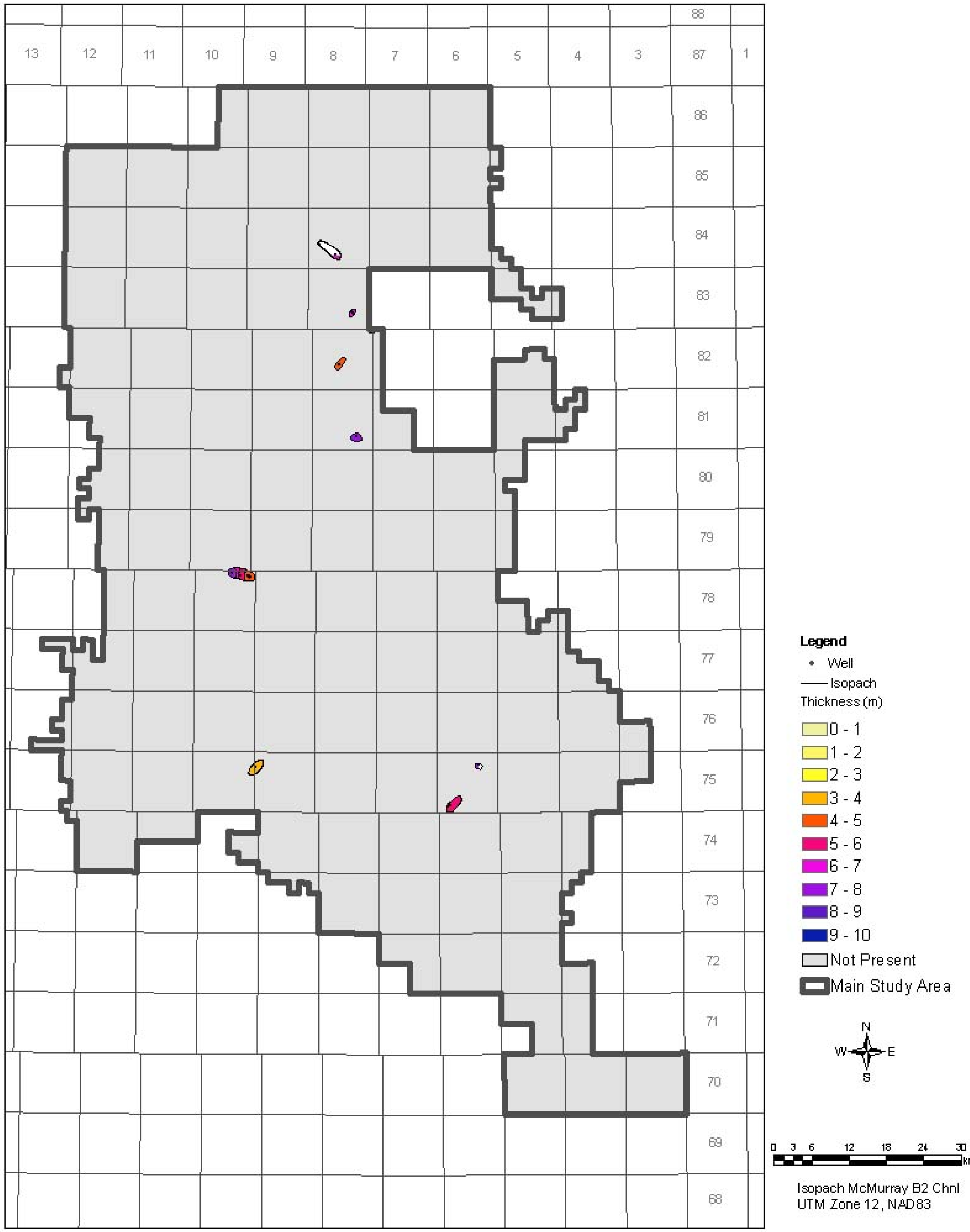


Figure 22 – McMurray B2 Channel Isopach Map

McMurray B1 Sequence and B1 Channel

The B1 Sequence is present over about 50 per cent of the northern and western parts of the main study area, proximal to the main and secondary valleys outlined on the McMurray Channel and C Channel maps. The valley outlines are roughly identified by the B1 isopach map that displays the erosional nature of the succession (Figure 23). As described earlier, the main valley is oriented northward along most of the eastern edge of the study area and reaches a width of over three townships (18 miles) in some areas, (e.g., Townships 73, 77, and 86). One of the secondary valleys is oriented toward the southeast from Township 80, Range 10, joining the main valley at a junction near Township 77, Range 07. This valley continues north-northeast from Township 80, Range 10, to Township 83, Range 09. The other secondary valley is oriented approximately due east from Township 75, Range 10, to join the main valley near Township 76, Range 07.

When compared with the isopach map of the B2 Sequence (see above), the two maps show distinct similarities in that the two units appear to share regions of erosion and preservation likely due to the nature of McMurray channel deposition. However, the B1 Sequence is more often preserved, and distinct trends are more easily identified.

In the main part of the study area, the B1 Sequence is most commonly between 5 and 10 m in thickness. The isopach map of this unit does not display obvious trends in thickness.

Well-defined B1 Channel deposits are rare, occurring sporadically throughout the main study area. These channels have been identified both in single wells and in narrow trends correlatable between up to 5 adjacent wells. B1 Channels are often between 5 and 10 m thick, but can reach 21 m in thickness. See Figure 24 for the isopach map of this unit.

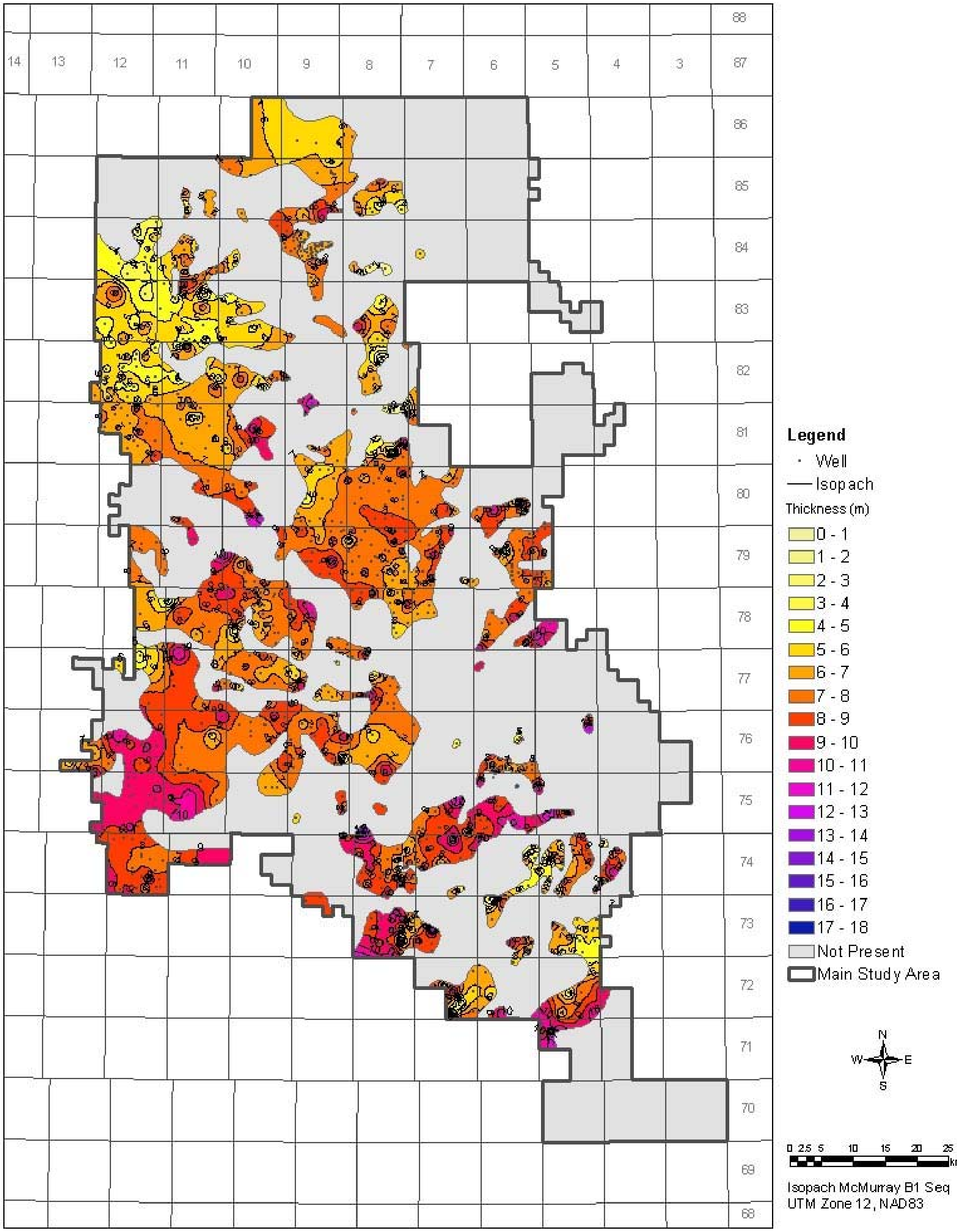


Figure 23 – McMurray B1 Sequence Isopach Map

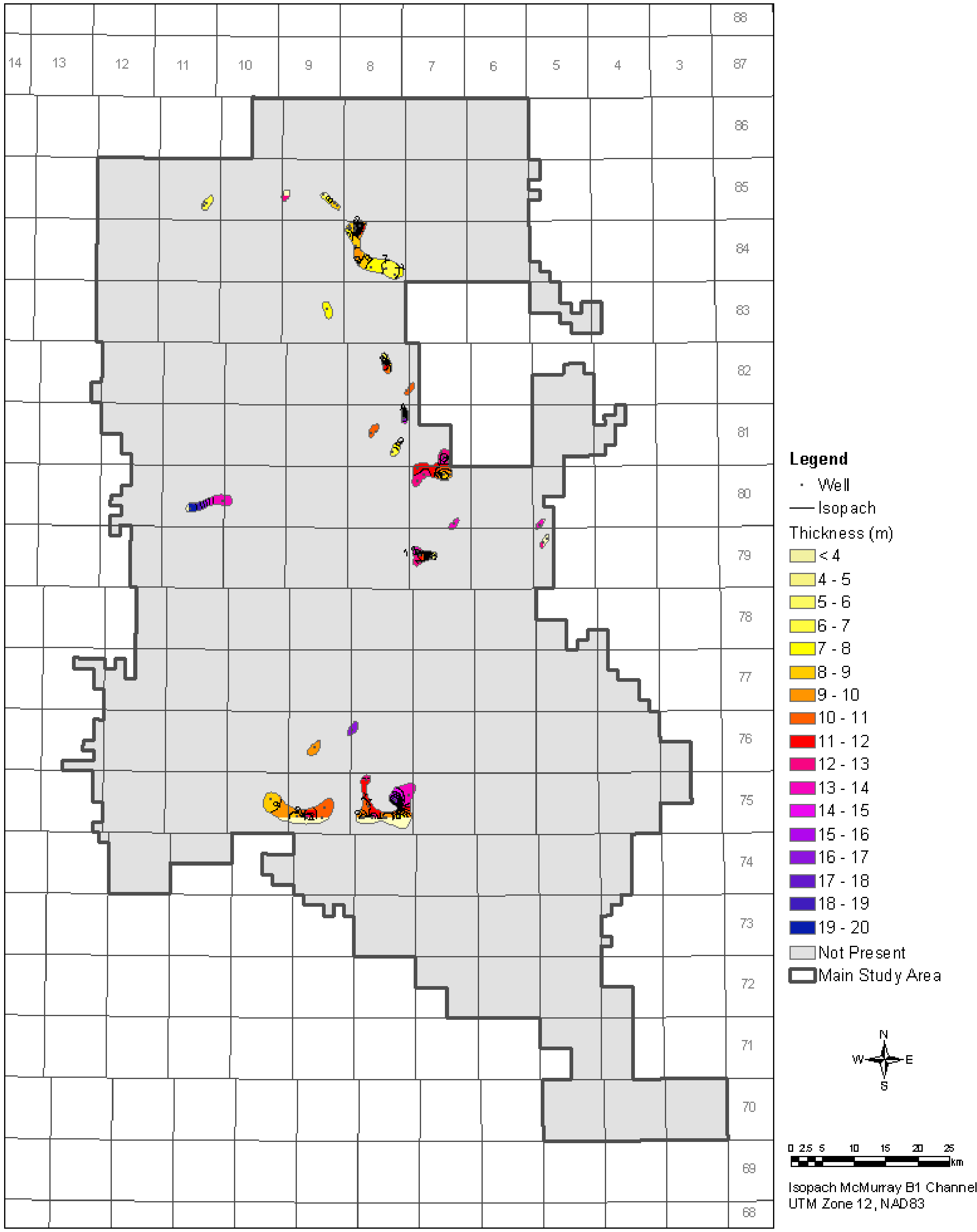


Figure 24 – McMurray B1 Channel Isopach Map

McMurray A2 Sequence and A Channel

The A2 Sequence is best preserved within the central region of the main study area and is clearly dissected by channel trends (Figure 25). The size and orientation of these channels is similar to those seen in the B1 Sequence, although channel trends are oriented slightly differently. As well, linear channel trends are better defined, and secondary channels exhibit distinct tributaries.

In the main part of the study area, the A2 Sequence ranges in thickness from 3 to 9 m. The isopach map of this unit shows thicker deposits in the Chard-Leismer area and thinner deposits to the north and west. The A2 Sequence may appear thicker if a sandy overlying A1 Sequence is present but is not differentiated and interpreted as part of the A2 Sequence.

Given that the McMurray A2 Mudstone defines the base of the McMurray A2 Sequence, its distribution is the same as that of the A2 Sequence. Figure 26 illustrates the distribution of the McMurray A2 Mudstone. This map is used later in the study to identify nonassociated gas pools.

McMurray A Channel deposits are rarely developed in the northern and central parts of the main study area and are best developed south of Township 75 (Figure 27). Identification of a channel as McMurray A Channel is contingent upon the preservation of the B2 Mudstone. As a result, the extent of the A Channels may be larger than mapped where they cut deep enough to remove the B2 mudstone, in which case McMurray Channel terminology is applied.

While single well deposits are more typical of the northern part of the study area, McMurray A Channel deposits south of Township 75 can often be correlated among several wells. The most extensive channelling occurs in Township 74 in Ranges 04, 05, 06 and in Township 72, Ranges 05 and 06; however, the A Channel sands in these areas are often difficult to distinguish from clean Wabiskaw D Valley-fill sands, which are also prevalent.

Throughout the main study area, the McMurray A Channel deposits are typically 5 to 10 m thick but reach a maximum thickness of 25 m in Township 74, Range 06.

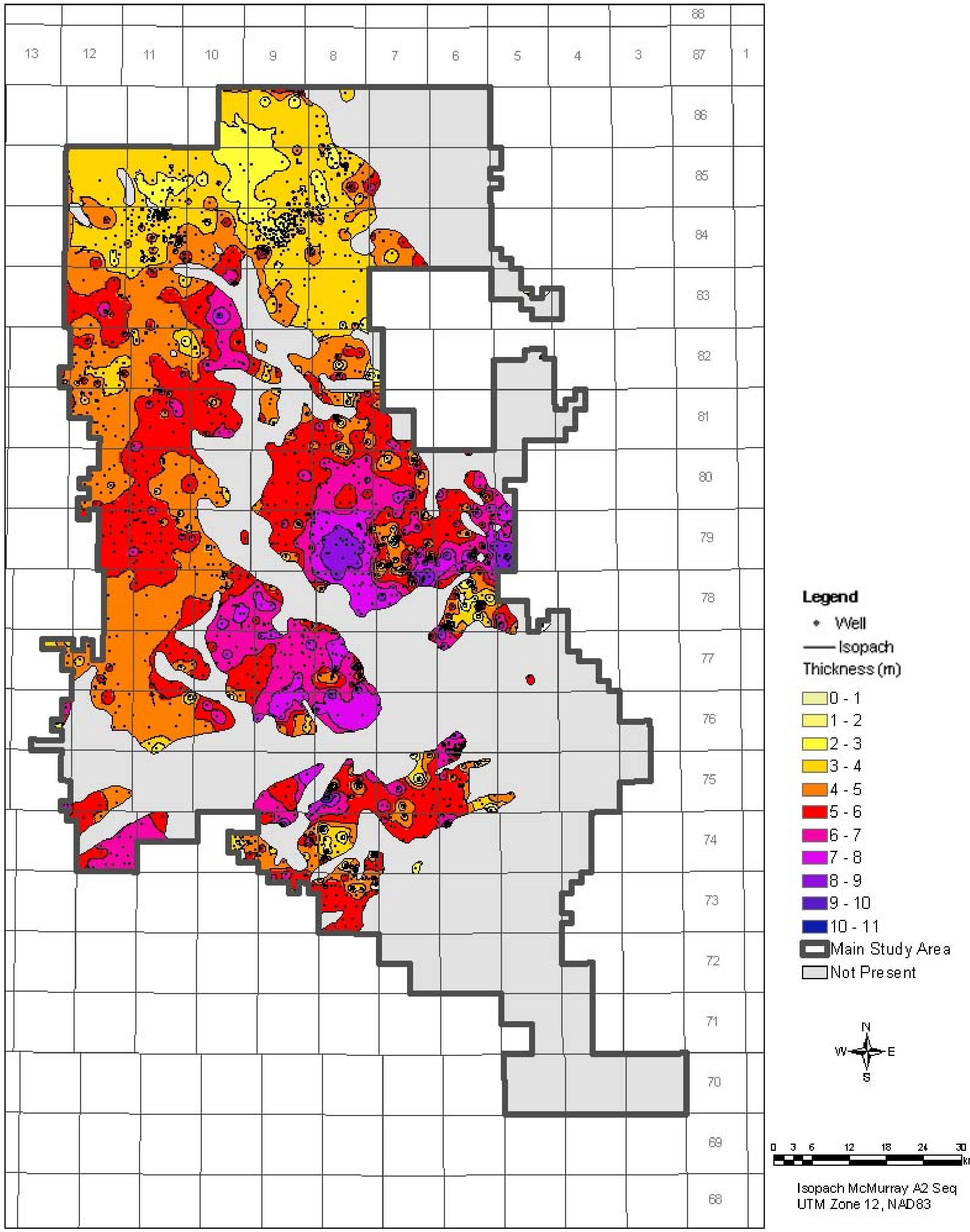


Figure 25 – McMurray A2 Sequence Isopach Map

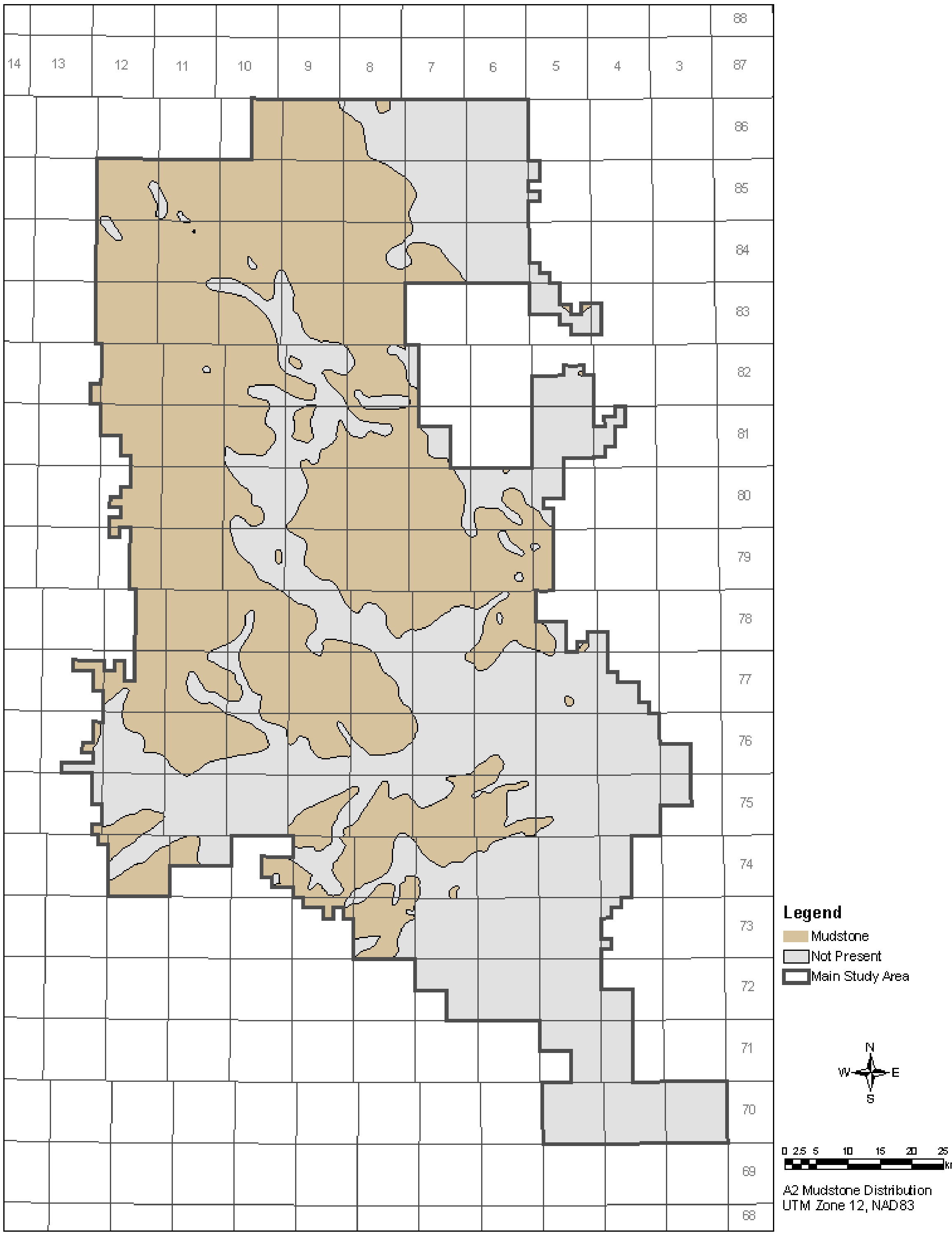


Figure 26 – McMurray A2 Mudstone Distribution

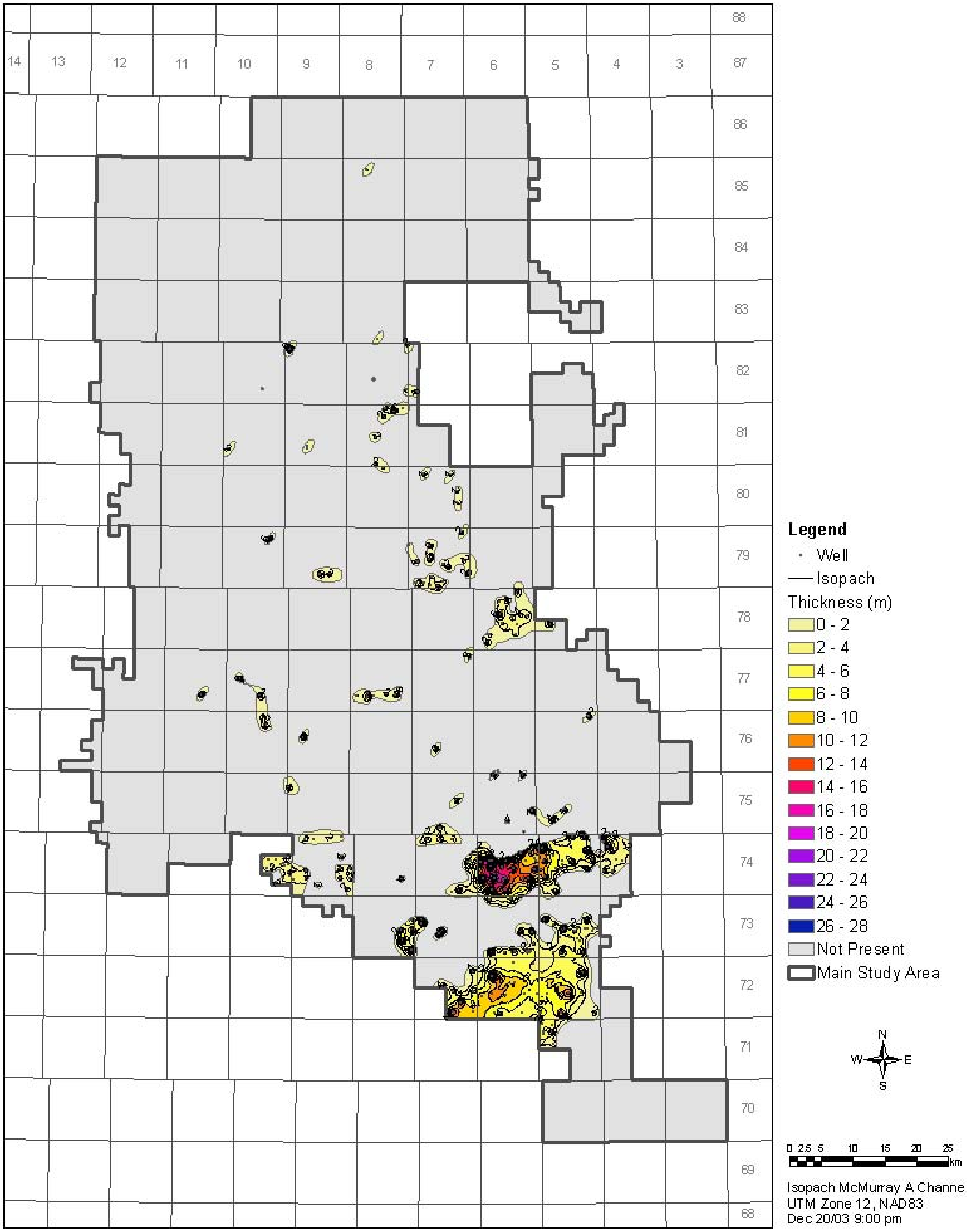


Figure 27 – McMurray A Channel Isopach Map

McMurray A1 Sequence

The A1 Sequence is largely present in the north and northwest part of the main study area and preserved only locally in the south part of the main study area (Figure 28). In the northwest part of the main study area, the A1 Sequence is present in two north-northwest trends, separated by a valley system with a similar orientation. The more westerly trend of the A1 Sequence lies in and between Township 82, Range 12, to Township 86, Range 09, and its counterpart lies in and between Township 78, Range 11, to Township 84, Range 08. A southerly trend of A1 Sequence is oriented south-southwest from Township 77, Range 05, to Township 74, Range 04. Smaller patches of the A1 Sequence are scattered throughout the southern part of the main study area.

In the central part of the main study area, the A1 Sequence ranges in thickness from 2 to 5 m, although thicknesses of 1 to 3 m are most common. The isopach map of this unit does not display obvious trends in thickness.

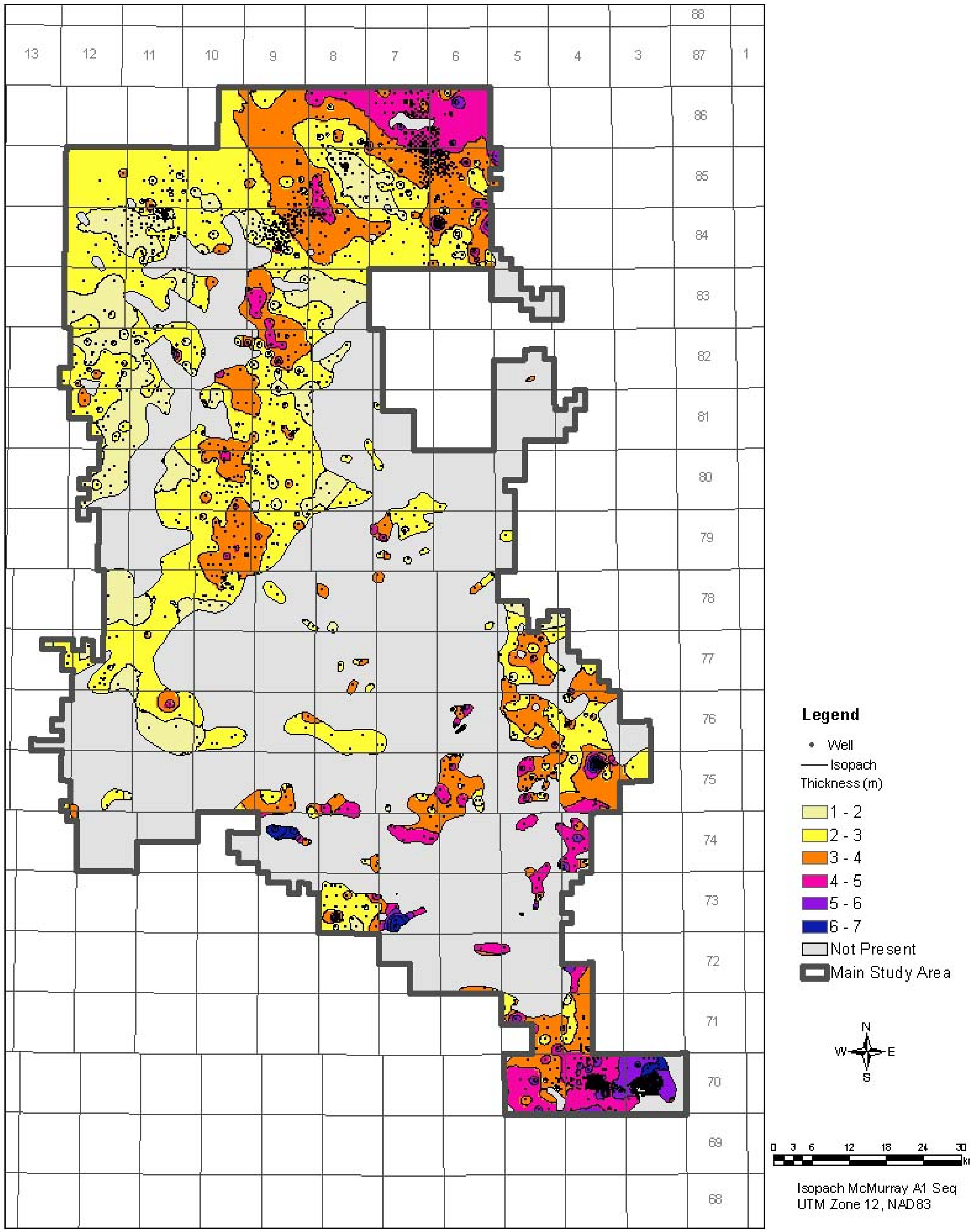


Figure 28 – McMurray A1 Sequence Isopach Map

Wabiskaw D Valley-fill

Wabiskaw D Valley-fill deposits are present in the eastern parts of the study area from north to south (Figure 29). The D Valley-fill deposits are most prominent in the southeast. The largest contiguous deposit of Wabiskaw D Valley-fill is oriented south-southeast from Township 77, Range 06, to Township 75, Range 05. Two sinuous secondary valleys oriented roughly eastward in Townships 75 and 77 join the main valley deposit. One of the valleys connects a large, more easterly deposit of Wabiskaw D Valley-fill that is located mainly in Townships 74 and 75, Range 08. The D Valley-fill deposits in this area are predominantly sand and are difficult to distinguish from McMurray Channel sediments. The third large deposit of Wabiskaw D Valley-fill is located on the north boundary of the Surmont area in Township 84, Ranges 06 and 07.

Where present north of Township 78, Wabiskaw D Valley-fill deposits are typically thin, usually ranging in thickness from 2 to 3 m, and occasionally exceeding 5 m. South of Township 78, the unit generally ranges in thickness from 5 to 10 m but can reach 25 m thick in local areas, as in Townships 75 to 77, Range 06.

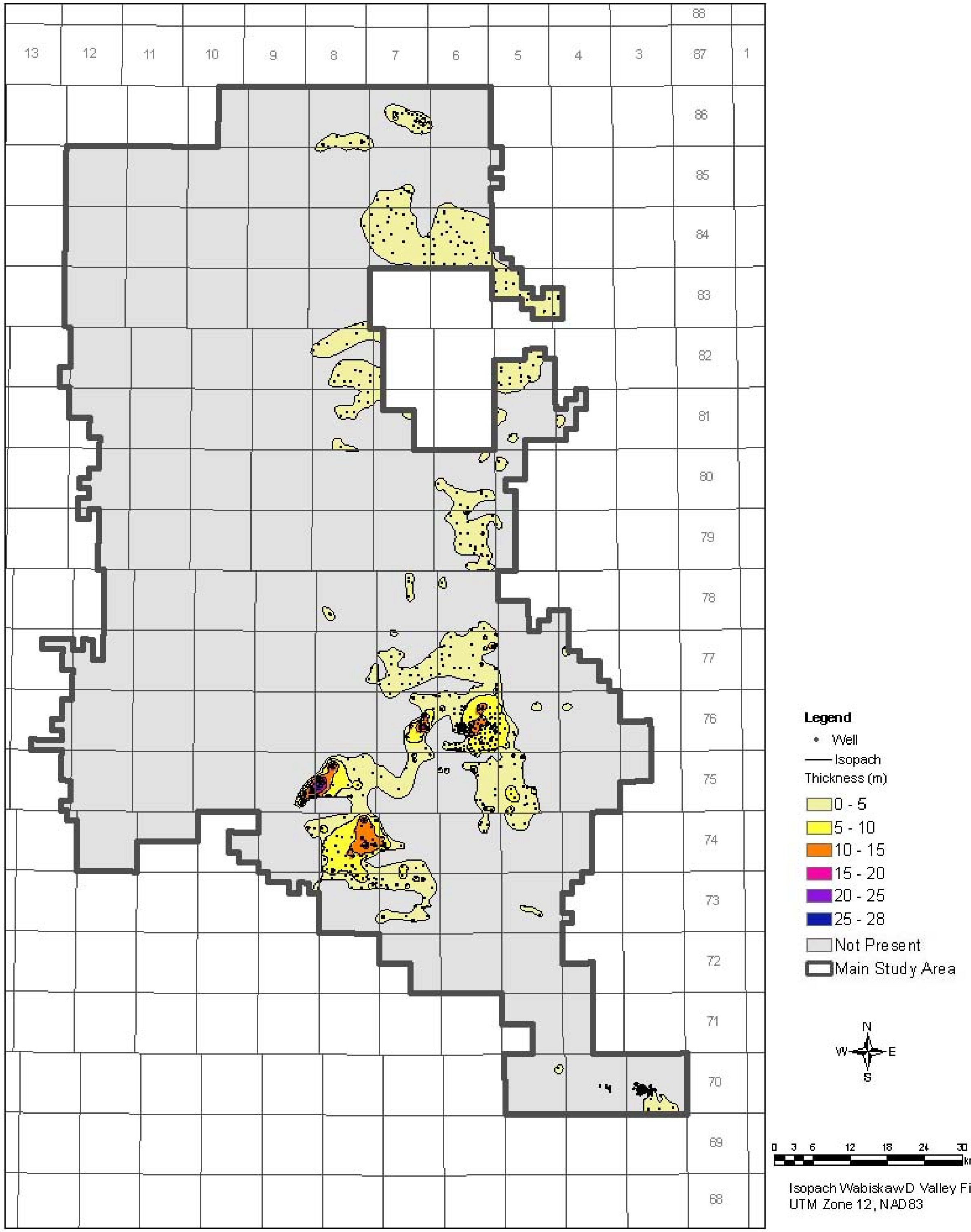


Figure 29 – Wabiskaw D Valley-fill Isopach Map

Wabiskaw D Shale

The Wabiskaw D Shale is present mainly in the eastern part of the main study area (Figure 30). The western edge of the Wabiskaw D Shale is sinuous in nature, with few small remnants preserved just west of the main edge that may indicate the depositional extent of the D Shale but also may be partially due to erosion. Near the northern boundary of the main study area, the unit is present across Townships 84 and 85 from east to west. The Wabiskaw D Shale is rare south of Township 75.

In the main study area, the Wabiskaw D Shale is usually between 0.1 (confirmed in core) and 2 m in thickness. The isopach map of this unit does not display obvious trends in thickness.

Due to the thin nature of the shale, a distribution map of the D Shale was not produced. Instead, a hand-drawn edge approximating 0.5 m thickness was produced for the communication assessment in Section 5.

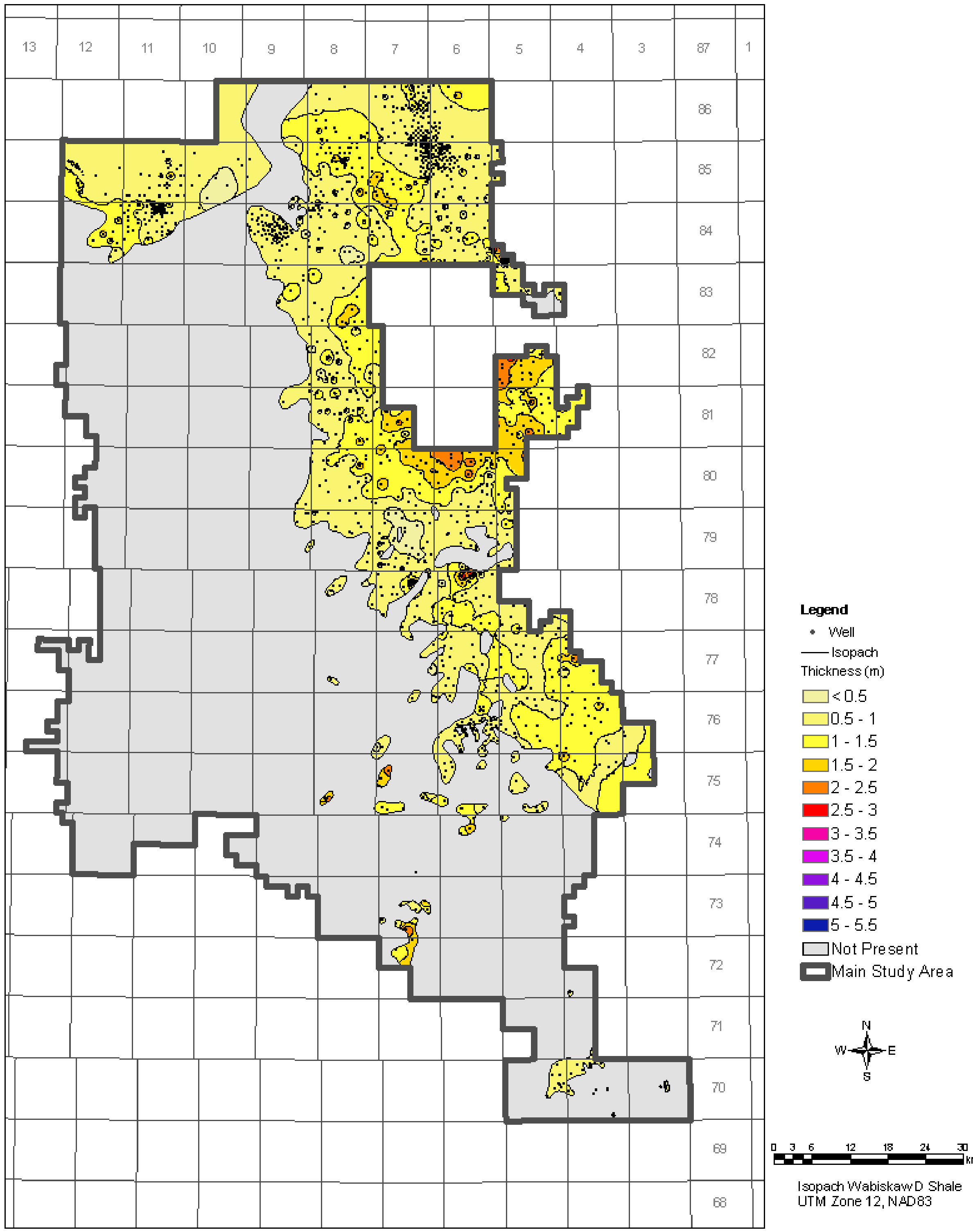


Figure 30 – Wabiskaw D Shale Isopach Map

Wabiskaw C Sand

The Wabiskaw C Sand is present across most of the main study area and is absent in three distinct regions (Figure 31). An area of erosion in the southeast part of the study area is centred near Township 73, Range 06, and corresponds with the presence of overlying Wabiskaw B Valley-fill. A similar sized area is present in the southwest part of the study area centred on Township 75, Range 10. The largest area of erosion/non-deposition is centred in Township 81, Range 10, and lies against the west-central border of the study area. In this area, the Wabiskaw C Sand is either completely eroded or present as a very thin unit (< 0.5 m) that is recognizable in core but too thin to be resolved in the bulk of the well logs. Since most of the wells in this area are without core through this unit, the C Sand is interpreted to be eroded.

In the main part of the study area, the Wabiskaw C Sand varies in thickness between 0.2 (confirmed in core) and 10 m, with most values between 3 and 6 m. The thinnest deposits are found in the northwest, and the Wabiskaw C Sand thickens to both the south and the east. The thickest deposits are present in the southeast part of the main study area and reach 10 m in thickness.

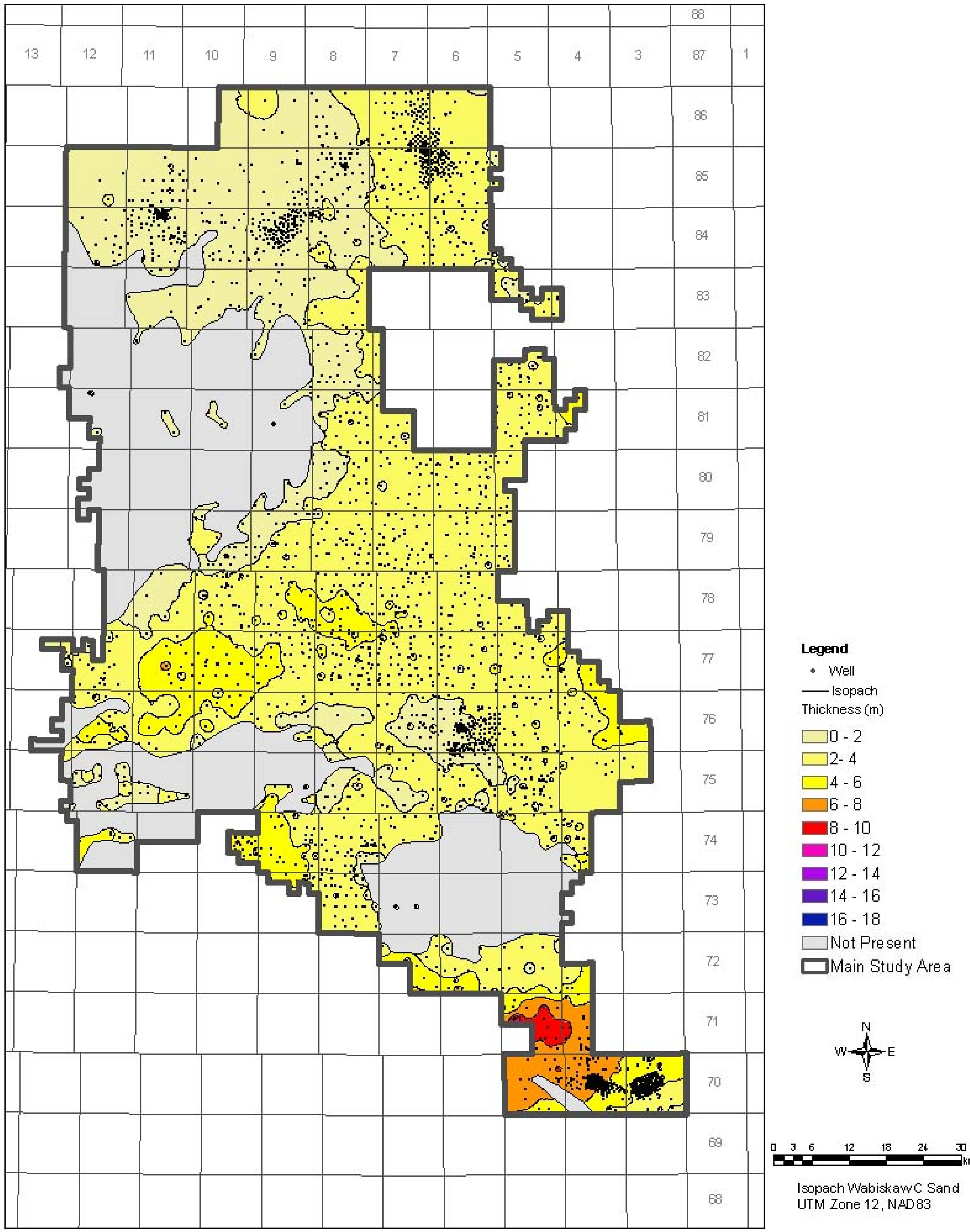


Figure 31 – Wabiskaw C Sand Isopach Map

Wabiskaw B Valley-fill

Wabiskaw B Valley-fill deposits are present only south of Township 77 (Figure 32), occurring in an east-west trend between Townships 71 and 75, Ranges 04 and 10. A much smaller area of valley-fill is preserved along the southwestern edge of the study area, near Township 76, Range 12. This smaller region containing B Valley-fill deposits may be continuous with the valley to the southeast, but there is insufficient well control to allow definitive correlation between the two areas.

The unit ranges in thickness from 5 to 40 m and is thickest in Township 73, Range 06, and near the intersection of Townships 73 and 74, Range 05. The unit thins rapidly to the north and south and less rapidly to the west, resulting in an eastward-thickening trend to the unit.

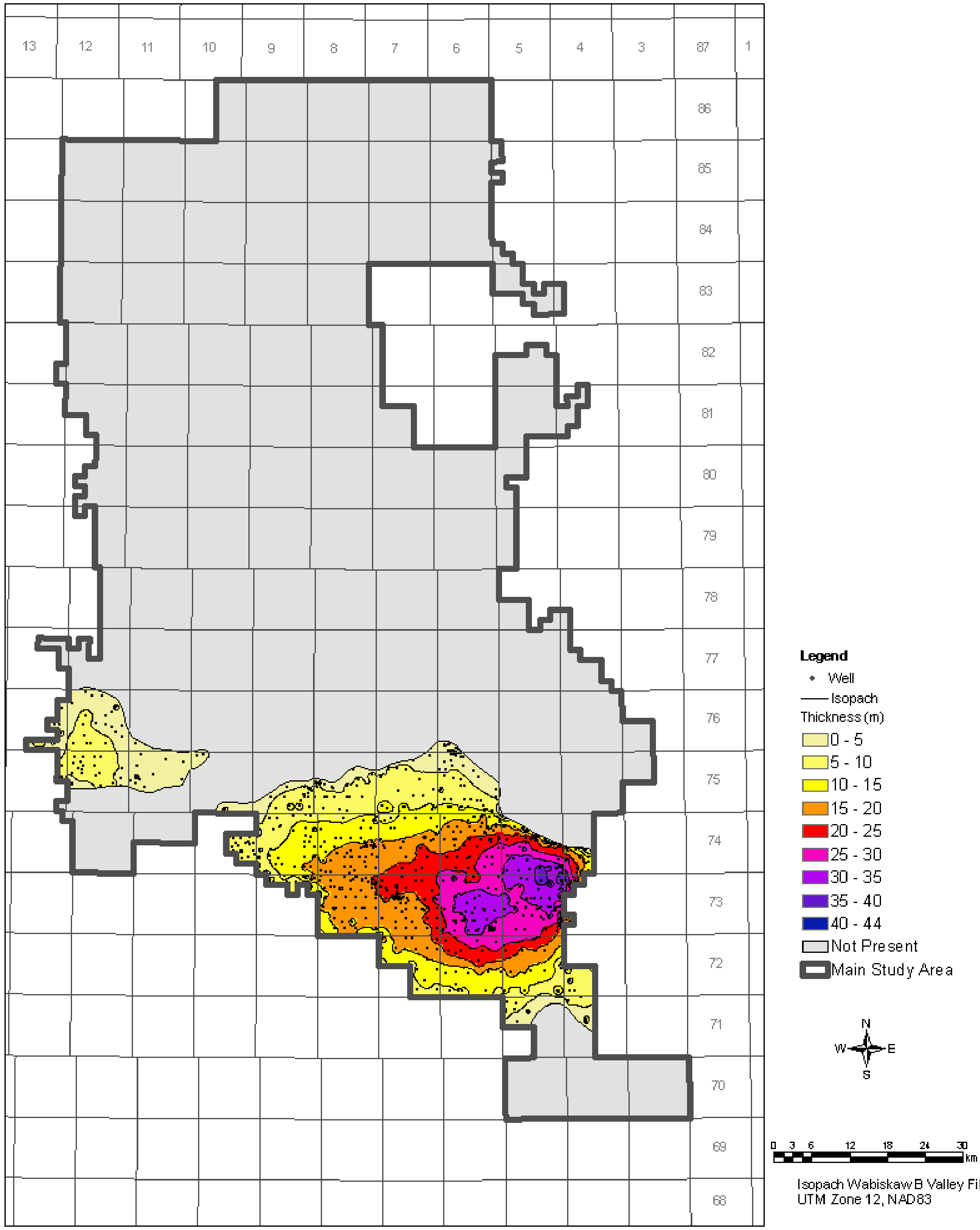


Figure 32 – Wabiskaw B Valley-fill Isopach Map

2.3 Northern Study Area

2.3.1 Stratigraphic Model and Unit Descriptions

The northern study area lies over 60 km north-northwest of the main study area. Although McMurray Channel sediments are present, the various McMurray A and B Sequences are not recognizable in this area. Further, the Wabiskaw units are thicker and more homogeneous than in the main study area. The Wabiskaw units are named, from bottom to top, the Wabiskaw D, Wabiskaw C, and Wabiskaw A. A mappable Wabiskaw B unit appears to be present outside the northern study area but not within it and is not discussed here. A schematic cross-section illustrating the relationship of the Wabiskaw-McMurray units in the northern study area is shown in Figure 33.

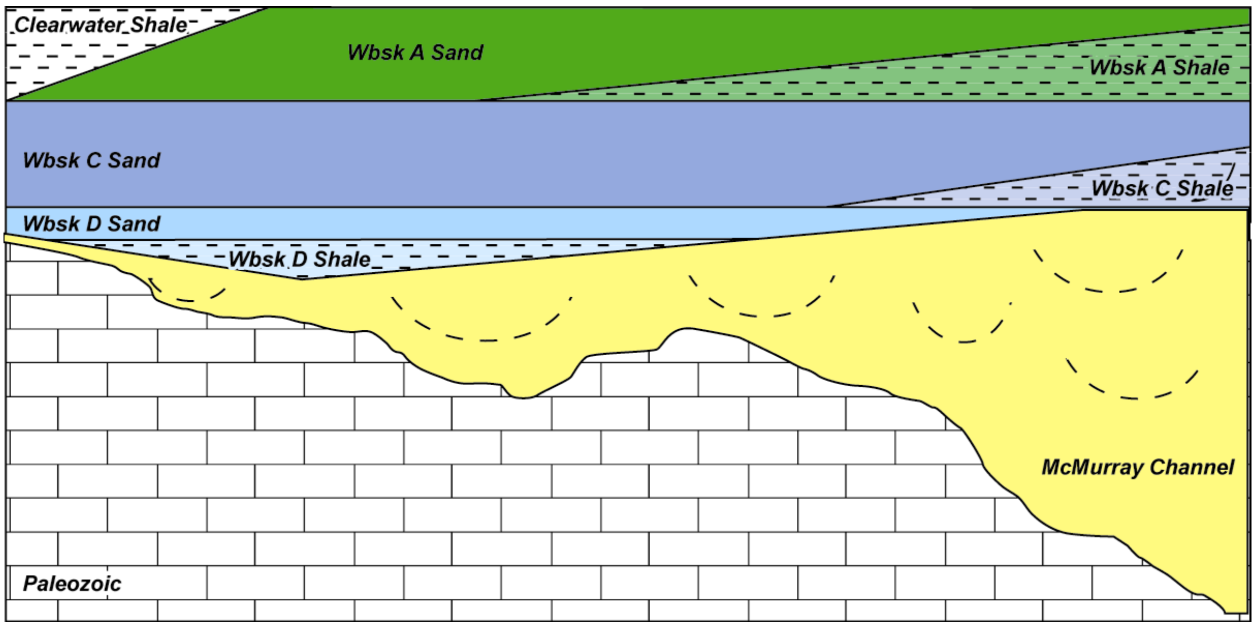


Figure 33 – Northern Study Area Stratigraphic Model

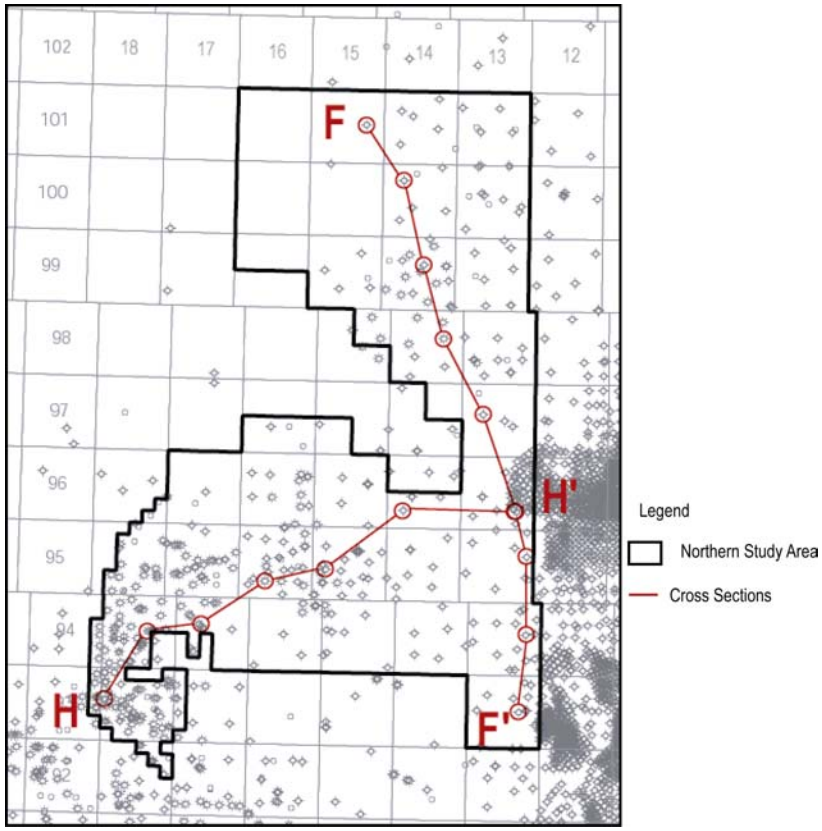


Figure 34 – Stratigraphic Cross Sections Across the Northern Study Area

In the northern study area, the Wabiskaw Marker is only present in the eastern part of the area, where it defines the top of the uppermost Wabiskaw sand (Wabiskaw A Sand). Farther to the west and southwest, the top of the Wabiskaw A Sand rises stratigraphically and is equivalent to the base of another low-resistivity mudstone in the Clearwater shales (Clearwater C Marker). This means that the top of the Wabiskaw A Sand is a diachronous surface and therefore cannot be used as a datum. In addition, the Wabiskaw A Sand shales out into the Clearwater shales in a defined area in the southwest of the northern study area (Townships 94 and 95, Range 18). For the construction of cross-sections in the northern area, a Clearwater mudstone marker that coincides with the top of the Wabiskaw A Sand in the extreme southwest of the study area was chosen as a datum. A dip cross-section (H-H') is presented at the end of the report. Regional stratigraphic cross-sections through the northern study area are contained on the CD. Lines of cross-section for the northern area are shown on Figure 34.

Figures 35, 36, and 37 respectively present a structure map on the Wabiskaw C Sand, an isopach map on the Wabiskaw C Sand to the Paleozoic surface, and a structure map of the Paleozoic surface onto which the basal stratigraphic units were deposited. The Wabiskaw C Sand is the only continuous unit in the northern study area and therefore was used to create the Wabiskaw-McMurray isopach map.

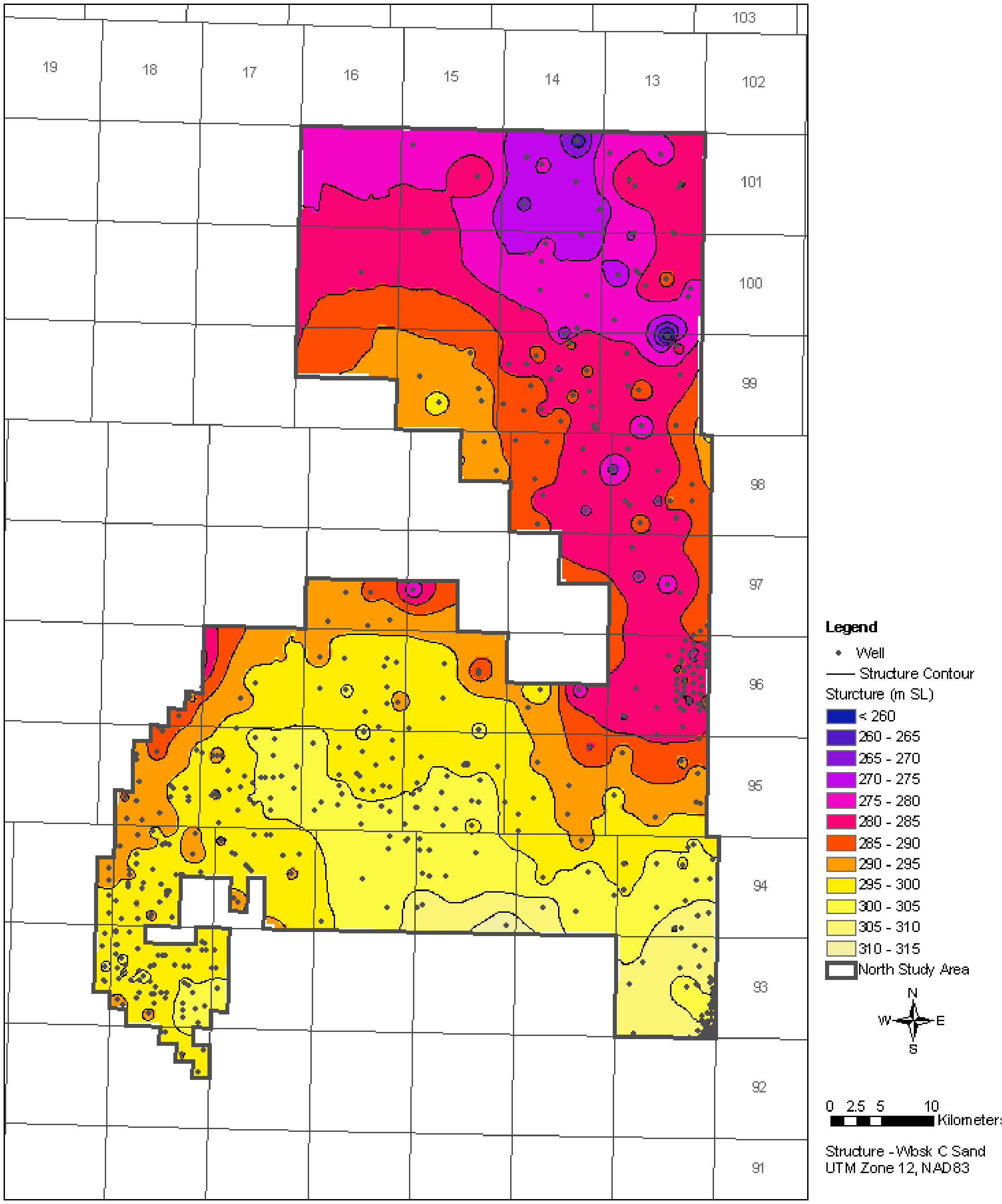


Figure 35 – Wabiskaw C Sand Structure Map

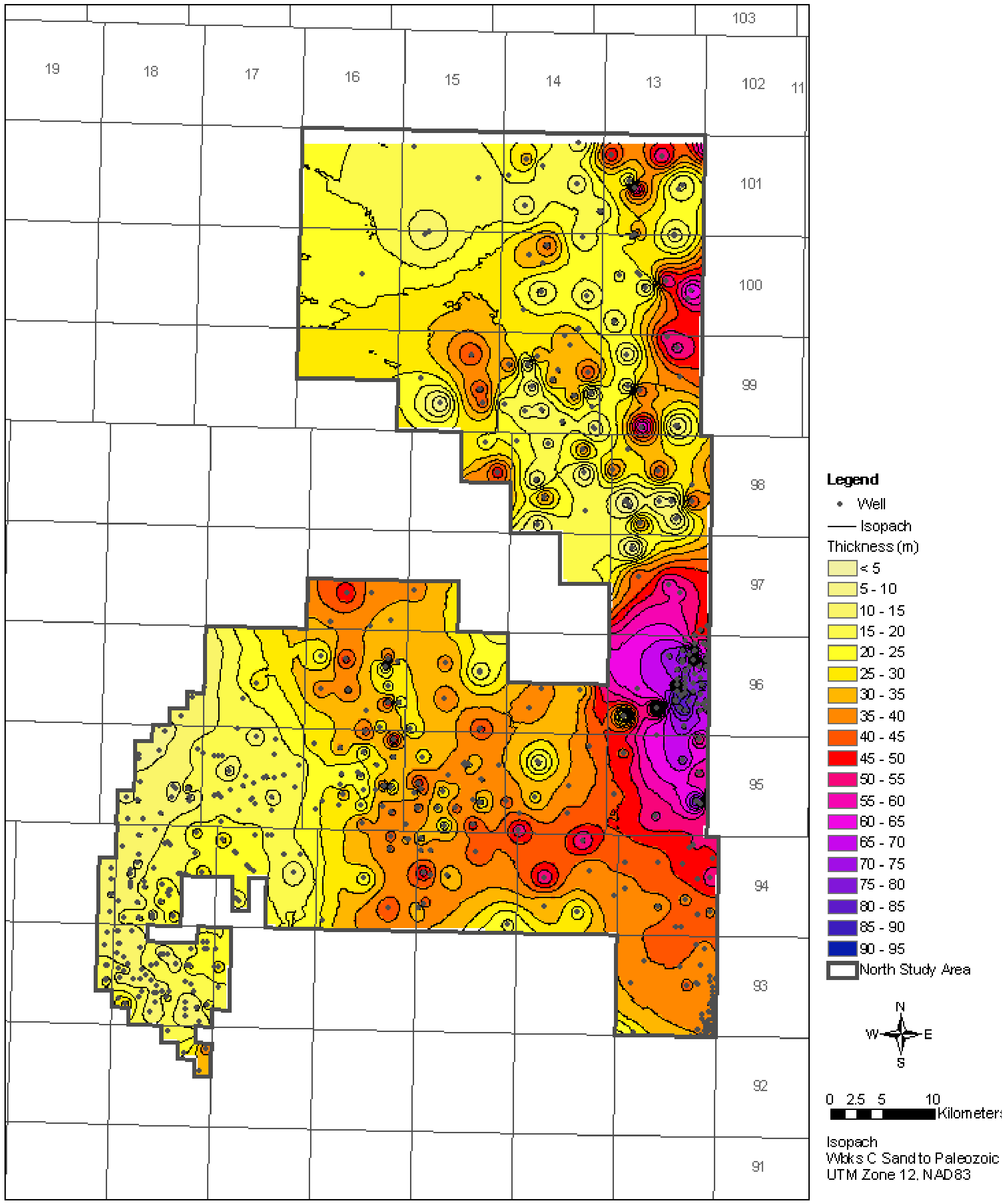


Figure 36 – Wabiskaw C Sand to Paleozoic Isopach Map

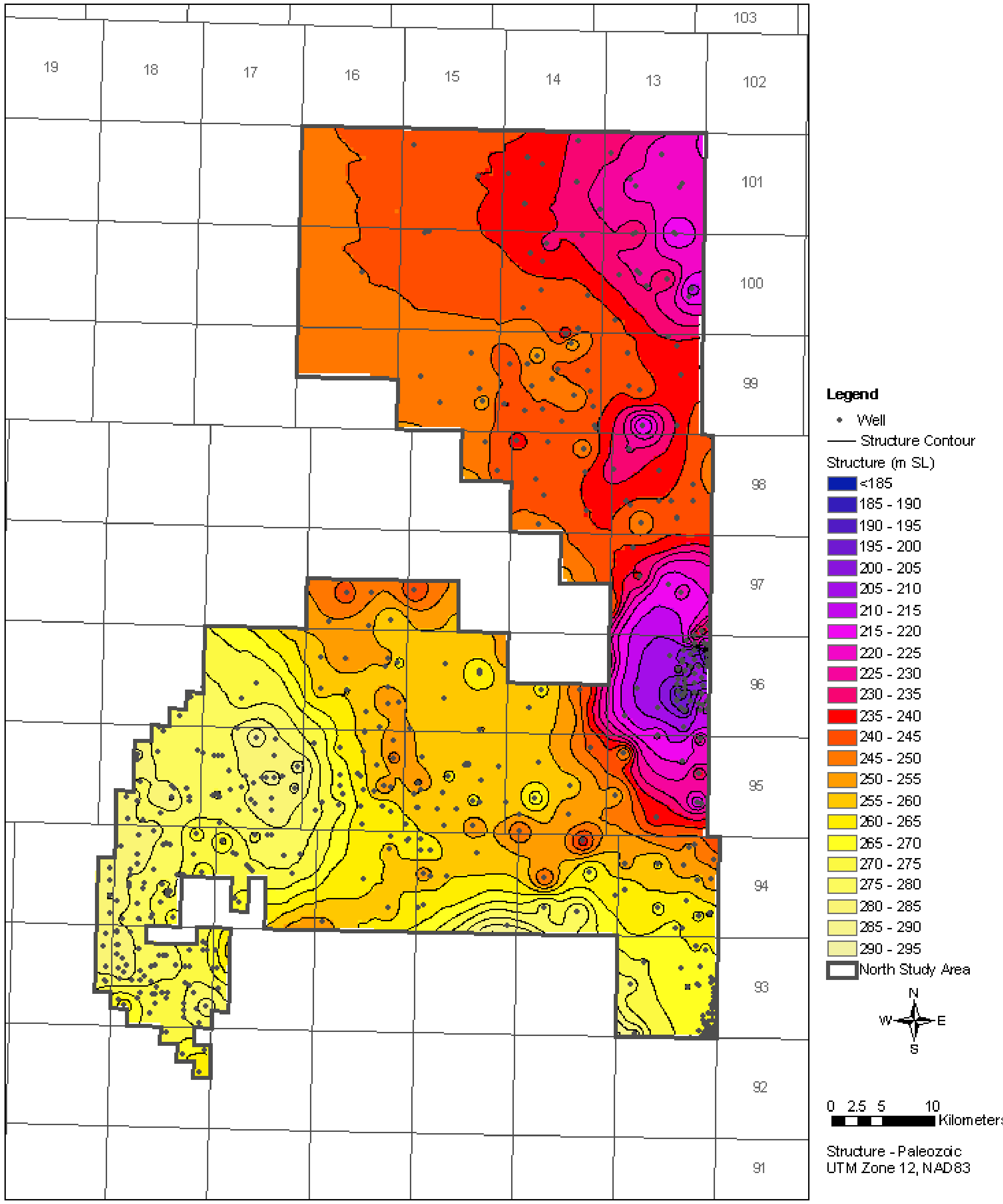


Figure 37 – Paleozoic Structure Map

McMurray Channel

Unit Description

The lowest recognizable regional mudstone of the main study area, the B2 Mudstone, is not present in the northern study area. Therefore, following the terminology framework in the main study area, the channel deposits in the northern study area are referred to as McMurray Channel. As in the main study area, the McMurray channels here originate from more than one horizon and should not be considered a unique mappable unit.

Channel deposits have variable lithology, consisting of stacked assemblages of the following facies: clean blocky sands, sands with interbedded mudstone layers, muddy channel fill, and associated lateral facies. Channel packages range in thickness from 0 to 90 m, pinching out in the western part of the northern study area against the flanks of the Grosmont High. McMurray Channel deposits overlie Paleozoic carbonates and are themselves overlain by a variety of Wabiskaw units.

Log Characteristics

Typical log signatures for clean sands include a GR of 25 to 45 API units in a blocky or bell shape. Several blocky or bell GR profiles may occur superimposed, reflecting more than one fining-upward package. Resistivity is variable, and neutron and density porosities are typically over 30 per cent. Figure 38 presents a typical McMurray Channel sequence and corresponding well log.

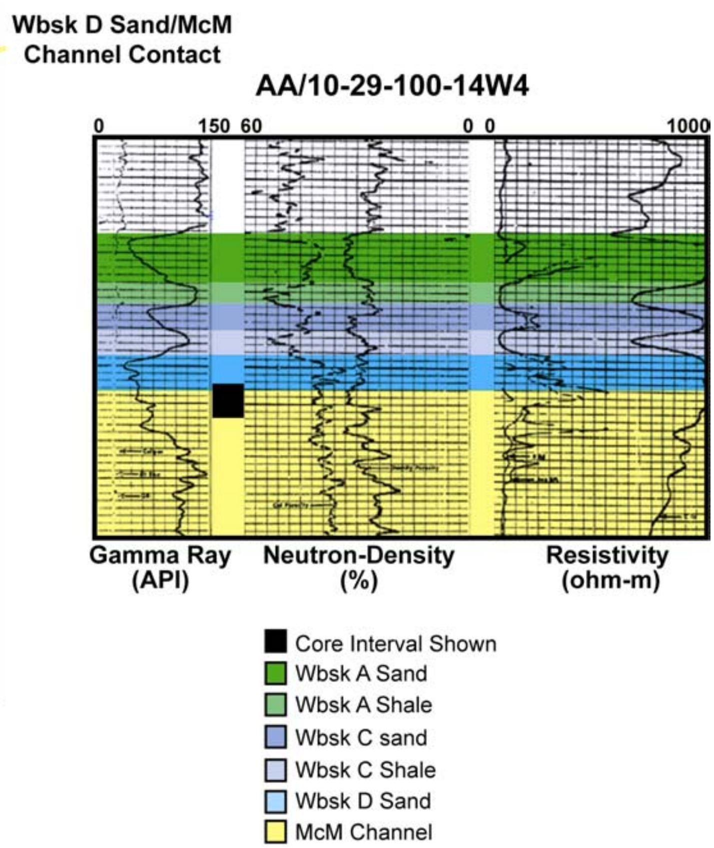


Figure 38 – McMurray Channel Core Photo and Well Log

Wabiskaw D Shale

Unit Description

In the northern study area, the Wabiskaw D Shale is the lower part of the Wabiskaw D cleaning-upward package. It consists of interbedded fissile blue-grey and brown shales, dark in colour, commonly broken by platy fractures in core. Trace fossils are typically absent. The D Shale varies in thickness from a 0.3 to 4.5 m but is commonly 1.5 m thick. It is the basal Wabiskaw unit in only limited parts of the northern study area.

Log Characteristics

The typical log signature includes a GR of about 75 API units and density porosity of 21 to 25 per cent. The corresponding resistivity is always below 10 ohm-m. Figure 39 presents a well log for the D Shale.

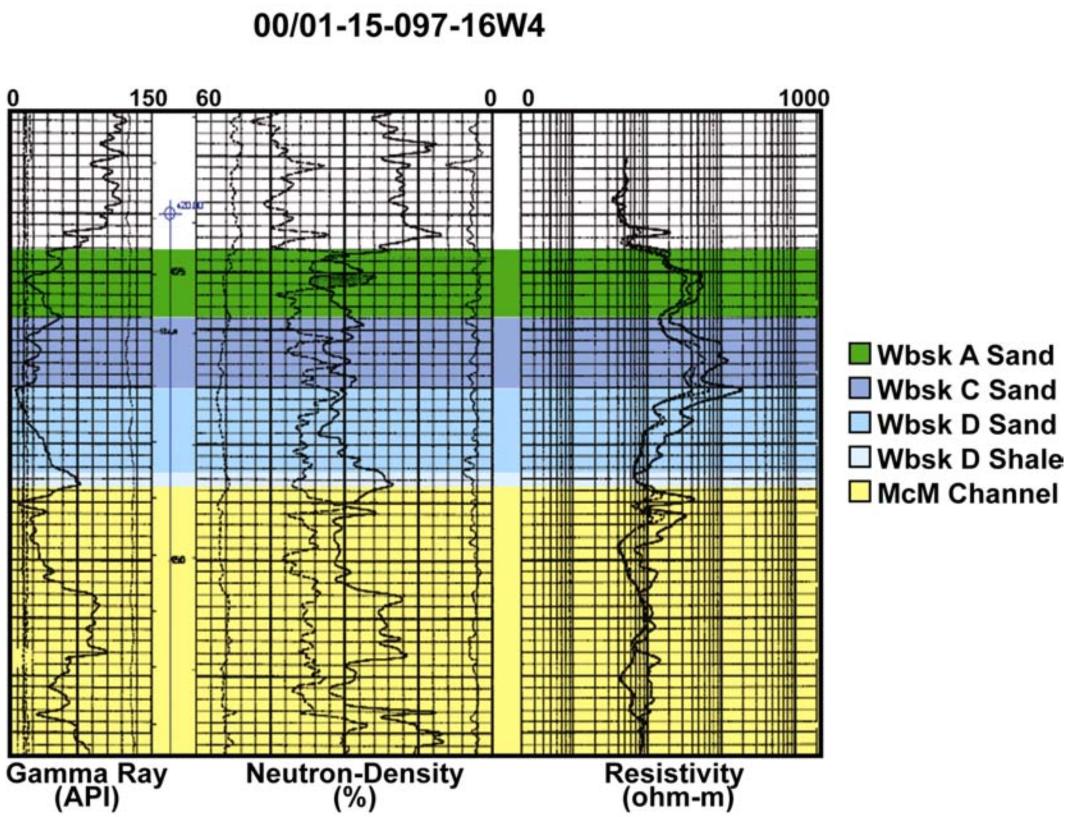


Figure 39 – Wabiskaw D Shale Well Log

Wabiskaw D Sand

Unit Description

The Wabiskaw D Sand is the upper part of the Wabiskaw D cleaning-upward package. Variable in lithology, the unit consists mainly of a mixture of quartz and lithic grains that are brownish-grey in colour. Sands with both blocky and cleaning-upward GR profiles are also present within this unit. Burrows are present and increase in number and diversity toward the base of the unit. The Wabiskaw D sand ranges in thickness from 1 to 23 m, although the most common thickness is near 9 m. Where the Wabiskaw D Shale is not present, the contact with the underlying McMurray Channel sediments or Paleozoic units (in the southwestern part of the northern study area) is abrupt.

Log Characteristics

The GR curve is typically funnel shaped, with values near the top between 20 and 30 API units, density porosity near 33 per cent, and neutron porosity near 36 per cent. Resistivity values are near 100 ohm-m when saturated with bitumen and in the absence of shales. Figure 40 presents a typical Wabiskaw D Sand sequence and corresponding well log.

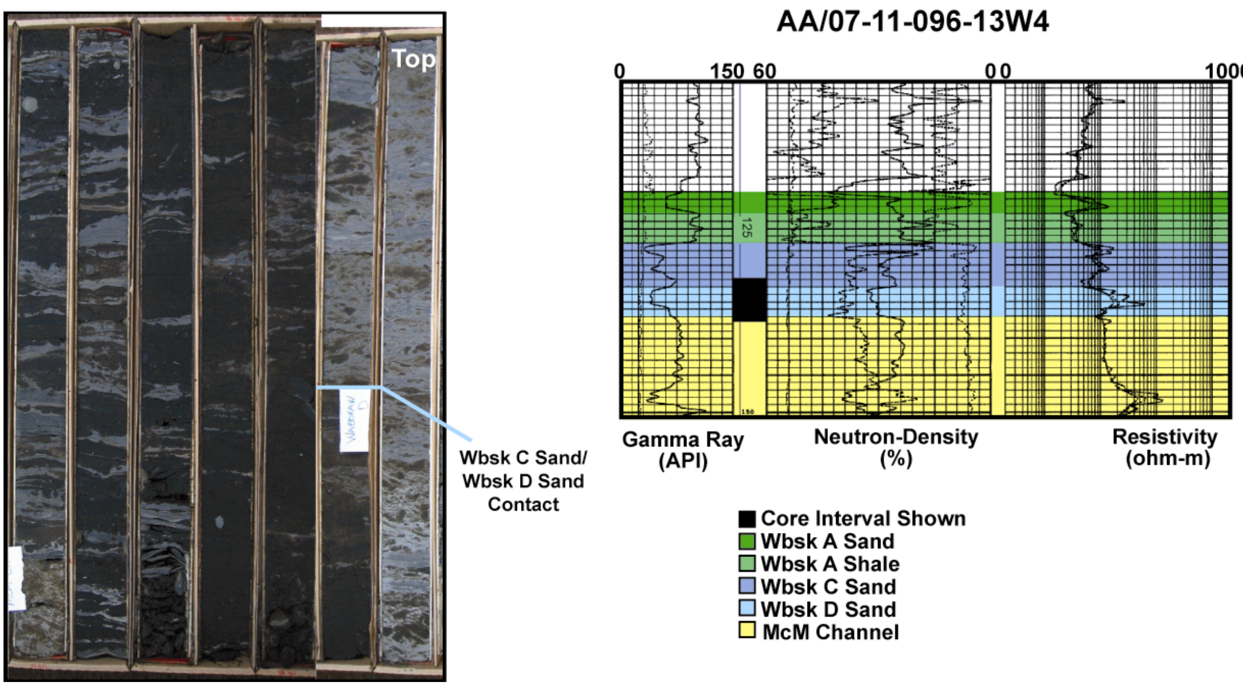


Figure 40 - Wabiskaw D Sand Core Photo and Well Log

Wabiskaw C Shale

Unit Description

The Wabiskaw C Shale is the lower part of the Wabiskaw C cleaning-upward package. It consists of dark grey-green fissile shales that range in thickness from 0.3 to 5 m, although the most common thickness is near 1.5 m. The unit typically lacks trace fossils. The upper contact with the overlying Wabiskaw C Sand is gradational, and the lower contact with the underlying Wabiskaw D sand is sharp.

Log Characteristics

The typical log signature includes a GR between 75 and 120 API units, density porosity near 20 per cent, and resistivity values between 5 and 10 ohm-m. Figure 41 presents typical Wabiskaw C Shale sequence and corresponding well log.

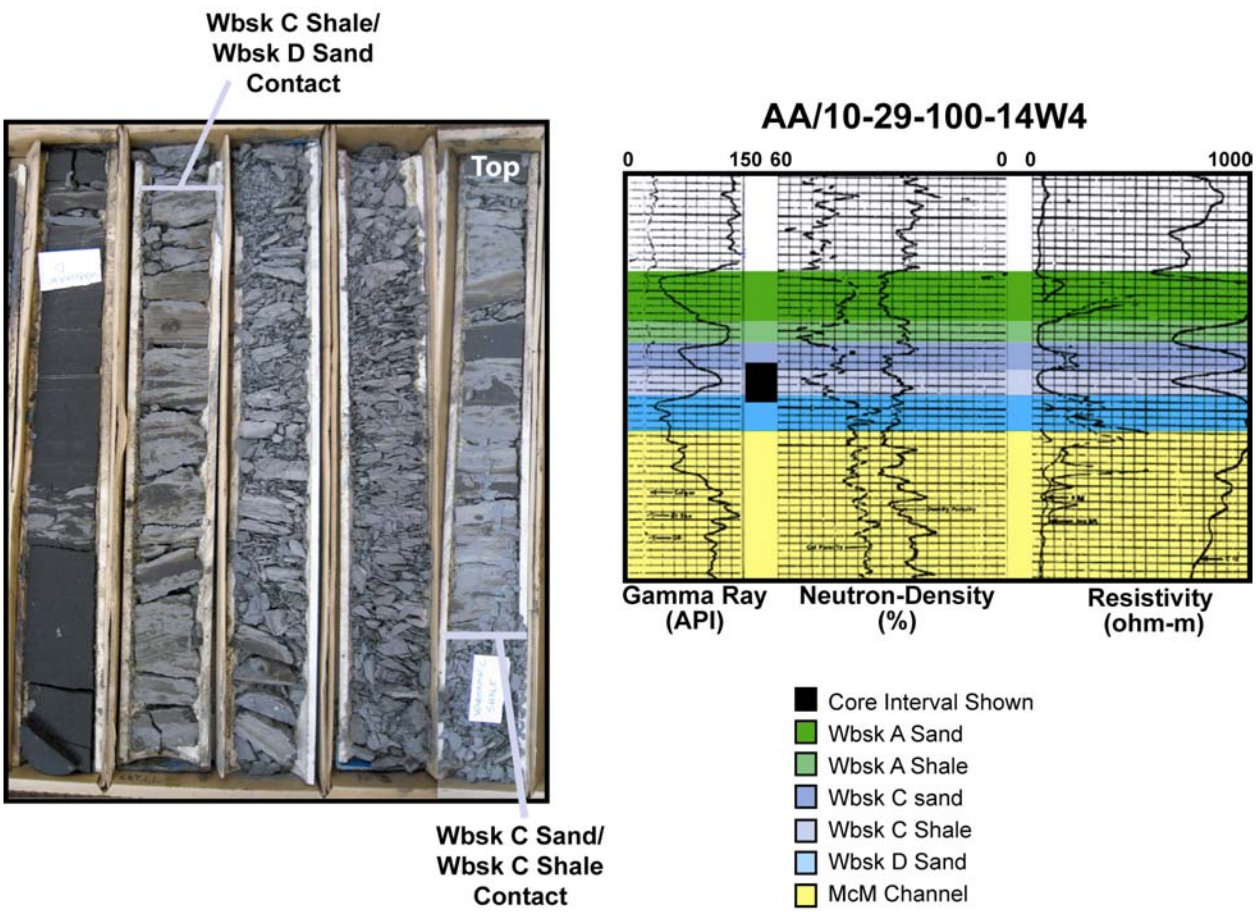


Figure 41 – Wabiskaw C Shale Core Photo and Well Log

Wabiskaw C Sand

Unit Description

The Wabiskaw C Sand is the upper part of the Wabiskaw C cleaning-upward package in the northern study area. It consists of glauconitic and lithic sandstone and is fine to medium grained, occasionally alternating with finer-grained silts and mudstones. The sands are often heavily bioturbated, and bioturbation typically destroys primary bedding structures. This unit varies in thickness from 1 to over 27 m, but most values are near 6 m.

Log Characteristics

The typical log signature includes GR values of 30 to 40 API units where the sands are cleaner and display a typical funnel shape. A weak to strong SP deflection is common, and density porosity ranges up to 30 per cent. Resistivity is usually 100 ohm-m or more when saturated with bitumen. As in the main study area, clean Wabiskaw C Sands show separation of the neutron and density porosity curves. Figure 42 presents a typical Wabiskaw C Sand sequence and corresponding well log.

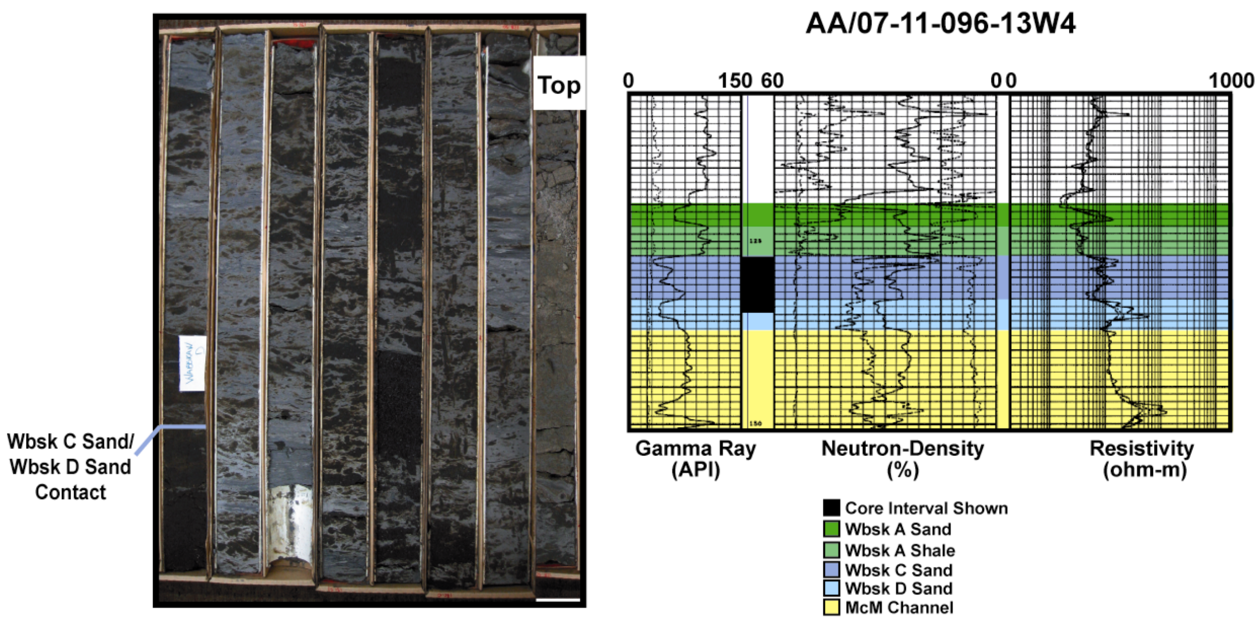


Figure 42 – Wabiskaw C Sand Core Photo and Well Log

Wabiskaw A Shale

Unit Description

The Wabiskaw A Shale is the lower part of the Wabiskaw A cleaning-upward package. It consists of dark grey-green fissile shales that range in thickness from 0.5 to 7.5 m, although the most common thicknesses are near 3 m. The A Shale typically lacks trace fossils. Where present, the upper contact with the Wabiskaw A sand is gradational, and the lower contact with the underlying Wabiskaw C Sand is abrupt.

Log Characteristics

The typical log signature includes a GR between 120 and 135 API units, density porosity values near 15 per cent, and neutron porosities near 60 per cent. Resistivities are typically about 2 to 3 ohm-m. Figure 43 presents a typical Wabiskaw A Shale sequence and corresponding well log.

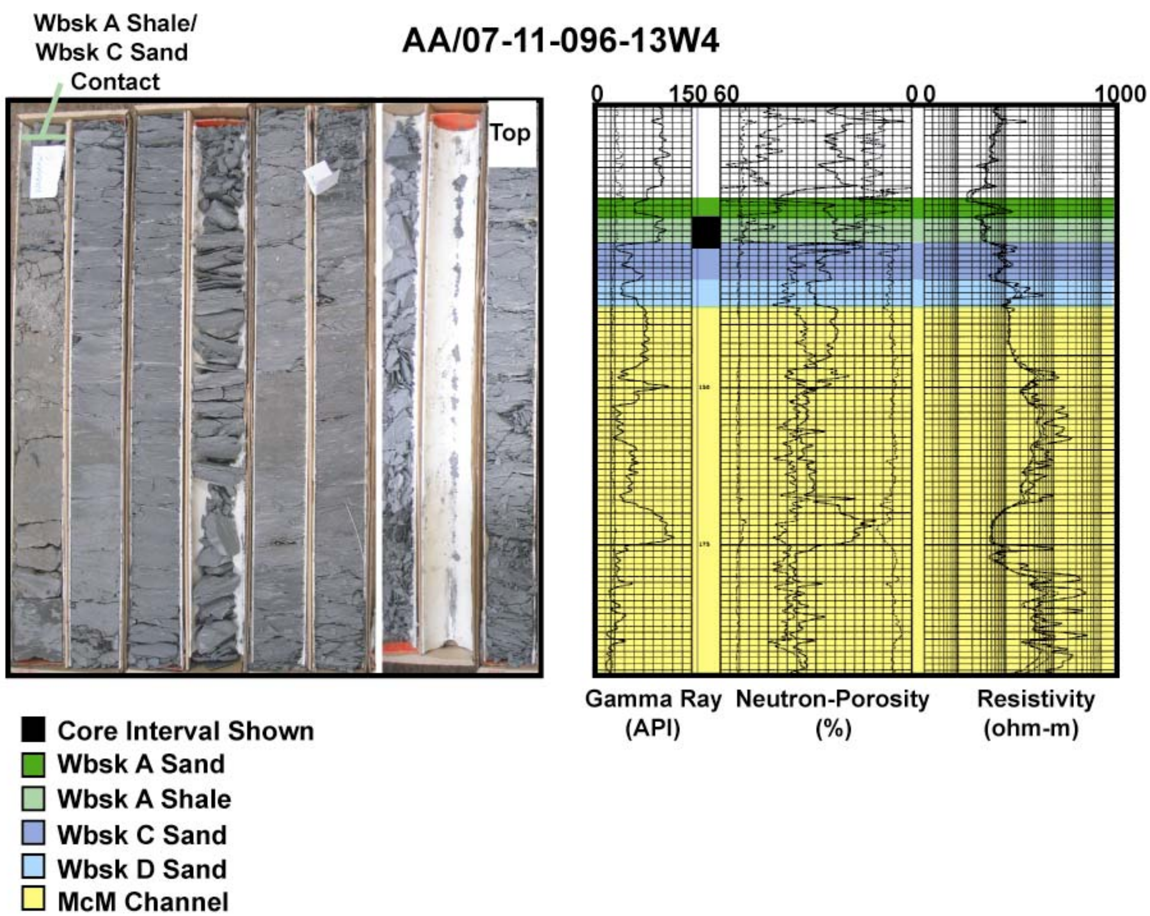


Figure 43 – Wabiskaw A Shale Core Photo and Well Log

Wabiskaw A Sand

Unit Description

The Wabiskaw A sand is the upper part of the Wabiskaw A cleaning-upward package. It is dark grey-green in colour, consisting of fine- to medium-grained glauconitic and lithic sands that are poorly cemented. The sands are planar and hummocky cross-stratified. Overall numbers and diversity of trace fossils increase downward into the finer-grained sediments. Total thickness of unit ranges from 1 to 20 m, with an average thickness near 7 m. The Wabiskaw A sand grades below into the underlying Wabiskaw A Shale (where present).

Log Characteristics

The typical log signature includes a GR between 30 and 40 API units, decreasing upward through the sand in a funnel shape. GR values can be higher, near 100 API units where the unit is thinnest. Density porosity is typically near 33 per cent, neutron porosity near 36 per cent, and resistivities are near 100 ohm-m when saturated with bitumen. Figure 44 presents a typical Wabiskaw A Sand sequence and corresponding well log.

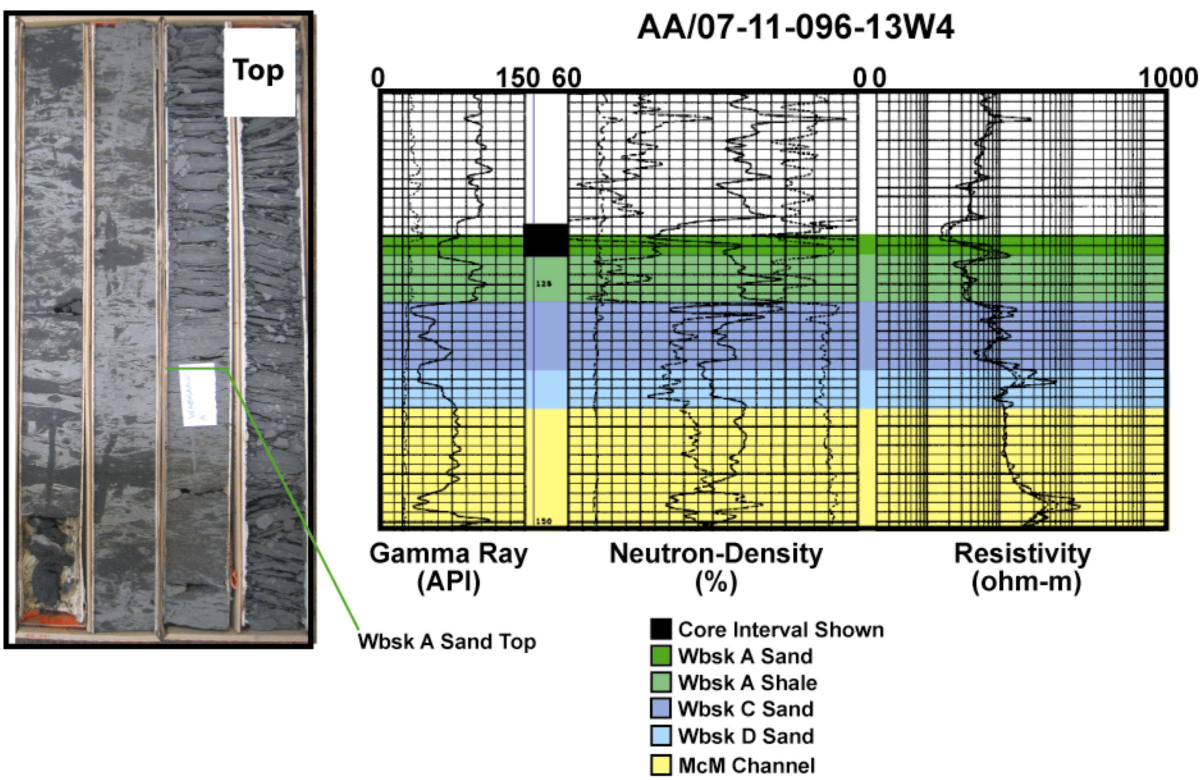


Figure 44 – Wabiskaw A Sand Core Photo and Well Log

2.3.2 Distribution of Stratigraphic Units

McMurray Channel

McMurray Channel deposits cover most of the northern study area, except for localized areas of nondeposition controlled by recognized Paleozoic paleotopographic highs. Figure 36, an isopach map of Wabiskaw C Sand top to Paleozoic, depicts the paleotopographic surface on which the Wabiskaw-McMurray sediments were deposited. The thickness of the McMurray Channel deposits across the central and eastern portion of the study area is strongly linked to the paleotopography of the sub-Cretaceous unconformity (Figure 37), where thicker deposits have accumulated in Paleozoic lows (Figure 45).

McMurray Channel deposits in the northern study area are commonly between 25 and 50 m in thickness and increase in thickness to the east. Deposits reach a maximum thickness of approximately 95 m along the eastern boundary of the northern study area in Range 13 of Townships 95 to 101. Some areas of thick deposits also extend west in Townships 94 and 95, Range 14, and Townships 99 to 101, Range 14. McMurray Channel deposits thin out against the flanks of a Paleozoic high in the west part of the area.

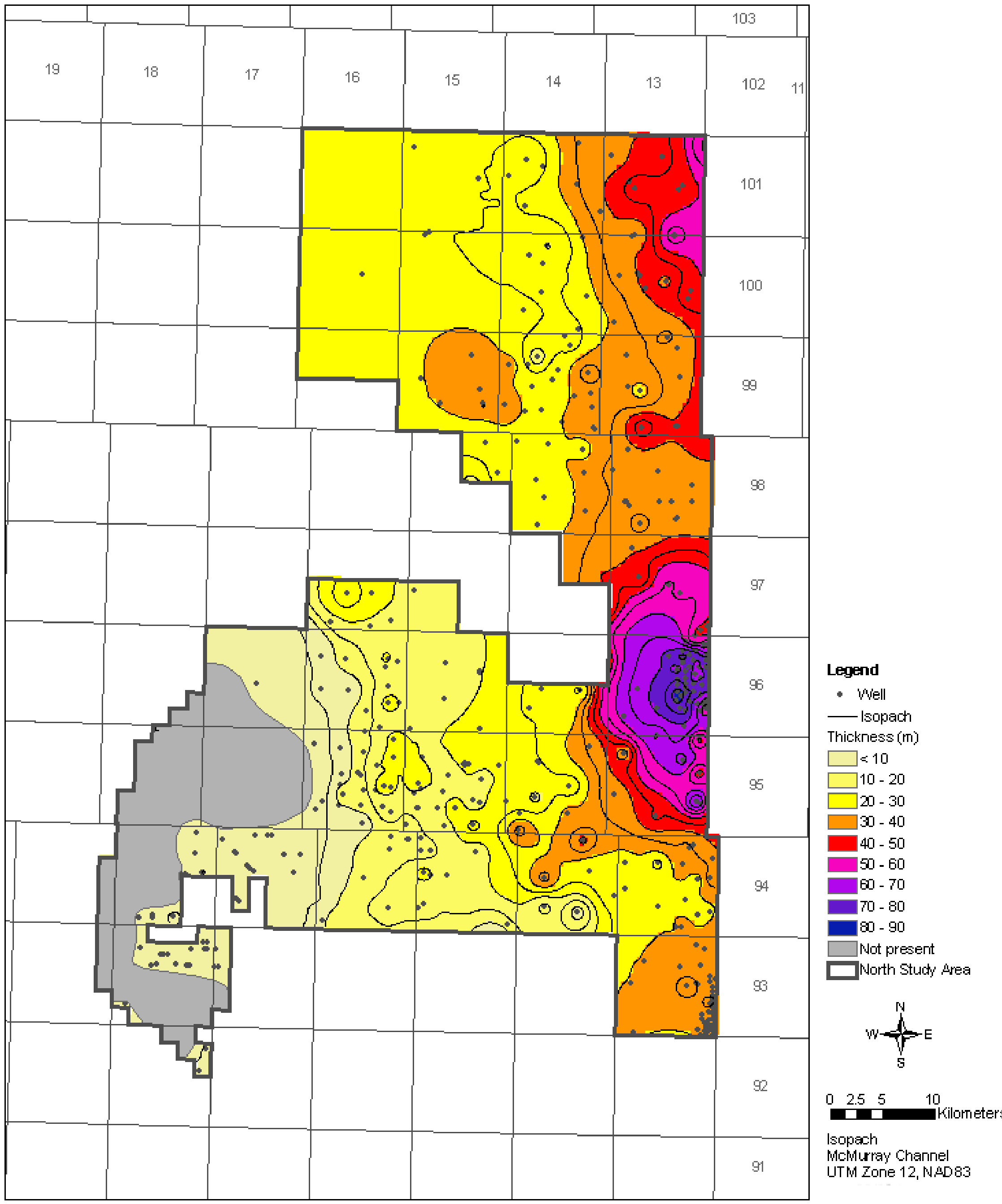


Figure 45 – McMurray Channel Isopach Map

Wabiskaw D Shale

The Wabiskaw D Shale is present only in two local areas. The northernmost area is in Township 101, Ranges 14 and 15, while the southern area is centred near the junction of Townships 96 and 97, Ranges 15 and 16. In the northern study area, the Wabiskaw D shale ranges in thickness from 0 to 4.5 m, with the thickest deposits occurring in Township 101, Range 14. See Figure 46 for the isopach map of this unit.

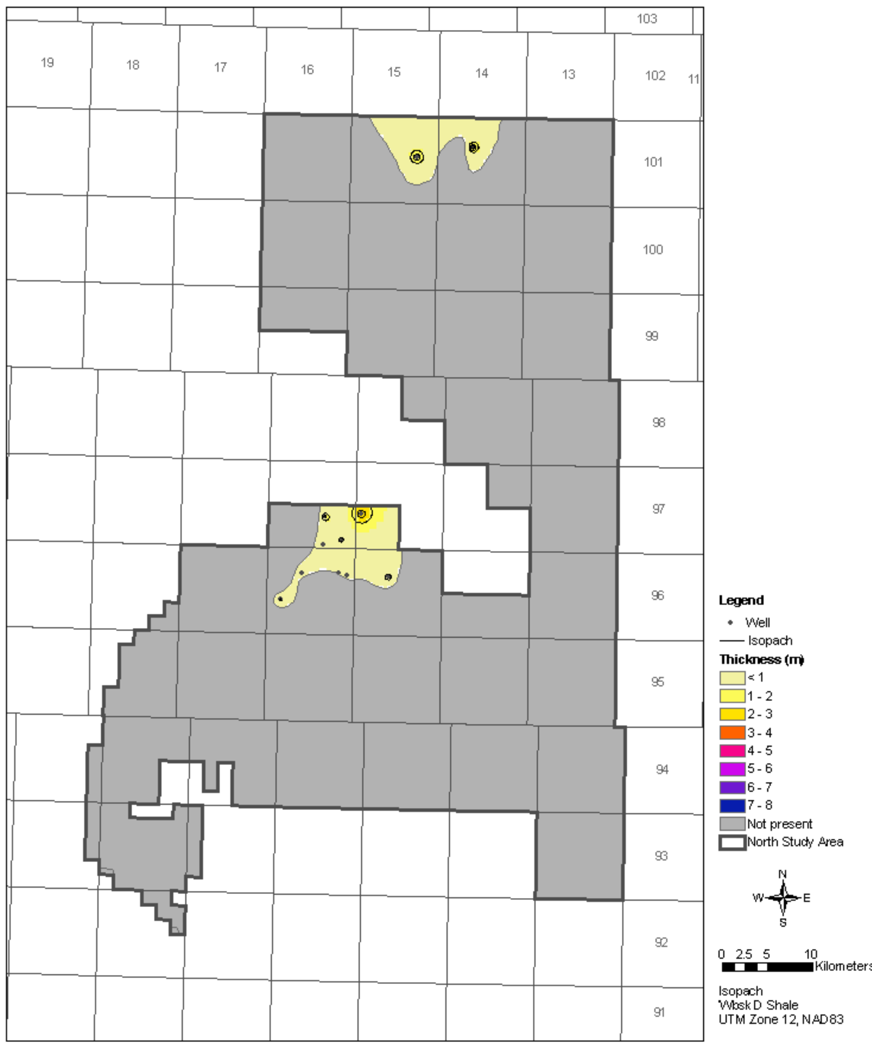


Figure 46 – Wabiskaw D Shale Isopach Map

Wabiskaw D Sand

The Wabiskaw D Sand is present across most of the northern study area (Figure 47). It is absent along the central eastern edge of the area, near Township 97, Range 13. The Wabiskaw D Sand is also absent along two smaller east-west trends, the first in the north part of Township 95, Range 13, and the second in Township 99, Ranges 14 and 15.

The unit is thickest (> 15 m) in a north-northwest trending area between Township 94, Range 15, and Township 96, Range 16, as well as in Township 93, Range 18, and Township 98, Range 15. These areas roughly correspond to areas of decreased thickness in the underlying McMurray Channel succession. Where McMurray channels are thickest, the Wabiskaw D Sand is thin or absent.

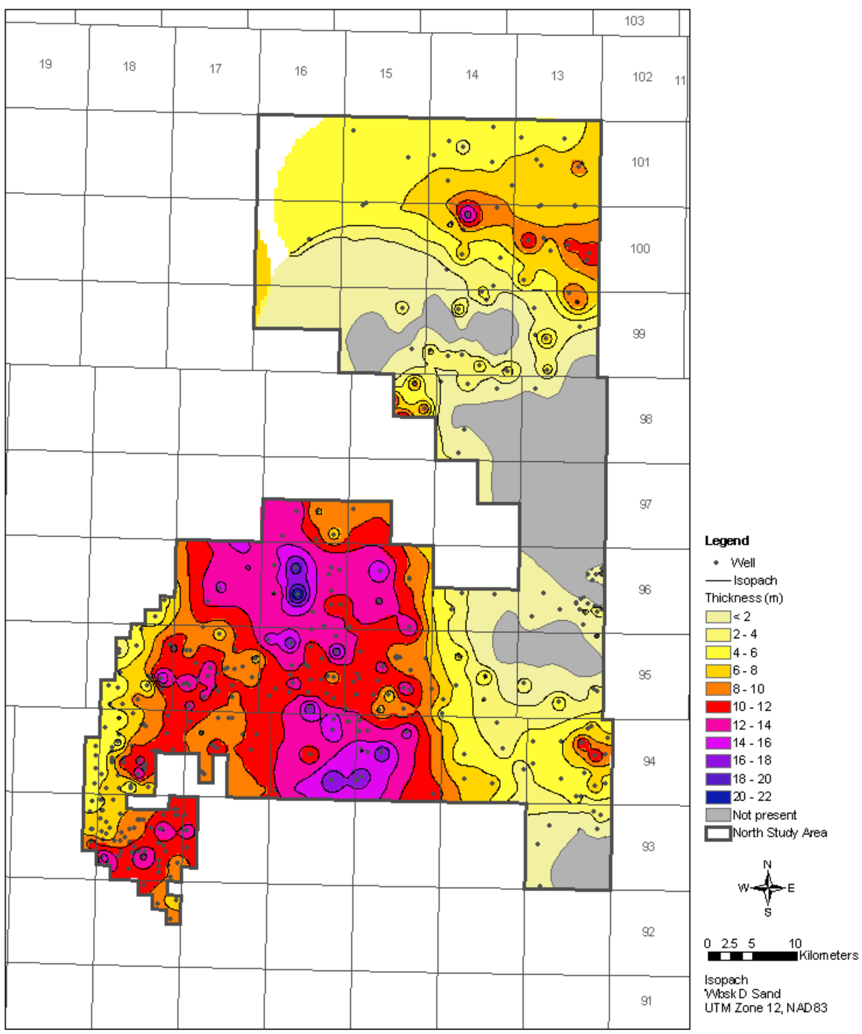


Figure 47 – Wabiskaw D Sand Isopach Map

Wabiskaw C Shale

The Wabiskaw C Shale covers about one-third of the northern study area (Figure 48). Present in all of Township 101 and most of Township 100, the unit is also present along a linear trend on the western edge of the area. The unit is also present in two areas along the southern boundary, the first in Township 94, between Ranges 16 and 17, and the second in Township 93, Range 13, and trending northwest to Township 94, Range 14.

The Wabiskaw C Shale is most commonly near 1.5 m thick, although it ranges in thickness from 0.5 to 5 m. The thickest Wabiskaw C shale deposits occur in Range 14.

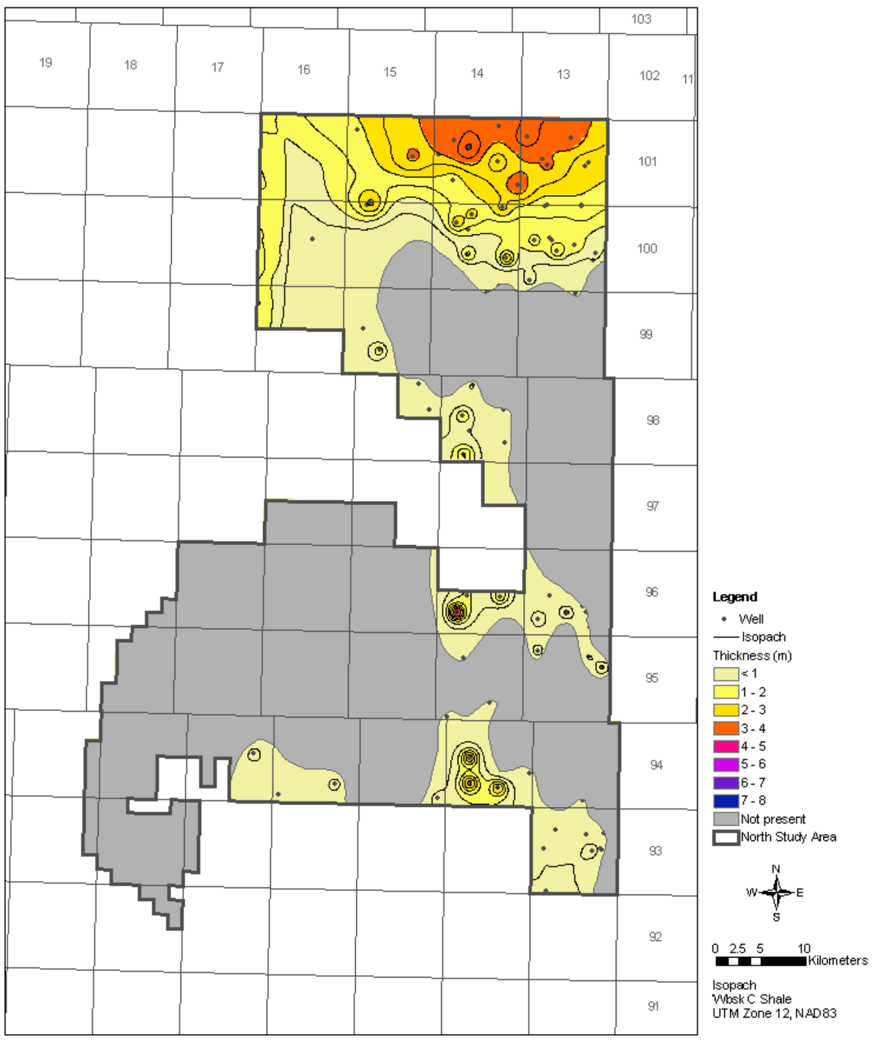


Figure 48 – Wabiskaw C Shale Isopach Map

Wabiskaw C Sand

The Wabiskaw C Sand is present across the entire northern study area (Figure 49). The thickest deposits (>10 m) of Wabiskaw C Sand occur in the southwestern portion of the area, describing an arcuate shape bordering the Paleozoic high to the west. Another less pronounced area of increased thickness (> 6 m) is present in Townships 98 and 99, Ranges 13, 14, and 15. Areas of increased thickness roughly correspond with areas where the Wabiskaw C Shale is thin or absent.

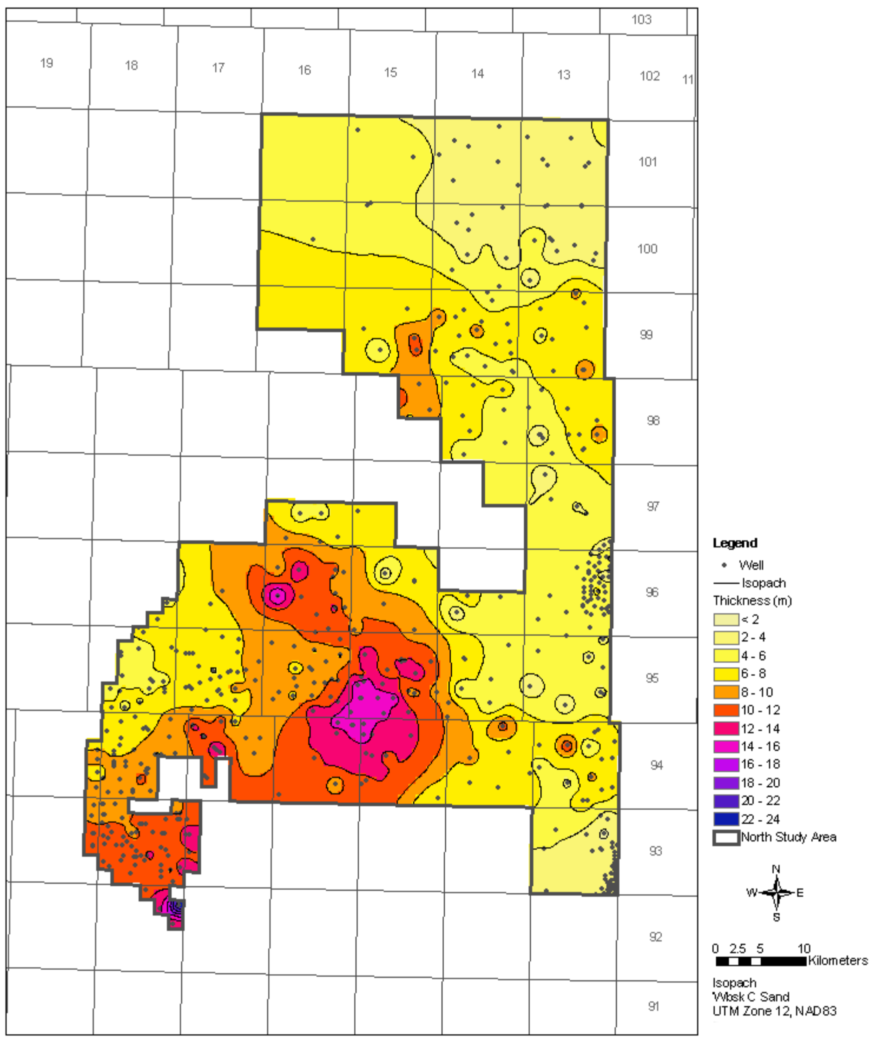


Figure 49 – Wabiskaw C Sand Isopach Map

Wabiskaw A Shale

The Wabiskaw A Shale is present throughout most of the northern study area, but is completely absent in Range 16 and parts of Ranges 15, 17, and 18 (Figure 50). It ranges in thickness from 0.5 to 7.5 m, although the most common thickness is about 3 m. The Wabiskaw A Shale is thickest (> 5 m) in the eastern and northern parts of the area. In Townships 94 and 95, Range 18, the Wabiskaw A Shale thickens westward as the Wabiskaw A Sand shales out.

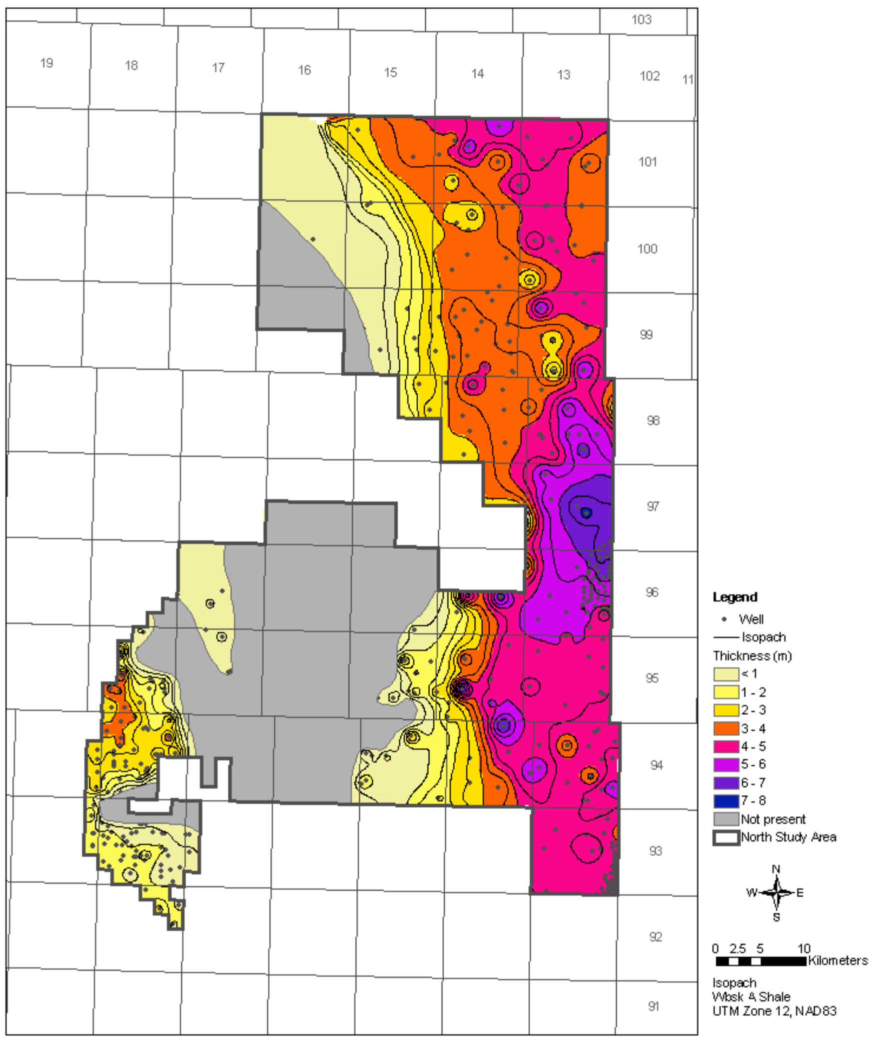


Figure 50 – Wabiskaw A Shale Isopach Map

Wabiskaw A Sand

The Wabiskaw A Sand appears in all wells in the northern study area, except in Township 94 and 95, Range 18, where it thins and transitions into shales of the Clearwater Formation (Figure 51). In this area, the top of a silty streak above the Wabiskaw C Sand was interpreted as the top of the Wabiskaw A Shale.

The total thickness of the Wabiskaw A Sand unit ranges from 1 to 20 m, with an average thickness near 7 m. The sand thickens along two main trends, the first of which runs approximately north-south from Township 97 to 101, Ranges 13 and 14, and has thicknesses ranging between 6 and 8 m. The second thickness trend follows an arcuate shape bordering the Paleozoic high in the central and southwestern part of the northern study area, with thicknesses ranging between 6 and 20 m.

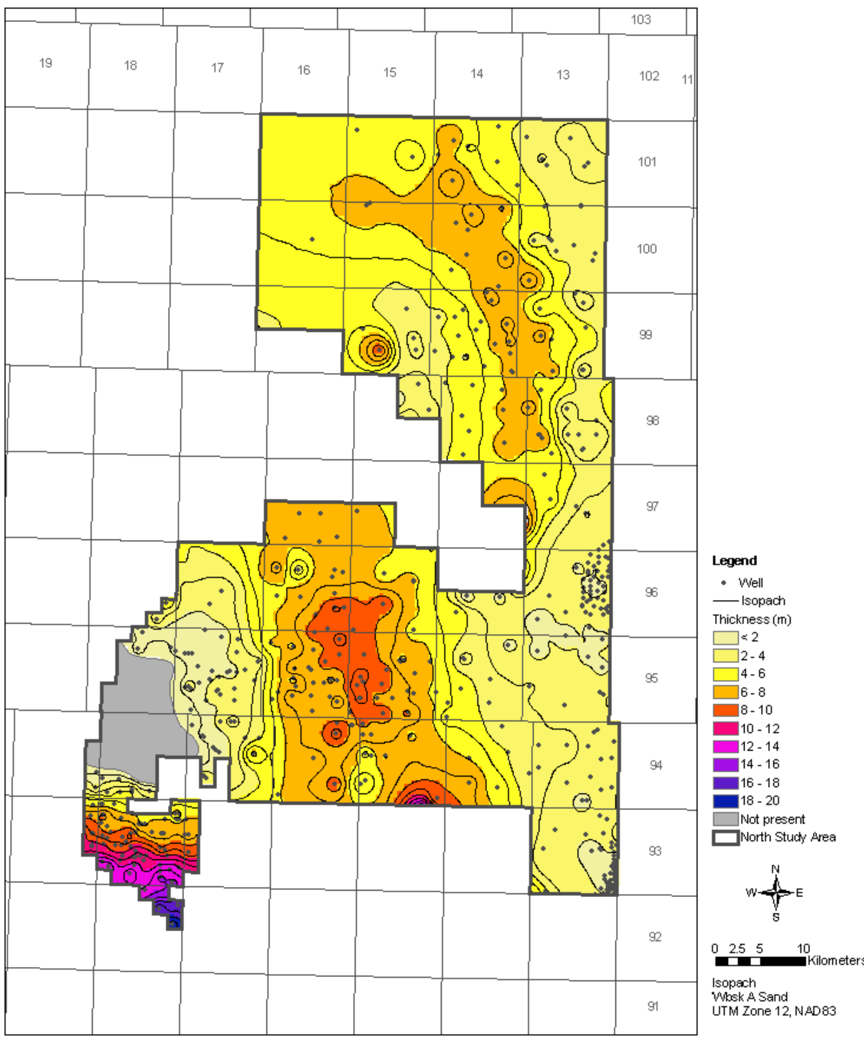


Figure 51 – Wabiskaw A Sand Isopach Map

2.4 Controls on Gas / Bitumen Communication

2.4.1 Main Study Area

Identifying regional mudstones and mapping their areal distribution is critical to understanding which gas pools are associated or nonassociated. The study accepted the conclusions from the Chard-Leismer Decision that a mudstone that could be correlated regionally, or a shale that was greater than 0.5 m in thickness and could also be correlated regionally, would act as a potential barrier to vertical hydraulic communication. In the main study area, three units including the mudstones present at the base of the McMurray B2 and A2 Sequences and the Wabiskaw D Shale are interpreted to meet these criteria. This is consistent with the interpretation presented in the Chard-Leismer Decision. However, because of the limited distribution of the Wabiskaw D Shale, the McMurray B2 and A2 mudstones are the most significant in differentiating between associated and nonassociated gas.

2.4.2 Northern Study Area

In the northern study area, the shales present at the base of the Wabiskaw sands were interpreted to act as a potential barrier to vertical hydraulic communication where they are greater than 0.5 m in thickness. Of these, only the Wabiskaw C Shale and the Wabiskaw A Shale are significant in differentiating between associated and non-associated gas because of their broad areal extent and the presence of gas in the overlying sand units.

3 Gas Evaluation and Delineation

3.1 Method

Most gas-bearing units within the Wabiskaw-McMurray in the study area are easily identified by crossover on the neutron-density log curves. However, the more lithic Wabiskaw C Sand may only show approachment of the two curves rather than actual crossover. The corresponding resistivity must also be considered when assigning gas pay because of the potential for some crossover in a depleted gas zone.

For each gas interval in the wells in the study area, the top and base elevations from logs measured from Kelly Bushing (mKB) were identified and entered into a resource database. The corresponding stratigraphic unit and net gas thickness were also captured. These data were then reproduced on maps for each stratigraphic interval.

The lateral and vertical extent of each gas pool was determined. This was a multistep process that involved identifying which wells penetrate a common pool within a single stratigraphic unit (the lateral extent of the gas pool) and interpreting whether that gas could be in communication with a gas pool in an overlying or underlying stratigraphic unit (the vertical extent of the gas pool).

Interpreting the lateral extent of a pool within a given stratigraphic unit was accomplished by posting the porosity top structure elevations and porosity base or fluid contact structure elevations for each well with gas pay in the subject stratigraphic unit on a map. This information, along with well logs and information from offset wells, was used to determine the lateral extent of each gas accumulation. Specifically, gas was pooled between wells if the following conditions were met:

- Gas was present in the same stratigraphic interval.
- Gas/water interfaces were within ± 1 m.
- Wells were in adjacent sections.

Gas/bitumen interface differences were also considered in pooling. A tolerance of ± 5 m was considered and may be used depending on the size of the pool and regional dip.

The vertical extent of gas pools depends upon the nature of separation between gas-bearing stratigraphic units. Many wells penetrated gas-bearing stratigraphic units that could be correlated and mapped separately but that showed minimal vertical separation. Shales, mudstones, or silty intervals of 0.5 m or less were considered inadequate barriers to hydraulic flow between these gas-bearing units. In these circumstances, the two gas-bearing intervals were assigned to the same pool. This results in a number of pool outlines mapped at the stratigraphic unit level being amalgamated in a vertical sense to create one common pool. Figure 52 illustrates through a schematic section and a sample pool map, an example of how a number of gas accumulations in individual stratigraphic units could communicate. Each of these gas accumulations is assigned a “sequence code” identifying that it is part of a common pool. The map view illustrates the four individual gas accumulations that are combined to create the corresponding EUB-designated pool outline.

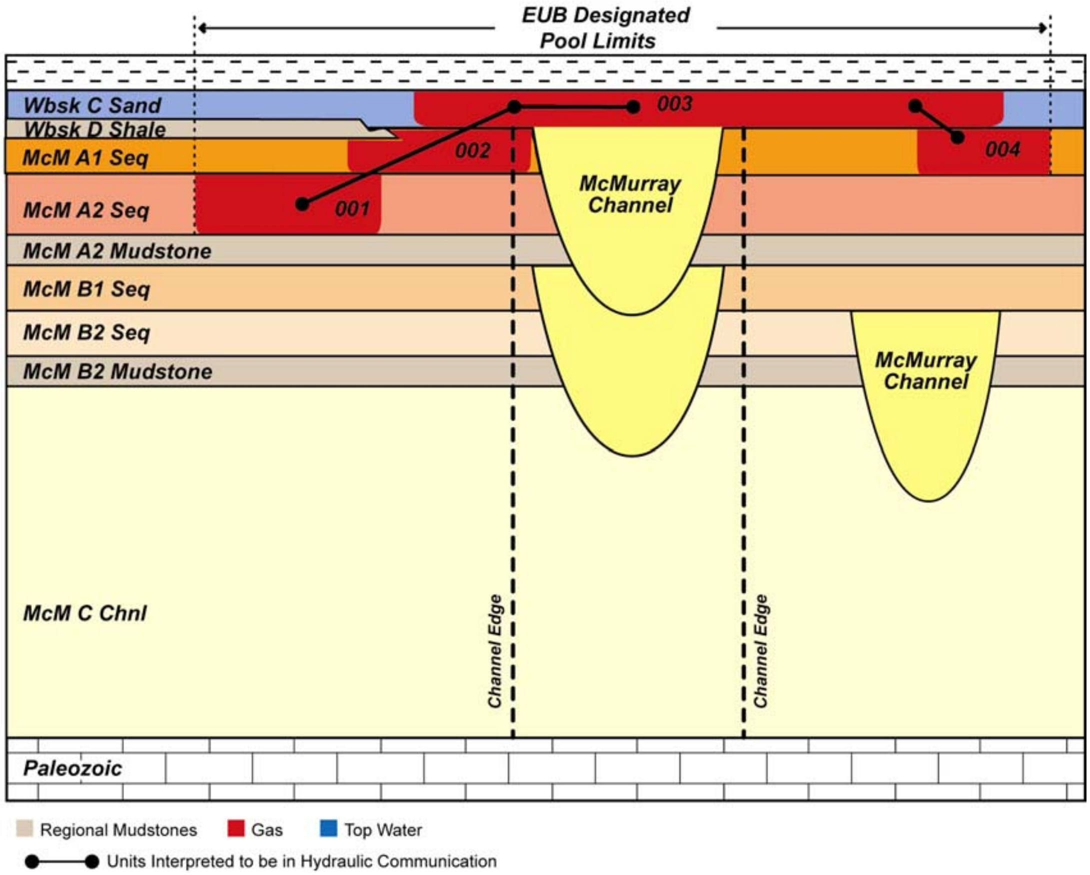


Figure 52 – Schematic Illustrating Individual Gas Accumulations and Corresponding EUB Designated Pool

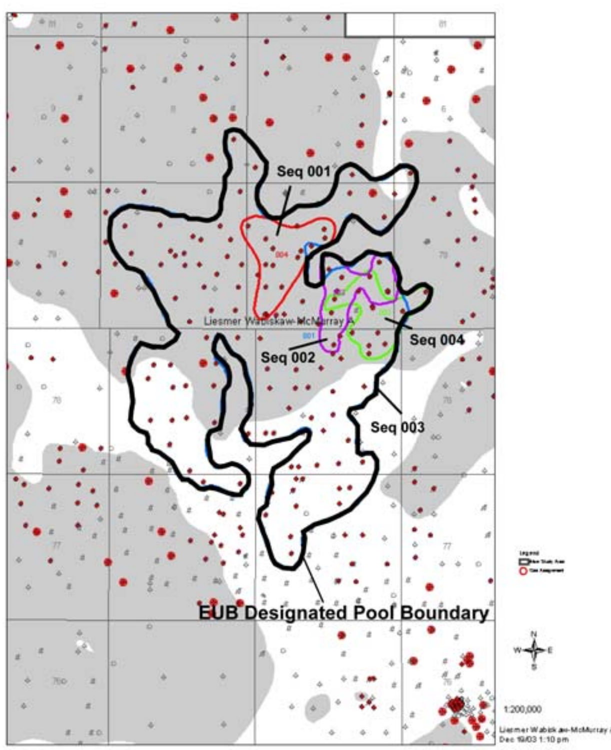


Figure 53 – Corresponding EUB Designated Pool

In some situations, gas pools are associated with an underlying water zone (called top water because it often overlies any bitumen present in the unit). The top and base of any top water zones were identified and the lateral extent mapped to establish the region of influence (ROI) of the overlying gas. Top water zones are not included within EUB-designated pools.

3.2 Pressure and Production Data Analysis

Publicly available pressure and production data were analyzed to complement the geological interpretation of gas pooling. The first priority for review was pools located in areas where regional sands are adjacent to channel sands. A total of 83 gas pools, listed in Appendix B1, were reviewed. A summary of each of the pool reviews is on the attached CD, including a pressure-versus-time plot, p/z-versus-cumulative production plot, and gas rate-versus-cumulative production plot, where completed.

Historical pressure trend data (i.e., time series data) from wells in geologically defined pools were reviewed to identify anomalous pressure data that might suggest different pooling. Pressure data from offsetting wells were also reviewed to determine whether they suggested different pooling (i.e., do the pressure data follow the same trend?). Where possible, material balance and production decline analysis were conducted to validate the areal extent of the pool.

The pool reviews identified limitations respecting pressure data analysis for gas pooling. These limitations were due to the quantity and quality of the available data. In particular, factors that limited the analysis were

- commingled gas production (i.e., due to the lack of wellbore segregation, pressure data cannot be used to assess natural communication between gas zones);

- the lack of adequate time series data, including
  - virgin pool pressures (i.e., pressures taken prior to gas production from a pool),
  - initial well pressures (i.e., pressures taken prior to or shortly after gas production has commenced from a well), and
  - well pressures following the commencement of gas production;

- the practice of measuring pressure at the surface and converting it to a downhole pressure when an acoustic survey to determine if water is present in the wellbore is absent; and

- the difficulty in interpreting small pressure differences or changes in the gas pools when they are all shallow, low-pressure pools.

Given the above limitations, where limited confidence could be placed on the existing pressure data, the resultant gas pooling was primarily based on the geological interpretation.

3.3 Gas Evaluations and Delineations

Gas maps for each of the stratigraphic units are included in this section and are described briefly. Many of these gas pools can extend laterally beyond the depositional limits of any one stratigraphic unit to include gas in laterally offsetting stratigraphic units. For that reason, gas pools on the subsequent maps can overlap the depositional edges of a unit.

Larger versions of the following maps with additional detail and well control are on the CD. The gas pay interval data are also included as a table on the CD.

3.3.1 Main Study Area

McMurray C Channel / McMurray Channel

The McMurray C Channel only contains a small number of gas pools, the majority of which are interpreted as single-well pools. Many of these have associated top water. Net gas pay thickness is typically less than 2 m.

The McMurray Channel sequence contains significantly more gas than the McMurray C Channel. However, like the McMurray C, the areal extent of pools is limited to single-well pools and small multiwell pools. McMurray Channel pools contain the thickest net gas pay observed in any of the stratigraphic units and also account for the majority of the associated top water accumulations. Net pay thickness can range from 2 to 15 m, with an average of about 4 m. Many pools within this sequence are interpreted to be in lateral communication with gas within the McMurray B1, McMurray A2, McMurray A1, McMurray A Channel, and the Wabiskaw D Valley-fill. Gas may also be in vertical communication with gas in overlying McMurray A1, Wabiskaw C Sand, and Wabiskaw D Valley-fill, where regional mudstones are absent. Figure 54 presents the McMurray Channel gas/top water map.

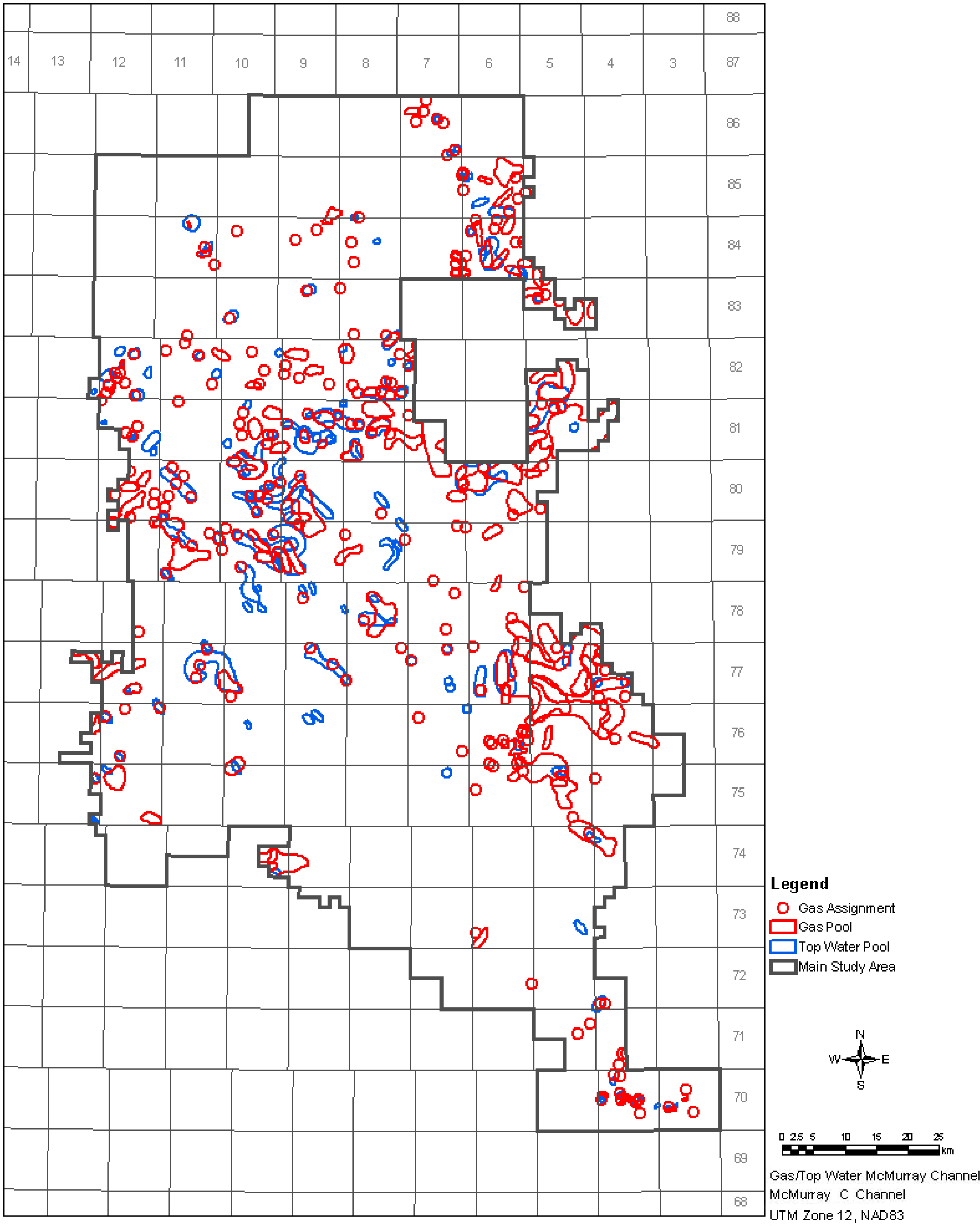


Figure 54 – McMurray Channel/McMurray C Channel Gas/Top Water Map

McMurray B2 Sequence

Gas pools within this sequence are typically small 3-6 well pools distributed primarily in the central portion of the area with average net pay thickness of 1-2 m. Figure 55 presents the B2 Sequence gas/top water map. These pools can be associated laterally with gas in offsetting McMurray B1 and B2 Channels and McMurray Channels.

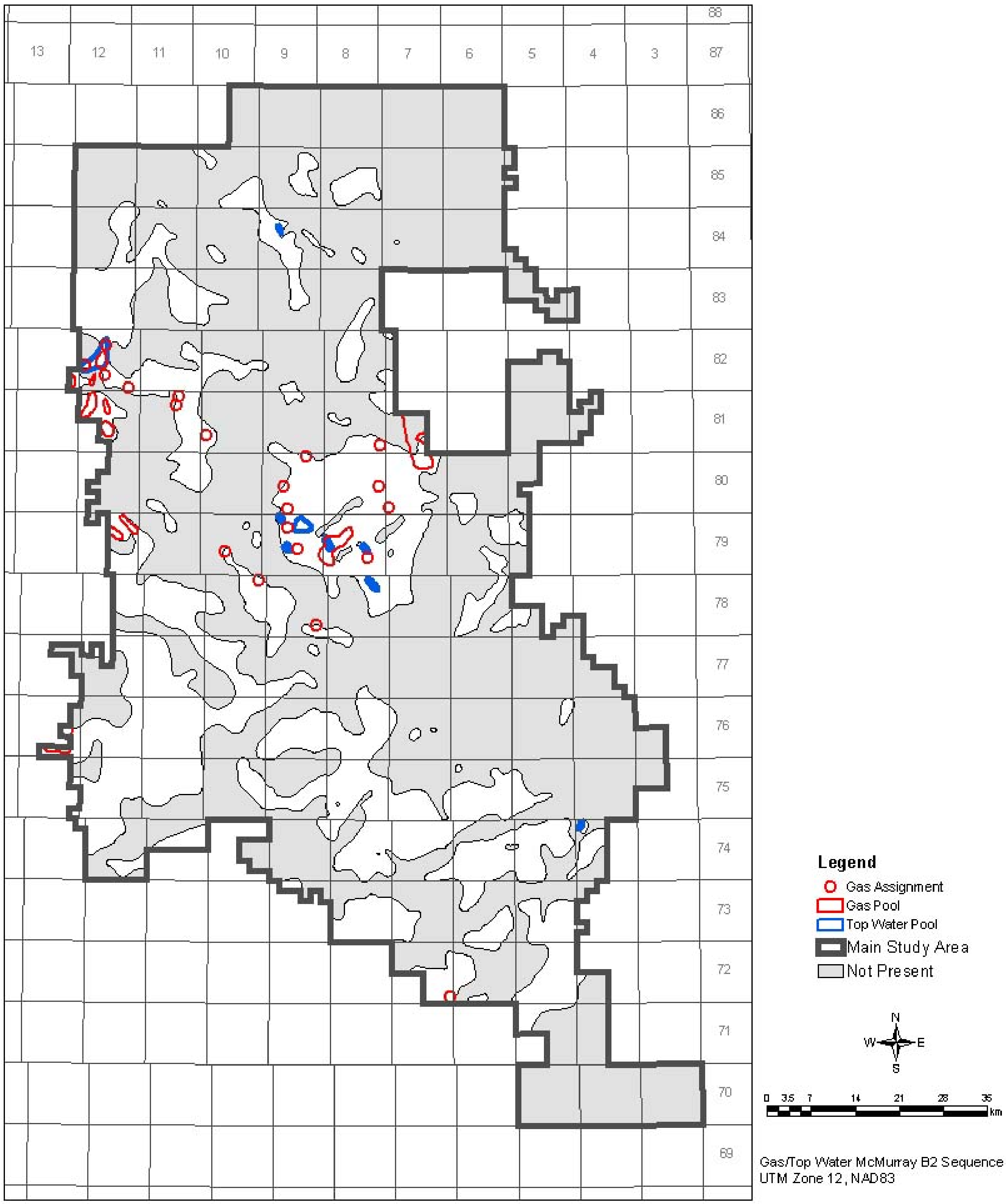


Figure 55 – McMurray B2 Sequence Gas/Top Water Map with B2 Distribution

McMurray B2 Channel
Pools are limited in size and number to a few single-well pools in the central part of the study area. Pay thickness is generally less than 2 m. Figure 56 presents the B2 Channel gas/top water map.

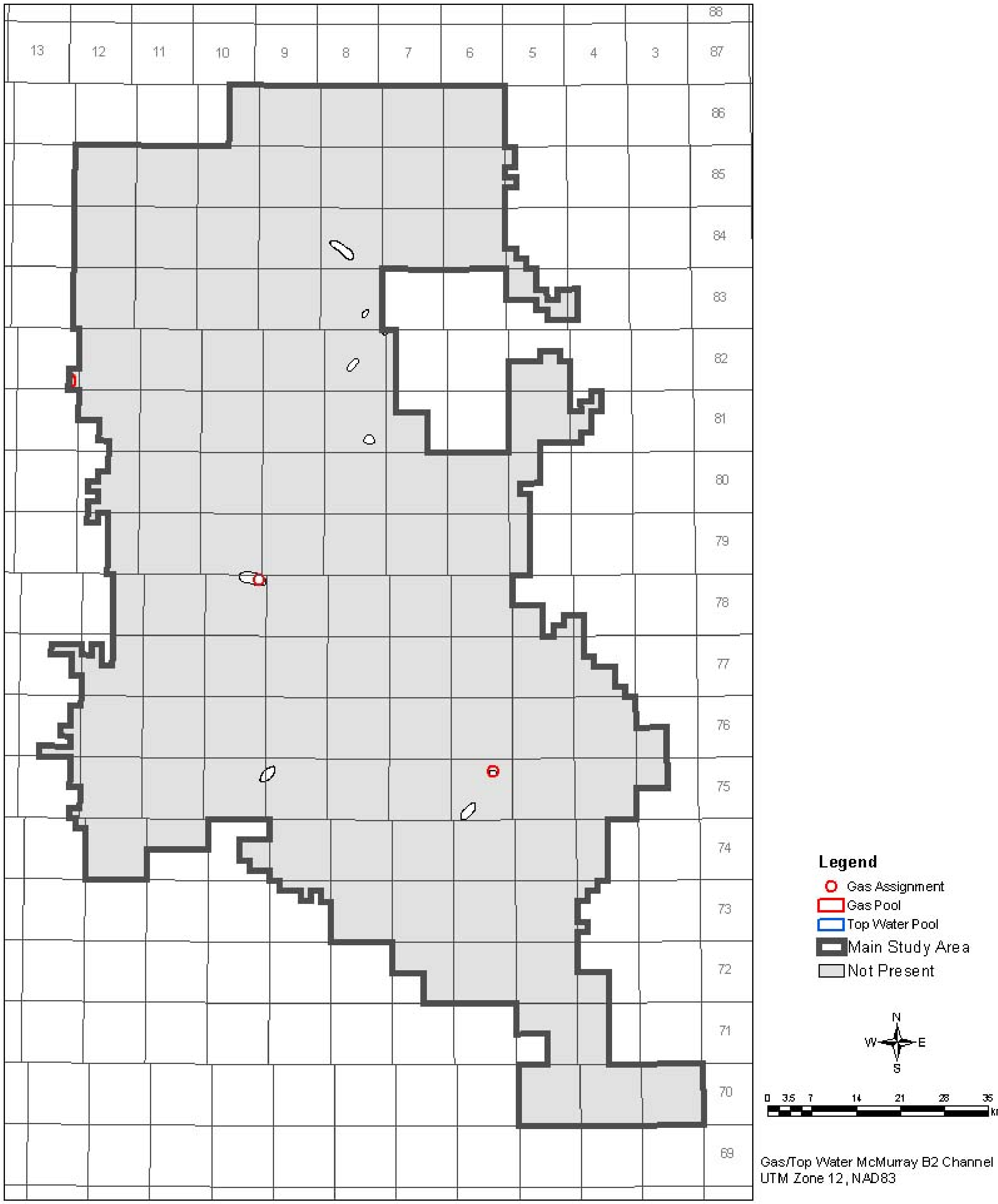


Figure 56 – McMurray B2 Channel Gas/Top Water Map with B2 Channel Distribution

McMurray B1 Sequence

The majority of B1 pools are multiwell (2 to 10) pools and are thin, averaging about 1 m of net pay. In some instances they may be in communication laterally with gas in McMurray Channels or McMurray B1 Channels. Vertical communication potential exists with gas in the McMurray B2 Sequence. Figure 57 presents the B2 Sequence gas/ top water map.

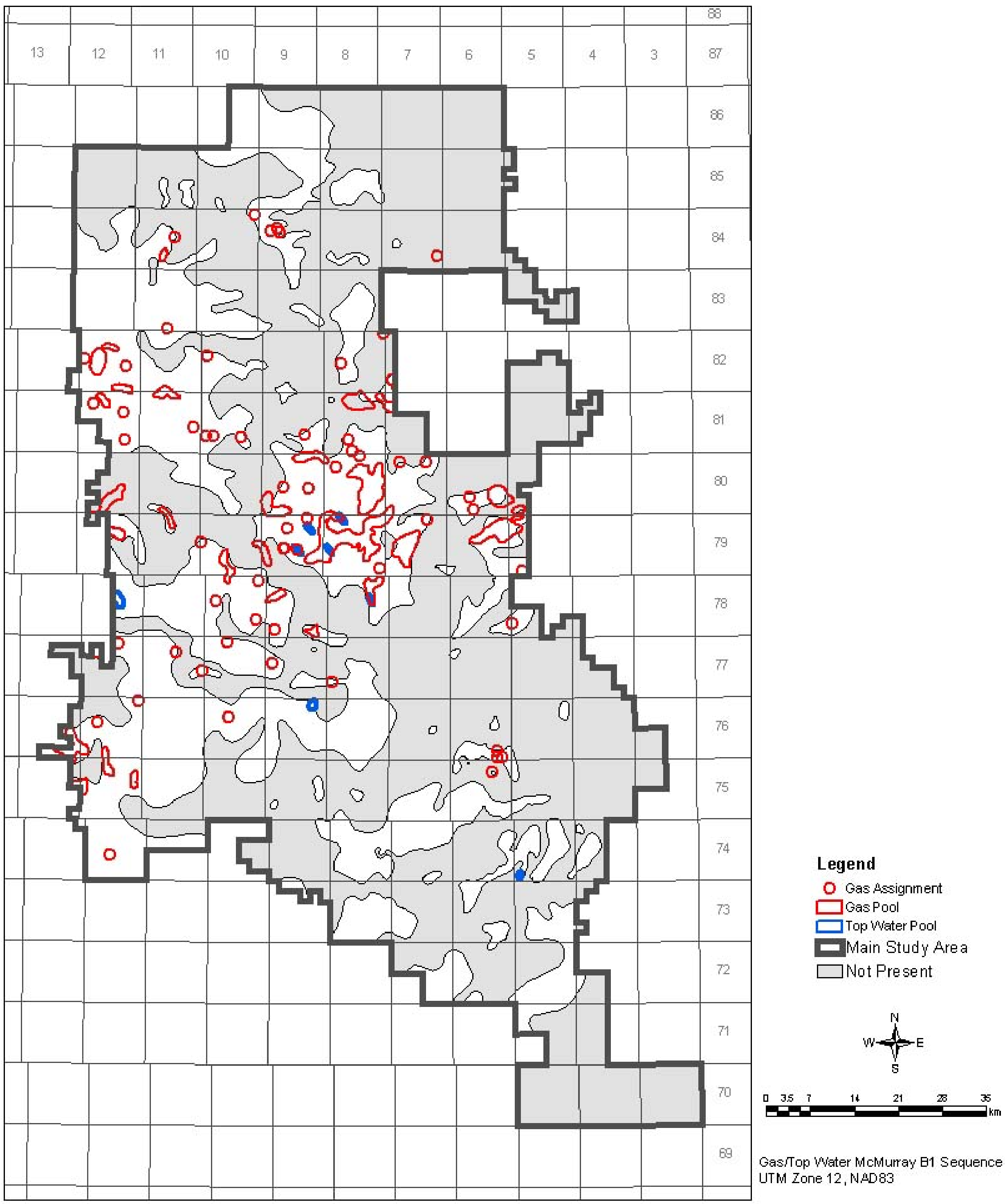


Figure 57 – McMurray B1 Sequence Gas/Top Water Map with B1 Distribution

McMurray B1 Channel

Coincident with the sporadic distribution of the McMurray B1 Channel, gas pools are few and are small, usually single-well pools. Pay thickness is less than 2 m. There can be lateral communication with gas in the McMurray B1 Sequence. Figure 58 presents the B1 Channel gas/top water map.

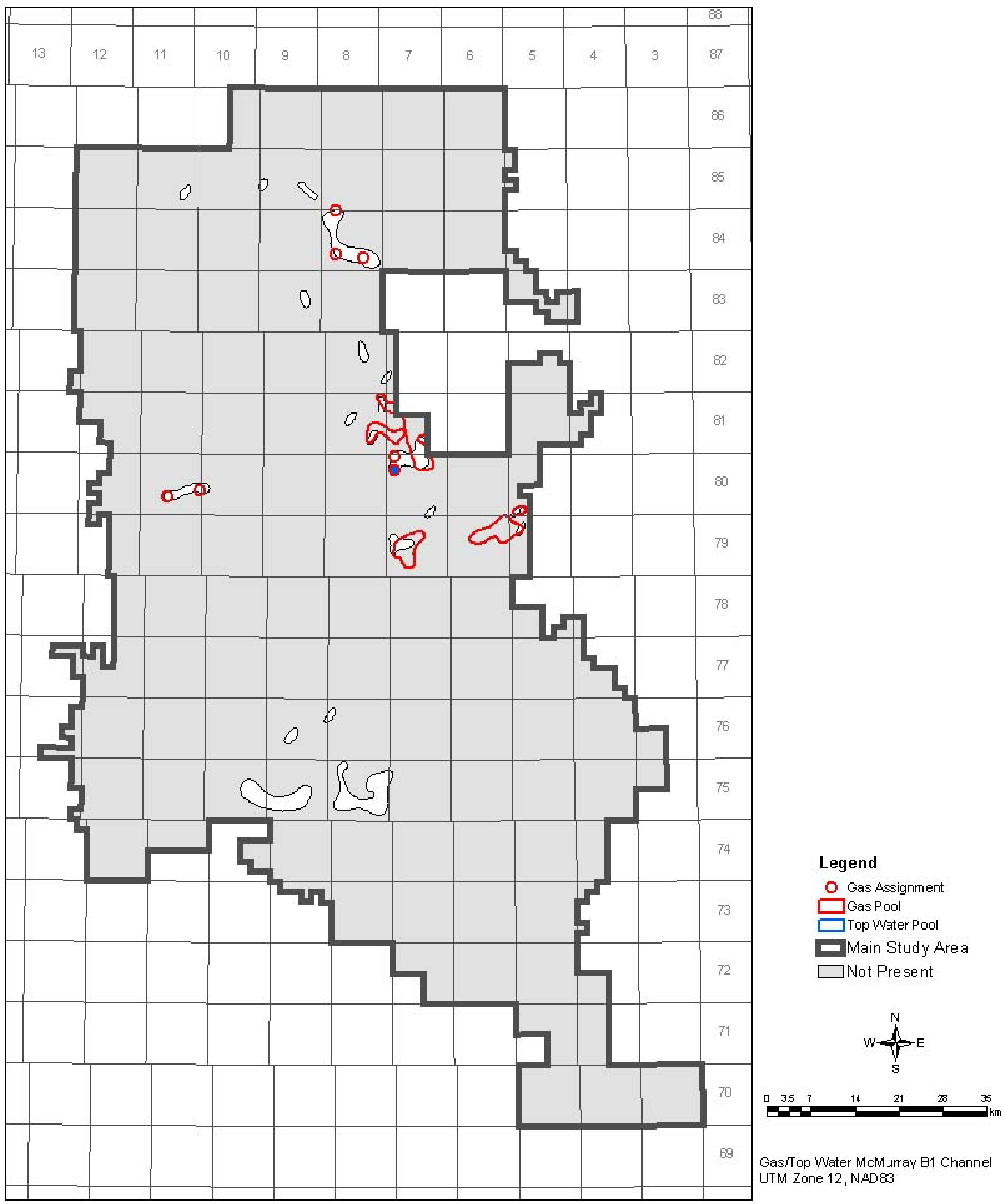


Figure 58 – McMurray B1 Channel Gas/Top Water Map with B1 Channel Distribution

Composite McMurray B Gas Pools and Top Water Zones

Figure 59 presents all gas/top water pools between the A2 and B2 Mudstone. These pools are a compilation of the McMurray B1 and B2 Sequence and B1 and B2 Channel gas pools and top water zones. The McMurray B2 Mudstone often underlies these pools separating them from the underlying McMurray C Channel gas and bitumen.

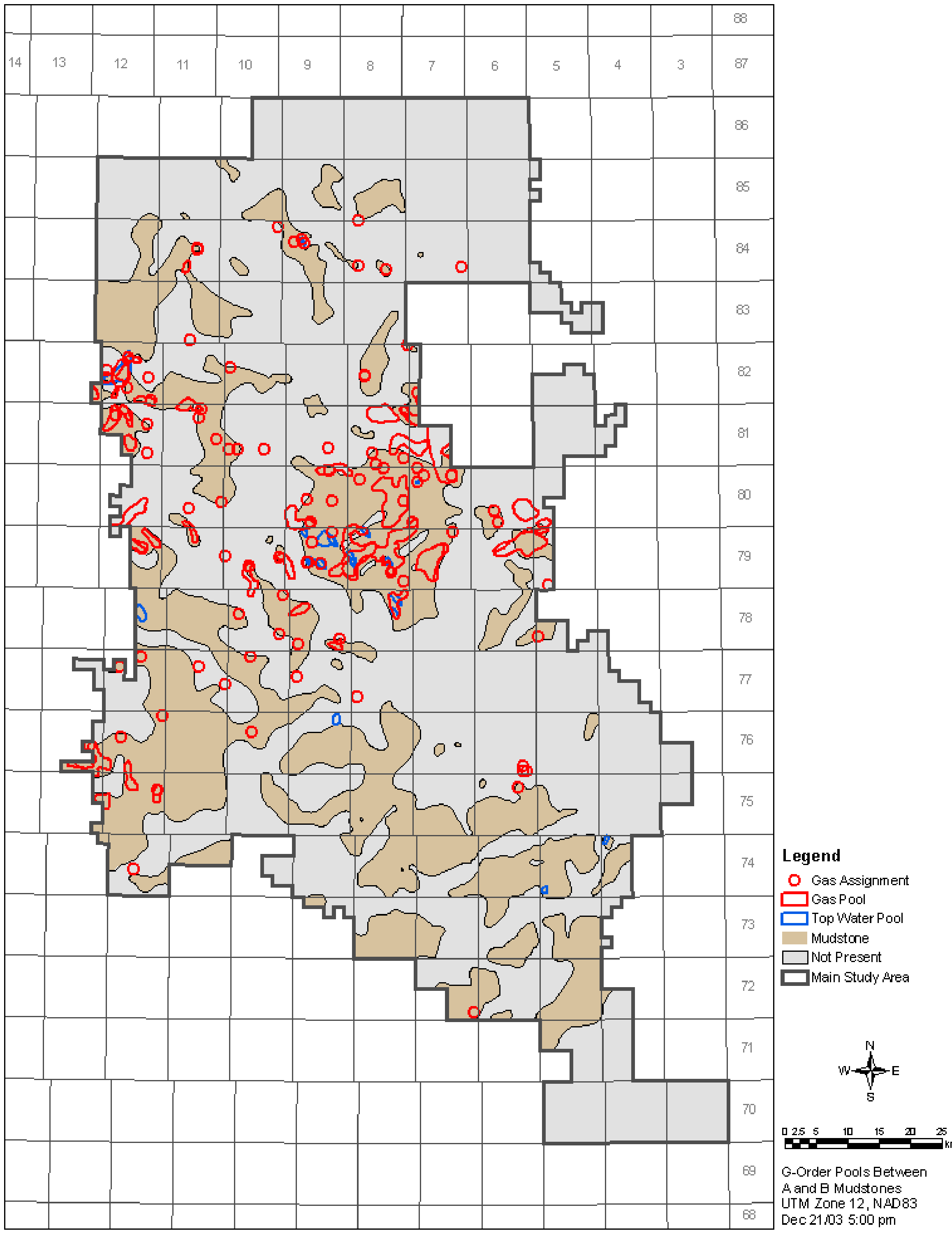


Figure 59 – Composite McMurray B Gas / Top Water with B2 Mudstone Distribution

McMurray A2 Sequence

Pools are distributed primarily throughout the central portion of the area and typically cover 3–10 sections in size. Pay thicknesses are thin, averaging 1-2 m, with minor instances of top water. There is potential for lateral communication with gas in McMurray A Channel and McMurray Channel sands and vertical communication with the McMurray A1 Sequence, Wabiskaw C Sand, and Wabiskaw D Valley-fill. Figure 60 presents the A2 Sequence gas/top water map.

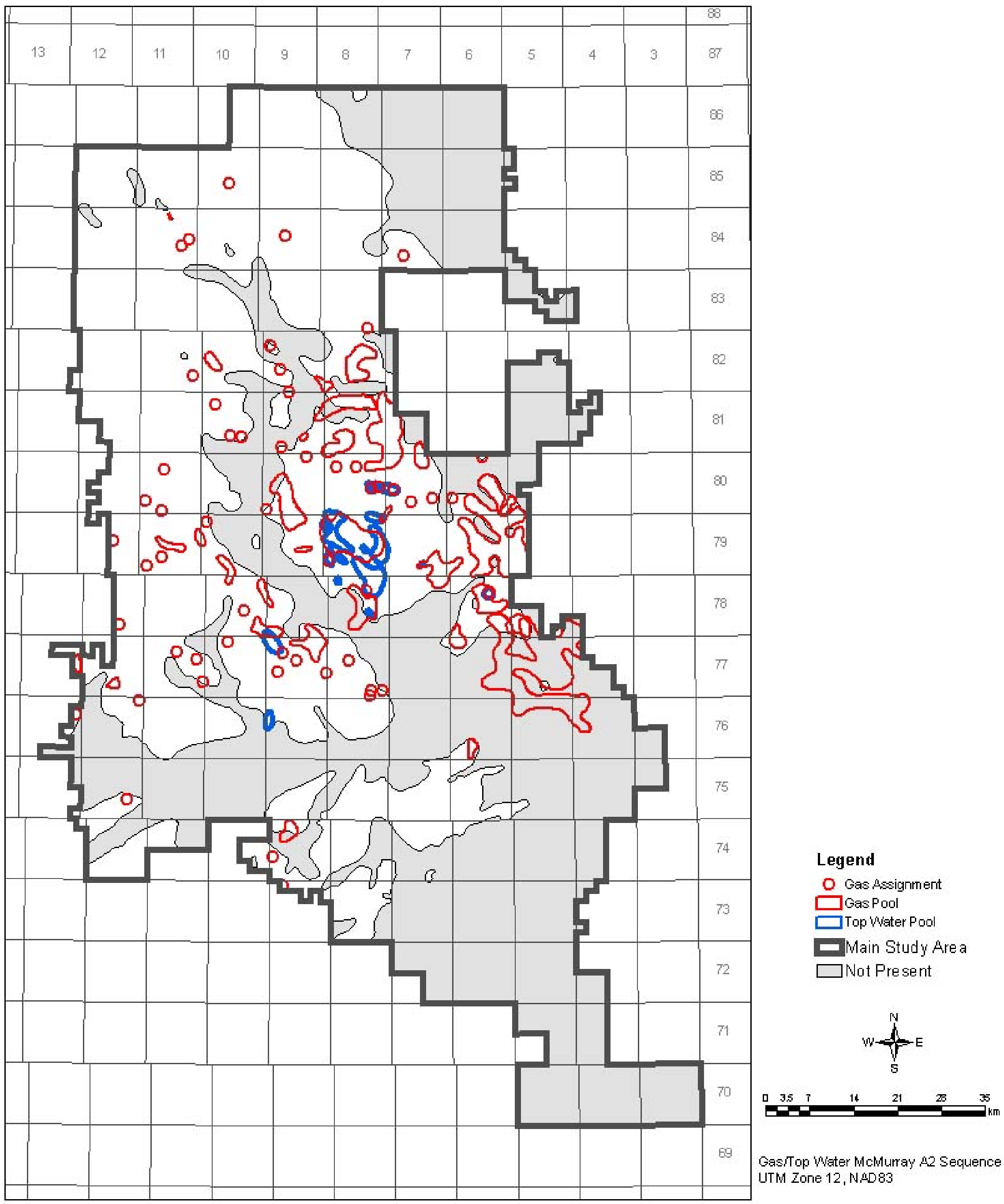


Figure 60 – McMurray A2 Sequence Gas/Top Water Map with A2 Distribution

McMurray A Channel

Pools can range from single-well to multiwell over much of the area and tend to contain relatively thick net pay, averaging 2 to 5 m. There is potential for lateral communication with gas in the McMurray A2, McMurray A1, and McMurray Channel, such that pools can extend beyond the depositional limits of the A Channel distribution. Figure 61 presents the A Channel gas/top water map.

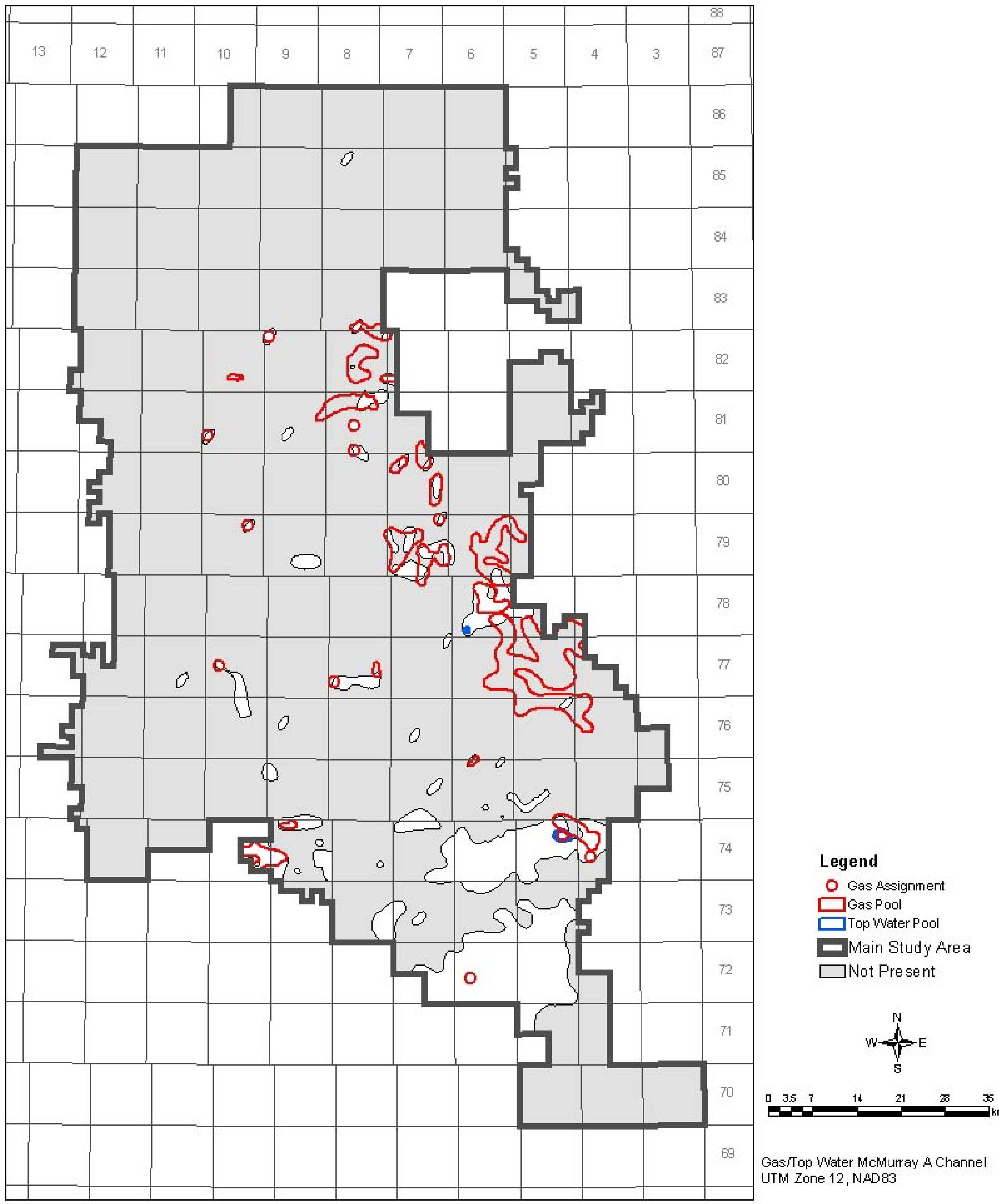


Figure 61 – McMurray A Channel Gas/Top Water Map with A Channel Distribution

McMurray A1 Sequence

Pools tend to cover a wide range of sizes, from single-well pools to multiwell pools of up to 15 wells, but are relatively thin, with an average of 1 m of net pay. Gas can be in lateral communication with gas in the McMurray A Channel and McMurray Channel and in vertical communication with McMurray Channel, McMurray A2 Sequence, Wabiskaw D Valley-fill, and Wabiskaw C Sand. Figure 62 presents the A1 Sequence gas/top water map.

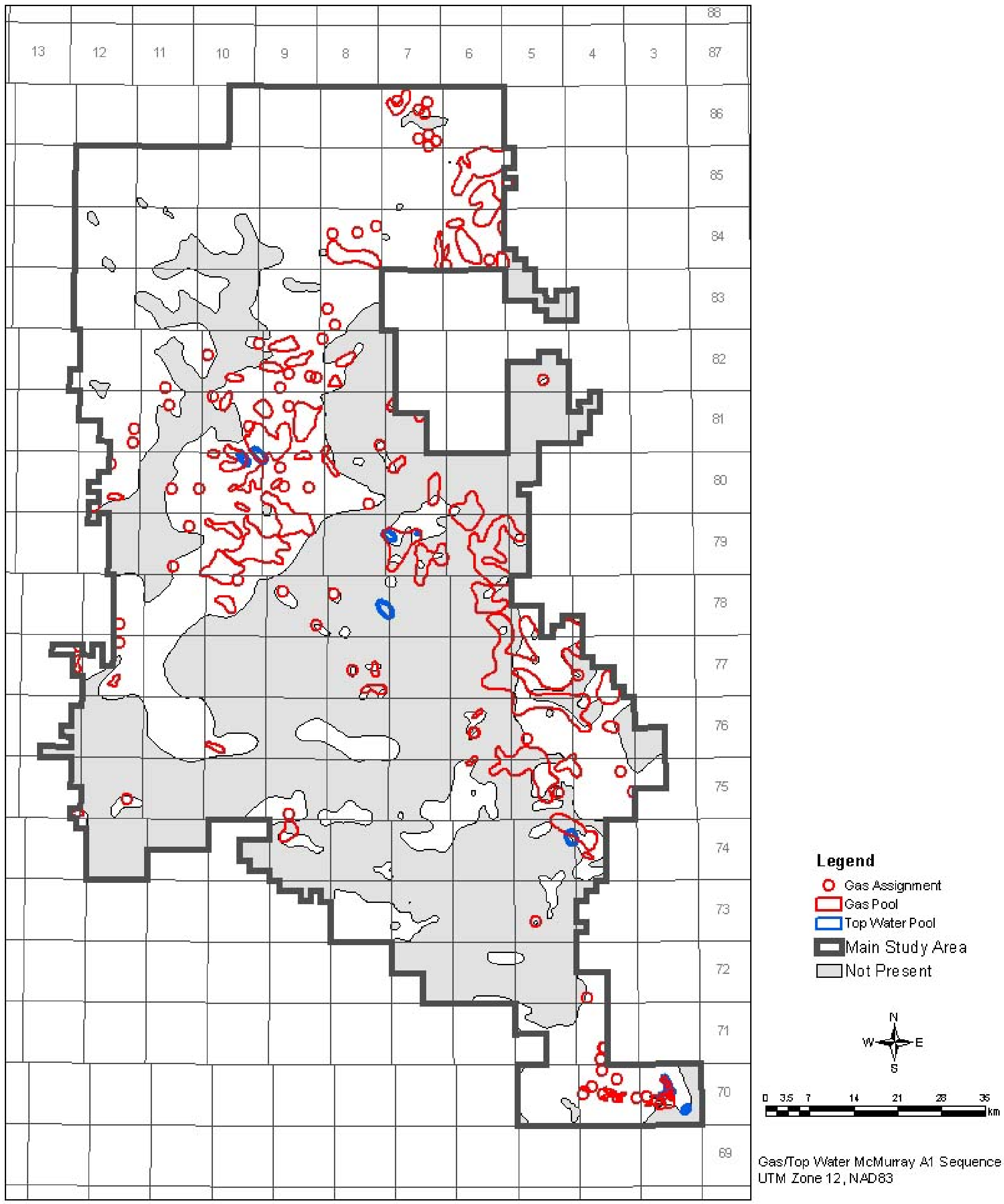


Figure 62 – McMurray A1 Sequence Gas/Top Water Map with A1 Distribution

Wabiskaw D Valley-Fill

Moderate-sized pools with average pay thickness from 2 to 5 m exist within the study area. There is lateral communication potential with gas in the McMurray Channel in the extreme northeast area and vertical communication potential with McMurray Channel, McMurray A1, McMurray A2, and Wabiskaw C Sand. Figure 63 presents the D Valley-fill gas/top water map.

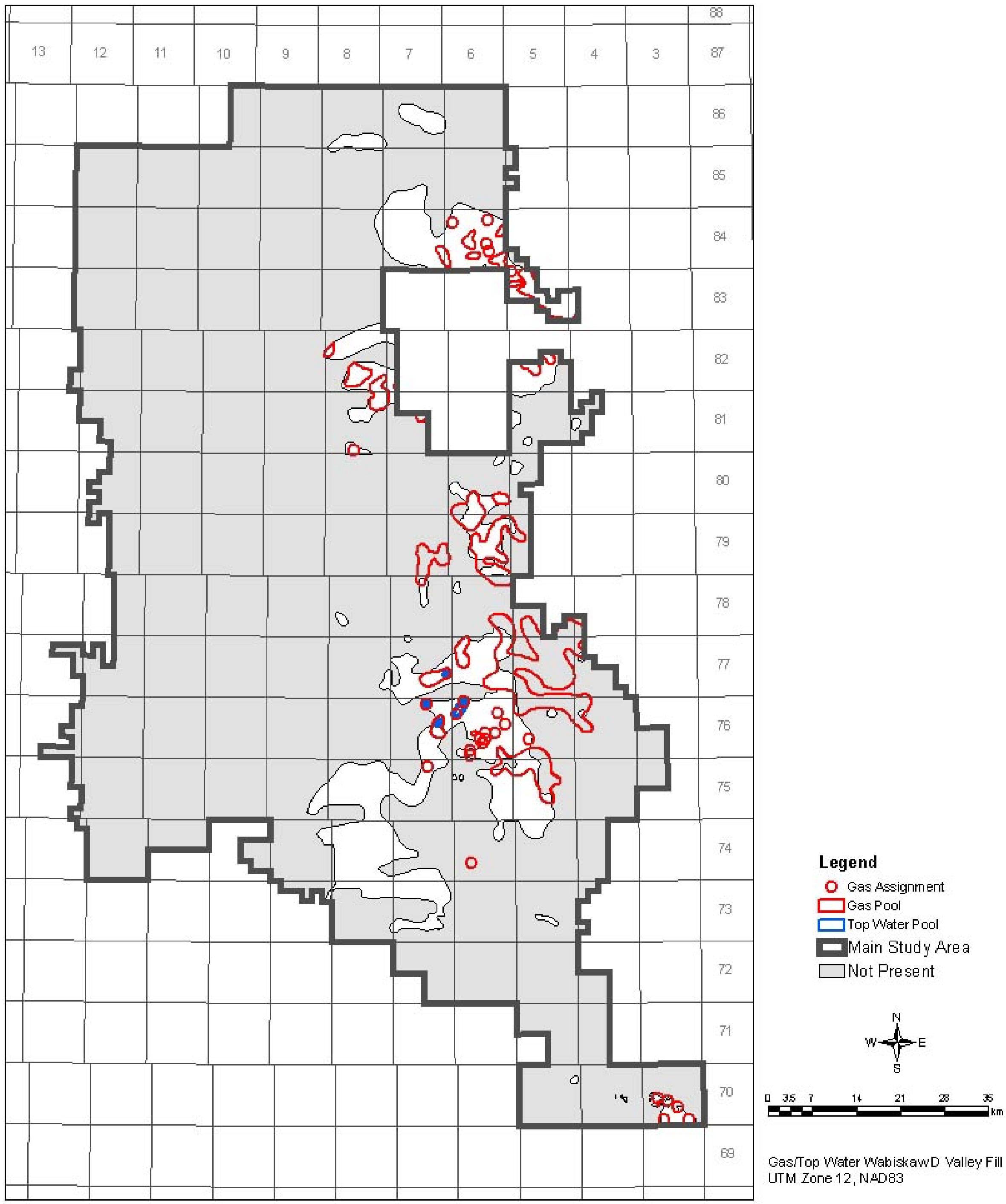


Figure 63 – Wabiskaw D Valley-fill Gas/Top Water Map with D Valley-fill Distribution

Wabiskaw C Sand

Gas pools in the Wabiskaw C Sand are interpreted to be the most laterally extensive of any of the stratigraphic units in the main study area. Pay thickness is relatively thin, averaging 1 to 2 m. There is vertical communication potential with gas in the McMurray A1, McMurray A2, McMurray Channel, and Wabiskaw D Valley-fill. Figure 64 presents the C Sand gas/top water map.

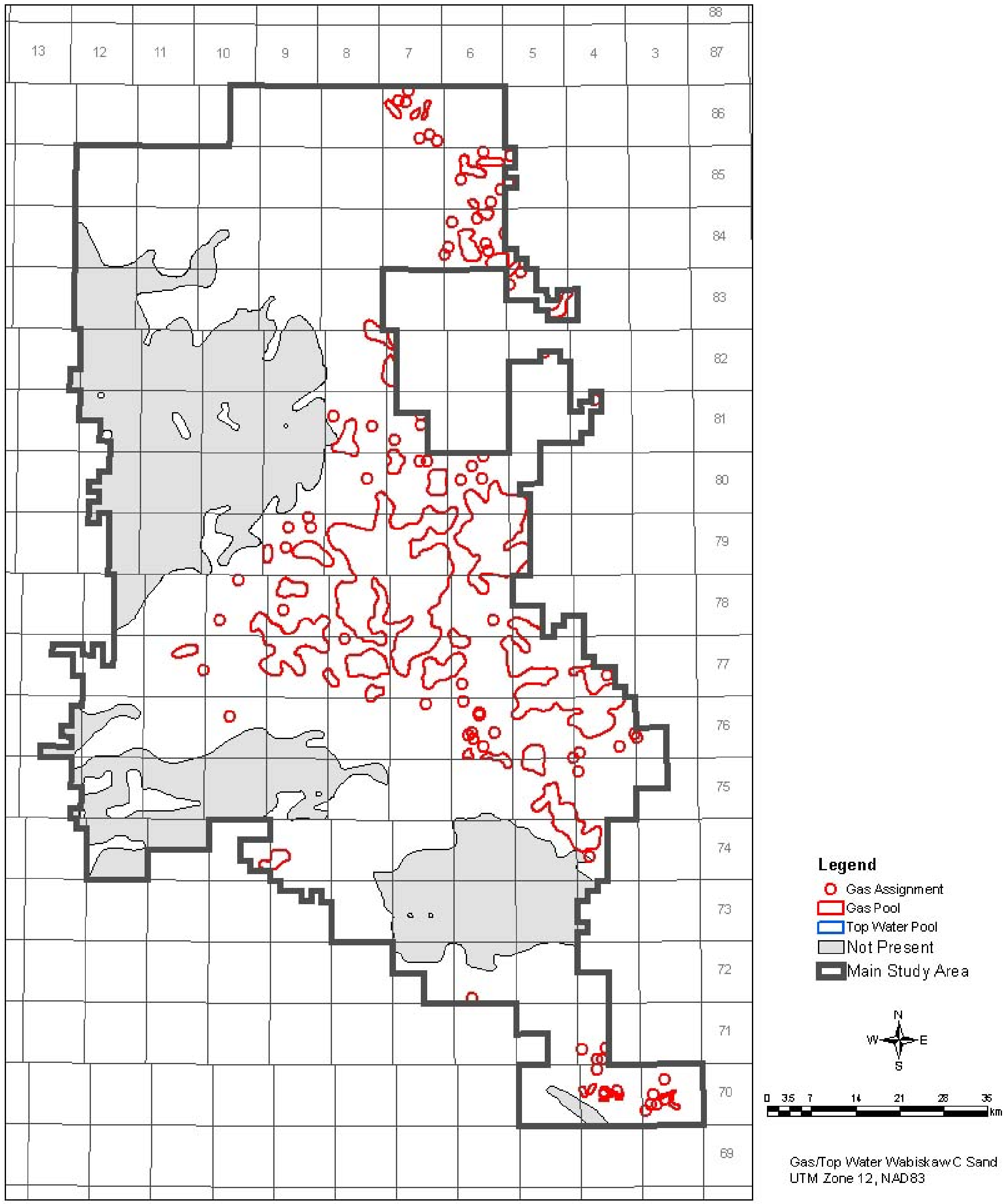


Figure 64 – Wabiskaw C Sand Gas/Top Water Map with C Sand Distribution

Composite of Gas / Top Water Above McMurray A2 Mudstone

Figure 65 presents the gas/top water pools above the A2 Mudstone. These pools are a compilation of McMurray A1, A2, A Channel, Wabiskaw D Valley-fill and C Sand gas pools and top water zones. The McMurray A2 and B2 Mudstones often underlie these pools separating them from the underlying McMurray Channel and C Channel gas and bitumen. The Wabiskaw C Sand is vertically separated by the Wabiskaw D Shale greater than 0.5 m thick.

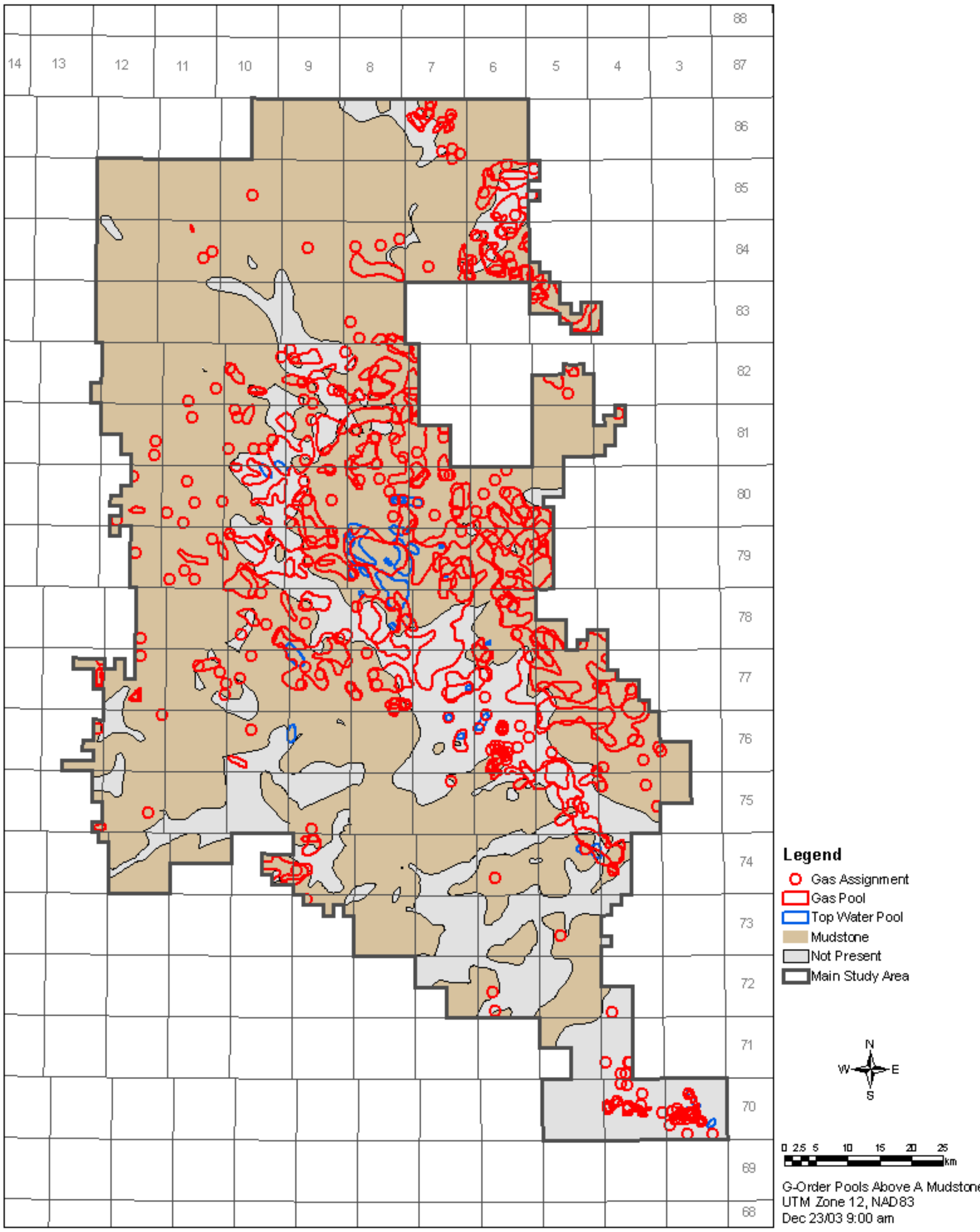


Figure 65 – Composite of Gas / Top Water above A2 Mudstone with A2 and B2 Mudstone and D Shale Distribution

Wabiskaw B Valley-Fill

The main gas pool coincides with the large valley-fill deposit located in the southern portion of the study area. Pay thickness are significant, from 2 to 20 m, averaging about 4 m. Extensive top water is present at some locations. There is limited vertical communication between the Wabiskaw B Valley-fill and the underlying stratigraphic units. Figure 66 presents the B Valley-fill gas/top water map.

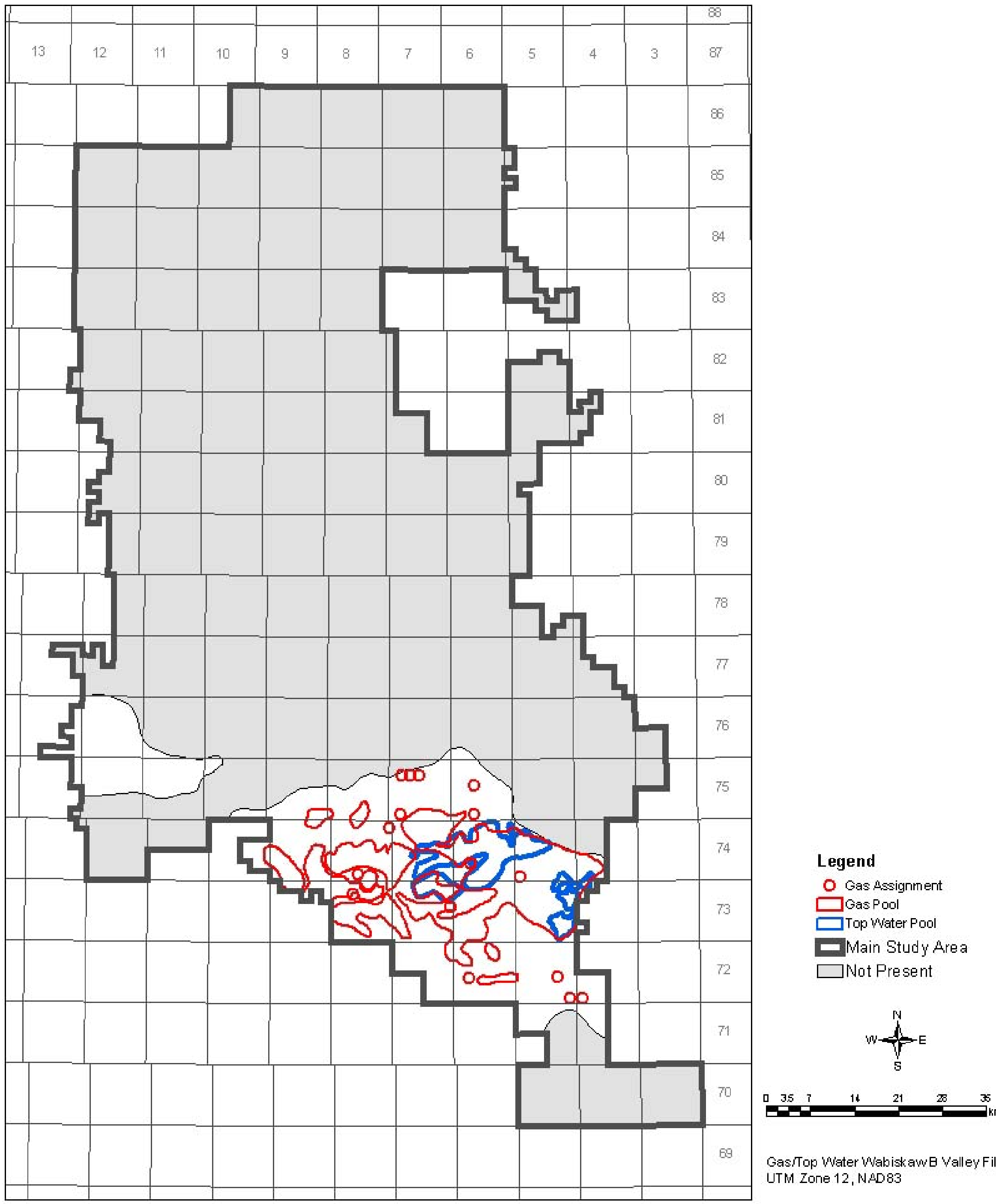


Figure 66 - Wabiskaw B Valley-fill Gas/Top Water Map

3.3.2 North Study Area

In general, the gas accumulations are confined to the southwest, central, and northeastern regions of the study area.

McMurray Channel

Gas pools are limited in size to predominantly single-well pools. Pay thickness range from 1 to 5 m, with no top water present. There is no lateral or vertical gas communication with any other stratigraphic units. Figure 67 presents the McMurray Channel gas map.

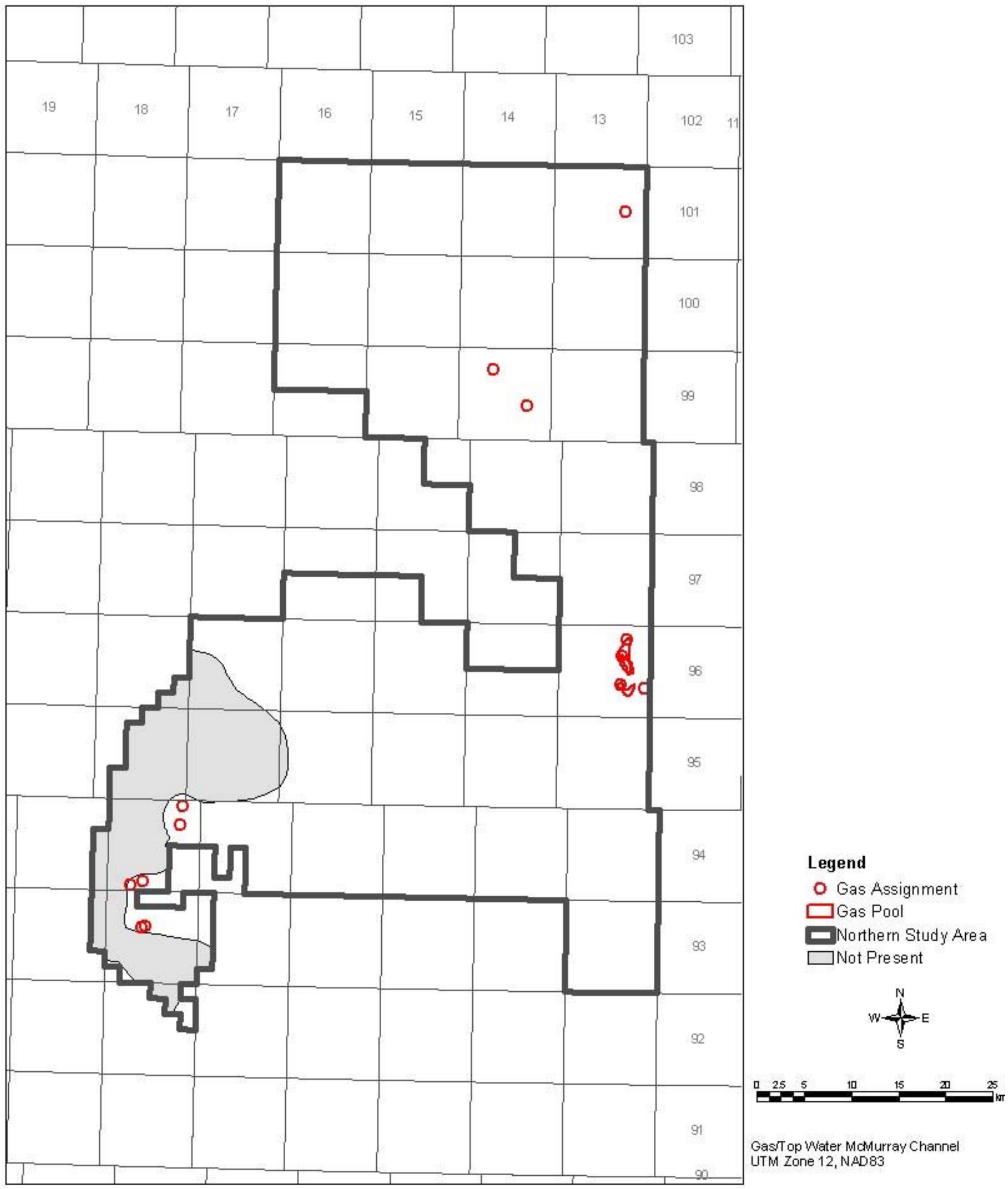


Figure 67 - McMurray Channel Gas Map

Wabiskaw D Sand

Gas pools are typically multiwell pools, confined predominantly to the southwest portion of the study area, with thickness ranging from 4 to 15 m. There is no associated top water. There is potential vertical communication with gas in the overlying Wabiskaw C Sand. Figure 68 presents the D Sand gas/top water map.

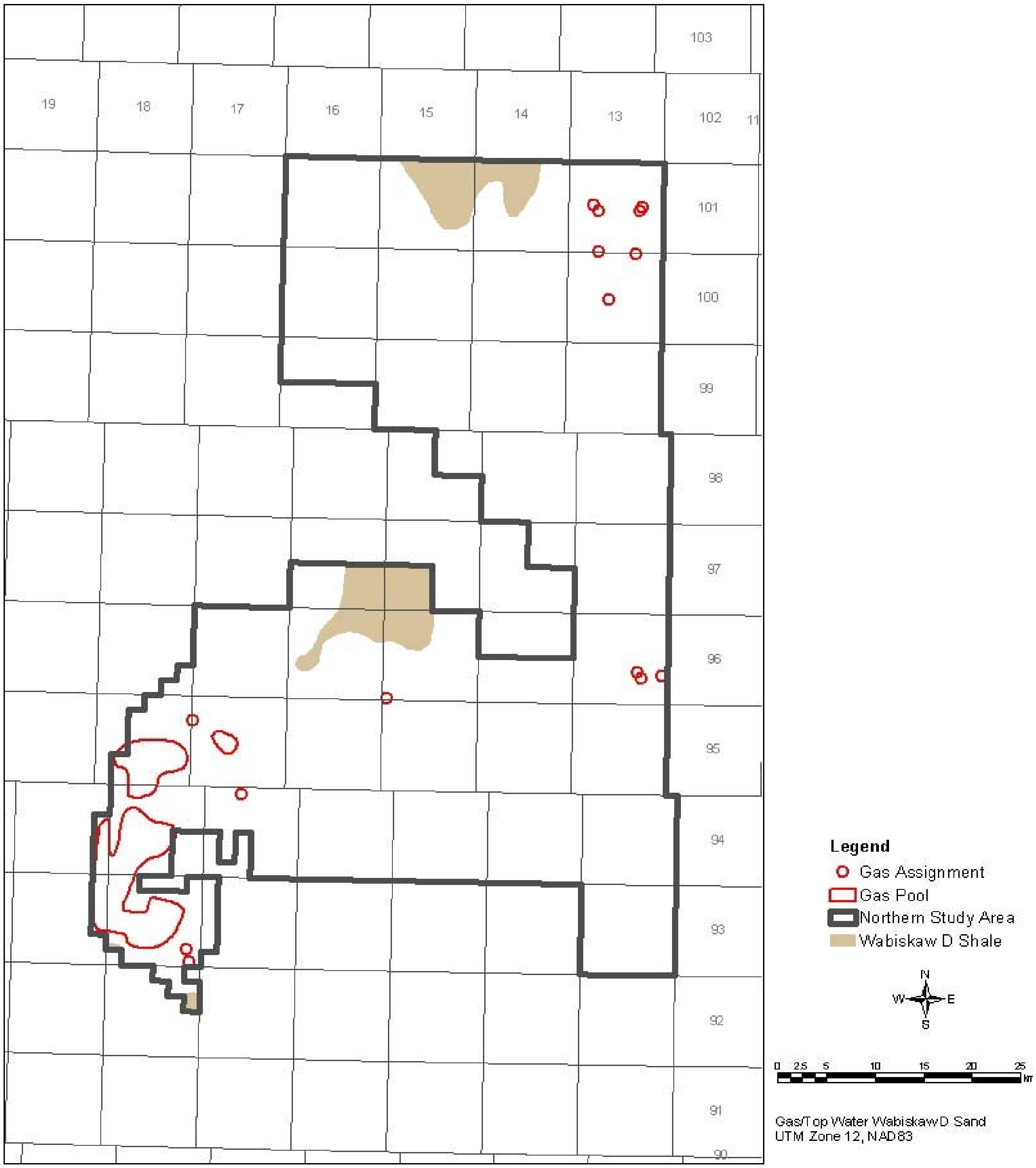


Figure 68 – Wabiskaw D Sand Gas/Top Map

Wabiskaw C Sand

A large multiwell pool is present in the southwest, with smaller pools located in the northeast portion of the study area. Pay thickness ranges from 4 to 15 m, with some top water in the extreme southwest. There is vertical communication with gas within the Wabiskaw D Sand in the southwest. Figure 69 presents the C Sand gas/top water map.

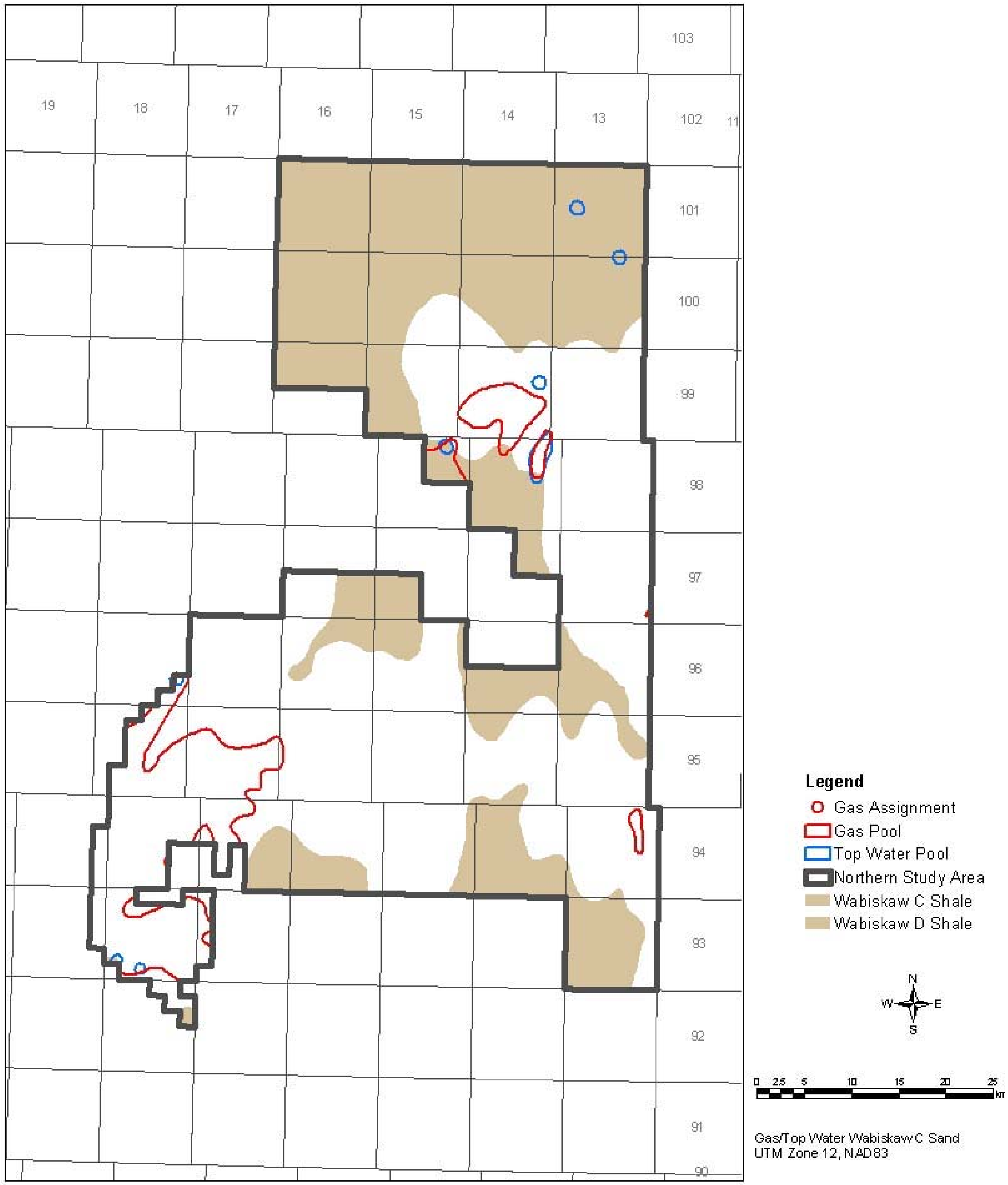


Figure 69 - Wabiskaw C Sand Gas/Top Water Map

Wabiskaw A Sand

Significant gas pools are present in the southwest, central, and northeastern areas of the region, ranging in thickness from 1 to 20 m. Top water is present. There is vertical communication with Wabiskaw C Sand gas pools in the southwest. Figure 70 presents the A Sand gas/top water map.

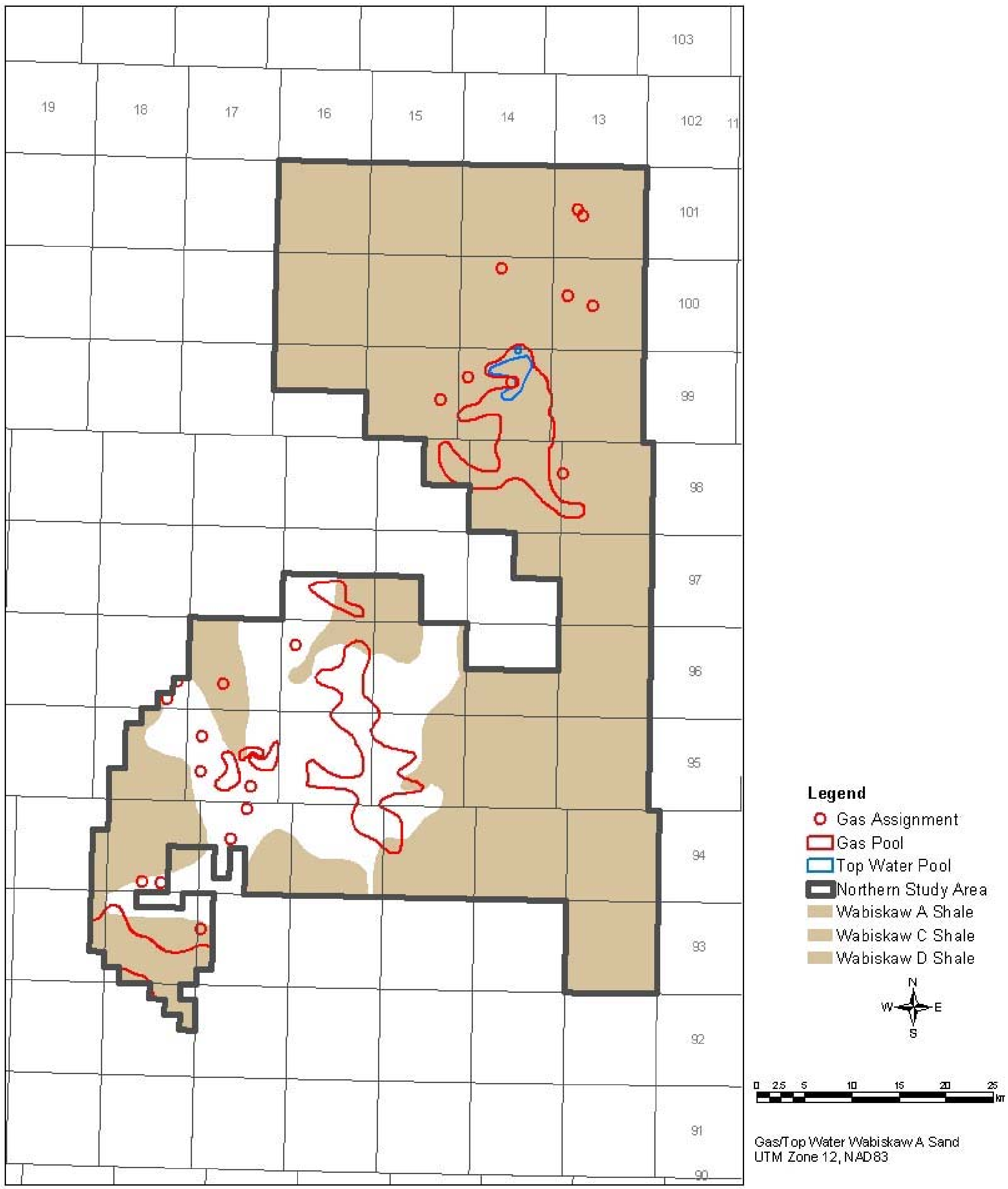


Figure 70 - Wabiskaw A Sand Gas/Top Water Map

4 Bitumen Evaluation

4.1 Method

The EUB evaluates and maps bitumen resources and reserves as part of its core business. As a result, many wells had already been evaluated within the study area, but it was necessary to expand this work and provide a greater density of evaluation data. At the conclusion of the project, 3265 wells were evaluated and available for the study. The remaining unevaluated wells included wells with poor log data and wells located in oil sands leases where dense drilling was present.

The EUB uses computer log evaluation software (Geolog) to evaluate bitumen. Standard algorithms (see Appendix B2) are used to determine volume of shale (Vsh), average porosity, and percent bitumen saturation by weight (wt% bitumen). Values are calculated in 0.3 m increments from the top of the Wabiskaw to the base of the McMurray in all wells evaluated. The values are plotted as a set of answer curves and are presented along with core-derived porosity and bitumen saturation for comparison purposes. Answer curves are matched to core analysis data, where available, by adjusting input parameters where necessary. Final answer curve data are stored in a database.

To produce bitumen net pay maps, answer curve data are extracted between the top and base depths that represent each stratigraphic unit being evaluated. This is done for all wells. A cutoff of 6 wt% bitumen is then applied to the answer curve data. All increments within a stratigraphic unit that meet this cutoff are accumulated into a net bitumen pay thickness for that unit. Net bitumen pay values are then mapped using ESRI ArcMap GIS software.

The EUB currently uses a 50% bitumen saturation cutoff[1]. For the study, an equivalent wt% bitumen cutoff was used. A cutoff of 6 wt% bitumen is considered to approximate a combined 50% bitumen saturation cutoff and a 27% porosity cutoff. The wt% bitumen cutoff was preferred over the bitumen saturation and porosity cutoff because of ease of calibrating core analysis results to log results.

[1] EUB *Interim Directive (ID) 99-1: Gas/Bitumen Production in Oil Sands Areas – Application, Notification, and Drilling Requirements,* February 3, 1999.

4.2 Bitumen Evaluation Results

The following provides a brief description of the bitumen maps constructed using the approach described above. Only those stratigraphic units that contain bitumen exceeding 10 m in thickness are included.

4.2.1 Bitumen Evaluation Results, Main Study Area

Wabiskaw / McMurray

Figure 71 is a composite map of all bitumen-bearing intervals > 6 wt % bitumen saturation from the top of the Wabiskaw to the base of the McMurray. This map has not been used in the assessment of where gas may be associated; however, it is illustrative of where the thickest cumulative bitumen exists. When compared against the McMurray C Channel / McMurray Channel map, similar patterns are evident and it is clear that McMurray Channels account for the majority of bitumen within the study area. The exception to this is the significant accumulation in the southern end of the main study area centred at about Township 74, Range 07. This reflects thick bitumen-bearing McMurray Channel sands overlain by bitumen-bearing sands in the Wabiskaw B Valley-fill trend.

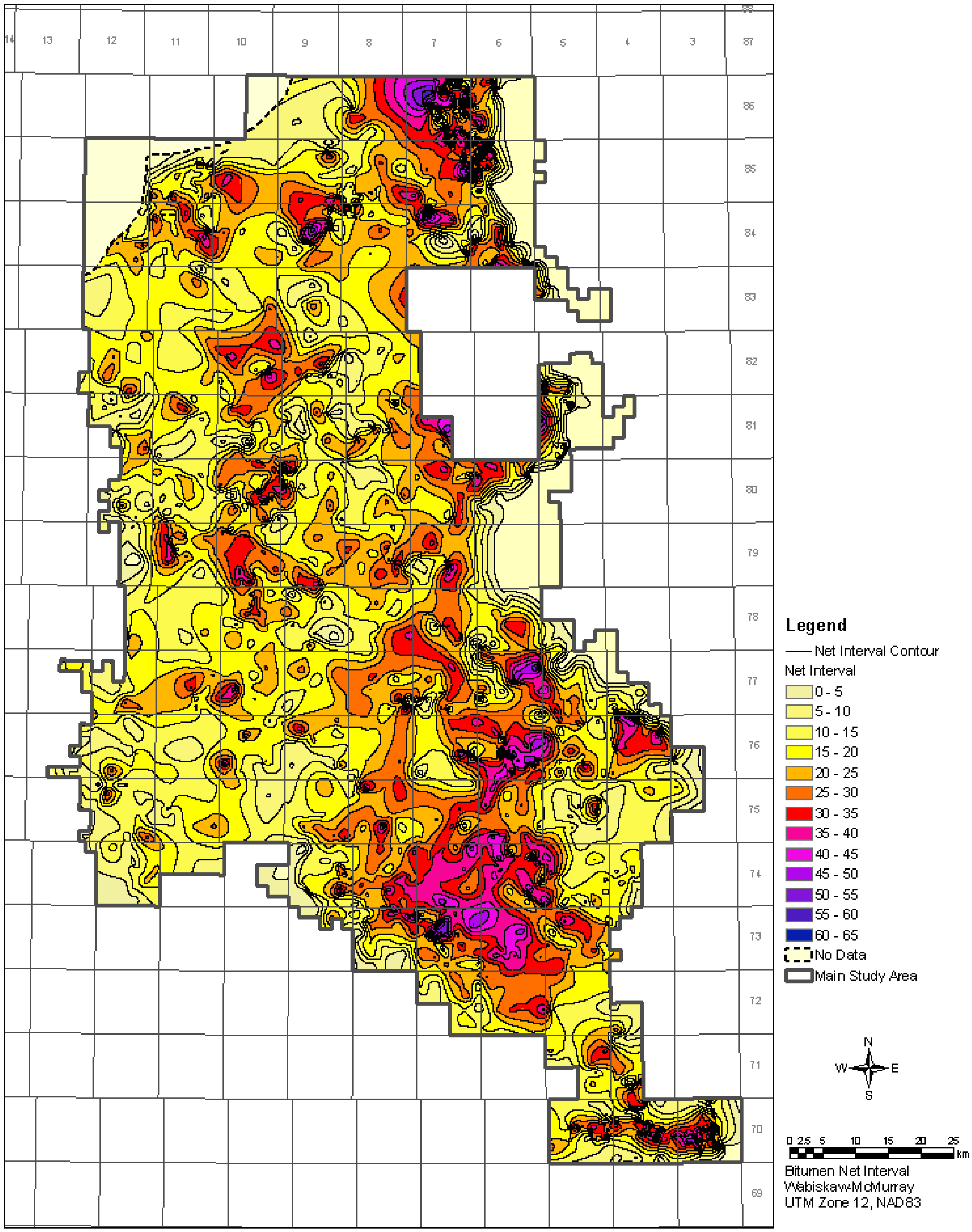


Figure 71 – Wabiskaw / McMurray Bitumen Isopach Map

McMurray C Channel / McMurray Channel

The McMurray C Channel / McMurray Channel bitumen thickness typically exceeds 10 m over much of the main study area and is occasionally over 40 m thick. Figure 72 presents the McMurray Channel and McMurray C Channel bitumen isopach map. Figure 73 highlights areas where bitumen exceeds 10 m in thickness.

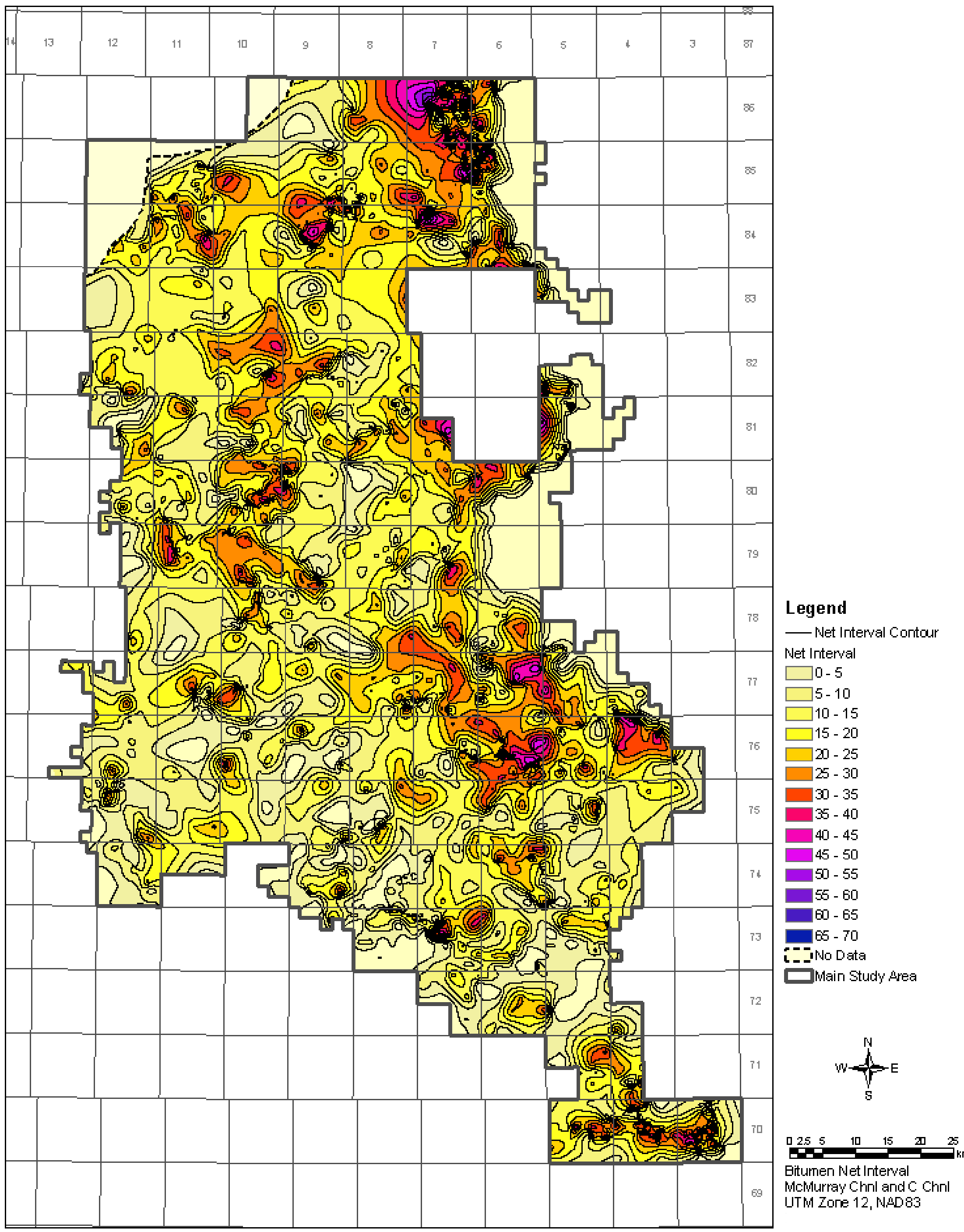


Figure 72 –McMurray C Channel / McMurray Channel Bitumen Isopach Map

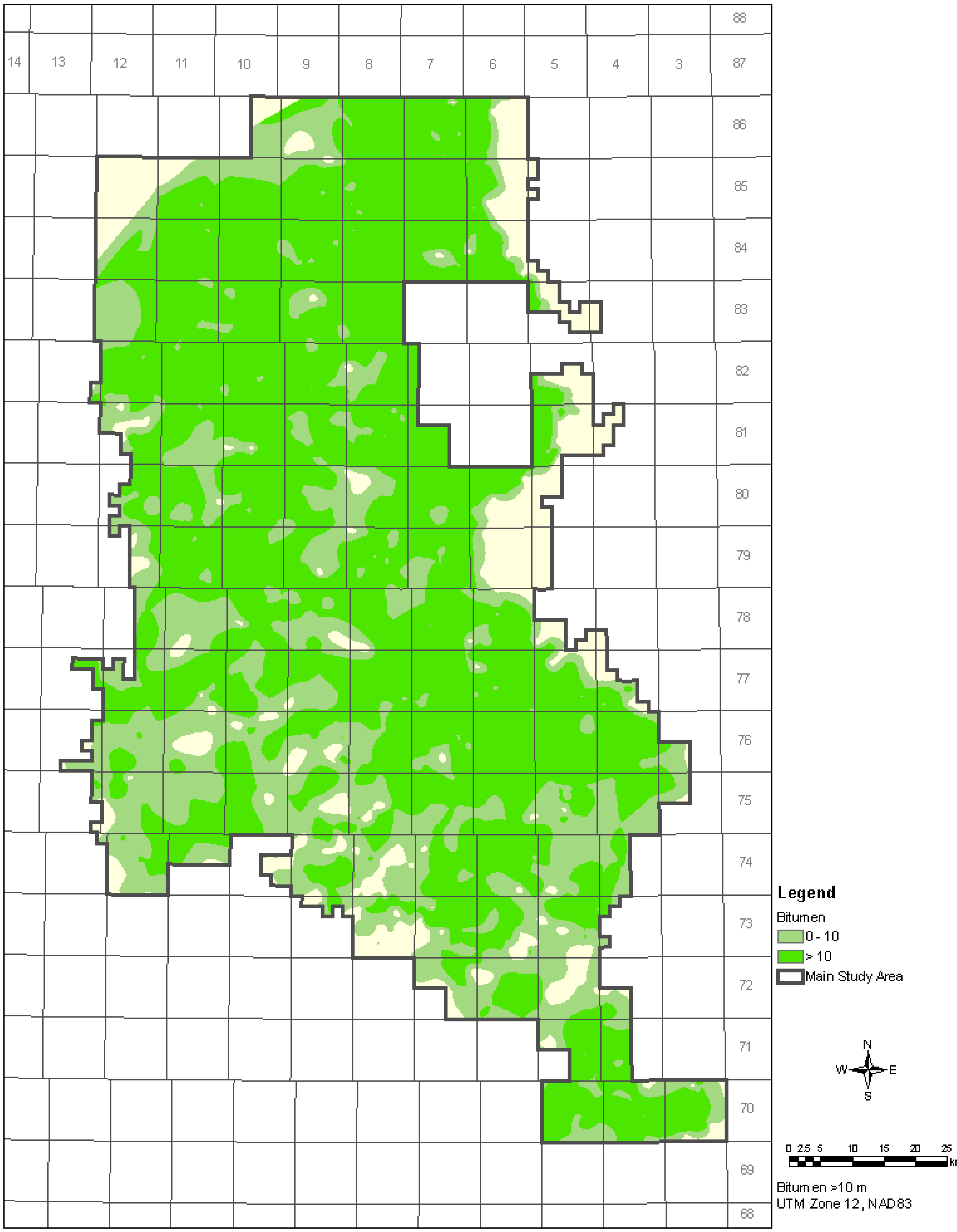


Figure 73 – McMurray C Channel / McMurray Channel Bitumen >10 m

Wabiskaw D Valley-fill

Bitumen exceeding 10 m thickness is restricted to three small areas in the south-central portion of the main study area. Figure 74 presents the D Valley-fill bitumen isopach map. Figure 75 shows where bitumen thickness exceeds 10 m.

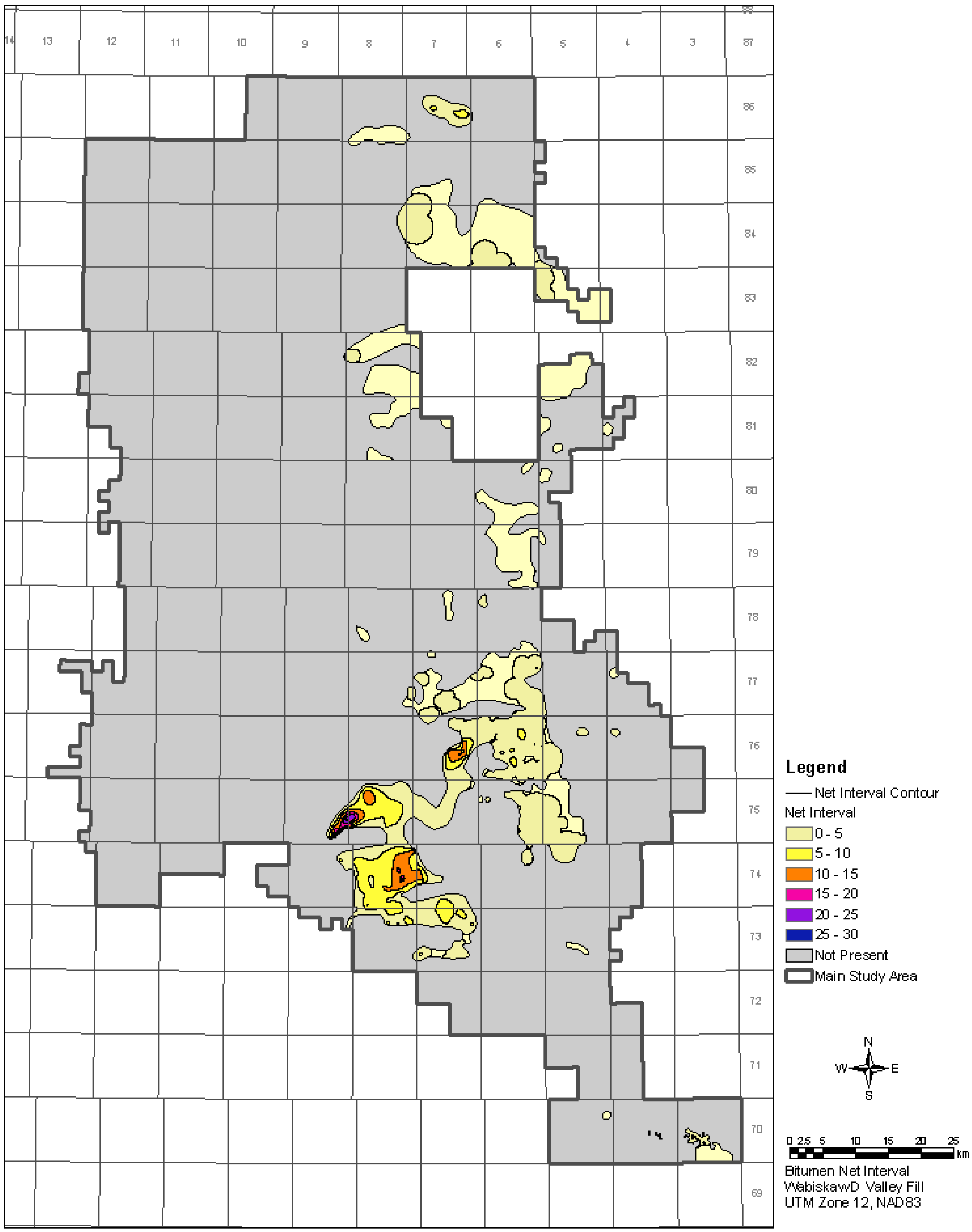


Figure 74 – Wabiskaw D Valley-fill Bitumen Isopach Map

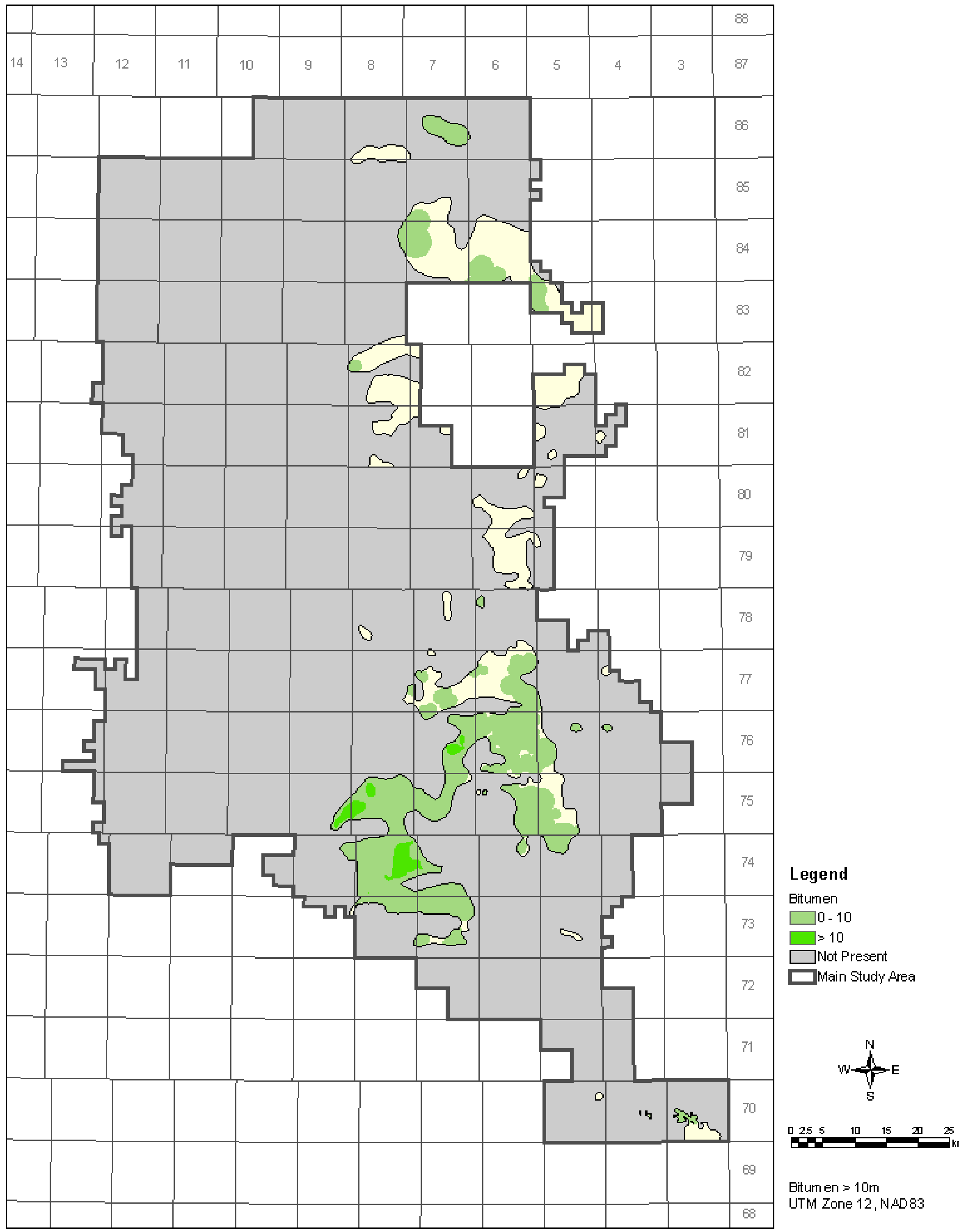


Figure 75 – Wabiskaw D Valley-fill Bitumen >10 m

Wabiskaw B Valley-fill

Wabiskaw B Valley-fill covers a significant region in the southern end of the main study area. Bitumen thickness commonly exceeds 20 m, with the thickest portion of the deposit centred in Township 73, Range 06. Figure 76 presents the B Valley-fill bitumen isopach map. Figure 77 shows where bitumen thickness exceeds 10 m.

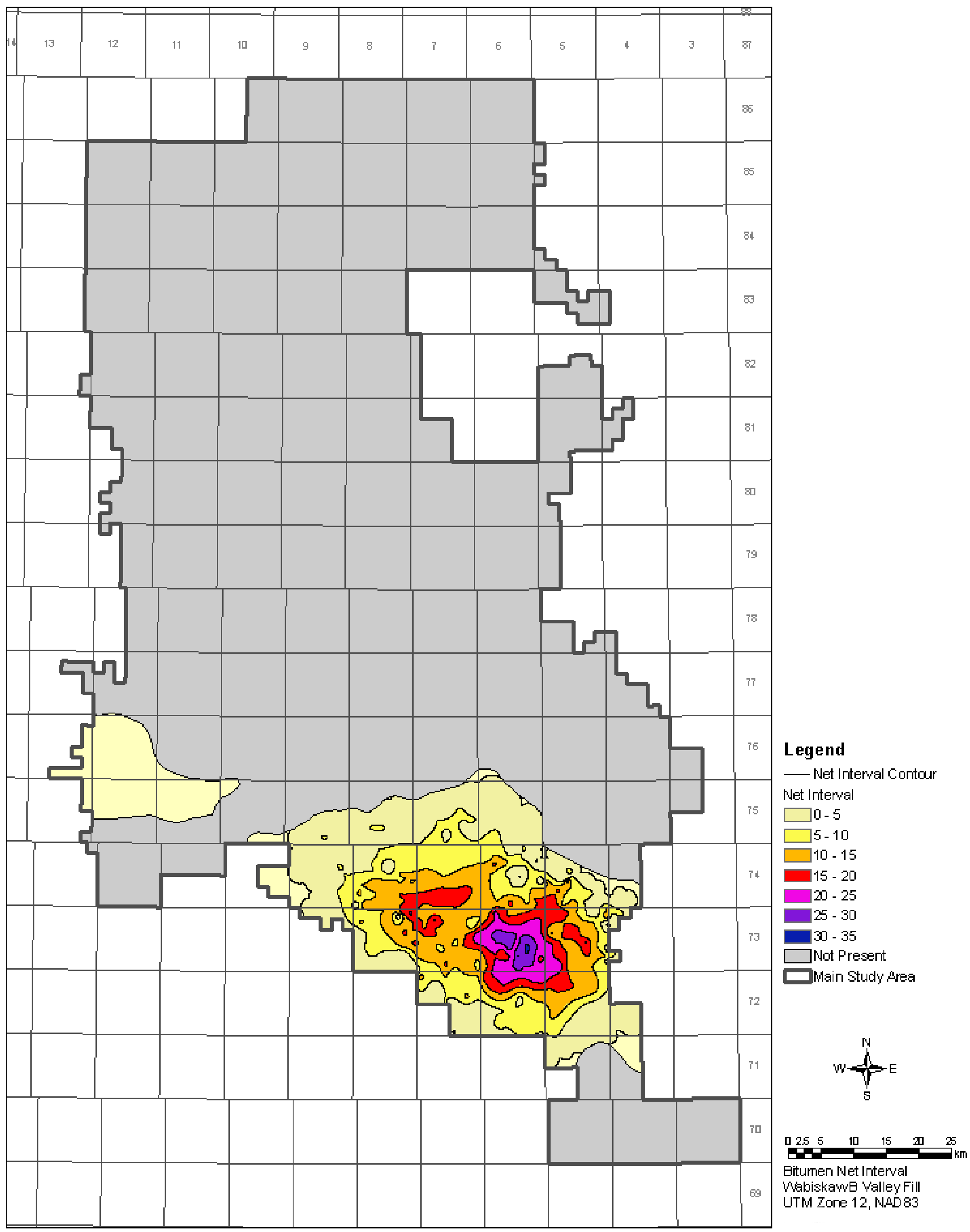


Figure 76 – Wabiskaw B Valley-fill Bitumen Isopach Map

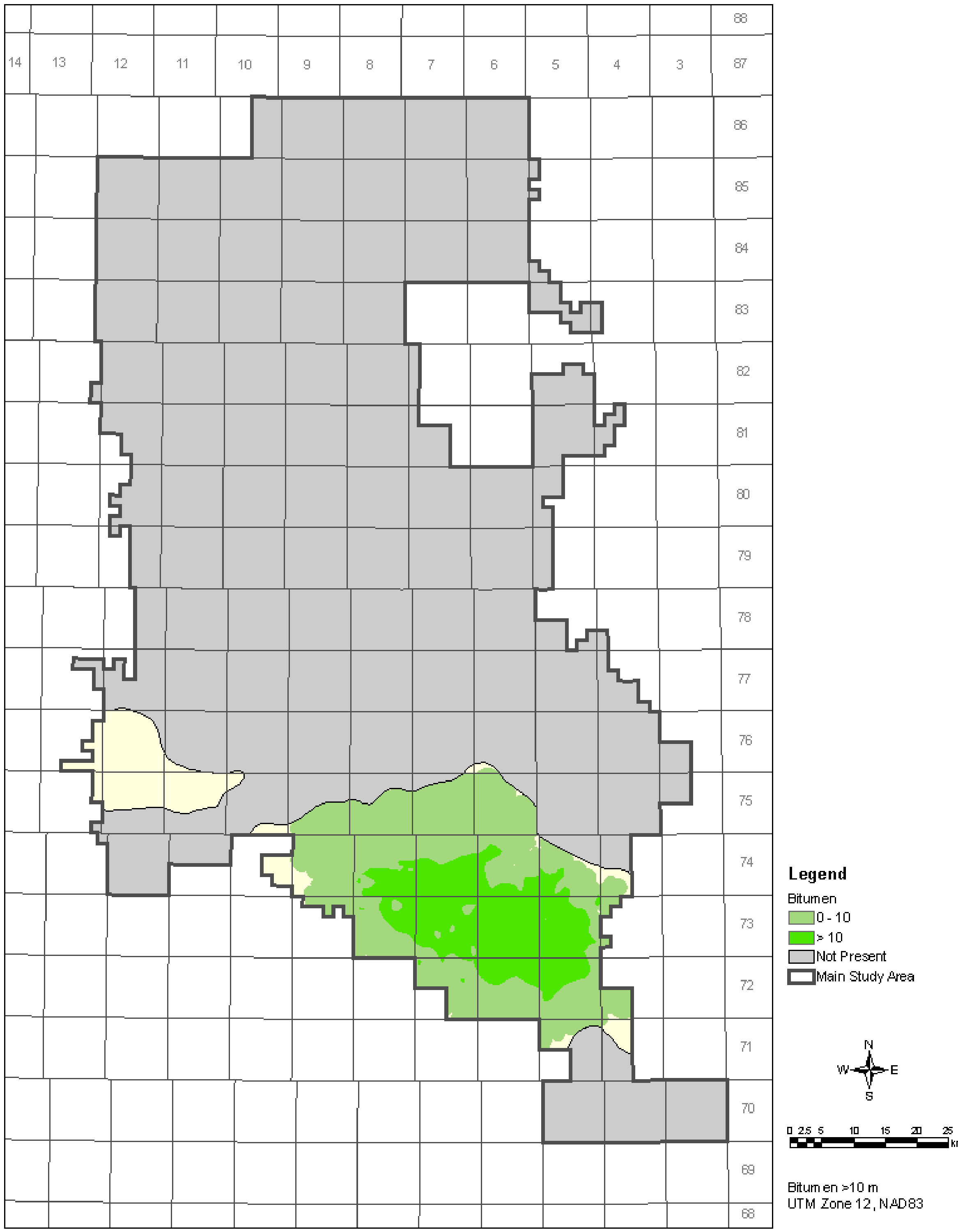


Figure 77 – Wabiskaw B Valley-fill Bitumen >10 m

4.2.2 Bitumen Evaluation Results, North Study Area

McMurray to Wabiskaw Inclusive

In the north study area, total bitumen thickness can exceed 25 m, with the thickest accumulations occurring in the south and along the western edge of the study area. Wabiskaw regional shales are absent over much of the southern portion of the region, resulting in the potential for the Wabiskaw units to be in direct hydraulic continuity with each other and the underlying McMurray Channel sequence. Figure 78 presents the Wabiskaw to McMurray bitumen isopach map.

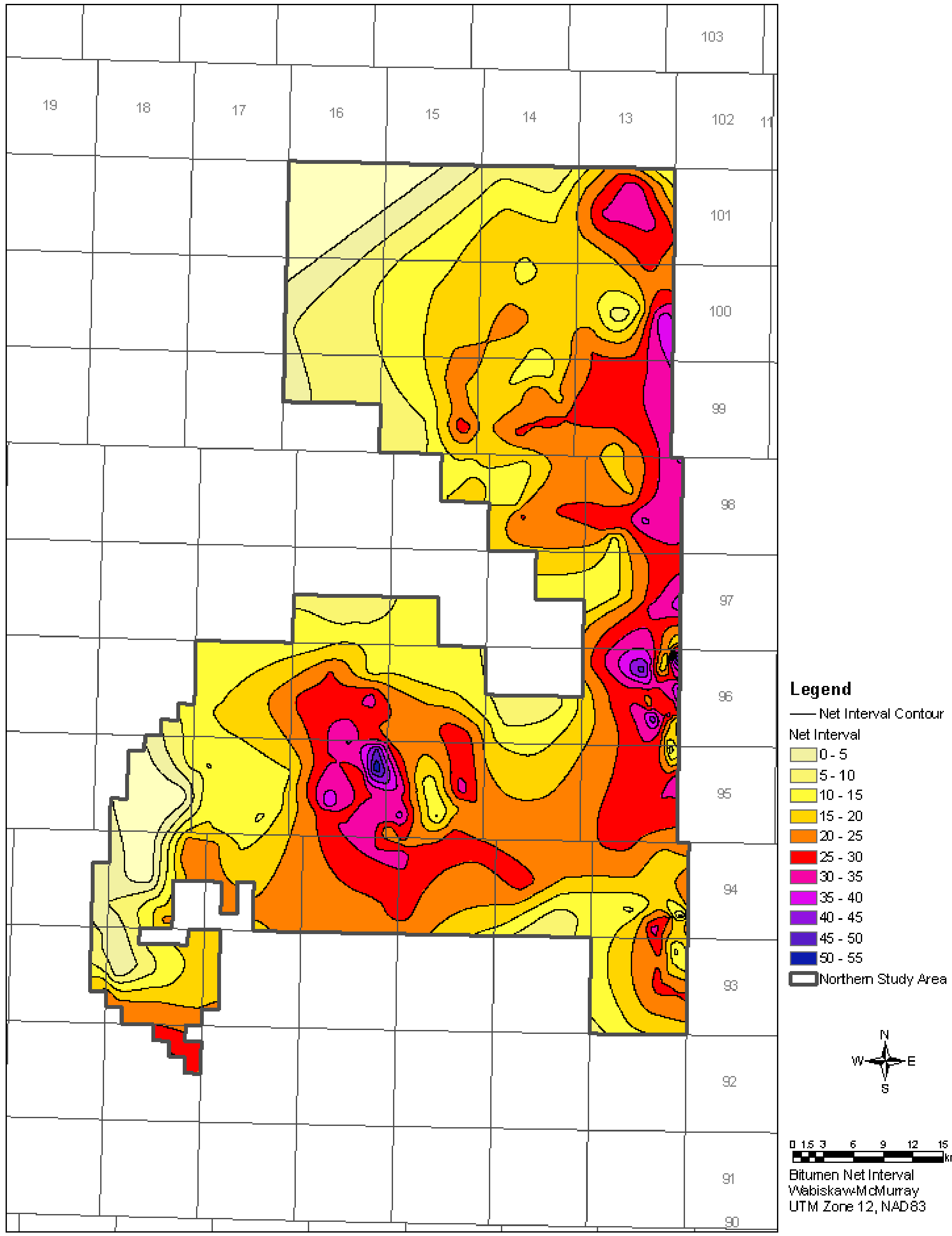


Figure 78 – Wabiskaw to McMurray Bitumen Isopach Map

McMurray Channel

As in the main study area, the McMurray Channel contains the most significant volume of bitumen. The thickest accumulations occur along the eastern edge of the study area bordering the surface mineable area, as illustrated in Figure 79. Figure 80 shows where the bitumen exceeds 10 m in thickness.

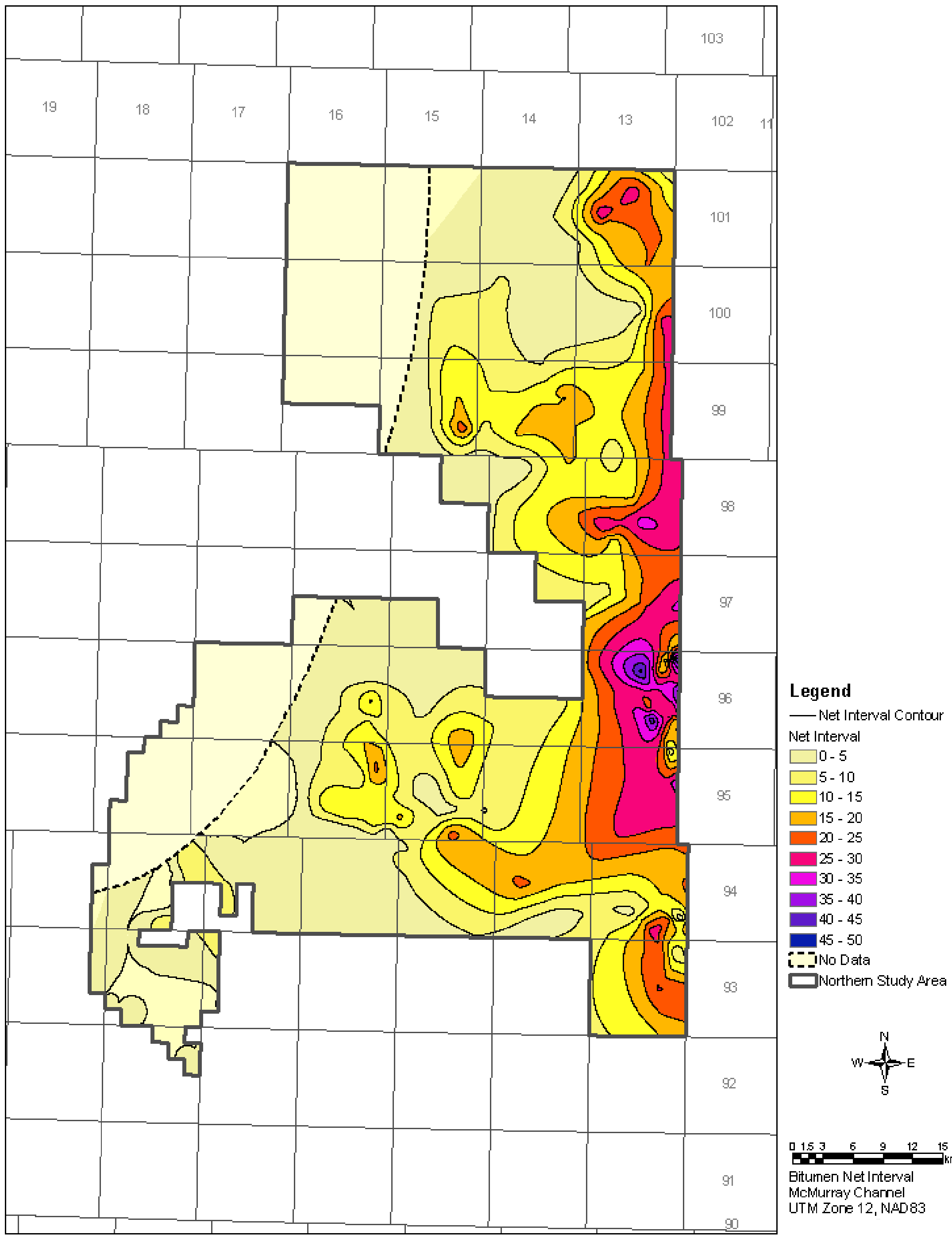


Figure 79 – McMurray Channel Bitumen Isopach

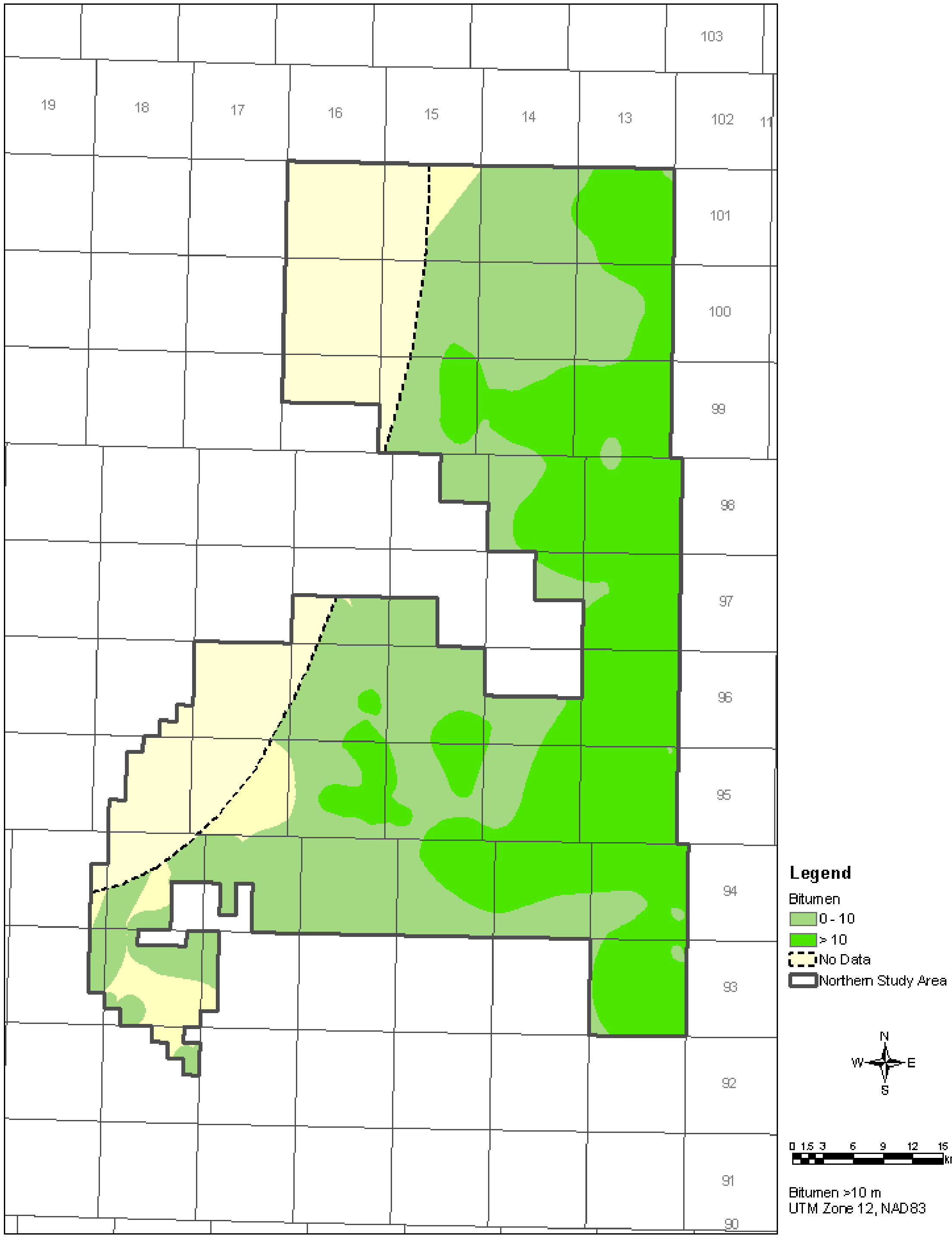


Figure 80 – McMurray Channel Bitumen >10 m

McMurray Channel and Wabiskaw D Sand

The Wabiskaw D Shale is absent over most of the study area, including where the most significant bitumen thickness occurs within the Wabiskaw D Sand. This occurs in the southwest portion of the study area, where bitumen can exceed 10 m in thickness. Consequently, bitumen within the Wabiskaw D Sand and the McMurray Channel are interpreted to be in communication and are shown mapped together in Figure 81. Figure 82 shows where the bitumen in these units exceeds 10 m in thickness.

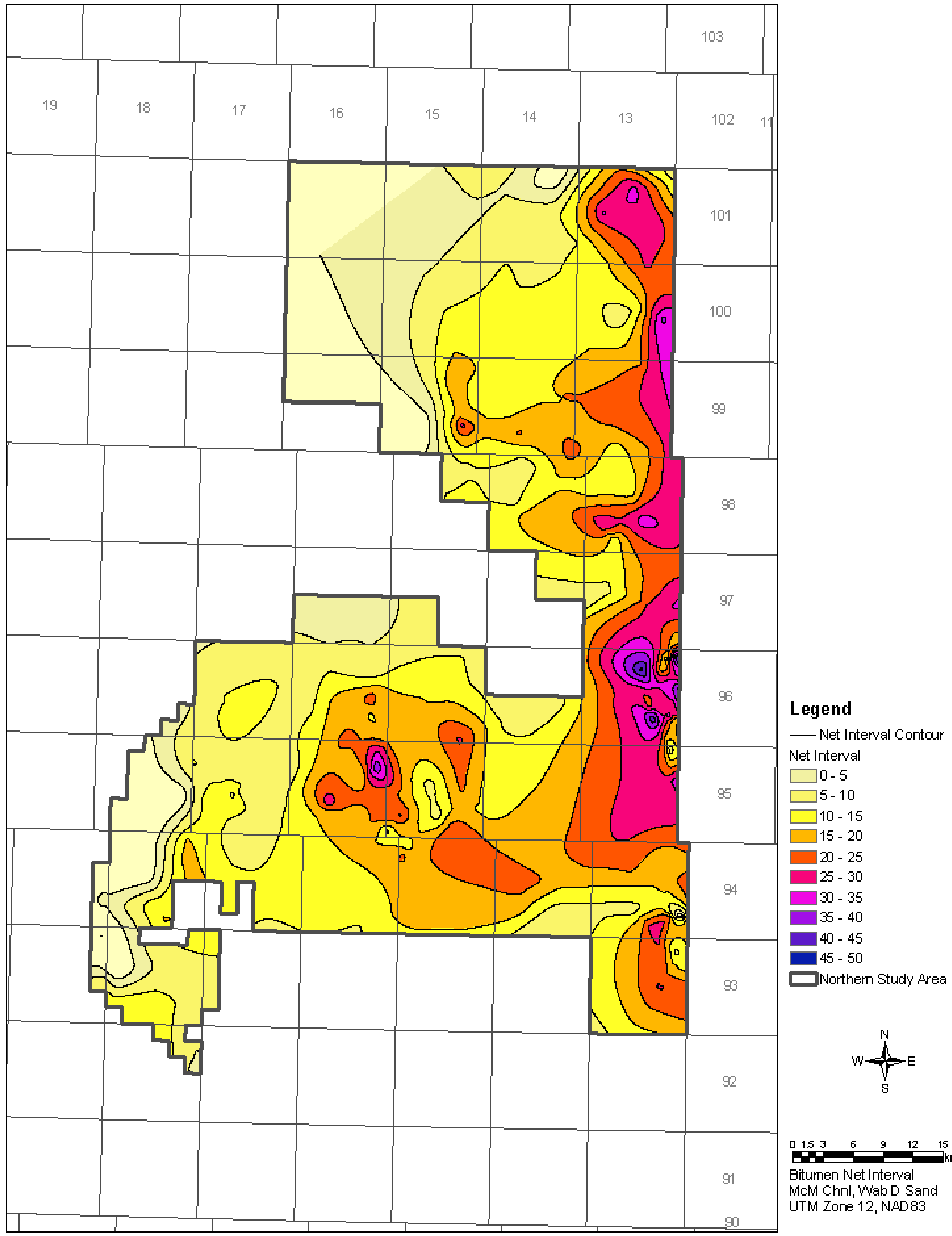


Figure 81 – McMurray Channel and Wabiskaw D Sand Bitumen Isopach

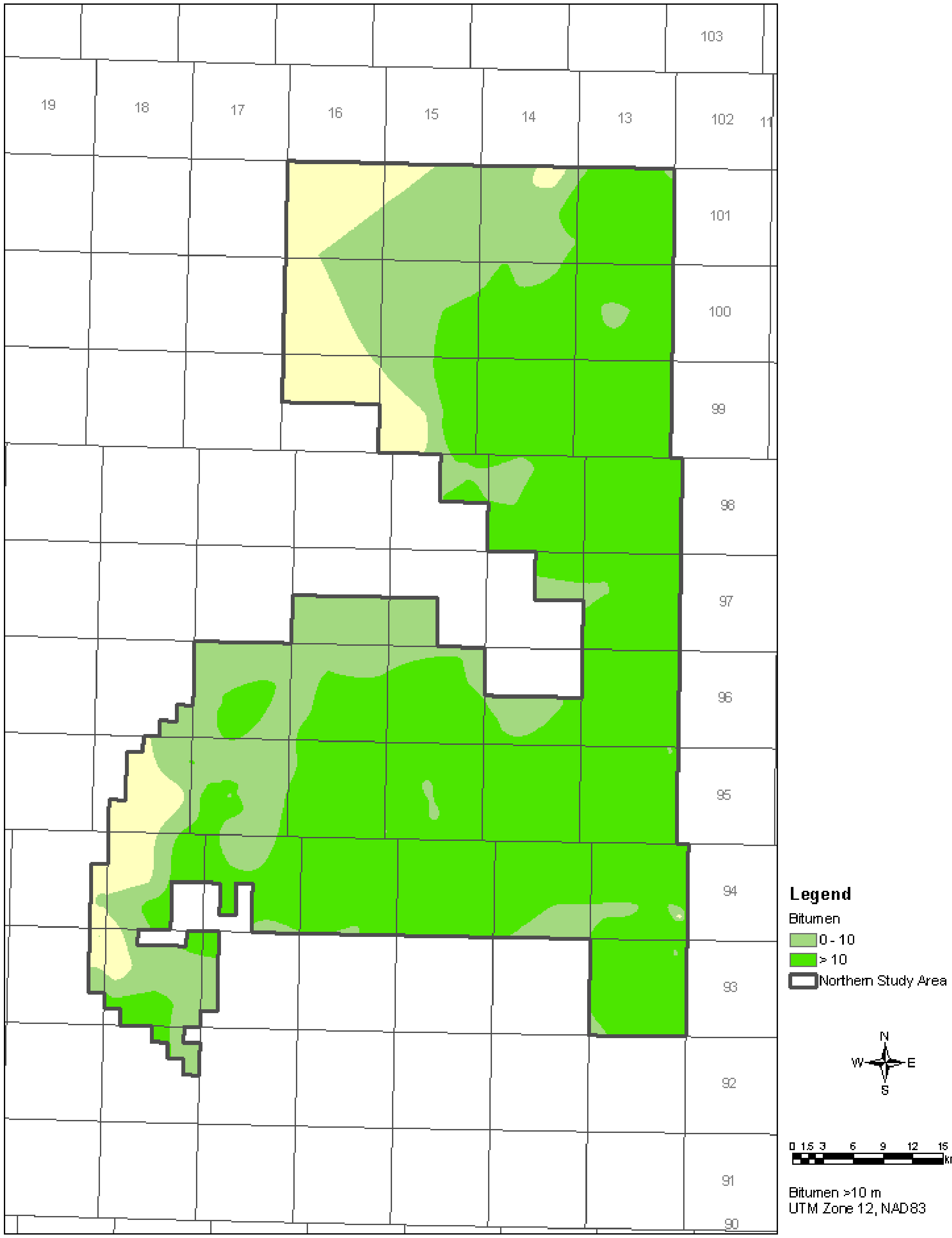


Figure 82 – McMurray Channel and Wabiskaw D Sand Bitumen >10 m

McMurray Channel, Wabiskaw D Sand, and Wabiskaw C Sand

The Wabiskaw C Shale extends over much of the northern part of the study area and some areas within the southeast; however, it is absent where bitumen within the Wabiskaw C Sand contains bitumen that exceeds 10 m thickness. This occurs in the southwest portion of the study area, roughly coincident with the thickest bitumen in the Wabiskaw D Sand. Figure 83 shows bitumen within the combined McMurray Channel, Wabiskaw D Sand, and Wabiskaw C Sand. Figure 84 shows where bitumen in these units exceeds 10 m thickness.

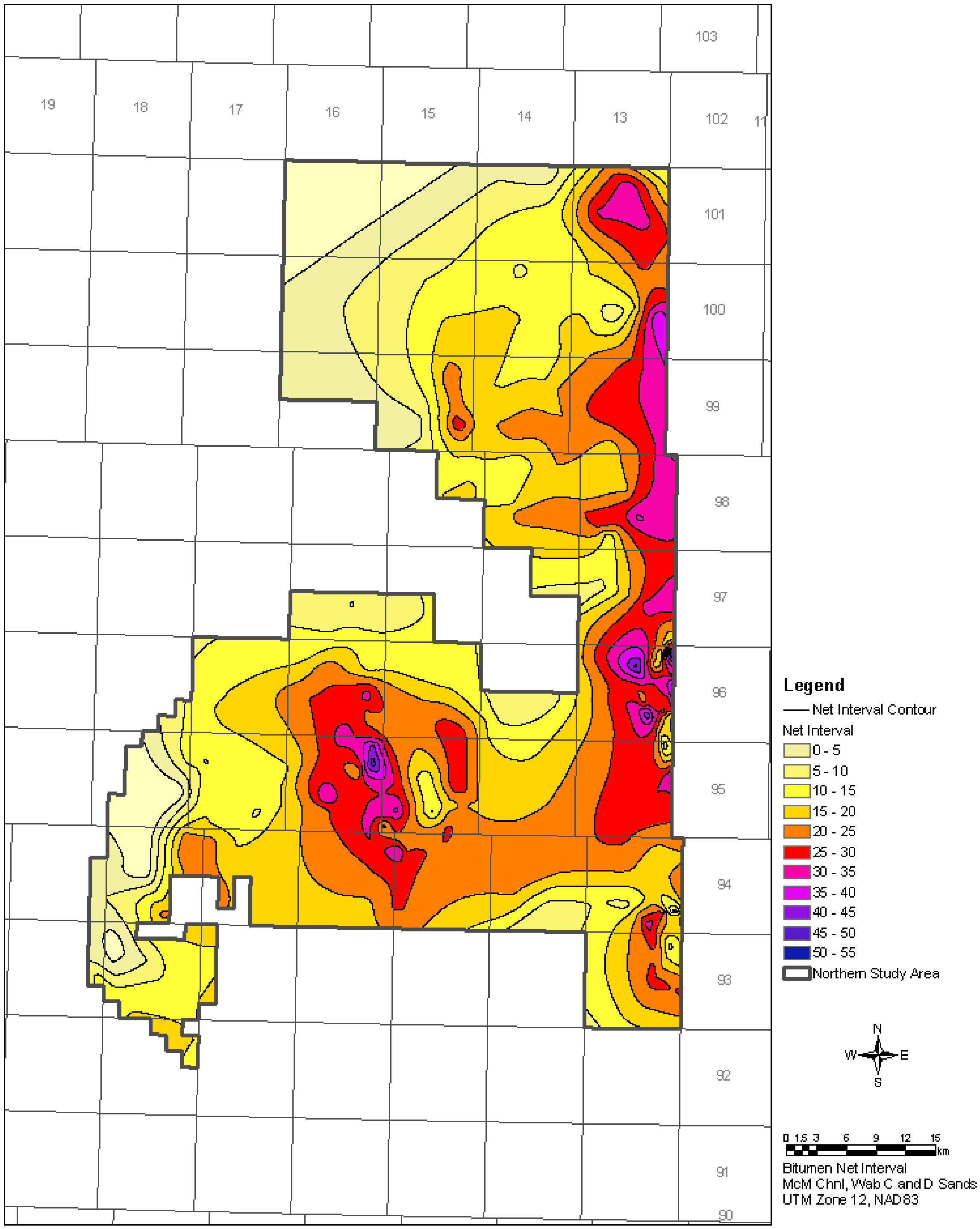


Figure 83 – McMurray Channel, Wabiskaw D Sand, and Wabiskaw C Sand Bitumen Isopach

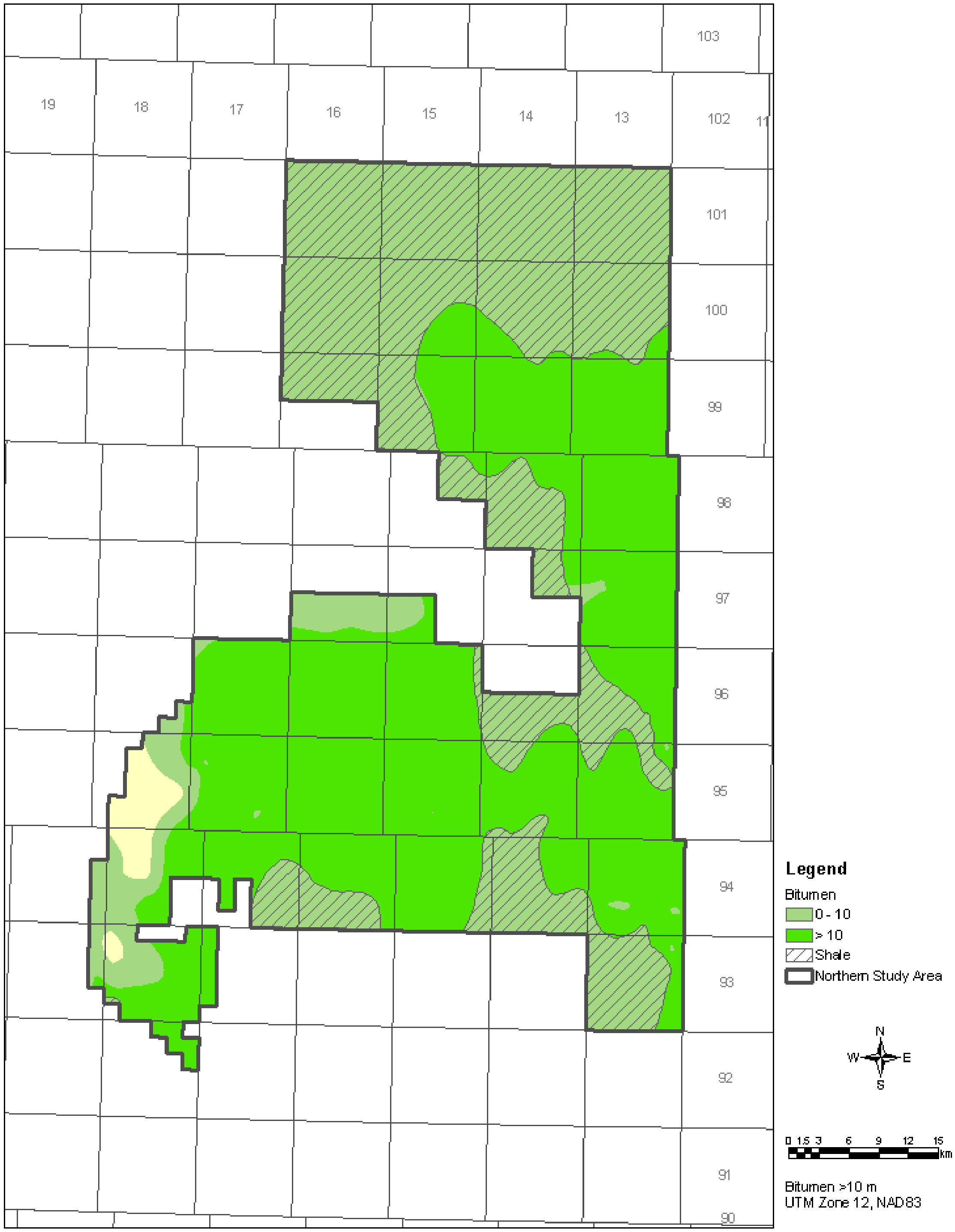


Figure 84 – McMurray Channel, Wabiskaw D Sand and Wabiskaw C Sand Bitumen >10 m

McMurray Channel, Wabiskaw D Sand, Wabiskaw C Sand, and Wabiskaw A Sand

The Wabiskaw A Sand has very little bitumen that exceeds 10 m and this occurs in the extreme southwest portion of the area. The addition of this unit to Figure 83 results in the total bitumen map, from the McMurray to the Wabiskaw inclusive (Figure 85). The individual Wabiskaw units do not contain large volumes of bitumen relative to the McMurray Channel; however, the cumulative bitumen within the Wabiskaw in the southwest part of the study area becomes significant. Figure 86 shows where the bitumen in these units exceeds 10 m in thickness.

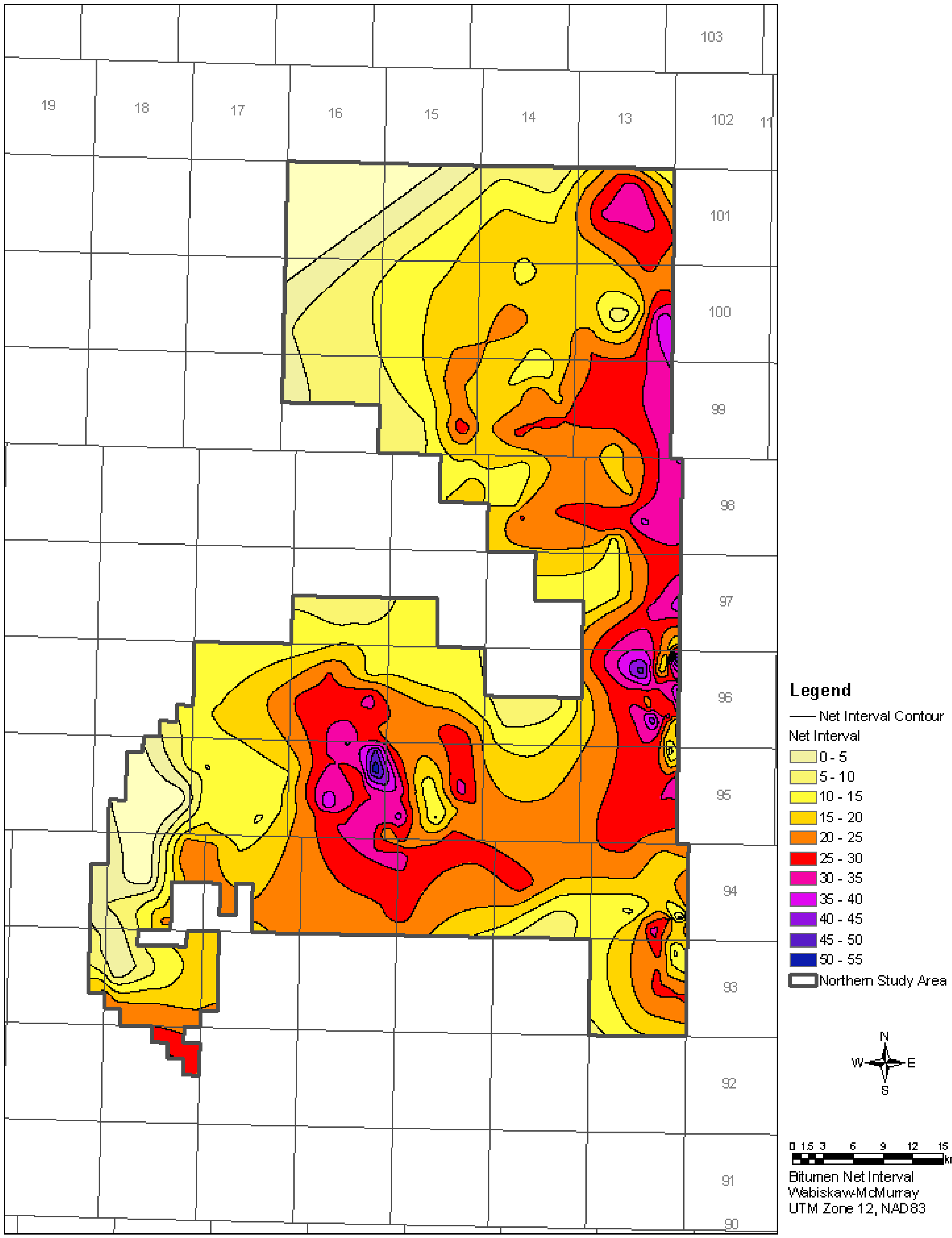


Figure 85 – McMurray Channel, Wabiskaw D Sand, Wabiskaw C Sand, Wabiskaw A Sand Bitumen Isopach

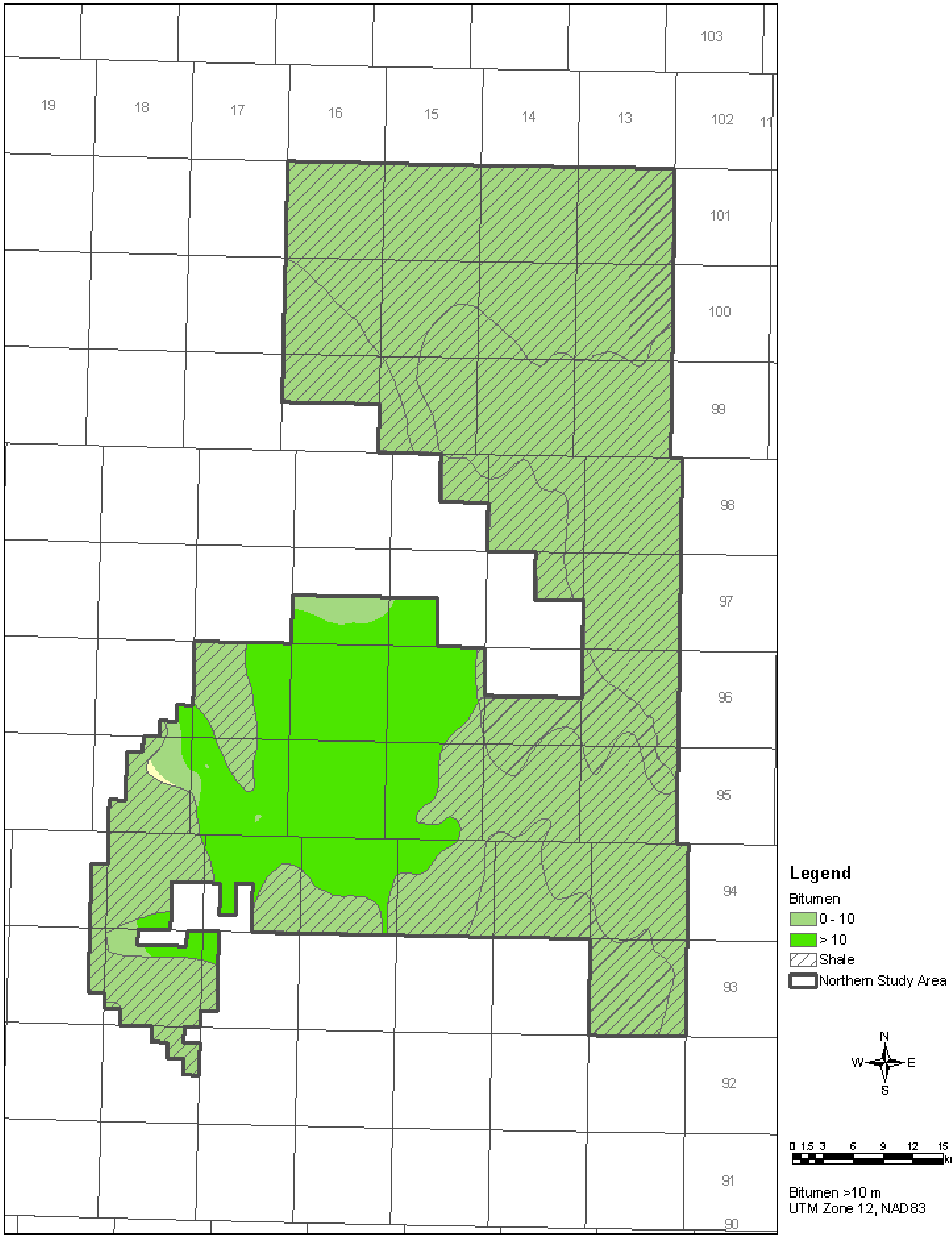


Figure 86 – McMurray Channel, Wabiskaw D Sand, Wabiskaw C Sand and Wabiskaw A Sand Bitumen >10 m

5 Communication Assessment

5.1 Method

The communication assessment process involved integrating information derived from the stratigraphic model (which also identified the significant mudstones and shales), gas evaluation, and bitumen evaluation to identify where gas is associated with bitumen.

The following considerations were used to assess communication:

- Only those stratigraphic units that have demonstrated, through evaluation and mapping, the capacity to contain bitumen with saturations over 6 wt% and exceeding 10 m thickness were considered. In the main study area, this included the McMurray C Channel / McMurray Channel Sequence, the Wabiskaw D Valley-fill, and the Wabiskaw B Valley-fill. In the northern study area, this included the McMurray Channel, the Wabiskaw D Sand, the Wabiskaw C Sand, and the Wabiskaw A Sand.

- The study accepted the Chard-Leismer findings that regionally correlatable mudstones, specifically the McMurray A2 and B2 Mudstones, would provide effective barriers to vertical pressure communication where they are not removed by channelling within the ROI of the overlying gas pool. The Chard-Leismer Decision concluded that the Wabiskaw D Shale would provide an effective barrier providing it exceeded 0.5 m in thickness. This finding was also accepted and was extended to include the Wabiskaw C and Wabiskaw A shales in the northern study area.

- In the main study area, three regional units considered capable of providing effective seals, including the McMurray A2 and B2 Mudstones and the Wabiskaw D Shale, were identified. At least one of these units must be present below the entire ROI of a gas pool to prevent pressure communication between the gas pool and an underlying bitumen-bearing unit. In the northern area, any of the three Wabiskaw shales could provide a barrier.

To identify where gas is associated or nonassociated, maps were constructed that superimposed the designated gas pools and top water on underlying mudstones and the corresponding bitumen-bearing unit of concern. Information from these maps was then used to construct Table 1, which describes those cases where gas is associated. Individual pools that fit these cases are identified in Table 2. Detailed information identifying wells and intervals is provided on the CD.

5.2 Gas/Bitumen Communication Assessment Results

The following section presents the cases where gas is interpreted to be in association with bitumen. Each case is illustrated with a map or maps that are composites of gas pools in the selected stratigraphic unit superimposed on mudstones or shales acting as potential barriers to communication to the bitumen in the layer below. Also included is a generalized schematic cross-section to assist in understanding the scenario. A well log example is presented with the maps and schematic of each case, but it is not intended to be an actual depiction of the detail that is on the schematic.

Colours representing fluid types found in the reservoir rock are presented on the maps, schematic, and well log example. The left side (Gamma Ray) of the well log is coloured to show the stratigraphic units in colour consistent with the geology section of the report.

Case 1 – Main Study Area – McMurray C Channel / McMurray Channel Gas

Figure 87 is composed of two layers. The lowermost layer, shown in dark green, displays the area where the McMurray C Channel / McMurray Channel bitumen exceeds the applied cutoffs. Superimposed on this are those gas pools contained within the same strata and therefore considered to be in association with bitumen (see Figures 88 and 89). There are no regional mudstones within these units.

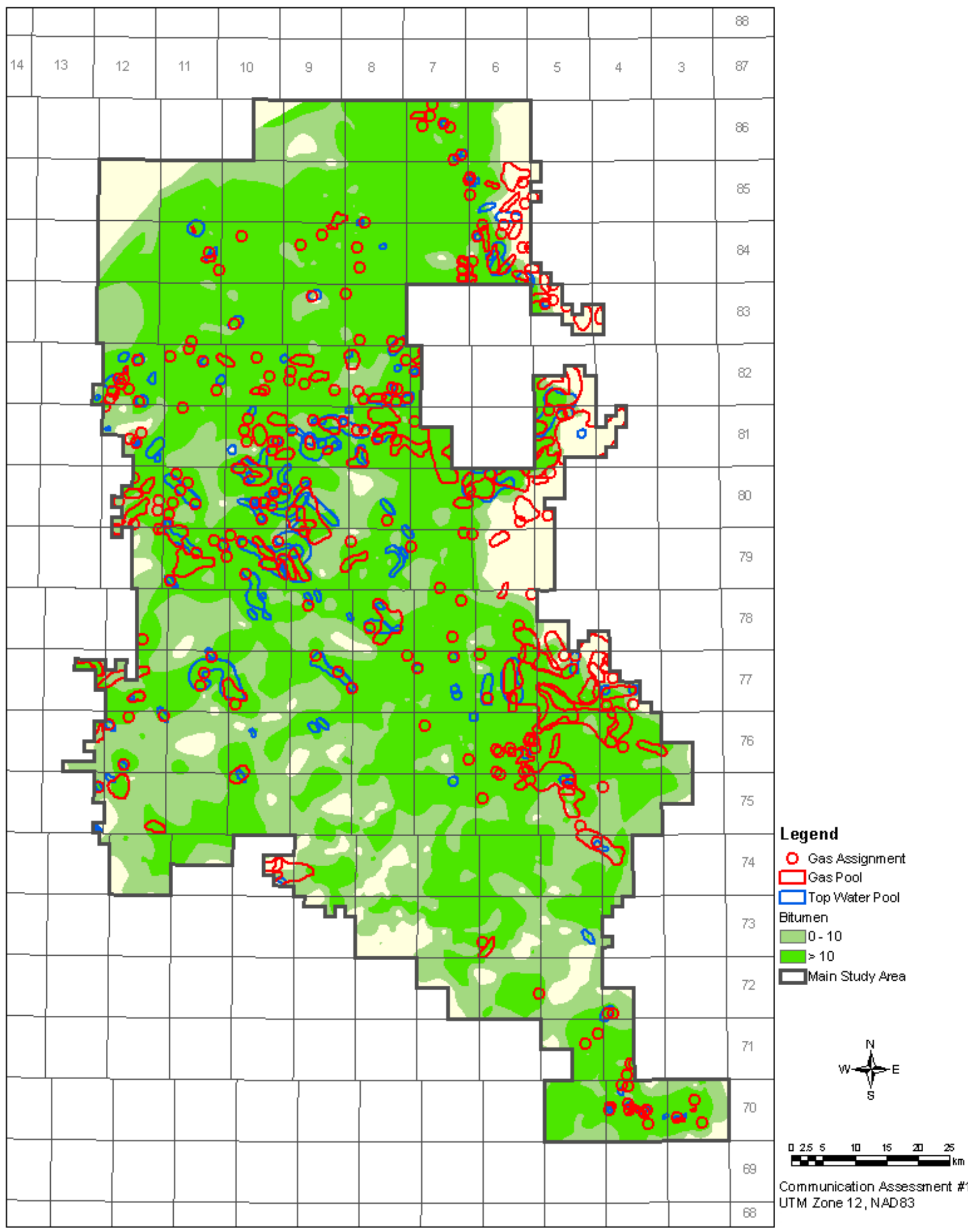


Figure 87 – Case 1, McMurray C Channel / McMurray Channel Gas / Top Water and McMurray C Channel / McMurray Channel Bitumen

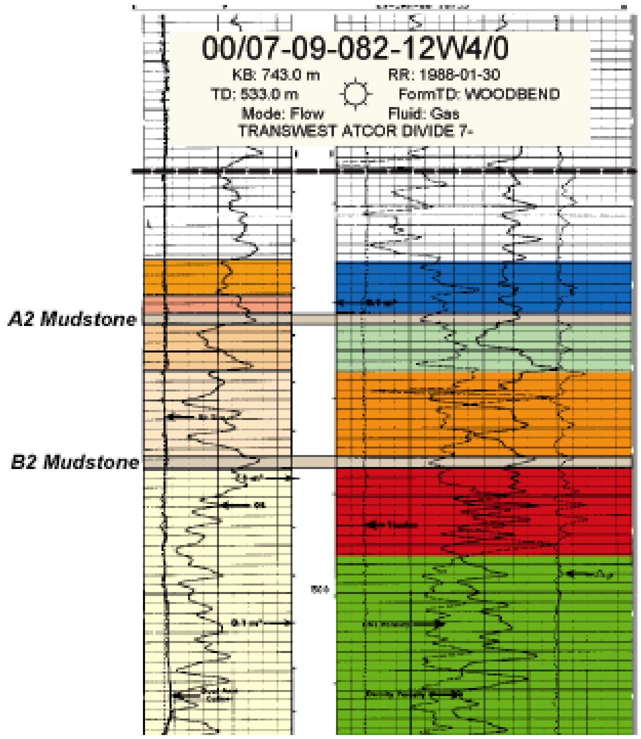


Figure 88 – Case 1, Well Log Example

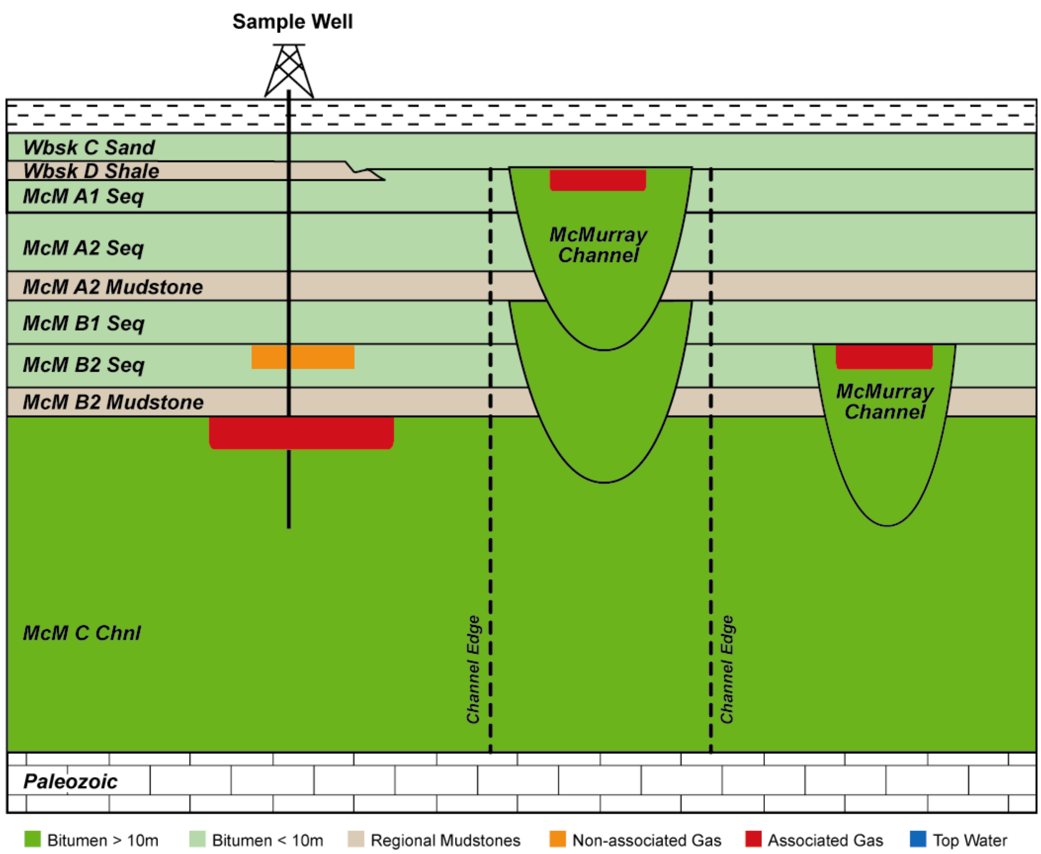


Figure 89 – Case 1, Main Study Area Schematic

Case 1 – Northern Study Area – McMurray Channel Gas

Case 1 for the northern study area is the same as for the main study area. Figure 90 shows gas pools within the McMurray Channel in association with bitumen and Figure 91 is a schematic to illustrate McMurray gas pools in association with underlying bitumen.

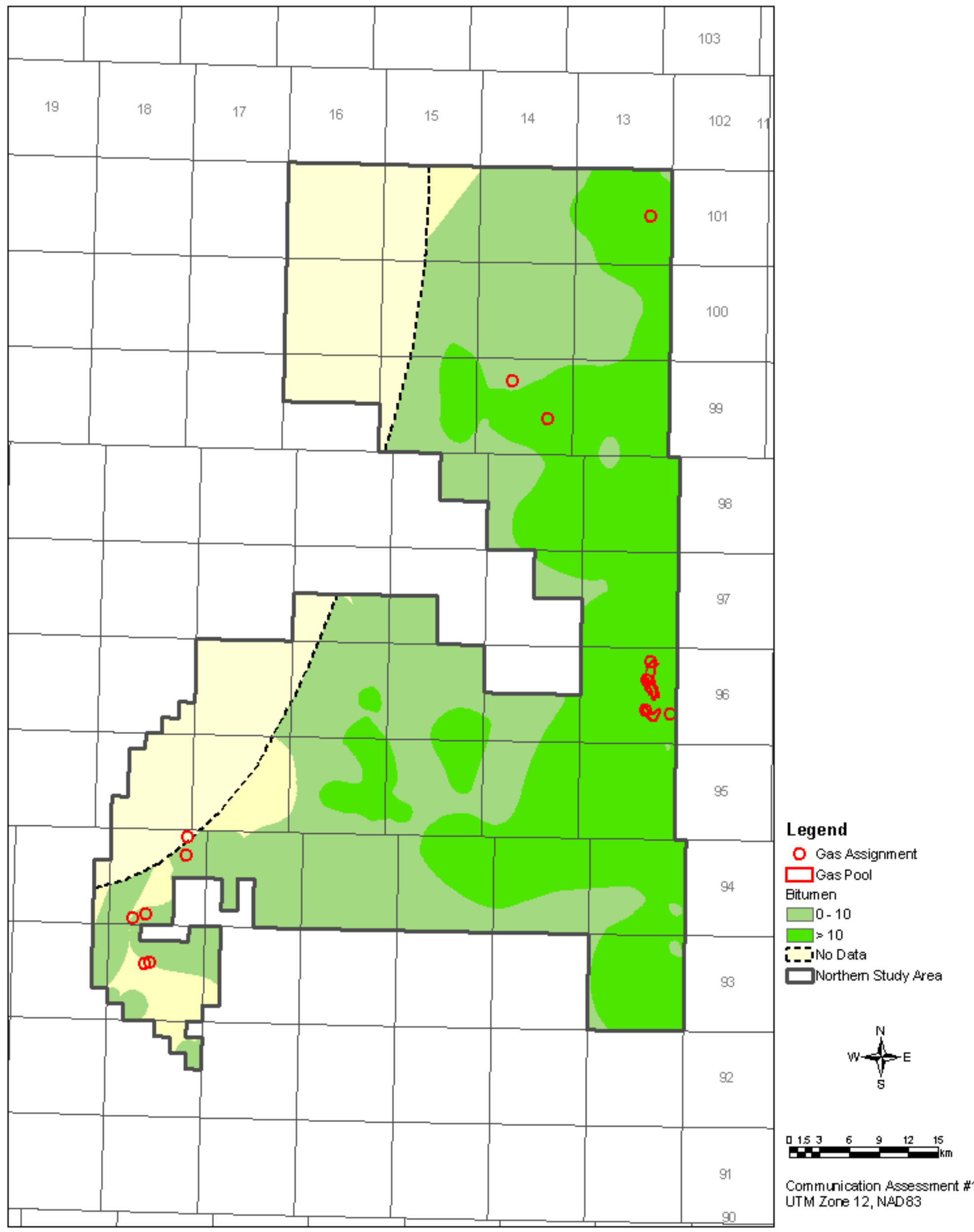


Figure 90 – Case 1, McMurray Channel Gas and McMurray Channel Bitumen

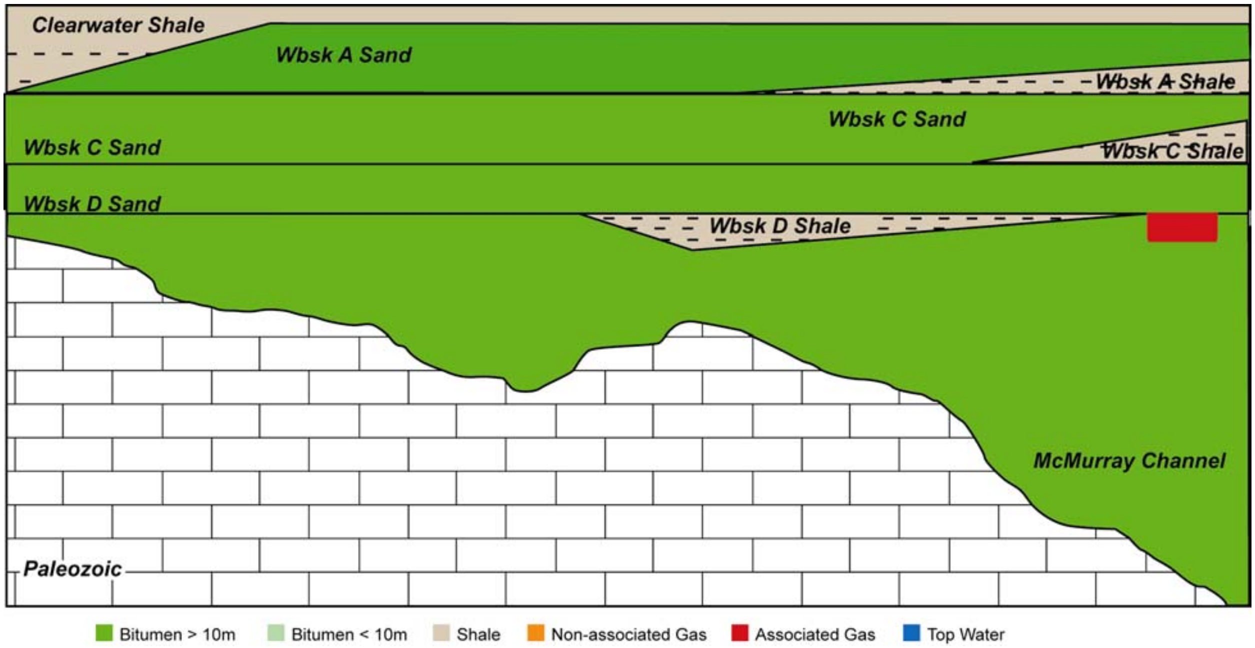


Figure 91 – Case 1, Northern Area Schematic

Case 2 – McMurray B Gas

Figure 92 is composed of three layers. As with Figure 87, the lower layer displays the area within the McMurray C Channel / McMurray Channel where bitumen exceeds the applied cutoffs. Superimposed on this is the area where the McMurray B2 Mudstone is interpreted to be present and could provide separation between overlying gas and underlying bitumen. The uppermost layer displays gas pool outlines for gas pools within the McMurray B units. Gas pools that extend beyond the limits of the B2 Mudstone are considered to be associated with McMurray Channel bitumen. A sample well log and schematic are shown in Figures 93 and 94.

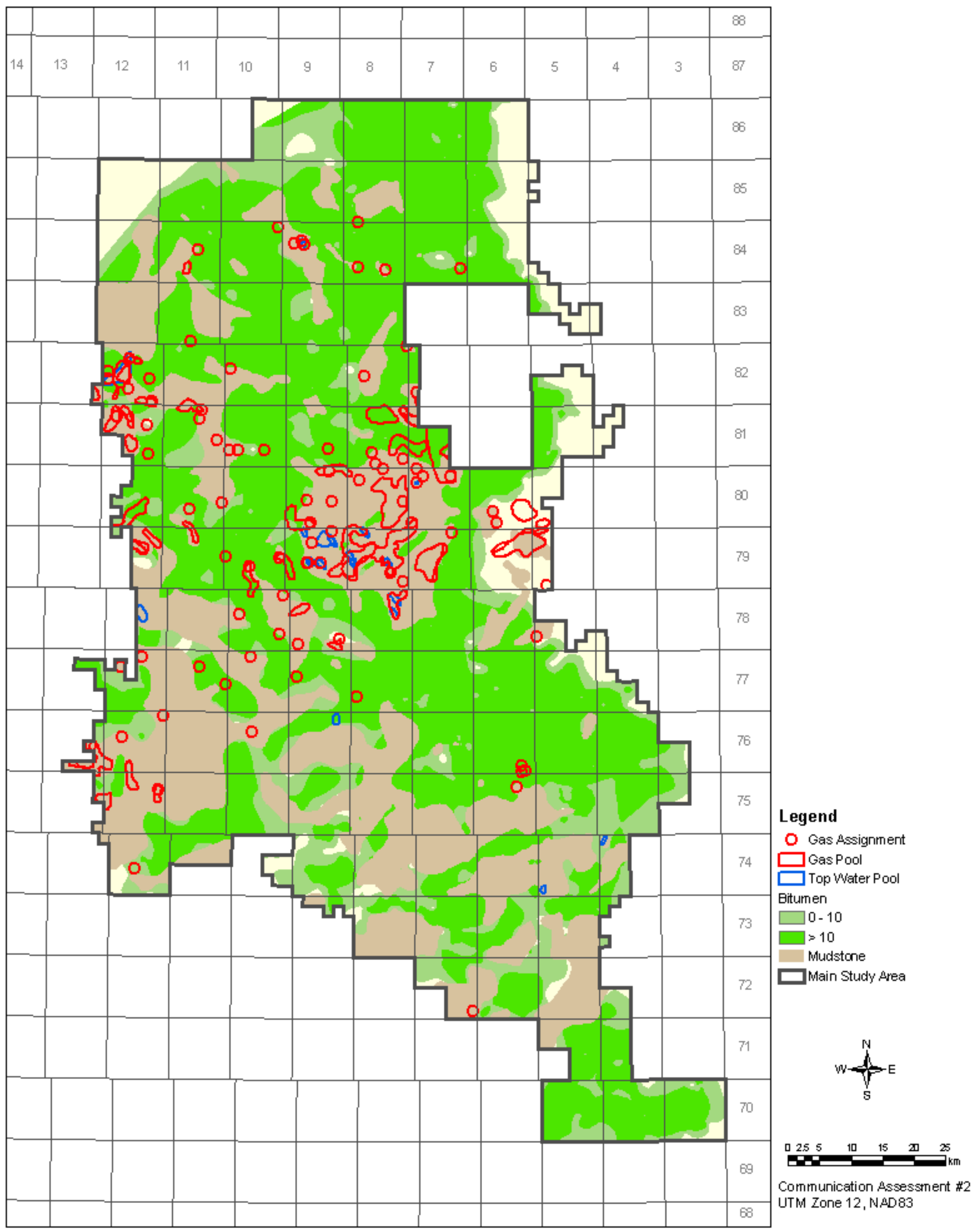


Figure 92 – Case 2, McMurray B Gas / Top Water and McMurray Channel Bitumen

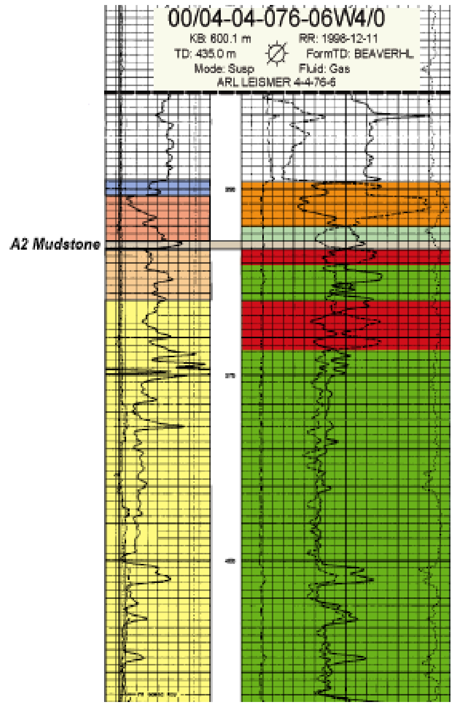


Figure 93 – Case 2 Well Log Example

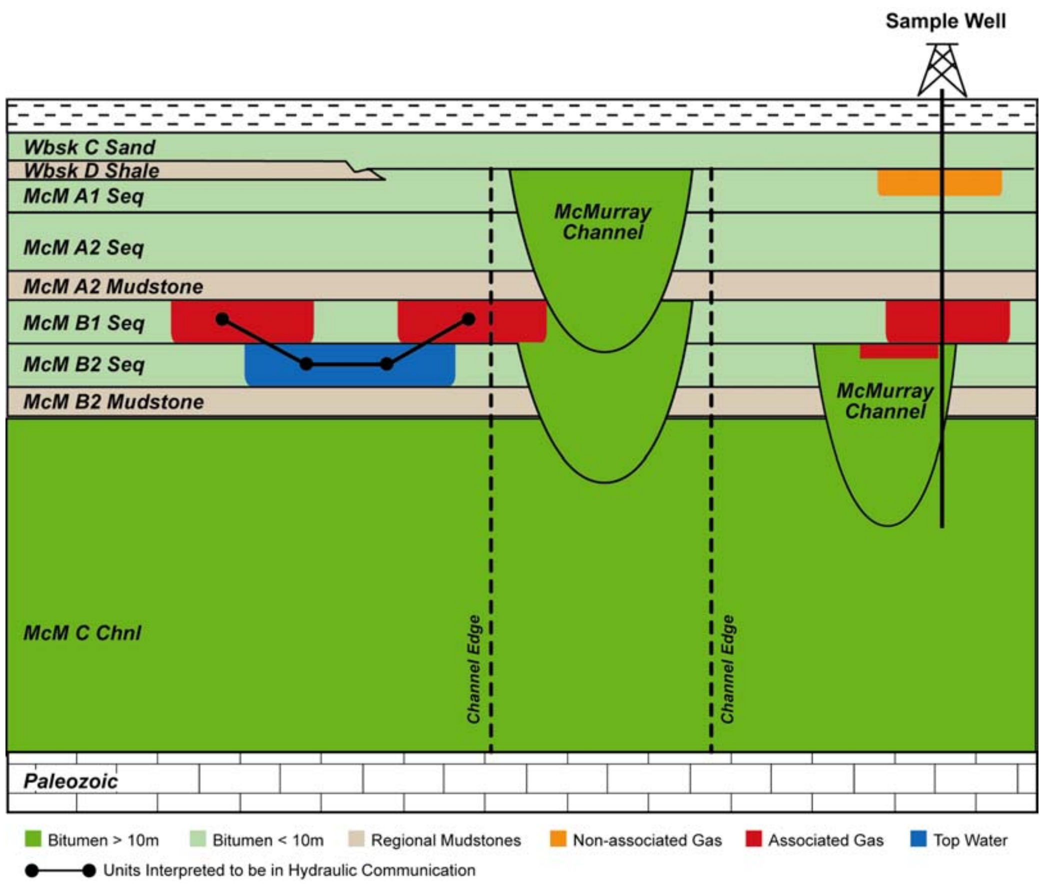


Figure 94 – Case 2 Schematic

Case 3 – Gas Above McMurray A2 Mudstone

Figure 95 is also composed of three layers. Again, the lowermost layer displays the area within the McMurray C Channel/McMurray Channel where bitumen exceeds the applied cutoffs. Superimposed on this are the areas where the McMurray A2 and B2 Mudstones and the Wabiskaw D Shale are present. The final layer includes the various gas pools and top water zones that occur above the McMurray A2 Mudstone. Gas pools and top water zones that extend beyond the limits of the A2 and B2 Mudstones are associated with McMurray Channel bitumen. The Wabiskaw C Sand gas pools that extend beyond the limits of the D Shale and A2 and B2 Mudstones are also associated with McMurray Channel bitumen. Sample well logs and schematics are shown in Figures 96, 97, 98 and 99.

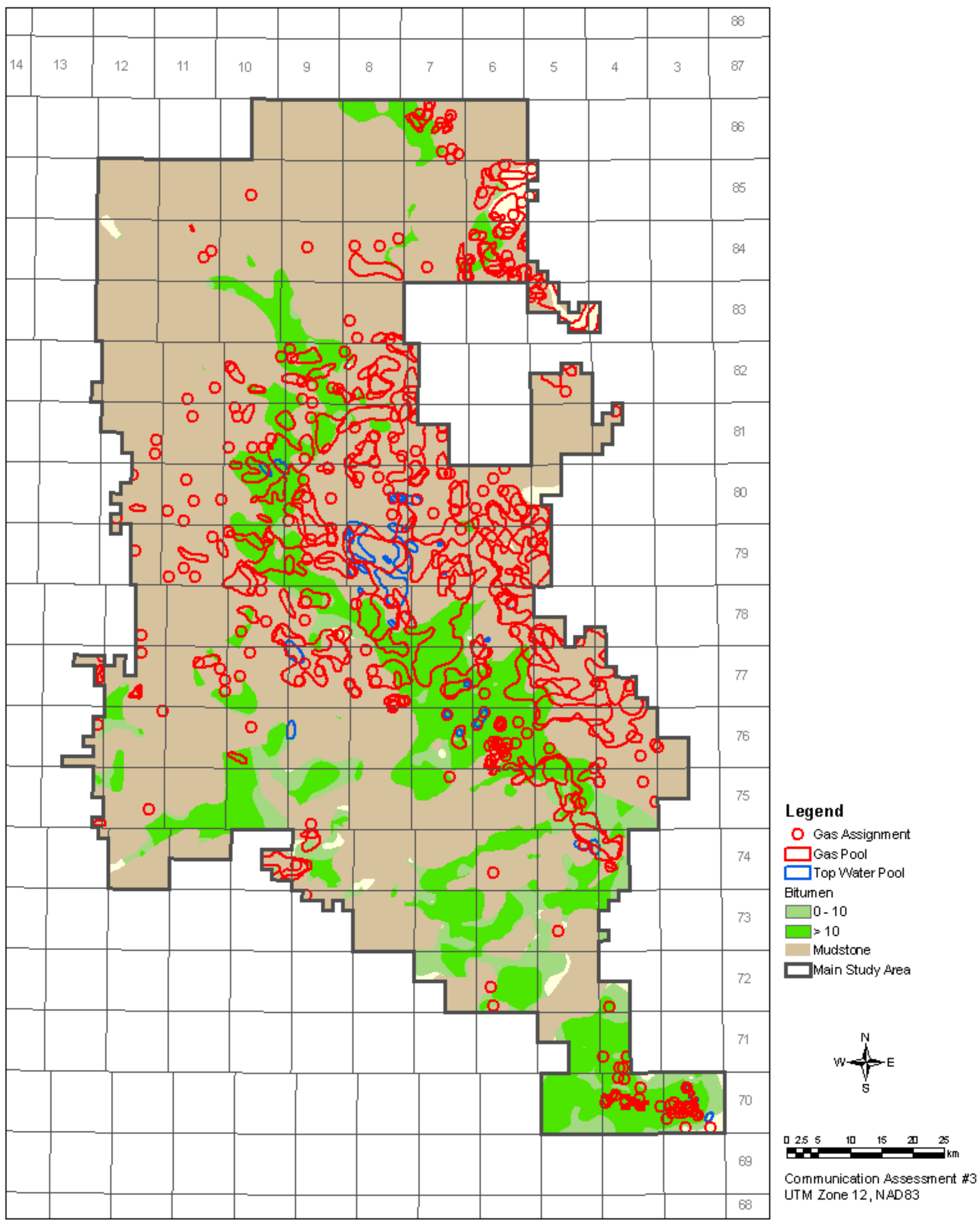


Figure 95 – Case 3, Gas / Top Water above McMurray A2 Mudstone and McMurray Channel Bitumen

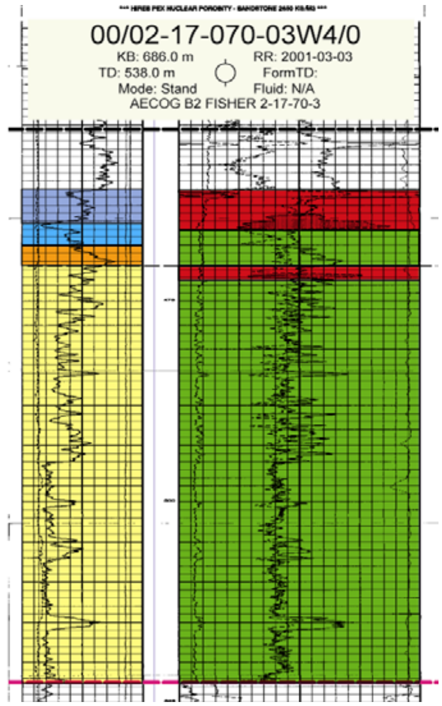


Figure 96 – Case 3 Well Log Example #1

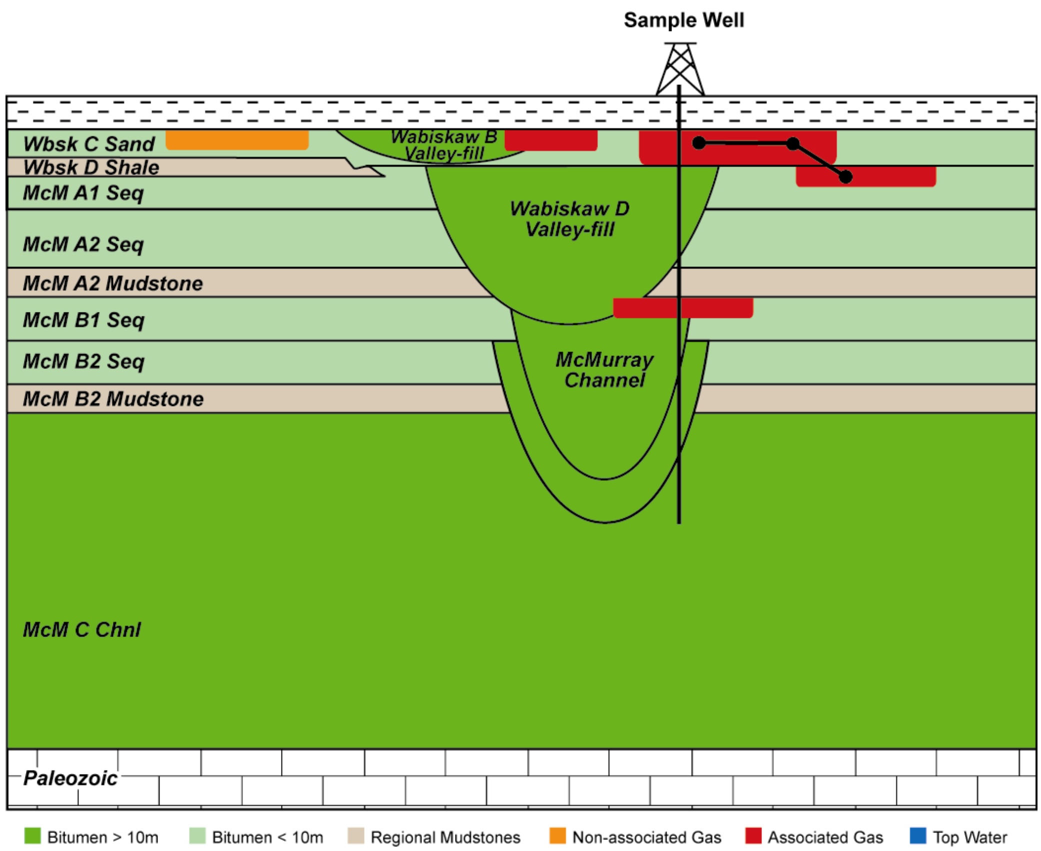


Figure 97 – Case 3 Schematic #1

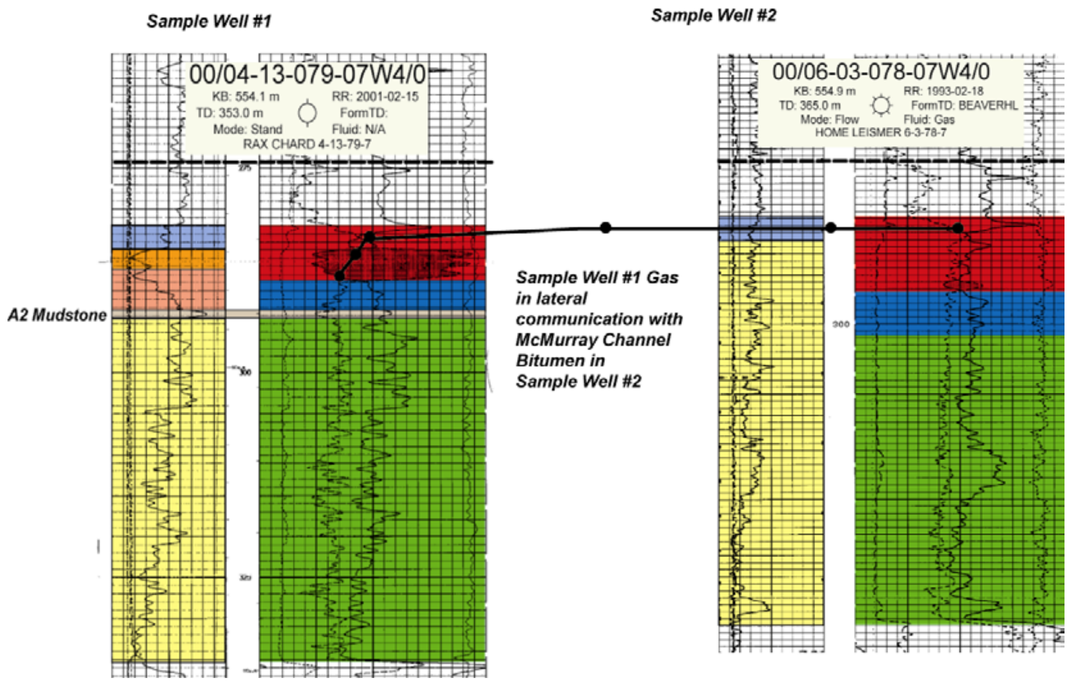


Figure 98 – Case 3 Well Log Example #2

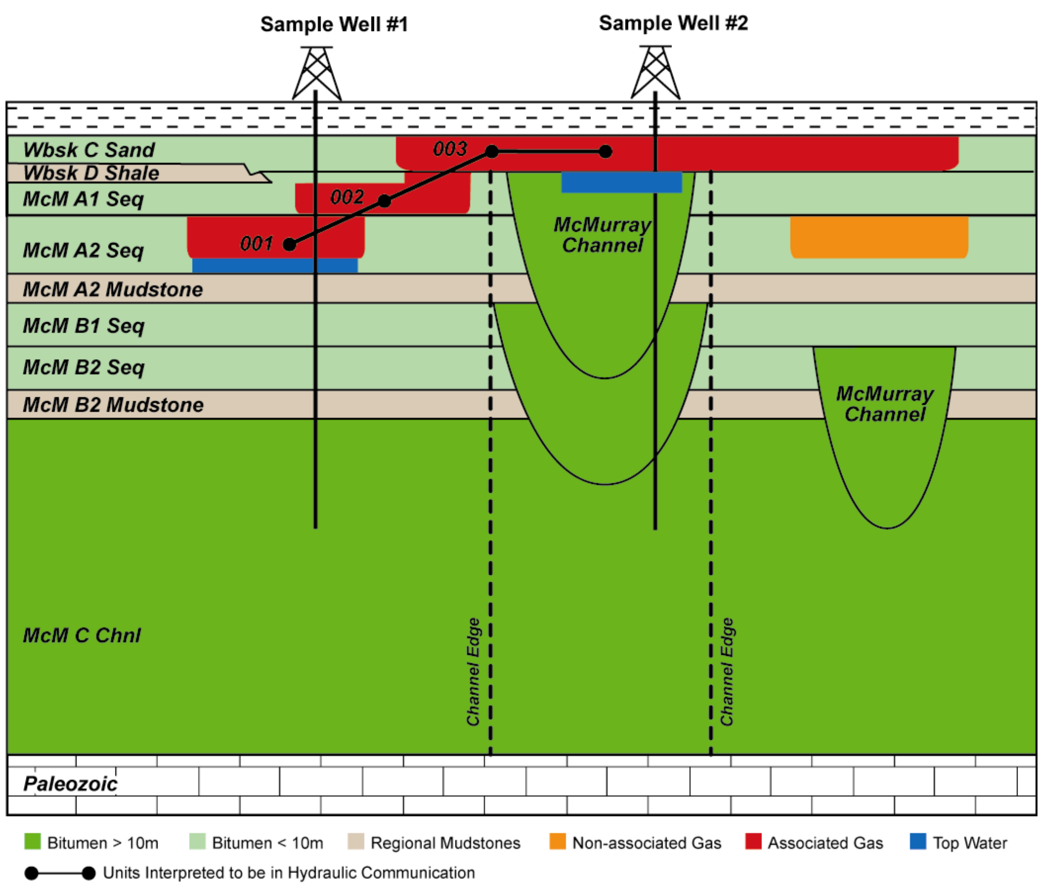


Figure 99 – Case 3 Schematic #2

Case 4 – Wabiskaw D & B Valley-fill Gas

Figures 100 (Wabiskaw D Valley-fill) and 101 (Wabiskaw B Valley-fill) are composed of two layers. The lowermost layer in each map identifies the areas where Wabiskaw D and B Valley-fills are present and bitumen bearing but are separated from any underlying McMurray Channel bitumen by the presence of the McMurray A2 and/or B2 Mudstones. The upper layer displays gas pool and top water zone outlines that may be associated with either D or B Valley-fill bitumen (Figure 103).

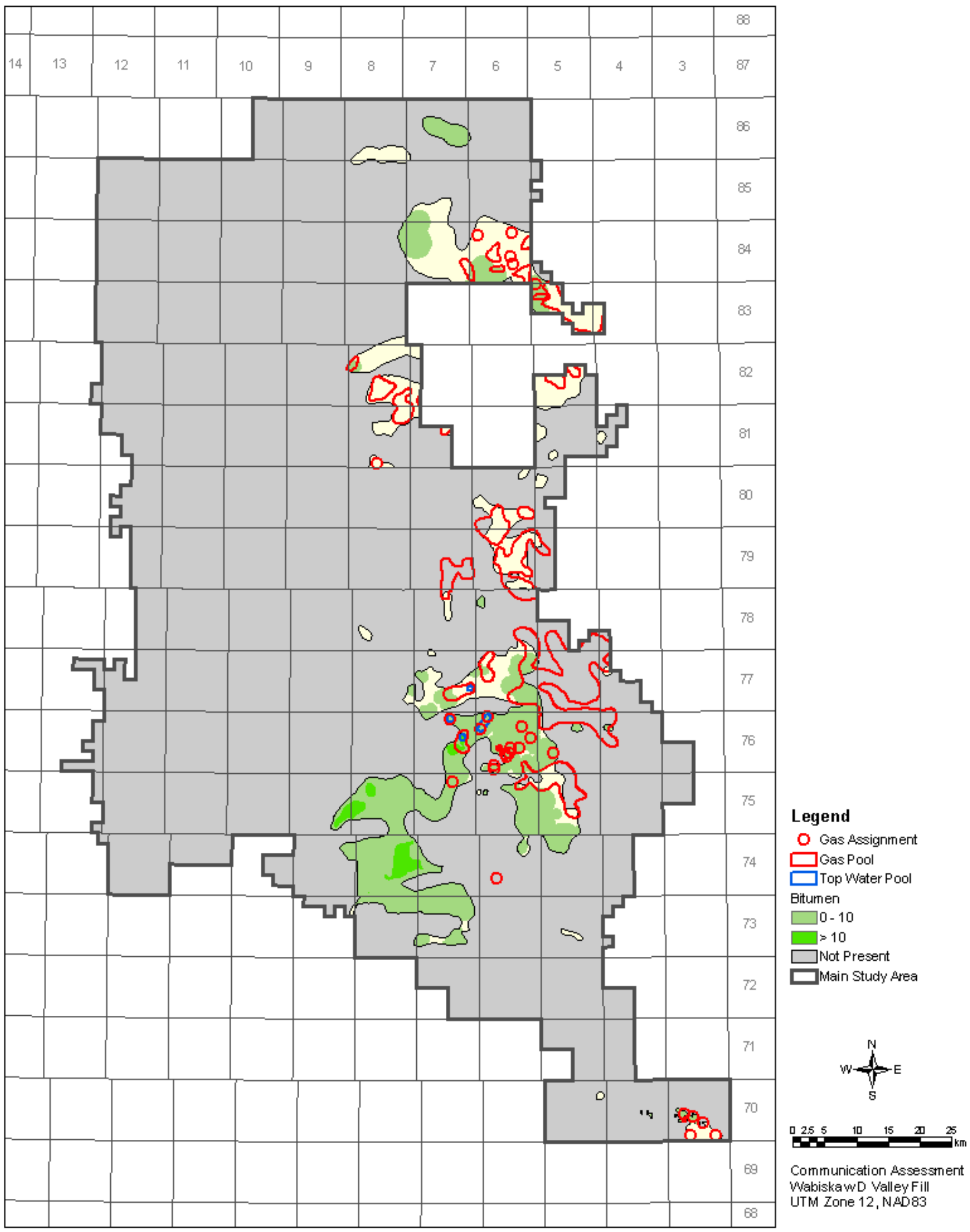


Figure 100 – Case 4, Wabiskaw D Valley-fill Gas / Top Water and Wabiskaw D Valley-fill Bitumen

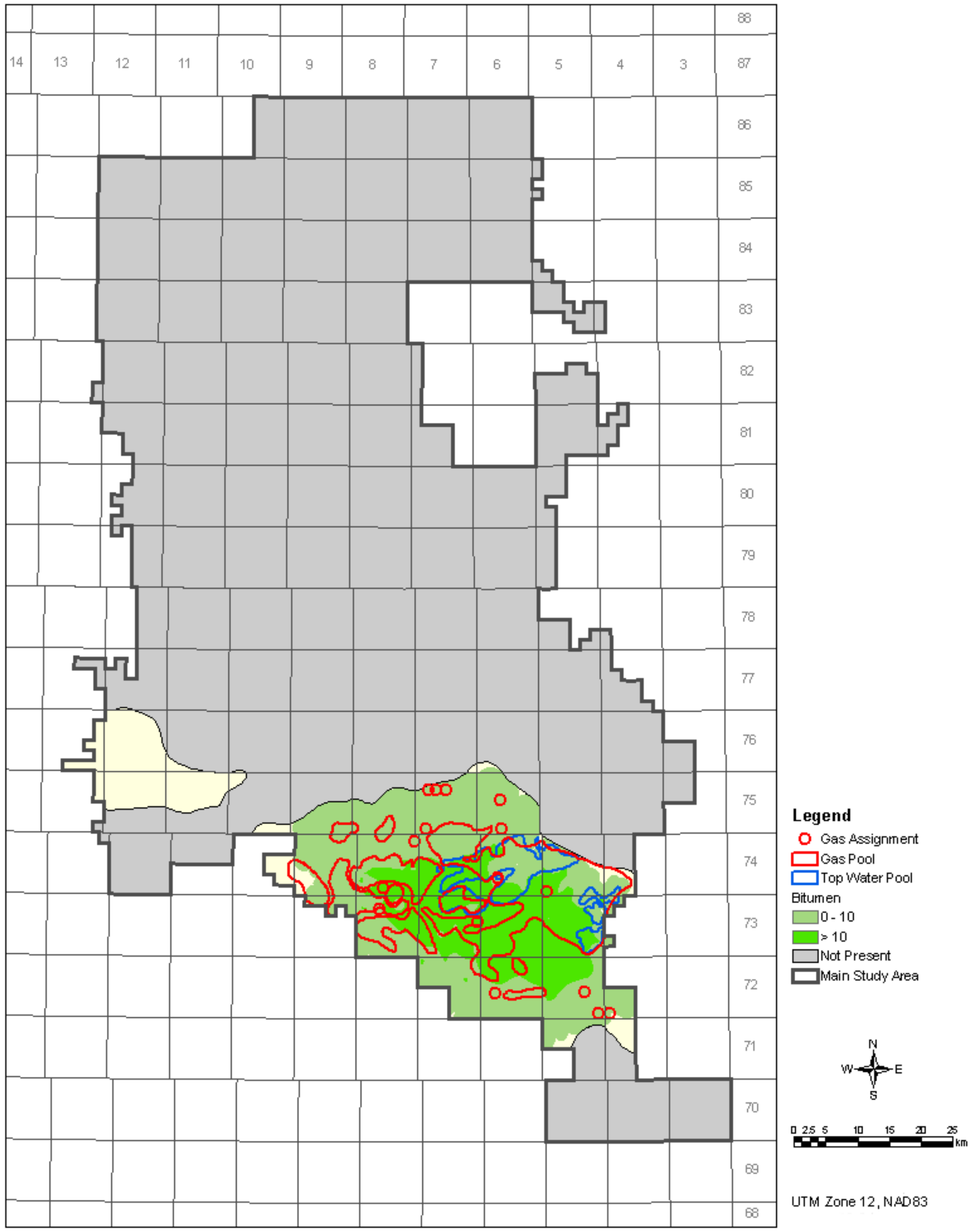


Figure 101 – Case 4, Wabiskaw B Valley-fill Gas / Top Water and Wabiskaw B Valley-fill Bitumen

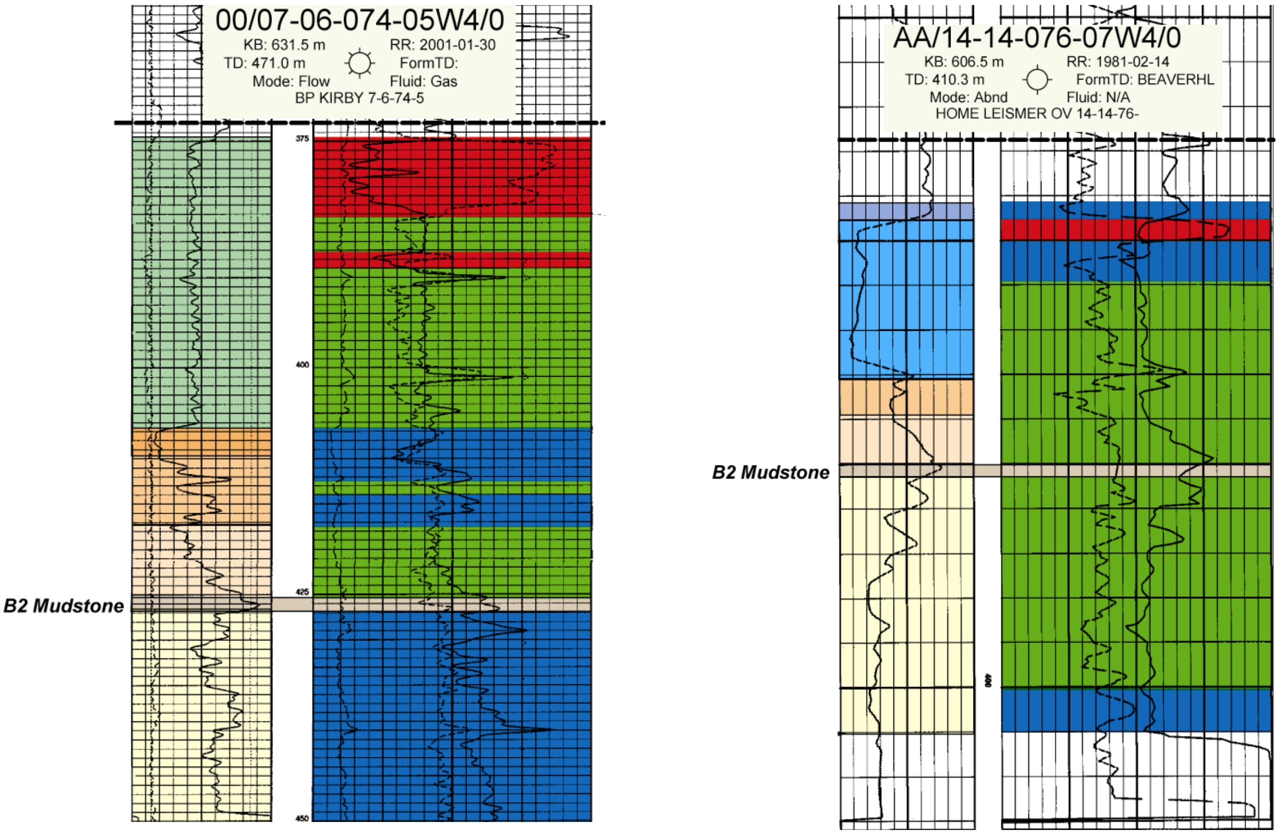


Figure 102 – Case 4 Well Log Examples

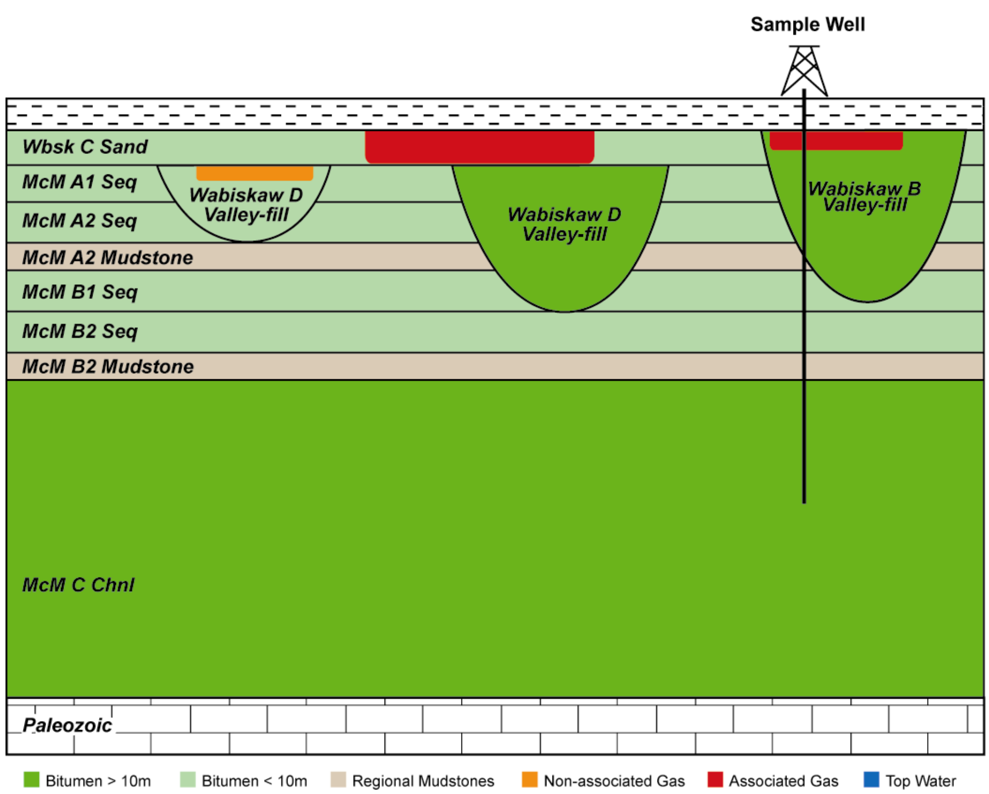


Figure 103 – Case 4 Schematic

Case 5 – Wabiskaw D Sand Gas

Figure 104 superimposes Wabiskaw D Sand gas on Wabiskaw D Sand and McMurray Channel bitumen. Wabiskaw D Sand gas is associated with Wabiskaw D Sand bitumen where the Wabiskaw D Shale is absent, as depicted in the schematic in Figure 105. The Wabiskaw D Shales are not present in the gas prone areas.

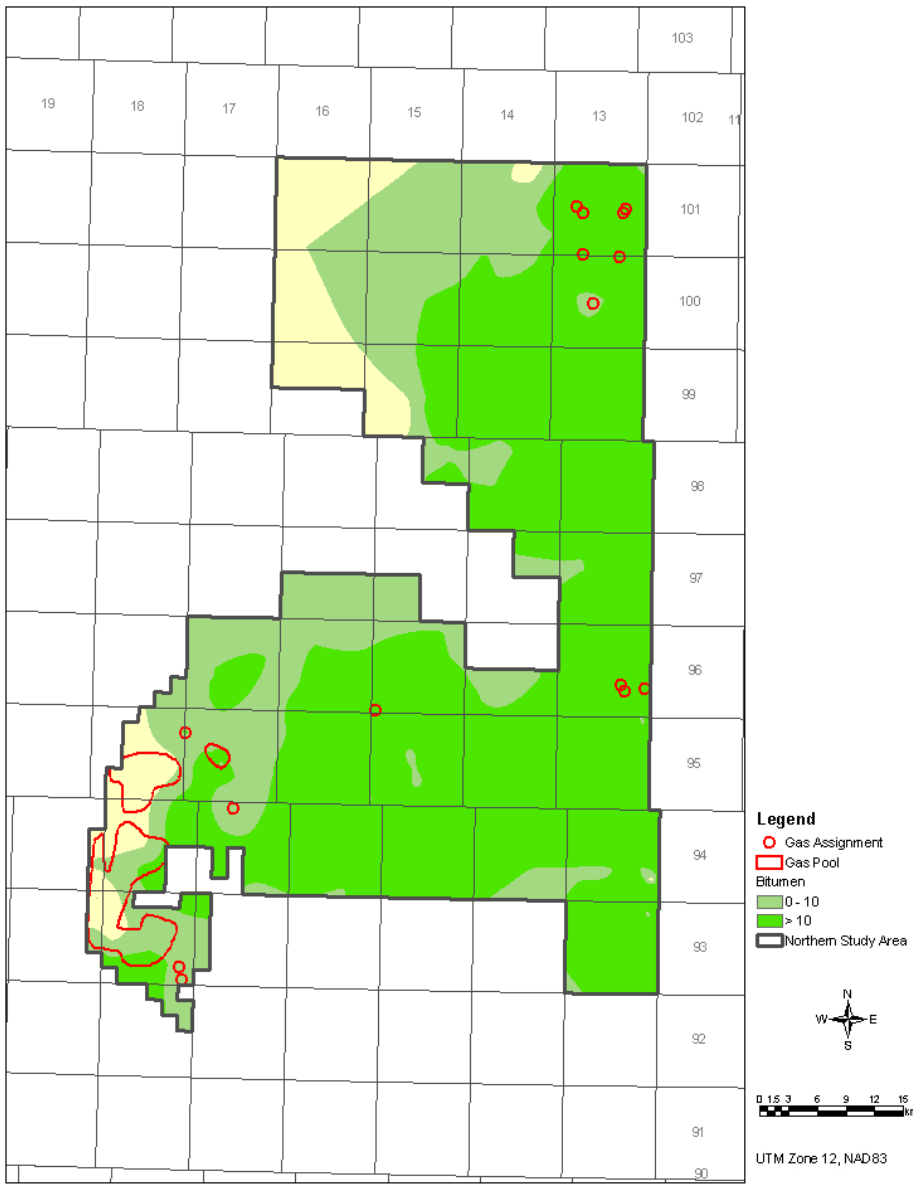


Figure 104 – Case 5, Wabiskaw D Sand Gas and McMurray Channel / Wabiskaw D Bitumen

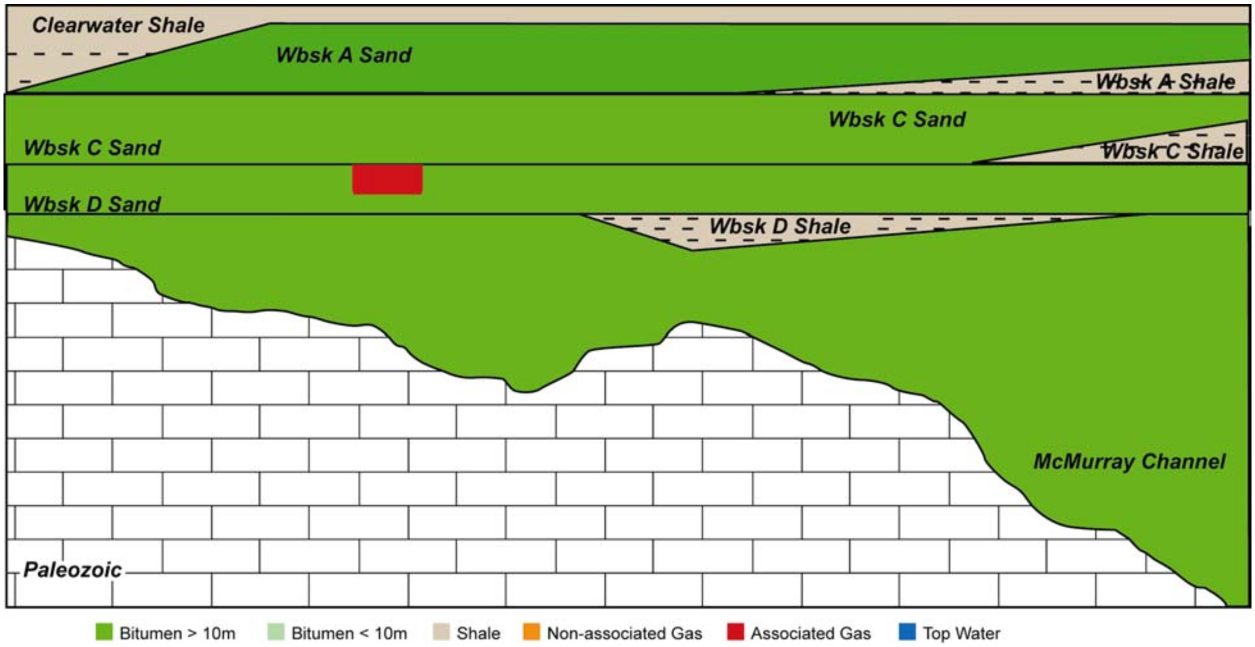


Figure 105 – Case 5 Schematic

Case 6 – Wabiskaw C Sand Gas

Figure 106 is a map of the cumulative thickness of McMurray Channel, Wabiskaw D, and Wabiskaw C Sand bitumen. Superimposed on this are the Wabiskaw C Shale and gas pools and top water zones within the Wabiskaw C Sand.

Figure 107 depicts examples of where Wabiskaw C Sand gas is associated and not associated with underlying bitumen.

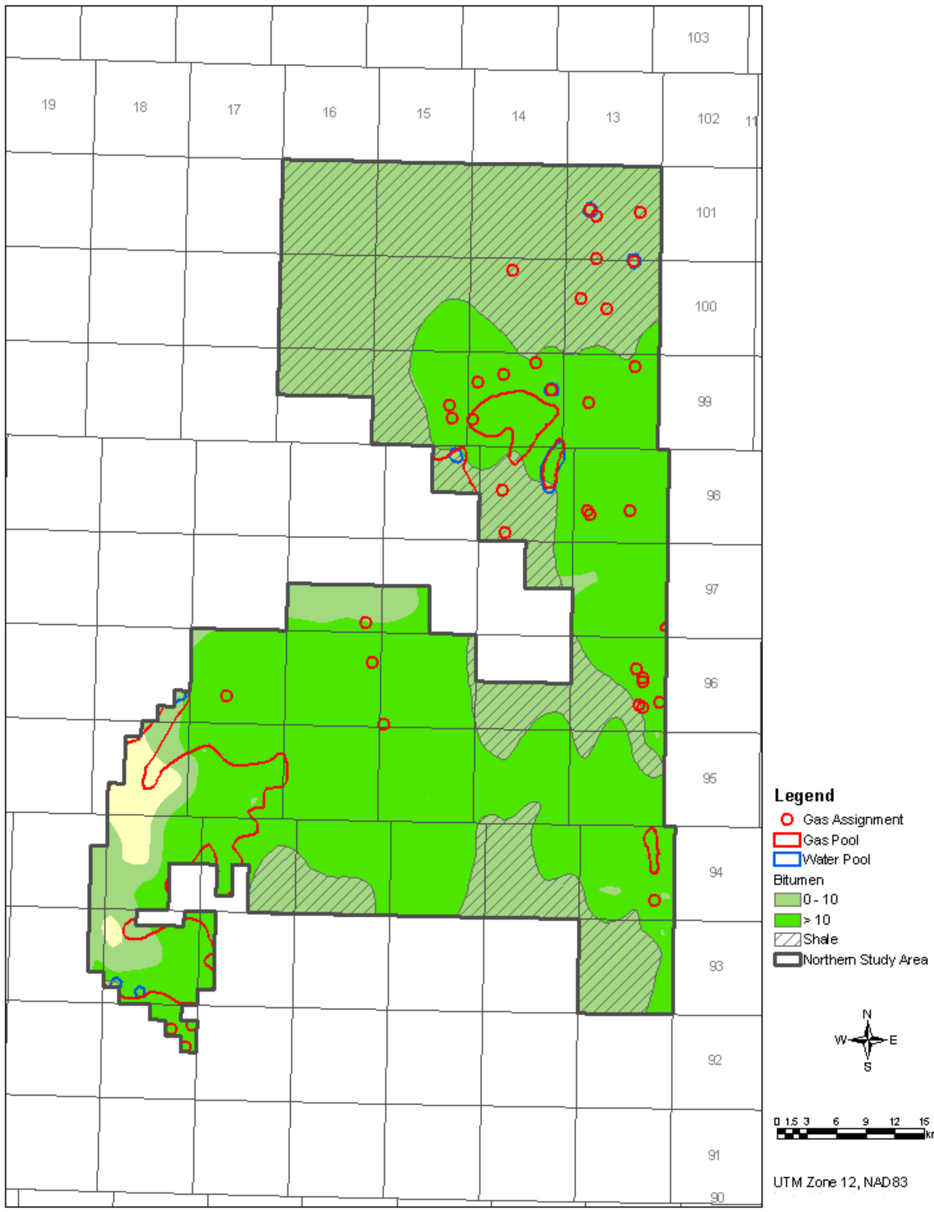


Figure 106 – Case 6, Wabiskaw C Sand Gas / Top Water and McMurray Channel / Wabiskaw D and C Bitumen

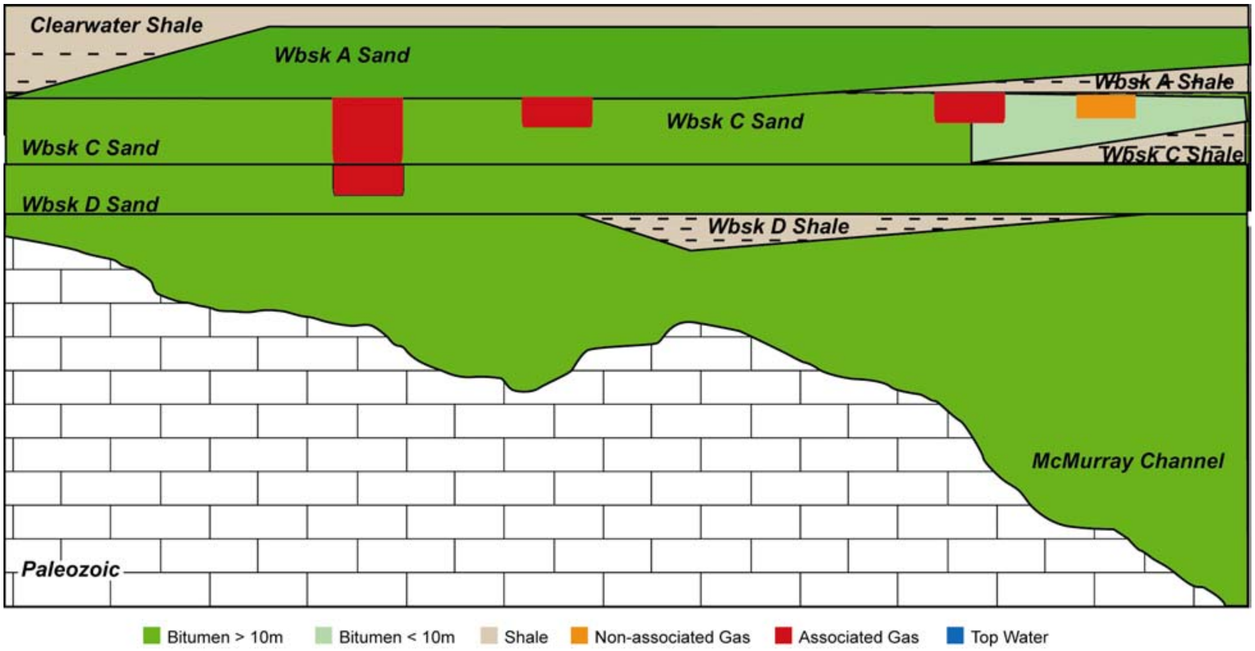


Figure 107 – Case 6 Schematic

Case 7 – Wabiskaw A Sand Gas

Figure 108 is composed of three layers. The lowermost layer shows cumulative thickness of bitumen within the McMurray Channel and all Wabiskaw sands. Superimposed on this are the Wabiskaw C and A Shales. Gas pools within the Wabiskaw A Sand constitute the upper layer. In areas where one or more of the Wabiskaw shale units are present, only bitumen above the uppermost shale unit was considered. Gas can be associated with bitumen within any or all of the four units, depending on the presence or absence of intervening shales. Gas in the Wabiskaw A Sand can also be in vertical communication with the underlying Wabiskaw C Sand gas that is associated with bitumen (Figure 109).

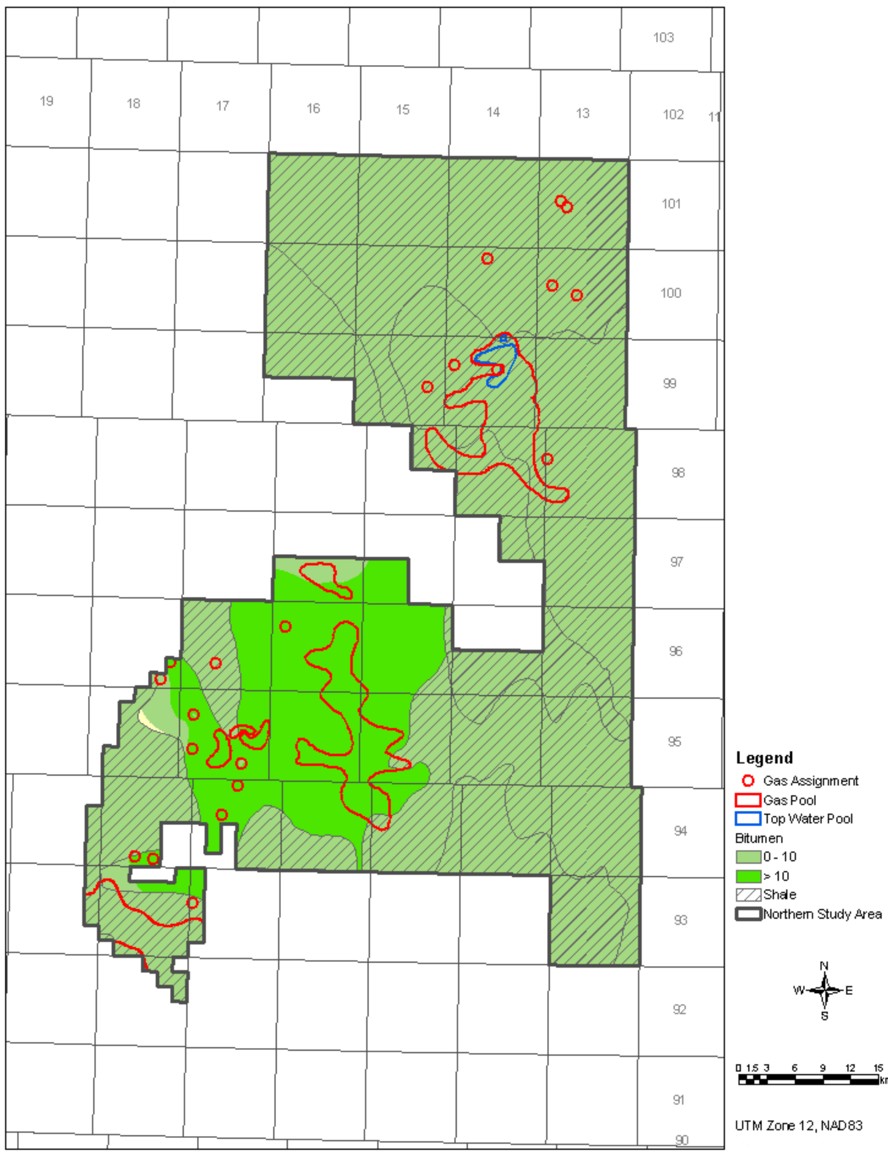


Figure 108 – Case 7, Wabiskaw A Gas / Top Water and McMurray / Wabiskaw D, C and A Bitumen

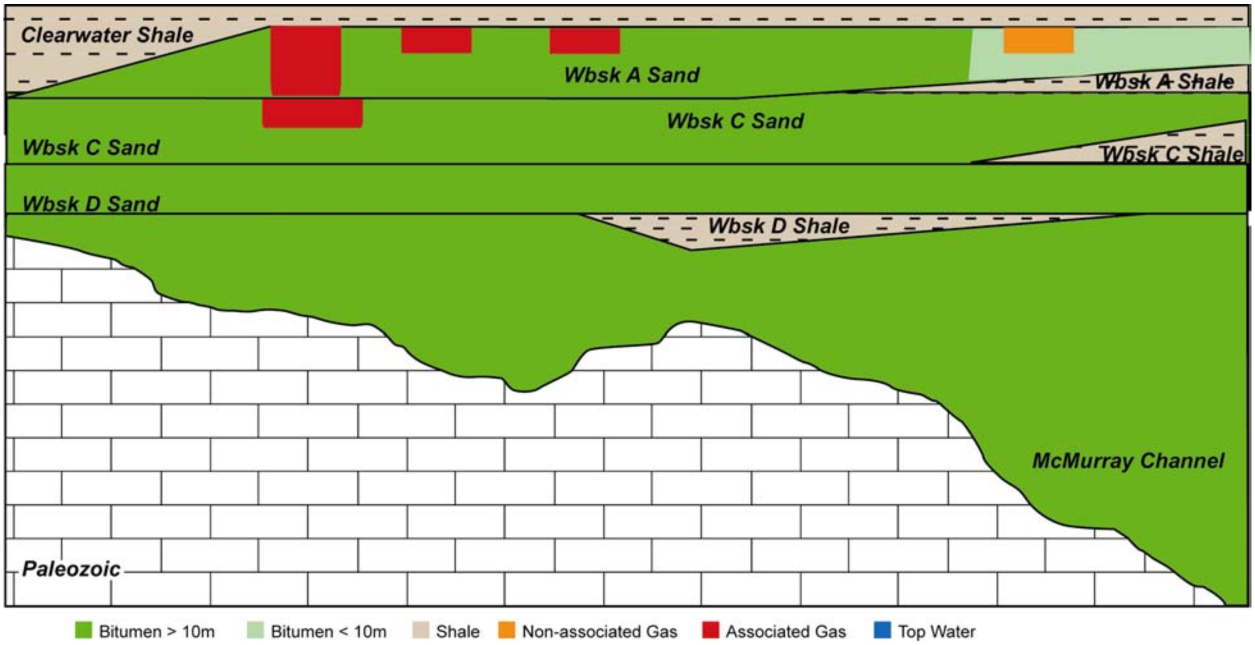


Figure 109 – Case 7 Schematic

Table 1. Association of Gas with Bitumen-Bearing Intervals

Case	Stratigraphic zone(s) containing gas pool	Corresponding bitumen-bearing zones	Description
1	McMurray C, McMurray Channel	McMurray C, McMurray Channel	• Gas pools* located within the McMurray C or within a McMurray Channel. Although gas may appear to be separated from bitumen within a single wellbore, there is no identifiable regional mudstone present.
2	McMurray B Sequence	McMurray C, McMurray Channel	• Gas pools within the McMurray B Sequence that are laterally connected to gas in a McMurray Channel. • Gas pools within the McMurray B1 Sequence that directly overlie a McMurray Channel and the McMurray B mudstone is absent.
3	McMurray A Sequence, Wabiskaw C Sand, Wabiskaw D Valley-fill, Wabiskaw B Valley-fill	McMurray C, McMurray Channel	• Gas pools within the McMurray A Sequence that are laterally connected to gas in a McMurray Channel. • Gas pools within the McMurray A1 Sequence that directly overlie a McMurray Channel and the McMurray A and B mudstones are absent. • Gas pools within the Wabiskaw C sand where the Wabiskaw D shale is absent or less than 0.5 m thick over all or some portion of the pool. • Gas pools within the Wabiskaw B or D Valley-fill that are in lateral communication with gas pools in the McMurray Channel or are vertically associated with bitumen in underlying McMurray Channels.
4	Wabiskaw B Valley-fill, Wabiskaw D Valley-fill	Wabiskaw B Valley-fill, Wabiskaw D Valley-fill	• Gas pools within the Wabiskaw D Valley-fill with bitumen in the same unit. • Gas pools within the Wabiskaw B Valley-fill with bitumen in the same unit. • Gas pools in the McMurray A Sequence or the Wabiskaw C Sand that are in lateral communication with gas in the Wabiskaw B or D Valley-fill or are vertically associated with bitumen in the underlying Wabiskaw D Valley-fill. (continued)

Table 1. Association of Gas with Bitumen-Bearing Intervals (concluded)

Case	Stratigraphic zone(s) containing gas pool	Corresponding bitumen-bearing zones	Description
5	Wabiskaw D Sand	Wabiskaw D Sand, McMurray Channel	• Gas pools within Wabiskaw D Sand in association with bitumen within the same unit. • Gas pools within Wabiskaw D Sand in association with bitumen within the same unit and bitumen in the underlying McMurray Channel where Wabiskaw D Shale is absent or < 0.5 m thick.
6	Wabiskaw C Sand Wabiskaw D Sand	Wabiskaw C Sand, Wabiskaw D Sand, McMurray Channel	• Gas pools within Wabiskaw C Sand in association with bitumen within the same unit and Wabiskaw D Sand where Wabiskaw C Shale is absent or < 0.5 m thick but Wabiskaw D Shale is present. • Gas pools within Wabiskaw C Sand in association with underlying bitumen within the same unit and underlying Wabiskaw D Sand and McMurray Channel where Wabiskaw C and D shales are absent or < 0.5 m thick over all or some portion of the pool. • Gas pools within Wabiskaw C Sand in vertical association with gas pools within the Wabiskaw D Sand that are in association with underlying bitumen where Wabiskaw D Shale is absent or < 0.5 m thick over all or some portion of the pool.
7	Wabiskaw A Sand, Wabiskaw C Sand	Wabiskaw A Sand, Wabiskaw C Sand, Wabiskaw D Sand, McMurray Channel	• Gas pools within Wabiskaw A Sand in association with bitumen within the same unit where the Wabiskaw A Shale is present. • Gas pools within Wabiskaw A Sand in association with underlying bitumen where Wabiskaw A, C, and D shales are absent or < 0.5 m thick over all or some portion of the pool. • Gas pools within Wabiskaw A Sand in vertical association with gas pools within the Wabiskaw C Sand that are in association with underlying bitumen where Wabiskaw C and D shales are absent or < 0.5 m thick over all or some portion of the pool. • Gas pools within Wabiskaw A Sand in association with underlying bitumen where Wabiskaw A and C shales are absent or < 0.5 m thick over all or some portion of the pool and Wabiskaw D shale is present.

* Gas pools include the ROI of any associated top water zone.

Table 2. Gas Pool Association Assessment Table

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
CHARD	WABISKAW K	N	
CHARD	WABISKAW N	N	
CHARD	WABISKAW O	N	
CHARD	WABISKAW UNDEFINED-034	N	
CHARD	WABISKAW UNDEFINED-035	N	
CHARD	WABISKAW UNDEFINED-037	N	
CHARD	WABISKAW-MCMURRAY A	A	3
CHARD	MCMURRAY B	N	
CHARD	MCMURRAY E	N	
CHARD	MCMURRAY G	N	
CHARD	MCMURRAY I	N	
CHARD	MCMURRAY P	A	3
CHARD	MCMURRAY Z	A	1
CHARD	MCMURRAY EE	A	1
CHARD	MCMURRAY VV	A	3
CHARD	MCMURRAY XX	A	1
CHARD	MCMURRAY YY	A	1
CHARD	MCMURRAY ZZ	A	1
CHARD	MCMURRAY UNDEFINED-074	N	
CHARD	MCMURRAY UNDEFINED-076	N	
CHARD	MCMURRAY UNDEFINED-108	A	1
CHARD	MCMURRAY UNDEFINED-119	N	
CHARD	MCMURRAY UNDEFINED-126	N	
CHARD	MCMURRAY UNDEFINED-136	A	1
CHARD	MCMURRAY UNDEFINED-150	N	
CHARD	MCMURRAY AAA	A	1
CHARD	MCMURRAY BBB	A	1
CHARD	MCMURRAY CCC	N	
CHARD	MCMURRAY DDD	N	
CHARD	MCMURRAY EEE	N	
CHARD	MCMURRAY FFF	N	
CHARD	MCMURRAY HHH	N	
CLYDEN	MCMURRAY C	A	1
CLYDEN	MCMURRAY L	N	
CLYDEN	MCMURRAY M	A	1
CLYDEN	MCMURRAY N	A	1
CLYDEN	MCMURRAY S	N	
CLYDEN	MCMURRAY U	N	
CLYDEN	MCMURRAY W	A	1
CLYDEN	MCMURRAY X	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
CLYDEN	MCMURRAY Y	A	1
CLYDEN	MCMURRAY Z	N	
CLYDEN	MCMURRAY AA	N	
CLYDEN	MCMURRAY BB	N	
CLYDEN	MCMURRAY CC	N	
CLYDEN	MCMURRAY DD	N	
CLYDEN	MCMURRAY EE	N	
CLYDEN	MCMURRAY FF	N	
CLYDEN	MCMURRAY NN	N	
CLYDEN	MCMURRAY OO	N	
CLYDEN	MCMURRAY UNDEFINED-074	A	1
CLYDEN	MCMURRAY UNDEFINED-088	N	
CONKLIN	WABISKAW UNDEFINED-006	A	3
CONKLIN	MCMURRAY UNDEFINED-013	A	3
CORNER	MCMURRAY A	A	3
CORNER	MCMURRAY C	A	3
CORNER	MCMURRAY D	A	3
CORNER	MCMURRAY G	A	3
CORNER	MCMURRAY J	A	1
CORNER	MCMURRAY K	A	3
CORNER	MCMURRAY P	A	1
CORNER	MCMURRAY Q	A	1
CORNER	MCMURRAY T	N	
CORNER	MCMURRAY U	A	2
CORNER	MCMURRAY V	A	2
CORNER	MCMURRAY X	N	
CORNER	MCMURRAY Y	N	
CORNER	MCMURRAY AA	A	1
CORNER	MCMURRAY BB	A	1
CORNER	MCMURRAY CC	A	1
CORNER	MCMURRAY MM	A	3
CORNER	MCMURRAY NN	N	
CORNER	MCMURRAY OO	A	1
CORNER	MCMURRAY UNDEFINED-061	A	1
DEVENISH	WABISKAW A	N	
DEVENISH	WABISKAW B	A	4
DIVIDE	MCMURRAY A	A	2
DIVIDE	MCMURRAY D	N	
DIVIDE	MCMURRAY G	N	
DIVIDE	MCMURRAY H	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
DIVIDE	MCMURRAY K	A	1
DIVIDE	MCMURRAY P	N	
DIVIDE	MCMURRAY Q	N	
DIVIDE	MCMURRAY R	N	
DIVIDE	MCMURRAY S	A	1
DIVIDE	MCMURRAY U	N	
DIVIDE	MCMURRAY V	A	2
DIVIDE	MCMURRAY W	A	2
DIVIDE	MCMURRAY X	N	
DIVIDE	MCMURRAY Y	N	
DIVIDE	MCMURRAY Z	N	
DIVIDE	MCMURRAY AA	N	
DIVIDE	MCMURRAY CC	A	1
DIVIDE	MCMURRAY DD	A	1
DIVIDE	MCMURRAY FF	A	1
DIVIDE	MCMURRAY GG	A	2
DIVIDE	MCMURRAY HH	A	1
DIVIDE	MCMURRAY II	A	1
DIVIDE	MCMURRAY JJ	N	
DIVIDE	MCMURRAY KK	A	1
DIVIDE	MCMURRAY UNDEFINED-037	N	
DIVIDE	MCMURRAY UNDEFINED-051	A	1
DIVIDE	MCMURRAY UNDEFINED-052	A	2
DIVIDE	MCMURRAY UNDEFINED-056	A	2
DIVIDE	MCMURRAY UNDEFINED-065	A	1
DIVIDE	MCMURRAY UNDEFINED-066	A	1
DIVIDE	MCMURRAY UNDEFINED-068	N	
DIVIDE	MCMURRAY UNDEFINED-069	N	
DIVIDE	MCMURRAY UNDEFINED-070	A	1
DIVIDE	MCMURRAY UNDEFINED-074	A	1
DOVER	WABISKAW UNDEFINED-001	A	6
DOVER	WABISKAW UNDEFINED-002	A	6
DUNCAN	MCMURRAY Y	A	1
DUNCAN	MCMURRAY Z	A	1
DUNCAN	MCMURRAY AA	A	1
DUNCAN	MCMURRAY RR	N	
DUNCAN	MCMURRAY SS	A	1
DUNCAN	MCMURRAY UU	N	
DUNCAN	MCMURRAY YY	A	1
DUNCAN	MCMURRAY ZZ	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
DUNCAN	MCMURRAY UNDEFINED-086	N	
DUNCAN	MCMURRAY UNDEFINED-087	N	
DUNCAN	MCMURRAY CCC	N	
DUNCAN	MCMURRAY GGG	A	1
EAGLENEST	WABISKAW UNDEFINED-001	N	
EAGLENEST	WABISKAW UNDEFINED-002	A	5
EAGLENEST	WABISKAW UNDEFINED-003	N	
EAGLENEST	WABISKAW UNDEFINED-004	A	5
EAGLENEST	WABISKAW UNDEFINED-005	N	
EAGLENEST	WABISKAW UNDEFINED-006	N	
EAGLENEST	WABISKAW UNDEFINED-007	A	5
EAGLENEST	MCMURRAY UNDEFINED-001	A	1
ELLS	WABISKAW C	A	7
ELLS	WABISKAW E	A	6
ELLS	WABISKAW UNDEFINED-011	A	5
ELLS	WABISKAW UNDEFINED-013	N	
ELLS	WABISKAW UNDEFINED-015	A	7
ELLS	WABISKAW UNDEFINED-016	A	7
ELLS	WABISKAW UNDEFINED-017	A	6
FISHER	WABISKAW B	A	3
FISHER	WABISKAW D	A	3
FISHER	WABISKAW UNDEFINED-002	A	3
FISHER	WABISKAW UNDEFINED-005	A	3
FISHER	WABISKAW UNDEFINED-008	A	3
FISHER	WABISKAW UNDEFINED-010	A	3
FISHER	WABISKAW UNDEFINED-013	A	3
FISHER	WABISKAW UNDEFINED-014	A	3
FISHER	WABISKAW UNDEFINED-015	A	3
FISHER	WABISKAW UNDEFINED-016	A	3
FISHER	WABISKAW UNDEFINED-017	A	3
FISHER	WABISKAW UNDEFINED-018	A	3
FISHER	WABISKAW UNDEFINED-019	A	3
FISHER	WABISKAW UNDEFINED-020	A	3
FISHER	WABISKAW UNDEFINED-021	A	3
FISHER	WABISKAW UNDEFINED-022	A	3
FISHER	WABISKAW UNDEFINED-025	N	
FISHER	WABISKAW UNDEFINED-026	A	3
FISHER	WABISKAW UNDEFINED-027	A	3
FISHER	WABISKAW-MCMURRAY A	A	3
FISHER	WABISKAW-MCMURRAY B	A	3

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
FISHER	WABISKAW-MCMURRAY C	A	3
FISHER	WABISKAW-MCMURRAY D	A	3
FISHER	MCMURRAY I	N	
FISHER	MCMURRAY K	A	1
FISHER	MCMURRAY O	A	3
FISHER	MCMURRAY UNDEFINED-060	A	1
FISHER	MCMURRAY UNDEFINED-071	A	1
FISHER	MCMURRAY UNDEFINED-072	A	1
FISHER	MCMURRAY UNDEFINED-073	A	1
FISHER	MCMURRAY UNDEFINED-074	A	1
FISHER	MCMURRAY UNDEFINED-075	A	1
FISHER	MCMURRAY UNDEFINED-076	A	1
FISHER	MCMURRAY UNDEFINED-077	A	1
FISHER	MCMURRAY UNDEFINED-078	A	1
FISHER	MCMURRAY UNDEFINED-079	A	1
FISHER	MCMURRAY UNDEFINED-080	A	1
FISHER	MCMURRAY UNDEFINED-081	A	1
FISHER	MCMURRAY UNDEFINED-082	A	1
FISHER	MCMURRAY UNDEFINED-083	A	1
FISHER	MCMURRAY UNDEFINED-084	A	1
FISHER	MCMURRAY UNDEFINED-085	A	1
FISHER	MCMURRAY UNDEFINED-086	A	1
FISHER	MCMURRAY UNDEFINED-087	A	3
FISHER	MCMURRAY UNDEFINED-091	A	3
FISHER	MCMURRAY UNDEFINED-092	A	3
FISHER	MCMURRAY UNDEFINED-093	A	3
FISHER	MCMURRAY UNDEFINED-094	A	3
FISHER	MCMURRAY UNDEFINED-095	A	3
FISHER	MCMURRAY UNDEFINED-096	A	3
FISHER	MCMURRAY UNDEFINED-097	A	3
FISHER	MCMURRAY UNDEFINED-098	A	3
FISHER	MCMURRAY UNDEFINED-099	A	3
FISHER	MCMURRAY UNDEFINED-100	A	3
FISHER	MCMURRAY UNDEFINED-101	A	3
FISHER	MCMURRAY UNDEFINED-102	A	3
FISHER	MCMURRAY UNDEFINED-103	A	3
GLOVER	MCMURRAY A	A	1
GLOVER	MCMURRAY B	A	3
GROUSE	MCMURRAY UNDEFINED-026	A	2
HANGINGSTONE	WABISKAW A	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
HANGINGSTONE	WABISKAW B	N	
HANGINGSTONE	WABISKAW E	N	
HANGINGSTONE	WABISKAW J	N	
HANGINGSTONE	WABISKAW K	N	
HANGINGSTONE	WABISKAW L	N	
HANGINGSTONE	WABISKAW M	N	
HANGINGSTONE	WABISKAW N	N	
HANGINGSTONE	WABISKAW O	N	
HANGINGSTONE	WABISKAW P	N	
HANGINGSTONE	WABISKAW UNDEFINED-014	N	
HANGINGSTONE	WABISKAW-MCMURRAY A	A	3
HANGINGSTONE	WABISKAW-MCMURRAY B	N	
HANGINGSTONE	WABISKAW-MCMURRAY C	A	3
HANGINGSTONE	WABISKAW-MCMURRAY D	A	3
HANGINGSTONE	WABISKAW-MCMURRAY E	A	3
HANGINGSTONE	MCMURRAY C	A	1
HANGINGSTONE	MCMURRAY E	A	2
HANGINGSTONE	MCMURRAY G	A	1
HANGINGSTONE	MCMURRAY H	N	
HANGINGSTONE	MCMURRAY I	A	1
HANGINGSTONE	MCMURRAY L	N	
HANGINGSTONE	MCMURRAY U	A	1
HANGINGSTONE	MCMURRAY X	A	3
HANGINGSTONE	MCMURRAY Y	N	
HANGINGSTONE	MCMURRAY Z	A	3
HANGINGSTONE	MCMURRAY BB	A	3
HANGINGSTONE	MCMURRAY DD	N	
HANGINGSTONE	MCMURRAY GG	N	
HANGINGSTONE	MCMURRAY HH	A	1
HANGINGSTONE	MCMURRAY II	N	
HANGINGSTONE	MCMURRAY JJ	A	1
HANGINGSTONE	MCMURRAY KK	A	1
HANGINGSTONE	MCMURRAY LL	N	
HANGINGSTONE	MCMURRAY MM	A	1
HANGINGSTONE	MCMURRAY OO	A	1
HANGINGSTONE	MCMURRAY PP	A	1
HANGINGSTONE	MCMURRAY QQ	N	
HANGINGSTONE	MCMURRAY RR	A	2
HANGINGSTONE	MCMURRAY SS	N	
HANGINGSTONE	MCMURRAY TT	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
HANGINGSTONE	MCMURRAY VV	A	2
HANGINGSTONE	MCMURRAY WW	N	
HANGINGSTONE	MCMURRAY YY	N	
HANGINGSTONE	MCMURRAY ZZ	N	
HANGINGSTONE	MCMURRAY UNDEFINED-002	A	2
HANGINGSTONE	MCMURRAY UNDEFINED-006	N	
HANGINGSTONE	MCMURRAY UNDEFINED-022	N	
HANGINGSTONE	MCMURRAY UNDEFINED-043	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-051	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-055	N	
HANGINGSTONE	MCMURRAY UNDEFINED-060	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-062	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-074	N	
HANGINGSTONE	MCMURRAY UNDEFINED-079	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-081	N	
HANGINGSTONE	MCMURRAY UNDEFINED-095	N	
HANGINGSTONE	MCMURRAY UNDEFINED-096	A	3
HANGINGSTONE	MCMURRAY UNDEFINED-098	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-099	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-100	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-101	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-102	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-108	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-112	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-114	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-116	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-117	N	
HANGINGSTONE	MCMURRAY UNDEFINED-118	N	
HANGINGSTONE	MCMURRAY UNDEFINED-119	N	
HANGINGSTONE	MCMURRAY UNDEFINED-120	N	
HANGINGSTONE	MCMURRAY UNDEFINED-121	N	
HANGINGSTONE	MCMURRAY UNDEFINED-125	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-134	N	
HANGINGSTONE	MCMURRAY UNDEFINED-136	N	
HANGINGSTONE	MCMURRAY UNDEFINED-137	N	
HANGINGSTONE	MCMURRAY UNDEFINED-138	N	
HANGINGSTONE	MCMURRAY UNDEFINED-139	N	
HANGINGSTONE	MCMURRAY UNDEFINED-144	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-153	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-159	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
HANGINGSTONE	MCMURRAY UNDEFINED-160	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-161	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-162	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-163	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-164	N	
HANGINGSTONE	MCMURRAY UNDEFINED-167	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-168	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-172	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-175	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-176	A	1
HANGINGSTONE	MCMURRAY UNDEFINED-177	N	
HANGINGSTONE	MCMURRAY UNDEFINED-178	N	
HANGINGSTONE	MCMURRAY UNDEFINED-179	N	
HANGINGSTONE	MCMURRAY UNDEFINED-180	A	1
HANGINGSTONE	MCMURRAY AAA	N	
HANGINGSTONE	MCMURRAY BBB	N	
HANGINGSTONE	MCMURRAY CCC	N	
HANGINGSTONE	MCMURRAY DDD	N	
HANGINGSTONE	MCMURRAY FFF	N	
HANGINGSTONE	MCMURRAY GGG	N	
HANGINGSTONE	MCMURRAY III	A	3
HANGINGSTONE	MCMURRAY KKK	A	1
HANGINGSTONE	MCMURRAY LLL	A	3
HANGINGSTONE	MCMURRAY NNN	A	1
HANGINGSTONE	MCMURRAY QQQ	A	1
HANGINGSTONE	MCMURRAY RRR	A	1
HANGINGSTONE	MCMURRAY SSS	N	
HANGINGSTONE	MCMURRAY UUU	N	
HANGINGSTONE	MCMURRAY YYY	A	3
HANGINGSTONE	MCMURRAY B2B	N	
HANGINGSTONE	MCMURRAY D2D	N	
HANGINGSTONE	MCMURRAY E2E	N	
HANGINGSTONE	MCMURRAY F2F	N	
HANGINGSTONE	MCMURRAY G2G	A	1
HANGINGSTONE	MCMURRAY H2H	A	1
HANGINGSTONE	MCMURRAY K2K	A	1
HANGINGSTONE	MCMURRAY L2L	A	1
HANGINGSTONE	MCMURRAY O2O	A	1
HANGINGSTONE	MCMURRAY P2P	A	1
HANGINGSTONE	MCMURRAY R2R	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
HANGINGSTONE	MCMURRAY S2S	N	
HANGINGSTONE	MCMURRAY T2T	N	
HANGINGSTONE	MCMURRAY V2V	A	2
HANGINGSTONE	MCMURRAY W2W	N	
HANGINGSTONE	MCMURRAY X2X	N	
HANGINGSTONE	MCMURRAY Y2Y	N	
HANGINGSTONE	MCMURRAY Z2Z	A	1
HANGINGSTONE	MCMURRAY B3B	A	1
HANGINGSTONE	MCMURRAY C3C	A	1
HANGINGSTONE	MCMURRAY D3D	A	1
HANGINGSTONE	MCMURRAY F3F	A	1
HANGINGSTONE	MCMURRAY G3G	N	
HARDY	WABISKAW A	N	
HARDY	WABISKAW D	N	
HARDY	WABISKAW F	N	
HARDY	WABISKAW G	N	
HARDY	WABISKAW I	A	3
HARDY	WABISKAW L	N	
HARDY	WABISKAW UNDEFINED-011	N	
HARDY	WABISKAW UNDEFINED-013	A	3
HARDY	WABISKAW-MCMURRAY A	A	3
HARDY	LOWER MANNVILLE UNDEFINED-002	A	3
HARDY	MCMURRAY J	A	3
HARDY	MCMURRAY V	A	1
HARDY	MCMURRAY Z	A	3
HARDY	MCMURRAY MM	A	3
HARDY	MCMURRAY PP	A	3
HARDY	MCMURRAY QQ	A	3
HARDY	MCMURRAY RR	A	1
HARDY	MCMURRAY SS	N	
HARDY	MCMURRAY TT	N	
HARDY	MCMURRAY XX	A	1
HARDY	MCMURRAY YY	A	1
HARDY	MCMURRAY ZZ	A	1
HARDY	MCMURRAY UNDEFINED-060	A	3
HARDY	MCMURRAY UNDEFINED-065	A	1
HARDY	MCMURRAY UNDEFINED-070	A	1
HARDY	MCMURRAY UNDEFINED-071	A	1
HARDY	MCMURRAY UNDEFINED-073	A	1
HARDY	MCMURRAY UNDEFINED-074	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
KIRBY	UPPER MANNVILLE I	A	7
KIRBY	UPPER MANNVILLE J	A	3 & 4
KIRBY	UPPER MANNVILLE S	A	3 & 4
KIRBY	UPPER MANNVILLE II	A	3
KIRBY	UPPER MANNVILLE RR	A	4
KIRBY	UPPER MANNVILLE XX	A	3
KIRBY	UPPER MANNVILLE YY	N	
KIRBY	UPPER MANNVILLE UNDEFINED-381	A	4
KIRBY	UPPER MANNVILLE YYY	A	3
KIRBY	UPPER MANNVILLE U2U	A	3 & 4
KIRBY	UPPER MANNVILLE V2V	A	3 & 4
KIRBY	UPPER MANNVILLE O3O	A	3
KIRBY	UPPER MANNVILLE Z3Z	A	3 & 4
KIRBY	UPPER MANNVILLE A4A	N	
KIRBY	UPPER MANNVILLE B4B	A	3 & 4
KIRBY	UPPER MANNVILLE C4C	A	4
KIRBY	UPPER MANNVILLE D4D	N	
KIRBY	UPPER MANNVILLE F4F	N	
KIRBY	UPPER MANNVILLE G4G	N	
KIRBY	UPPER MANNVILLE H4H	N	
KIRBY	WABISKAW UNDEFINED-016	N	
KIRBY	WABISKAW UNDEFINED-017	N	
KIRBY	WABISKAW UNDEFINED-019	N	
KIRBY	WABISKAW-MCMURRAY A	A	3
KIRBY	WABISKAW-MCMURRAY B	N	
KIRBY	LOWER MANNVILLE G	A	1
KIRBY	LOWER MANNVILLE H	A	3
KIRBY	LOWER MANNVILLE I	A	1
KIRBY	LOWER MANNVILLE L	A	3
KIRBY	LOWER MANNVILLE Q	A	3
KIRBY	LOWER MANNVILLE R	A	1
KIRBY	LOWER MANNVILLE Y	A	1
KIRBY	LOWER MANNVILLE Z	A	1
KIRBY	LOWER MANNVILLE CC	A	3
KIRBY	LOWER MANNVILLE DD	N	
KIRBY	LOWER MANNVILLE EE	A	1
KIRBY	LOWER MANNVILLE FF	A	1
KIRBY	LOWER MANNVILLE GG	A	1
KIRBY	LOWER MANNVILLE HH	N	
KIRBY	LOWER MANNVILLE II	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
KIRBY	LOWER MANNVILLE JJ	A	2
KIRBY	LOWER MANNVILLE KK	A	1
KIRBY	LOWER MANNVILLE MM	N	
KIRBY	LOWER MANNVILLE NN	N	
KIRBY	LOWER MANNVILLE PP	A	1
KIRBY	MCMURRAY UNDEFINED-006	A	1
KIRBY	MCMURRAY UNDEFINED-014	N	
KIRBY	MCMURRAY UNDEFINED-035	A	1
KIRBY	MCMURRAY UNDEFINED-040	N	
KIRBY	MCMURRAY UNDEFINED-044	A	1
KIRBY	MCMURRAY UNDEFINED-045	A	1
KIRBY	MCMURRAY UNDEFINED-047	A	2
KIRBY	MCMURRAY UNDEFINED-054	N	
KIRBY	MCMURRAY UNDEFINED-057	N	
KIRBY	MCMURRAY UNDEFINED-058	N	
KIRBY	MCMURRAY UNDEFINED-059	A	1
LEISMER	WABISKAW A	N	
LEISMER	WABISKAW C	A	3
LEISMER	WABISKAW F	A	3
LEISMER	WABISKAW G	N	
LEISMER	WABISKAW J	N	
LEISMER	WABISKAW K	A	3
LEISMER	WABISKAW M	N	
LEISMER	WABISKAW O	N	
LEISMER	WABISKAW Q	A	3
LEISMER	WABISKAW S	A	3
LEISMER	WABISKAW T	A	3
LEISMER	WABISKAW U	N	
LEISMER	WABISKAW V	A	3
LEISMER	WABISKAW W	A	3
LEISMER	WABISKAW X	A	3
LEISMER	WABISKAW Y	A	3 & 4
LEISMER	WABISKAW Z	A	3
LEISMER	WABISKAW UNDEFINED-063	N	
LEISMER	WABISKAW UNDEFINED-064	A	3
LEISMER	WABISKAW UNDEFINED-066	A	3
LEISMER	WABISKAW UNDEFINED-067	A	3
LEISMER	WABISKAW UNDEFINED-079	N	
LEISMER	WABISKAW UNDEFINED-084	N	
LEISMER	WABISKAW UNDEFINED-086	A	3

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
LEISMER	WABISKAW UNDEFINED-093	N	
LEISMER	WABISKAW UNDEFINED-098	A	3
LEISMER	WABISKAW UNDEFINED-106	N	
LEISMER	WABISKAW UNDEFINED-110	N	
LEISMER	WABISKAW-MCMURRAY A	A	3
LEISMER	WABISKAW-MCMURRAY B	A	3
LEISMER	WABISKAW-MCMURRAY C	A	3
LEISMER	WABISKAW-MCMURRAY D	A	3
LEISMER	WABISKAW-MCMURRAY E	A	3
LEISMER	WABISKAW-MCMURRAY F	N	
LEISMER	WABISKAW-MCMURRAY G	N	
LEISMER	WABISKAW-MCMURRAY H	A	3
LEISMER	WABISKAW-MCMURRAY I	N	
LEISMER	MCMURRAY B	A	1
LEISMER	MCMURRAY D	A	1
LEISMER	MCMURRAY F	A	1
LEISMER	MCMURRAY G	N	
LEISMER	MCMURRAY L	N	
LEISMER	MCMURRAY M	N	
LEISMER	MCMURRAY N	N	
LEISMER	MCMURRAY P	A	1
LEISMER	MCMURRAY Q	A	1
LEISMER	MCMURRAY R	N	
LEISMER	MCMURRAY S	A	2
LEISMER	MCMURRAY T	N	
LEISMER	MCMURRAY V	N	
LEISMER	MCMURRAY X	A	1
LEISMER	MCMURRAY AA	A	2
LEISMER	MCMURRAY GG	N	
LEISMER	MCMURRAY HH	N	
LEISMER	MCMURRAY II	N	
LEISMER	MCMURRAY NN	A	1
LEISMER	MCMURRAY OO	A	1
LEISMER	MCMURRAY PP	N	
LEISMER	MCMURRAY QQ	A	1
LEISMER	MCMURRAY RR	N	
LEISMER	MCMURRAY SS	A	2
LEISMER	MCMURRAY TT	A	1
LEISMER	MCMURRAY UNDEFINED-025	N	
LEISMER	MCMURRAY UNDEFINED-207	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
LEISMER	MCMURRAY UNDEFINED-241	A	1
LEISMER	MCMURRAY UNDEFINED-243	N	
LEISMER	MCMURRAY UNDEFINED-245	N	
LEISMER	MCMURRAY UNDEFINED-258	N	
LEISMER	MCMURRAY UNDEFINED-263	N	
LEISMER	MCMURRAY UNDEFINED-271	N	
LEISMER	MCMURRAY UNDEFINED-275	N	
LEISMER	MCMURRAY UNDEFINED-279	N	
LEISMER	MCMURRAY UNDEFINED-299	N	
LEISMER	MCMURRAY UNDEFINED-319	A	1
LEISMER	MCMURRAY UNDEFINED-320	A	1
LEISMER	MCMURRAY UNDEFINED-321	A	1
LEISMER	MCMURRAY UNDEFINED-325	A	1
LEISMER	MCMURRAY UNDEFINED-334	N	
LEISMER	MCMURRAY UNDEFINED-335	N	
LEISMER	MCMURRAY UNDEFINED-343	N	
LEISMER	MCMURRAY UNDEFINED-345	A	2
LEISMER	MCMURRAY UNDEFINED-353	N	
LEISMER	MCMURRAY UNDEFINED-361	N	
LEISMER	MCMURRAY UNDEFINED-363	A	1
LEISMER	MCMURRAY UNDEFINED-364	A	1
LEISMER	MCMURRAY UNDEFINED-366	A	1
LEISMER	MCMURRAY UNDEFINED-368	A	1
LEISMER	MCMURRAY UNDEFINED-377	N	
LEISMER	MCMURRAY UNDEFINED-378	A	1
LEISMER	MCMURRAY UNDEFINED-379	A	1
LEISMER	MCMURRAY UNDEFINED-381	A	1
LEISMER	MCMURRAY UNDEFINED-382	N	
LEISMER	MCMURRAY UNDEFINED-383	N	
LEISMER	MCMURRAY UNDEFINED-384	N	
LEISMER	MCMURRAY UNDEFINED-385	N	
LEISMER	MCMURRAY UNDEFINED-386	A	1
LEISMER	MCMURRAY UNDEFINED-387	N	
LEISMER	MCMURRAY EEE	A	1
LEISMER	MCMURRAY FFF	N	
LEISMER	MCMURRAY GGG	N	
LEISMER	MCMURRAY KKK	N	
LEISMER	MCMURRAY MMM	A	1
LEISMER	MCMURRAY NNN	A	3
LEISMER	MCMURRAY OOO	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
LEISMER	MCMURRAY PPP	A	1
LEISMER	MCMURRAY QQQ	N	
LEISMER	MCMURRAY TTT	N	
LEISMER	MCMURRAY VVV	N	
LEISMER	MCMURRAY G2G	N	
LEISMER	MCMURRAY J2J	N	
LEISMER	MCMURRAY K2K	A	3
LEISMER	MCMURRAY O2O	N	
LEISMER	MCMURRAY P2P	A	2
LEISMER	MCMURRAY S2S	A	1
LEISMER	MCMURRAY U2U	N	
LEISMER	MCMURRAY W2W	N	
LEISMER	MCMURRAY X2X	N	
LEISMER	MCMURRAY Y2Y	A	1
LEISMER	MCMURRAY Z2Z	A	1
LEISMER	MCMURRAY A3A	A	1
LEISMER	MCMURRAY B3B	A	1
LEISMER	MCMURRAY C3C	A	1
LEISMER	MCMURRAY E3E	A	1
LEISMER	MCMURRAY G3G	N	
LEISMER	MCMURRAY H3H	N	
LEISMER	MCMURRAY K3K	N	
LEISMER	MCMURRAY N3N	N	
LEISMER	MCMURRAY O3O	N	
LEISMER	MCMURRAY Q3Q	N	
LEISMER	MCMURRAY R3R	N	
LEISMER	MCMURRAY S3S	N	
LEISMER	MCMURRAY T3T	N	
LEISMER	MCMURRAY U3U	N	
LEISMER	MCMURRAY V3V	A	2
LEISMER	MCMURRAY W3W	A	2
LEISMER	MCMURRAY X3X	N	
LEISMER	MCMURRAY Y3Y	A	1
LEISMER	MCMURRAY Z3Z	A	1
LEISMER	MCMURRAY C4C	A	1
LEISMER	MCMURRAY D4D	N	
LEISMER	MCMURRAY E4E	N	
LEISMER	MCMURRAY F4F	N	
LEISMER	MCMURRAY G4G	N	
LEISMER	MCMURRAY H4H	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
LEISMER	MCMURRAY I4I	A	1
LEISMER	MCMURRAY J4J	N	
LEISMER	MCMURRAY K4K	N	
LEISMER	MCMURRAY L4L	N	
LEISMER	MCMURRAY M4M	N	
LEISMER	MCMURRAY N4N	A	1
LEISMER	MCMURRAY O4O	N	
LEISMER	MCMURRAY P4P	N	
LIEGE	WABISKAW A	N	
LIEGE	WABISKAW M	A	5
LIEGE	WABISKAW N	A	7
LIEGE	WABISKAW O	A	6
LIEGE	WABISKAW P	A	7
LIEGE	WABISKAW Q	N	
LIEGE	WABISKAW UNDEFINED-045	N	
LIEGE	WABISKAW UNDEFINED-049	A	6
LIEGE	WABISKAW UNDEFINED-050	A	6
LIEGE	WABISKAW UNDEFINED-051	A	6
LIEGE	WABISKAW UNDEFINED-053	A	7
LIEGE	WABISKAW UNDEFINED-055	A	7
LIEGE	WABISKAW UNDEFINED-059	N	
LIEGE	WABISKAW UNDEFINED-060	N	
LIEGE	WABISKAW UNDEFINED-061	A	7
LIEGE	WABISKAW UNDEFINED-062	A	7
LIEGE	WABISKAW UNDEFINED-063	A	7
LIEGE	WABISKAW UNDEFINED-064	A	7
LIEGE	WABISKAW UNDEFINED-065	N	
LIEGE	WABISKAW UNDEFINED-066	A	6
LIEGE	WABISKAW UNDEFINED-067	N	
LIEGE	MCMURRAY V	A	1
LIEGE	MCMURRAY UNDEFINED-074	A	1
LIEGE	MCMURRAY UNDEFINED-076	A	1
NEWBY	WABISKAW N	A	3
NEWBY	WABISKAW R	N	
NEWBY	WABISKAW S	N	
NEWBY	WABISKAW T	A	3
NEWBY	WABISKAW V	A	3
NEWBY	WABISKAW W	N	
NEWBY	WABISKAW X	N	
NEWBY	WABISKAW Y	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
NEWBY	WABISKAW Z	N	
NEWBY	WABISKAW AA	N	
NEWBY	WABISKAW BB	N	
NEWBY	WABISKAW DD	N	
NEWBY	WABISKAW EE	A	3
NEWBY	WABISKAW FF	N	
NEWBY	WABISKAW GG	N	
NEWBY	WABISKAW UNDEFINED-038	A	3
NEWBY	WABISKAW UNDEFINED-046	A	3
NEWBY	WABISKAW UNDEFINED-048	N	
NEWBY	WABISKAW UNDEFINED-049	A	3
NEWBY	WABISKAW UNDEFINED-050	N	
NEWBY	WABISKAW UNDEFINED-051	A	3
NEWBY	WABISKAW UNDEFINED-052	N	
NEWBY	WABISKAW UNDEFINED-053	N	
NEWBY	WABISKAW UNDEFINED-054	A	3
NEWBY	WABISKAW UNDEFINED-055	N	
NEWBY	WABISKAW UNDEFINED-056	A	3
NEWBY	WABISKAW UNDEFINED-060	N	
NEWBY	WABISKAW UNDEFINED-063	N	
NEWBY	WABISKAW UNDEFINED-066	A	3
NEWBY	WABISKAW UNDEFINED-070	N	
NEWBY	WABISKAW UNDEFINED-071	N	
NEWBY	WABISKAW UNDEFINED-073	N	
NEWBY	WABISKAW UNDEFINED-075	N	
NEWBY	WABISKAW UNDEFINED-076	N	
NEWBY	WABISKAW UNDEFINED-078	A	3
NEWBY	WABISKAW UNDEFINED-081	N	
NEWBY	WABISKAW-MCMURRAY F	N	
NEWBY	WABISKAW-MCMURRAY G	A	3
NEWBY	WABISKAW-MCMURRAY H	A	3
NEWBY	WABISKAW-MCMURRAY I	A	3
NEWBY	WABISKAW-MCMURRAY J	A	3
NEWBY	WABISKAW-MCMURRAY K	A	3
NEWBY	MCMURRAY B	N	
NEWBY	MCMURRAY V	A	3
NEWBY	MCMURRAY XX	A	1
NEWBY	MCMURRAY UNDEFINED-121	A	3
NEWBY	MCMURRAY UNDEFINED-122	A	3
NEWBY	MCMURRAY UNDEFINED-152	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
NEWBY	MCMURRAY UNDEFINED-156	A	1
NEWBY	MCMURRAY UNDEFINED-176	A	1
NEWBY	MCMURRAY UNDEFINED-177	A	1
NEWBY	MCMURRAY EEE	A	3
NEWBY	MCMURRAY III	A	1
NEWBY	MCMURRAY TTT	A	1
NEWBY	MCMURRAY XXX	A	1
NEWBY	MCMURRAY YYY	A	3
NEWBY	MCMURRAY ZZZ	A	1
NEWBY	MCMURRAY A2A	A	1
NEWBY	MCMURRAY B2B	A	1
NEWBY	MCMURRAY C2C	A	1
NEWBY	MCMURRAY D2D	N	
NEWBY	MCMURRAY E2E	A	3
NEWBY	MCMURRAY G2G	A	3
NEWBY	MCMURRAY H2H	A	3
NEWBY	MCMURRAY I2I	A	3
NEWBY	MCMURRAY J2J	A	3
NEWBY	MCMURRAY K2K	A	1
NEWBY	MCMURRAY L2L	A	1
NEWBY	MCMURRAY M2M	N	
RESDELN	WABISKAW H	N	
RESDELN	WABISKAW UNDEFINED-012	A	3
RESDELN	WABISKAW UNDEFINED-013	N	
RESDELN	WABISKAW-MCMURRAY A	A	3
RESDELN	MCMURRAY JJ	A	2
RESDELN	MCMURRAY OO	A	1
RESDELN	MCMURRAY PP	A	1
RESDELN	MCMURRAY QQ	A	1
RESDELN	MCMURRAY RR	A	3
RESDELN	MCMURRAY SS	A	3
RESDELN	MCMURRAY TT	N	
RESDELN	MCMURRAY UNDEFINED-060	A	1
RESDELN	MCMURRAY UNDEFINED-061	A	1
RESDELN	MCMURRAY UNDEFINED-072	A	1
RESDELN	MCMURRAY UNDEFINED-073	A	1
TAR	WABISKAW K	A	6
TAR	WABISKAW L	A	6
TAR	WABISKAW N	N	
TAR	WABISKAW O	A	6

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
TAR	WABISKAW P	A	6
TAR	WABISKAW Q	A	6
TAR	WABISKAW R	N	
TAR	WABISKAW S	A	6
TAR	WABISKAW T	N	
TAR	WABISKAW UNDEFINED-018	A	6
TAR	WABISKAW UNDEFINED-019	A	5
TAR	WABISKAW UNDEFINED-020	A	5
TAR	WABISKAW UNDEFINED-021	N	
TAR	WABISKAW UNDEFINED-022	A	5
TAR	WABISKAW UNDEFINED-027	A	6
TAR	WABISKAW UNDEFINED-028	N	
TAR	WABISKAW UNDEFINED-033	A	6
TAR	WABISKAW UNDEFINED-034	A	6
TAR	WABISKAW UNDEFINED-035	A	6
TAR	WABISKAW UNDEFINED-037	A	6
TAR	WABISKAW UNDEFINED-038	A	6
TAR	WABISKAW UNDEFINED-039	A	6
TAR	WABISKAW UNDEFINED-040	N	
TAR	WABISKAW UNDEFINED-041	N	
TAR	WABISKAW UNDEFINED-042	N	
TAR	WABISKAW UNDEFINED-043	N	
TAR	WABISKAW UNDEFINED-047	N	
TAR	WABISKAW UNDEFINED-049	N	
TAR	WABISKAW UNDEFINED-050	N	
TAR	WABISKAW UNDEFINED-052	N	
TAR	WABISKAW UNDEFINED-053	N	
TAR	WABISKAW UNDEFINED-054	N	
TAR	WABISKAW UNDEFINED-055	N	
TAR	WABISKAW UNDEFINED-057	A	6
TAR	WABISKAW UNDEFINED-058	A	6
TAR	WABISKAW UNDEFINED-059	A	6
TAR	WABISKAW UNDEFINED-060	A	6
TAR	MCMURRAY UNDEFINED-027	A	1
TAR	MCMURRAY UNDEFINED-028	A	1
TAR	MCMURRAY UNDEFINED-029	A	1
TAR	MCMURRAY UNDEFINED-030	A	1
TAR	MCMURRAY UNDEFINED-031	A	1
TAR	MCMURRAY UNDEFINED-032	A	1
TAR	MCMURRAY UNDEFINED-033	A	1

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
TAR	MCMURRAY UNDEFINED-034	A	1
TAR	MCMURRAY UNDEFINED-035	A	1
TAR	MCMURRAY UNDEFINED-036	A	1
THORNBURY	MCMURRAY XX	A	2
THORNBURY	MCMURRAY YY	A	1
THORNBURY	MCMURRAY UNDEFINED-125	N	
THORNBURY	MCMURRAY UNDEFINED-129	N	
THORNBURY	MCMURRAY UNDEFINED-158	N	
THORNBURY	MCMURRAY UNDEFINED-166	N	
THORNBURY	MCMURRAY UNDEFINED-168	A	1
THORNBURY	MCMURRAY UNDEFINED-203	A	1
THORNBURY	MCMURRAY UNDEFINED-228	A	1
THORNBURY	MCMURRAY UNDEFINED-236	A	1
THORNBURY	MCMURRAY UNDEFINED-237	A	1
THORNBURY	MCMURRAY UNDEFINED-240	A	1
THORNBURY	MCMURRAY UNDEFINED-241	A	1
THORNBURY	MCMURRAY UNDEFINED-245	N	
THORNBURY	MCMURRAY UNDEFINED-252	A	2
THORNBURY	MCMURRAY UNDEFINED-262	N	
THORNBURY	MCMURRAY UNDEFINED-267	A	1
THORNBURY	MCMURRAY FFF	N	
THORNBURY	MCMURRAY GGG	A	1
THORNBURY	MCMURRAY HHH	A	1
THORNBURY	MCMURRAY KKK	N	
THORNBURY	MCMURRAY QQQ	A	1
THORNBURY	MCMURRAY TTT	N	
THORNBURY	MCMURRAY D2D	A	1
THORNBURY	MCMURRAY G2G	N	
THORNBURY	MCMURRAY X2X	N	
THORNBURY	MCMURRAY Z2Z	N	
THORNBURY	MCMURRAY J4J	N	
THORNBURY	MCMURRAY W4W	A	1
THORNBURY	MCMURRAY X4X	A	1
THORNBURY	MCMURRAY Y4Y	A	1
THORNBURY	MCMURRAY A5A	A	1
THORNBURY	MCMURRAY B5B	A	1
THORNBURY	MCMURRAY C5C	A	1
THORNBURY	MCMURRAY D5D	N	
THORNBURY	MCMURRAY E5E	A	3
THORNBURY	MCMURRAY F5F	N	

Field Name	Pool Name	Associated (A) Nonassociated (N)	Case
THORNBURY	MCMURRAY H5H	N	
THORNBURY	MCMURRAY I5I	N	
THORNBURY	MCMURRAY J5J	N	
THORNBURY	MCMURRAY K5K	N	
THORNBURY	MCMURRAY M5M	N	
THORNBURY	MCMURRAY P5P	A	1
THORNBURY	MCMURRAY Q5Q	A	1
THORNBURY	MCMURRAY R5R	A	1
THORNBURY	MCMURRAY S5S	A	1
THORNBURY	MCMURRAY T5T	A	1
THORNBURY	MCMURRAY U5U	N	
THORNBURY	MCMURRAY V5V	A	2
THORNBURY	MCMURRAY W5W	A	1
THORNBURY	MCMURRAY Y5Y	A	1
THORNBURY	MCMURRAY Z5Z	A	1
THORNBURY	MCMURRAY A6A	A	1
THORNBURY	MCMURRAY B6B	A	1

6 Conclusions

As stated earlier, the objective of the study is to determine where gas is associated with bitumen. Therefore, the study focused on developing a regional geologic framework that would provide context for understanding site-specific gas/bitumen communication and includes the following conclusions:

- Regional stratigraphic units can be recognized and correlated throughout the study area.
- The McMurray B2 and A2 Mudstones (found at the base of the McMurray B2 and McMurray A2 sequences respectively) are the most significant barriers to communication in the study area. The Wabiskaw A, C, and D Shales can provide local barriers.
- Channel deposits dominate at the base of the McMurray and become progressively less frequent towards the top of the Wabiskaw-McMurray, but can occur at almost any stratigraphic level. Where they occur, channels can locally down-cut and remove regionally deposited sediments and subsequently fill with sands and muds.
- Gas pools can be laterally or vertically associated with bitumen where mudstones are absent under a portion of the region of influence.
- The vertical and lateral extents of gas pools contained within the regional stratigraphic units, particularly those above the McMurray A2 Mudstone, are difficult to determine.
- The quantity and quality of historical pressure data is limited. Therefore, the gas pooling was primarily based on the geological interpretation.
- Sand development within channels is difficult to predict.
- The most significant bitumen occurs within the channel sequences, primarily the McMurray C Channel / McMurray Channel in both the main and northern areas. The Wabiskaw B Valley-fill in the main study area also has significant bitumen.
- Regional sands in the main study area do not contain bitumen in excess of 10 m.
- Wabiskaw units in the northern study area do not contain significant areas of bitumen greater than 10 m. However, in the south central portion where the units are vertically in communication without intervening shales, the cumulative thickness of bitumen is significant.
- There are 464 associated and 313 nonassociated gas pools. These pools contain both producing and nonproducing wells.

The study provides a regional overview of the geological framework of the study area and identifies gas that is associated with bitumen. Further review of existing and new data will enhance and refine the interpretations presented.

7 Glossary

Accommodation Space

The amount of vertical thickness or space available for potential sediment accumulation. In the study area, bitumen thickness varies considerably within a channel because of lithological variability. Therefore, an understanding of accommodation space assists in interpreting the potential thickness of bitumen offsetting a well.

Associated Gas

Gas that is in pressure communication with bitumen within the region of influence either directly or through a connecting water zone. To identify associated gas, the bitumen and gas must be in direct fluid contact within a continuous porous interval, or if the gas/bitumen interval is in a channel environment, the mudstones/shales within the interval must not be regionally deposited.

EUB-Designated Pool

A gas pool that is formally defined by the EUB. The name and areal extent of the pool can be accessed through the EUB's Board Order System (BOS) on the EUB's Web site www.eub.gov.ab.ca.

Gas Assignment

A single-well pool.

Gas Pool

The area or lateral extent of a gas zone or zones believed to be in communication.

Mudstone

Fine-grained, detrital sedimentary rock made up of silt and clay sized particles. Distinguished from shale by lack of fissility, which is a property of splitting along closely spaced planes more or less parallel to bedding.

Nonassociated Gas

Gas that is not in pressure communication with bitumen within the region of influence either directly or through a connecting water zone. To identify nonassociated gas, mudstones/shales that may appear to separate gas from underlying bitumen must be shown to be associated with regionally deposited units. A regional geological understanding is necessary to establish the depositional environment.

Potentially Recoverable Bitumen

Bitumen in oil sands that has a minimum thickness of 10 m with a minimum bitumen saturation of 50 per cent. Consideration must be given to the volume of the bitumen encountered, the geological depositional environment, the presence of associated water zones, and the available well control.

Region of Influence

The area or extent of the gas pool in the case of gas directly overlying bitumen, or the combined extent of the gas pool and water zone in the case of gas overlying water overlying bitumen.

Steam-Assisted Gravity Drainage (SAGD)

A thermal bitumen recovery method that involves the drilling of horizontal well pairs one above the other, injection of steam in the upper well to heat and mobilize bitumen, and gravity drainage of the mobilized bitumen to the lower well from which it is recovered.

Shale

Fine-grained, detrital sedimentary rock containing clay minerals, as well as particles of quartz, feldspar, calcite, dolomite, and other minerals. Distinguished from mudstone by presence of fissility.

Top Water

A water zone recognizable on logs at the base of a gas zone and may overlie a bitumen-bearing zone.

APPENDIX A

A REVIEW OF THE EUB REGIONAL GEOLOGICAL STUDY

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16/12/03

EXECUTIVE SUMMARY

The major objective of the EUB Regional Geological Study (RGS) is to determine if gas pools have the potential to be in pressure communication with underlying commercial bitumen either directly or through an intervening water zone. Where such communication exists, the pressure in the gas zone or underlying water zone could limit the pressure attainable in the steam chamber of a SAGD operation following steam breakthrough. The Board has concluded that such situations present high risk to future bitumen recovery and associated gas wells are subject to shut-in.

On the other hand, where it can be shown that there is low risk of pressure communication between gas and bitumen zones, wells could be exempted from shut in. For example, where a regional mudstone barrier separates bitumen from gas.

The question of pressure communication between a potential zone of bitumen production and an overlying gas zone requires definition of:

- Regions with potentially commercial bitumen
- Gas zones and underlying water zones through which pressure could be communicated
- Mudstones or other low permeability deposits that could act as pressure barriers isolating bitumen from gas zones.

The RGS gives priority to providing a stratigraphic framework in which the above requirements can be assessed.

The RGS included examination and analysis of:

- ~4500 well logs
- >10,000 meters of core
- Pressure and production data from gas zones.

The project was completed in a four-month period.

Gas zones in the McMurray-Wabiskaw interval are significantly depleted creating urgency for decisions.

The basis for the stratigraphic study is the one-dimensional occurrence of lithologic units, gas zones, water zones and bitumen zones identified using well logs and core. These data are extended to three-dimensional space and the risk of pressure communication amongst units is interpreted.

Several thin mudstone/shale units, recognized from well logs and core, are areally extensive in the McMurray-Wabiskaw interval, and are important in regional correlation within the Athabasca deposit. These markers are used to provide a stratigraphic framework within which other lithofacies are mapped. Regional sands typically overlie the mudstone/shale units in upward coarsening sequences that are <10 m thick. These sands are too thin to meet criteria for commercial SAGD operations.

Channel sands and valley fill cut both the regional sands and mudstone/shale units locally and, where this occurs, sand thickness commonly is much greater than 10 m. These deposits, along with channel sands in the basal McMurray, are the major potential commercial sites for SAGD operations.

The McMurray-Wabiskaw stratigraphy is complex because channels originate from the tops of all of the McMurray sands and cut through variable thicknesses of underlying sediment. Also, the channels themselves are internally complex.

The Board believes that the regional mudstones/shales act as barriers to vertical pressure communication between underlying and overlying sands with contained gas and bitumen zones, provided they are thick enough, i.e., >0.5 m for the D Shale. (EUB, Decision 2003-023).

The inferred presence of one of these regional marine mudstones/shales, separating a gas zone from a recoverable bitumen zone, would be evidence for exempting the gas zone from shut in. It is for this reason that mapping of mudstone/shale continuity is a critically important aspect of the study.

The mapping of mudstone/shale units, regional sands and channel sands has been accomplished and integrated in the RGS with thoroughness and care. In particular, the extensive examination of core and matching of core lithology and well log response has reduced possibilities for errors in correlation.

However, I do not believe that questions of pressure communication amongst lithologic units or between gas and bitumen zones can be answered definitively by stratigraphic analysis and mapping alone.

One reason is that well spacing and availability of well logs and core place inherent limitations on the precision with which predictions can be made concerning the distribution and properties of lithologic units and the degree of communication amongst these units.

Also, the relatively thin (<2 m) regional, marine mudstones/shales, that are thought to be effective permeability barriers where they separate gas zones from bitumen, could be breached by faults on scales that are not detectable using available well-log and core data.

Furthermore, these mudstones have been truncated or removed by erosion in local regions that are difficult to predict precisely.

Faulting and jointing associated with salt-solution collapse and with Laramide tectonics, after deposition of McMurray-Wabiskaw sediments and emplacement of bitumen, is highly probable. The extent of such faulting is unknown but has the potential to breach thin mudstones that are considered as barriers to pressure communication. There is the added risk that faults in bitumen could contribute to accelerated steam breakthrough from a SAGD chamber to an overlying water or gas zone.

In principle, questions of pressure communication could be answered most directly by using appropriate pressure data. In practice, the volume and quality of pressure data combined with the difficulties of measuring pressure in deposits of solid bitumen make it impossible to meet the objectives of the study with pressure data alone.

The study integrates pressure, production and stratigraphic data to estimate the extent of regions of influence associated with gas zones and the risk of pressure communication between gas and bitumen zones.

Pressure data come primarily from gas pools. In the RGS, the stratigraphic units in which gas pools occur, within the McMurray-Wabiskaw interval, have been identified, on a regional basis to a higher level of detail than previously. This is necessary for comparison of pressures amongst pools and amongst stratigraphic units.

The RGS concludes with a statement as to whether gas is or is not associated with bitumen, in each of the stratigraphic zones. The criteria are stratigraphic and patterned on those used in the Chard-Leismer area (EUB, Decision 2003-023, Appendix 13)

In conclusion, my opinion is that the RGS is based on sound geologic principles that are reasonable and defendable. The final product is a stratigraphic framework that provides a basis for decisions about pressure communication between gas zones and bitumen zones. It also provides the necessary context for all future geological, hydrological and engineering analysis within the McMurray-Wabiskaw sequence.

Future work should include structural analysis of faults, joints and salt-solution collapse structures and should be fully integrated with the stratgraphic framework of the RGS. This would supplement stratigraphic analysis in assessing risk of pressure communication between gas zones and bitumen.

However, I do not believe that questions of pressure communication can be answered by stratigraphic-structural analysis and mapping alone. Pressure and potentiometric data should be used more extensively to provide independent evidence of pressure communication amongst units and between gas and bitumen zones within the McMurray-Wabiskaw interval.

1 INTRODUCTION

This review includes:

- The objectives, methods, scope and results of the EUB Regional Geological Study (RGS)

- My understanding of, and opinions about, the RGS.

- Recommendations for future work.

1.1 Objective and Rationale

The major objective of the regional geological study is to determine if gas pools have the potential to be in pressure communication with underlying commercial bitumen either directly or through an intervening water zone. Where such communication exists, the pressure in the gas zone or underlying water zone could limit the pressure attainable in the steam chamber of a SAGD operation following steam breakthrough. Reduced operating pressure in a steam zone reduces operating temperature and affects economics through reduced bitumen recovery rates and, perhaps, bitumen recovery efficiency. Additional lifting costs also are possible.

Based on these factors, the Board has concluded: "where gas is associated with bitumen, gas zone depressuring should be minimized to better ensure successful SAGD operations in terms of resource recovery and minimizing the technical difficulties of lifting SAGD fluids" (EUB, Decision 2003-023, Executive Summary, p. 6). Consistent with this, gas wells in such situations are subject to shut in.

On the other hand, where it can be shown that there is low risk of pressure communication between gas and bitumen zones, wells could be exempted from shut in. For example, where a regional mudstone barrier separates bitumen from gas.

The question of pressure communication between a potential zone of bitumen production and an overlying gas zone requires definition of:

- Regions with commercial bitumen
- Gas zones and underlying water zones through which pressure could be communicated
- Mudstones or other low permeability deposits that could act as pressure barriers isolating bitumen from gas zones.

The project was completed in a four-month period.

Gas zones in the McMurray-Wabiskaw interval are significantly depleted creating urgency for decisions.

1.2 Methods

Priority has been given to providing a stratigraphic framework. My opinion is that this approach is the necessary first requirement in meeting the purpose of the study. However, I do not believe that questions of pressure communication amongst lithologic units or between gas and bitumen zones can be answered definitively by stratigraphic analysis and mapping alone.

One reason for this is that well spacing and availability of well logs and core place inherent limitations on the precision with which predictions can be made concerning the distribution and properties of lithologic units and the degree of communication amongst these units. Also, the relatively thin (<2 m) regional, marine mudstones/shales, that are thought to be effective permeability barriers where they separate gas zones from bitumen, could be breached by faults on scales that are not detectable using available well-log and core data. This is discussed in following sections (2.2 Regional Mudstones/Shales as Pressure Seals and 3. Structure). Furthermore, these mudstones have been truncated or removed by erosion in local regions that are difficult to predict precisely.

In principle, questions of pressure communication could be answered most directly by using appropriate pressure data. In practice, the volume and quality of pressure data combined with the difficulties of measuring pressure in deposits of solid bitumen make it impossible to meet the objectives of the study with pressure data alone.

The intent of the study is to integrate pressure and production data with stratigraphic analysis to assess whether gas zones are, or are not, associated (ie. in pressure communication) with bitumen zones. Pressure data are discussed further in a subsequent section (4. Pressure Data).

Pressure data come primarily from gas pools. In the RGS, the stratigraphic units in which gas pools occur, within the McMurray-Wabiskaw interval, have been identified for the first time. This is necessary for comparison of pressures amongst pools and amongst stratigraphic units. These data are required to resolve questions of risk of pressure communication with bitumen zones.

Seismic data are not included in the RGS because they are not available publicly.

1.3 Scope

The study area lies within an area defined by Townships 70 to 101 and by Ranges 3 to 16 West of 4.

The study included examination and analysis of:

- ~4500 well logs
- >10,000 meters of core
- Pressure and production data from gas zones.

Twenty-four geologists, half from government and half from industry sources, worked in six teams with each team assigned to one of six areas within the Athabasca deposit. There was extensive interaction within and amongst teams to produce an integrated stratigraphic framework for the entire area investigated and mapped. Geologists interacted with a team of six engineers, a supervisory team of both geologists and engineers and with technical support staff and systems analysts.

The project was completed in a four-month period.

1.4 Deliverables

Deliverables include:

- A database with elevations of all stratigraphic units, gas zones, water zones and bitumen zones mapped.
- Structure surface maps and isopach maps on selected stratigraphic surfaces and units and gas pay maps and bitumen maps.
- Maps showing the areal extent of major regional mudstone/shale markers that are considered to be effective permeability barriers.

These data, in combination with other stratigraphic data, pressure and production data, are used to generate a table that identifies whether particular gas zones are associated (ie. in pressure communication) with potentially recoverable bitumen.

2 STRATIGRAPHIC MAPPING

The RGS includes the following priorities:

- Identify and map lithologic units that can be correlated over extensive regions and can be used as approximate time markers (regional marine mudstones/shales). Mudstones/shales are considered to be effective permeability barriers to fluid and pressure transmission.
- Map lithologic units that occur between (regional sands) and transect (channel sands) these regional marine mudstones.
- Where possible, apply a common nomenclature for lithologic units throughout the six geographic areas comprising the study using the "Type Sections" identified in the Chard-Leismer Report (some regional markers could not be identified in parts of Area 4 north of Fort McMurray).
- Identify and map all gas zones and zones with potentially recoverable bitumen (defined as 10 m minimum thickness of bitumen of >6 weight percent bitumen saturation).
- Identify zones of top water.
- Enter into a database the elevations of tops of all units mapped, gas zones, water zones and bitumen zones.
- Construct cross sections, structure contour and isopach maps to illustrate the distribution of major lithologic units and gas and bitumen zones.
- Provide a summary that identifies whether specific gas zones are associated, or not associated, with commercial bitumen.

The emphasis throughout the above is stratigraphic and requires that the one-dimensional occurrence of lithologic units, gas, water and bitumen zones identified in well logs and core be extended to three-dimensional space and that the probability of pressure communication amongst units be interpreted.

The 3-d extent (size, shape and orientation) of particular lithological units (lithofacies) commonly is related to their environment of deposition. For certain lithofacies, there is general agreement concerning the probable environments of deposition but, for others, differences of opinion exist. There are also differences of opinion concerning the complex nature of the stratigraphy and sedimentology of the deposit (Ranger and Pemberton, 1988; Ranger and Pemberton, 1997; Langenberg, et al, 2002; Ranger and Gingras, 2003, Discussion of Langenberg et al. 2002; and Hein and Langenberg, Reply, 2003).

In the RGS, although environments of deposition are inferred, the major emphasis is the correlation and mapping of lithologic units. Changes of opinion about environments of deposition are not likely to affect the results of mapping presented in the RGS.

In the McMurray-Wabiskaw deposits, some changes of lithofaces occur on scales that are small compared with the well spacing, and there are inherent uncertainties concerning the equivalence of certain mapped units and the positions of their boundaries.

2.1 Regional Mudstones/ Shales and Stratigraphic Framework

Four stratigraphic units, recognized from well logs and core, are areally extensive in the McMurray-Wabiskaw interval, and are important in regional correlation within the Athabasca deposit.

These four units, from oldest to youngest, are the McMurray B Mudstone, McMurray A Mudstone, Wabiskaw D Shale and Wabiskaw T-21 Marker. Two additional markers (Wabiskaw C and A Shales) are identified in the Northern Area.

The bases of these mudstone/shale units are interpreted as approximate time surfaces related to major marine transgressions. The origin of the T-21 marker is less clear but is also thought to represent an approximate time surface.

These four markers are used to provide a stratigraphic framework within which other lithofacies are mapped. The T-21 marker is the most widespread geographically and the one that is correlated with the greatest certainty. The McMurray A and B Markers can be mapped with confidence except where the overlying A and B sand sequences are missing or truncated. The sequence overlying the mudstone is necessary in order to identify the mudstone with confidence. These areas of truncation are larger for the McMurray B Mudstone than for the McMurray A Mudstone.

The Wabiskaw D Shale is more intermittent and difficult to correlate over wide areas.

Paleontological evidence (e.g. from pollen, spores, dinoflagellates, ostracods, foraminifera, etc.) has the potential to provide independent confirmatory evidence for some of the correlations made in the RGS study. Fossils can be used to interpret both relative age and environment of deposition. Given the complexity of the stratigraphy, this matter could be considered for future attention.

In summary, my opinion is that the lithofacies correlations using the regional mudstones/shales provide the best available stratigraphic framework for the McMurray-Wabiskaw interval and that the correlations have been made with care and attention to both well logs and core data. In particular, the extensive examination of cores and matching with log responses reduces the risk of errors in correlation.

2.2 Regional Mudstones/Shales as Pressure Seals

The regional mudstones/shales are thought to be seals preventing or restricting pressure communication between underlying and overlying sands with contained gas and bitumen zones

The inferred presence of one of these regional marine mudstones/shales, separating a gas zone from a recoverable bitumen zone, would be evidence for exempting the gas zone from shut in. It is for this reason that mudstone/shale continuity is a critically important aspect of the study.

These regional mudstones/shales are thin (generally <1.5 m) and are breached locally by erosion. Where present, they could be offset and breached by faults although no evidence for this is presented in the RGS (see section 3. Structure).

Vertical displacement of 1.5 m would be sufficient to breach a mudstone. Given the typical separation of wells and the accuracy with which elevations of mudstone contacts can be picked (i.e.accuracy of K.B. elevation and mudstone contact resolved from logs or core), faults with offsets of 1.5 m, if present, would not be detected.

In the case of a mudstone offset by a fault, the question of permeability along the fault remains unknown. This could not be determined by structural or stratigraphic observation. Sands underlying and overlying regional mudstones contain bitumen and, in the case of a fault, the extent to which bitumen acts as a seal and restricts pressure communication along the fault is not known.

It has been accepted that, at least in one region pressure transmission from a pressure-depleted gas zone through bitumen occurred (EUB Decision 2000-22: Gulf Canada Resources Ltd., Request for the shut-in of associated gas, Surmont Area, March 2000). This possibility requires confirmation. Also, the role of associated water, within a bitumen zone, in facilitating such pressure transmission requires investigation.

However, if a fault zone were sealed from pressure transmission by bitumen, a question remains concerning the significance of the fault during advance of high-pressure steam in a SAGD steam chamber. A fault plane is a zone of dislocation and structural weakness along which there could be more rapid steam advance and earlier steam breakthrough than otherwise might be the case.

In summary, faulting and jointing associated with salt-solution collapse and with Laramide tectonics, after deposition of McMurray-Wabiskaw sediments and emplacement of bitumen, is highly probable. The extent of such faulting is unknown but has the potential to breach thin mudstones that are considered as barriers to pressure transmission. There is the added risk that faults in bitumen could contribute to accelerated steam breakthrough from a SAGD chamber to an overlying water or gas zone.

Given the difficulties of observing faults directly in the subsurface without high resolution seismic data, it is recommended that regions of extensive post McMurray-Wabiskaw salt-solution collapse be identified and recognized as regions with higher probability of normal faulting. Regions of salt-solution collapse can be interpreted from structure contour and isopach maps for selected surfaces and intervals.

2.3 Stratigraphic Relations of Regional and Channel Sands

Regional sands, typically overlying mudstone/shale in upward cleaning (coarsening) sequences, generally are less than 10 m and are too thin to meet the criteria for commercial bitumen in SAGD operations.

Channel sands and valley fills cut the regional sands and mudstones locally and, where this occurs, sand thickness commonly is much greater than 10 m. These deposits are the major potential sites for SAGD.

The stratigraphy is complex because channels originate from the tops of all of the McMurray sands and incise through variable thickness of underlying sediment. The RGS adopts the nomenclature for channels used in the Chard-Leismer Decision. For example, a channel cutting down from the top of the McMurray B1 Sand is referred to as a McMurray B1 Channel and, similarly, for the other regional sands with incised channels.

The lower portion of the McMurray, referred to as the McMurray C Interval, is comprised largely of channel sands. These are of variable thickness reflecting irregularities of topography on the underlying Paleozoic surface. These irregularities are related, in part, to salt solution collapse.

Any channel cutting through the McMurray B2 Mudstone and penetrating the McMurray C Channel is referred to as a "McMurray Channel". These channels are of major importance because of their large size and volume of contained bitumen compared with, for example, the McMurray A and B Channels.

2.4 Regional and Channel Sands and Producible Bitumen

The McMurray C Interval and the McMurray Channel Sands, for reasons of thickness, areal extent and grade, have the best potential to contain commercial bitumen for a SAGD operation.

The Wabiskaw D Valley Fill meets the thickness criteria but is very shaly in the upper portions.

Sands in the McMurray A and B Sequences are generally less than 10 m thick and generally do not meet the thickness cutoff for commercial bitumen.

A and B Channel Sands are of smaller size, thickness and number making them less significant in terms of volume of bitumen in place.

2.5 Gas Zones

In the Athabasca deposit, there is evidence that biodegradation of oil may have contributed to the generation of biogenic gas by methanogenesis during the transformation of light oil to bitumen (Head, et al, 2003; Dimitrakopoulos, et al,1987; Barson, et al, 2001). That is, the gases are of biogenic origin and derived from bitumen.

In this case, gas is likely to have been present before the deformation of the bitumen-water contact caused by salt-solution collapse and Laramide tectonics. It follows that any associated faulting also could have affected gas zones.

It is possible that faulting occurred before, during or after gas emplacement. Faulting after gas emplacement could have fragmented once larger gas pools with attendant changes in elevation of water-gas contacts. Since most gas pools have maximum gas thickness of three or four meters, small fault displacements would be sufficient to offset a gas zone.

Given the possibility that both regional mudstone permeability barriers and sands containing gas zones could have been displaced and breached by faults, independent evidence is required to resolve questions of gas pool size and communication between gas pools and commercial deposits of bitumen.

Appropriate pressure measurements, possibly combined with production data, could provide evidence of degree of pressure communication.

2.6 Water Zones

Water overlying and underlying bitumen may cause constraints on SAGD.

Water in coarse-grained, high-permeability sands locally overlies bitumen. It has been mapped in the RGS because of its possible effects in transmitting pressure decline from a gas zone to underlying bitumen in situations where there is no intervening mudstone. Rate of pressure transmission can be estimated and a "region of influence" estimated and mapped.

Where water overlies bitumen, following steam breakthrough, there is the possibility of gravity drainage of water into the steam chamber or of steam escape into the water zone with rapid dissipation of heat. It has not been demonstrated in the field that it is possible to match steam chamber pressure to water pressure over long periods of time.

Bottom water was not mapped in the RGS study. Although it is recognized that bottom water may limit applicability of SAGD, it was not essential to the primary objectives of the study.

3 STRUCTURE

The McMurray-Wabiskaw deposits were structurally deformed by Laramide tectonics and by salt solution and collapse of underlying Devonian evaporites. Laramide deformation caused a regional tilt of ~10-20 feet per mile to the west or south-west whereas salt-solution collapse caused more local flexures; both events were accompanied by faulting.

Laramide movements, following biodegradation of light oil to bitumen, tilted the bitumen-water contact. This contact subsequently was unable to re-adjust to horizontal because of high bitumen viscosity and small density difference between bitumen and water.

There is evidence that salt solution and collapse occurred before, during and after deposition of McMurray-Wabiskaw sediments and emplacement of bitumen.

Salt-solution collapse in Pre-McMurray time created topographic lows on the Paleozoic surface that became the sites of thick channel deposits in McMurray time.

Later, following emplacement of bitumen, further salt-solution collapse deformed the bitumen-water contact and McMurray-Wabiskaw deposits. Normal faulting probably accompanied salt-solution collapse although there appear to be limited published data from mine sites, outcrops or the subsurface concerning faulting of the bitumen deposits either by Laramide tectonics or by salt-solution collapse.

There also is the possibility that faulting occurred during differential compaction where topographic relief caused variations in sediment types and thickness.

Faulting could have breached or dislocated both the regional marine mudstones and the sands containing gas zones, or the gas zones themselves. The Board agreed with Nexen that late changes in structure related to salt-solution collapse caused vertical displacement of the stratigraphic section that resulted in varying water/bitumen contacts within the same pool (EUB Decision 2003-023: Chard Area and Leismer Field Athabasca Oil Sands Area, Applications for the production and Shut-in of Gas, March 18, 2003).

Structure has received little attention in the RGS because of time constraints. With the well spacing over much of the Athabasca deposit, it would be possible to resolve only faults with large displacement. It is probably safe to speculate that, as well spacing decreases, interpretation of both structural and stratigraphic complexity will increase markedly.

A review of published structural information from the Athabasca deposit is not attempted in the RGS or in this Review.

In summary, faults and joints, if present, could breach mudstone/shale units that, otherwise, might be permeability barriers. Also, the determination of fault trends, if present, could be important to optimum placement of horizontal wells and to risk assessment for SAGD operations.

It is possible that regions of post-bitumen salt solution collapse could have more faults and joints and greater associated risks for vertical communication amongst layers.

4 PRESSURE DATA

Appropriate pressure measurements could be used to provide evidence for the degree of pressure communication:

1. between gas zones and bitumen zones; pressure decline, in a bitumen zone associated with an overlying gas zone that is undergoing pressure decline during depletion, could be taken as evidence of pressure communication between gas zone and bitumen zone;
2. between gas zones penetrated by several wells; that is, evaluation of the sizes of gas pools in a particular region; i.e. is there one larger pool or two or more smaller pools?
3. between a gas zone and a water zone overlying bitumen; and define a region of influence.
4. between gas zones in **regional sands** and gas zones **in channel sands** intersecting regional sands.

The primary interest is to determine the risk of pressure communication between gas zones and bitumen zones (1. above). However, measurement of pressure in bitumen zones may not be possible because bitumen is "solid" at reservoir conditions. The other cases (2, 3 and 4) do not require measurement of pressure in bitumen.

4.1 Pressure Communication Between Gas and Bitumen Zones

It has been argued that pressure cannot be transmitted through bitumen because it is "solid" at reservoir conditions. However, bitumen zones also contain liquid water. If the water is at "irreducible" saturation, it is thought to be essentially immobile and not capable of flowing or transmitting pressure. However, if the water saturation is greater than "irreducible", there is the possibility that water could transmit pressure in finite time within a bitumen zone. That is, it is possible that the ability of bitumen zones to transmit pressure could be dependent on water saturation.

If this were the case, the absence of pressure decline measured in a bitumen zone could be related to low water saturation ("irreducible") rather than to the absence of low pressure in a communicating water or gas sand.

Since "irreducible" saturation generally is not defined and water saturation generally is not known at the points of pressure measurement in a bitumen zone, pressure measured in bitumen is of limited use in resolving questions of pressure communication.

Regional mudstones and shales situated between gas zones and bitumen zones could be permeability barriers preventing pressure communication from gas to bitumen. On the other hand, it is recognized that a regional mudstone, although identified in all cores and logs of a given region, could be breached locally between control points by faulting, local erosion or a combination of both.

It is for this reason that the independent evidence of pressure measurements is sought to confirm or deny the presence of pressure communication. However, the lack of certainty as to whether a bitumen zone may or may not transmit pressure means that the apparent lack of pressure response measured in a bitumen zone cannot be used as evidence that a permeability barrier separates bitumen from an overlying pressure-depleted gas zone.

The Board accepted pressure measurements submitted by Gulf Canada at the Surmont hearings as indicative that pressure changes could be transmitted through a bitumen zone. The Board because of other possible interpretations did not accept evidence of pressure change in bitumen submitted at the Chard-Leismer hearing (EUB Decision 2003-023). It may be difficult to determine if pressure is being transmitted through a bulk bitumen zone or if it is an artifact of the pressure measurement technique related to conditions around the well-bore or to other causes.

The limited amount of pressure data measured in bitumen zones and uncertainties associated with these data limit their reliability and usefulness for purposes of interpreting the presence or absence of pressure communication with overlying water or gas zones.

A further indirect line of evidence can be cited for pressure communication between gas and bitumen zones. There is evidence that, in the Athabasca deposits, gas was derived from oil by microbial methanogenesis during bitumen formation (Head, I.M., Jones, M. and Larter, S., 2003). If this were the case, it follows, at least at the time of gas migration, that there was communication to allow passage of gas from bitumen to gas zones. The distance and rate of this migration, of course, remains unknown.

4.2 Pressure Communication Between Gas Zone and Gas Zone or Gas Zone and Water Zone

The problems of pressure measurement encountered in bitumen zones, discussed in the previous section, do not apply in the case of gas and water saturated zones.

It is presumed that if initial pressures and pressures measured during depletion of a gas zone of one well match those of a similar gas zone in an adjacent well, that both wells are in pressure communication and are from the same gas pool. Alternatively, differences between two wells in initial and subsequent pressures could indicate a lack of pressure communication and the presence of separate gas pools.

Similarly, the presence or absence of pressure communication between gas and water zones could be determined by using appropriate pressure measurements.

Although simple in principle, these determinations of presence or absence of pressure communication between gas and gas or gas and water zones commonly are difficult to make in practice. The following are factors contributing to the difficulties:

- Most of the pressure data are from gas zones; few data, if any, are available from associated water zones.
- In order to resolve questions of pressure communication in shallow wells, it is necessary to be able to detect pressure differences as small as ~100 kPa; accuracy of pressure measurement is a key requirement and, for some pressure data, this requirement is not met.
- To evaluate pressure decline, depletion and, therefore, the size of a gas pool, it is necessary to have pressure measurements prior to production (initial pressures) as well as subsequently; if initial pressure is not measured, there is no method to obtain it subsequently; not all gas wells have initial pressure measurements; in some regions, there is wide variance of recorded initial pressures.
- To evaluate pressure communication amongst gas pools, it may be necessary to have virgin pressures (pressures measured prior to man's intervention) in addition to initial pressures. There are limited numbers of virgin pressure measurements from any given stratigraphic zone..
- Only surface pressures are available for some wells and, in these cases, pressures have to be converted to bottom hole pressures; this conversion requires information about fluids (gas and/or water) filling the wellbore and, in some cases, this information is not available (eg. acoustic logs not available).
- For many wells, pressure data are limited to an initial pressure and one or two subsequent pressure measurements; this information is minimal for purposes of defining pressure decline with time.
- Observation wells, that is wells dedicated for pressure measurement over time, have the potential to define pressure and pressure change with the necessary accuracy but such wells are few in number. The Board does not require observation wells.
- There are cases where accurate pressure measurements are available but difficult to interpret because of co-mingling of gas from more than one zone. Also, interpretation of gas-zone continuity using pressure data can be affected by imposed back-pressures associated with gathering systems for gas; if wells in separate gas pools have the same gathering system and similar back-pressures, they could, over time, develop similar

pressures even though virgin pressures were different. Misinterpretations are possible where virgin pressures are not available.

In some cases, interpretation of the size of a gas pool and questions of gas continuity amongst several wells can be aided by the use of production data in combination with pressure data in material balance calculations. However, the material balance equation is one equation with many terms and can be solved only for one unknown.

4.3 Communication Between Gas Zones in Regional Sands and Gas Zones in Channel Sands that Intersect Regional Sands

Gas zones occur in both regional sands and channel sands. Bitumen deposits of thickness and quality suitable for SAGD are confined mainly to the channel sands.

In the Chard-Leismer area, evidence has been presented that, in at least four cases, there was no effective pressure communication between gas zones in regional sands and those in laterally offsetting channel sands. This is an important observation because it could provide reason for exemption from shut-in. However, in other areas, evidence of pressure communication between regional sands and channel sands is present.

In addition to pressure data, the elevations of gas-water contacts are useful in making decisions concerning the continuity and pressure communication of gas zones in proximity to, and within, channels. However, differences in contact elevation for gas occurrences within and outside channel sands may not indicate lack of gas continuity if the gas zone is bottom sealed.

4.4 Conclusions from Pressure Data

The question of pressure communication between gas zones and underlying bitumen zones cannot be answered directly with existing pressure data measured in bitumen zones and associated gas zones. This is because of the limited amount of pressure data available from bitumen zones and difficulties of interpretation concerning the ability of solid bitumen to transmit pressure and to register pressure changes occurring in overlying gas or water zones. Also, the role of variable water saturation on rate of pressure transmission through bitumen is not known.

It should be noted that, in one case, the Board accepted pressure data measured in a bitumen zone as indicative of pressure decline occurring within that bitumen zone related to depletion of an overlying gas zone (EUB Decision 2000-22: Gulf Canada Resources Ltd., Request for the shut-in of associated gas, Surmont Area, March 2000).

A full analysis of all available pressure data from the Athabasca deposit has yet to be done. Virgin pressures are particularly important. These data have the potential to provide independent evidence concerning the presumption that the McMurray A and B Mudstones, or other mudstone/shale markers, where present, act as barriers to vertical pressure transmission.

5 RECOMMENDED FUTURE WORK

The following, in an order of decreasing priority, are recommended for future work

5.1 Pressure Data

- Review all available pressure data for purposes of providing evidence about communication between gas and gas, gas and water and gas and bitumen zones. For the most part, pressure data were not measured with this use in mind. If the amount and quality of existing pressure data are insufficient, the possibility of obtaining additional data should be considered.
- Determine if pressure data support the opinion that mudstone/shale barriers are seals to vertical pressure communication.
- Review data, obtained from core, concerning water saturations in bitumen zones. Is "irreducible" water saturation a useful concept in relation to pressure transmission and is its value known for sediments in bitumen zones? Are there any experimental or other data concerning effects of water saturation on rates of pressure transmission in bitumen deposits? Is water necessary for pressure transmission through bitumen in finite time?

5.2 Structure

- Compile all publicly available data on structure within the area of the Athabasca deposit; this is not attempted in the RGS or in this Review. It could include surface linears from air photos, faults, joints and structures arising from salt-solution collapse and Laramide tectonics. Is there evidence that fault and joint trends could create permeability anisotropy within bitumen? See, for example, effects of structure in heavy-oil sands of Lloydminster area (Gregor, 1997).
- Possible associations between magnetic anomaly lineaments and known faults or surface photolineaments could be investigated.
- Published information on relative ages, extent and geographic areas of salt solution collapse should be compiled. Areas of collapse post-bitumen emplacement are particularly important because faults could be more frequent in these regions.
- The "tops" for stratigraphic units in the RGS could be used to produce structure surface and isopach maps that could reveal additional information concerning salt-solution collapse events.

5.3 Paleontological Evidence

Paleontological evidence (e.g. from pollen, spores, dinoflagellates, ostracods, foraminifera, etc.) has the potential to provide independent confirmatory evidence for some of the correlations made in the RGS study. Fossils can be used to interpret both relative age and environment of deposition. Given the complexity of the stratigraphy, this matter could be considered for future attention (eg. see Hein and Dolby, 2001; Hein and Langenberg, 2003).

5.4 Salinity of Formation Waters

All available data on the salinity of formation waters within the McMurray-Wabiskaw interval should be compiled and their quality assessed; salinity could be related to structure (faults and joints) and to regions of salt-solution collapse. Salinity affects wettability and could affect interpretation of bitumen saturation from resistivity logs (see Hein, Cotterill and Rottenfusser, 2001).

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Appendix B1: Gas Pool Pressure Review

Pool Name	Comments
Chard McMurray AAA	(included in Newby McMurray B review summary)
Chard McMurray BBB	(included in Newby McMurray B review summary)
Chard McMurray HHH	
Chard McMurray YY	(included in Newby McMurray B review summary)
Chard McMurray ZZ	(included in Newby McMurray B review summary)
Chard Wabiskaw O	
Chard Wabiskaw-McMurray A	
Corner McMurray A	
Corner McMurray G	
Corner McMurray NN	(included in Corner McMurray OO review summary)
Corner McMurray OO	
Corner McMurray T	
Corner McMurray U	
Corner McMurray Y	
Hangingstone McMurray BB	
Hangingstone McMurray CCC	
Hangingstone McMurray DDD	
Hangingstone McMurray E2E	
Hangingstone McMurray F2F	
Hangingstone McMurray G	
Hangingstone McMurray G2G	
Hangingstone McMurray H2H	(included in Hangingstone Wabiskaw-McMurray D review summary)
Hangingstone McMurray I	(included in Hangingstone McMurray CCC review summary)
Hangingstone McMurray NNN	(included in Hangingstone McMurray X review summary)
Hangingstone McMurray X	
Hangingstone McMurray YYY	
Hangingstone McMurray Z	
Hangingstone Wabiskaw J	
Hangingstone Wabiskaw K	(included in Hangingstone Wabiskaw-McMurray D review summary)
Hangingstone Wabiskaw-McMurray A	
Hangingstone Wabiskaw-McMurray B	
Hangingstone Wabiskaw-McMurray D	
Hangingstone Wabiskaw-McMurray E	

Pool Name	Comments
Kirby Upper Mannville B4B	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville C4C	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville F4F	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville I	
Kirby Upper Mannville J	
Kirby Upper Mannville O3O	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville U2U	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville V2V	(included in Kirby Upper Mannville J review summary)
Kirby Upper Mannville Z3Z	(included in Kirby Upper Mannville I review summary)
Leismer McMurray H3H	
Leismer McMurray J4J	
Leismer McMurray TTT	(included in Leismer Wabiskaw-McMurray A review summary)
Leismer Undefined-377	(included in Leismer Wabiskaw-McMurray A review summary)
Leismer Wabiskaw-McMurray A	
Leismer Wabiskaw-McMurray C	
Newby McMurray A2A	(included in Newby McMurray B review summary)
Newby McMurray B	
Newby McMurray B2B	(included in Newby McMurray B review summary)
Newby McMurray C2C	
Newby McMurray D	(included in Newby McMurray B review summary)
Newby McMurray EEE	
Newby McMurray III	(included in Newby McMurray B review summary)
Newby McMurray L2L	(included in Newby McMurray B review summary)
Newby McMurray M2M	(included in Newby McMurray B review summary)
Newby McMurray XXX	(included in Newby McMurray B review summary)
Newby McMurray ZZZ	
Newby Wabiskaw FF	
Newby Wabiskaw GG	
Newby Wabiskaw N	(included in Newby Wabiskaw-McMurray J review summary)
Newby Wabiskaw-McMurray G	
Newby Wabiskaw-McMurray H	
Newby Wabiskaw-McMurray J	
Newby Wabiskaw-McMurray K	(included in Newby Wabiskaw-McMurray J review summary)
Resdeln McMurray JJ	(included in Newby Wabiskaw-McMurray J review summary)
Resdeln McMurray RR	(included in Newby Wabiskaw-McMurray J review summary)
Resdeln McMurray SS	(included in Newby Wabiskaw-McMurray J review summary)

Pool Name	Comments
Resdeln Wabiskaw-McMurray A	(included in Newby Wabiskaw-McMurray J review summary)
Thornbury McMurray A5A	
Thornbury McMurray E5E	
Thornbury McMurray F5F	
Thornbury McMurray G2G	
Thornbury McMurray GGG	
Thornbury McMurray K5K	
Thornbury McMurray M5M	
Thornbury McMurray Q5Q	
Thornbury McMurray R5R	
Thornbury McMurray T5T	
Thornbury McMurray X4X	
Thornbury McMurray XX	
Thornbury McMurray YY	

Appendix B2: Standard Algorithms for Bitumen Evaluations

1.1 Evaluation Technique

Shale Volume

Calculated from the Gamma Ray log using the Clavier method.

Linear Shale Volume = (GRLOG – MINGR) / (MAXGR – MINGR)
VSH Clavier Correction = 1.7-(3.38-(Linear Vsh +0.7) 2) 0.5

Where:	GRLOG – Gamma log Reading
	MINGR – Minimum Gamma
	MAXGR – Maximum Gamma

Porosity

Calculated using one log Density method.

PHID = (RHOMA-RHOB)/(RHOMA-RHOF)

Shale Porosity = (RHOMA-RHOSH)/(RHOMA-RHOF)

Effective Porosity = PHID - (VSH * Shale Porosity)

Where:	PHID	- Density Porosity
	RHOMA	- Matrix Density
	RHOB	- Bulk Density
	RHOF	- Fluid Density
	RHOSH	- Bulk Density of Shale
	VSH	- Shale Volume (from Clavier)

Water Saturation

Calculated using a Modified Simandoux Equation.

$1/ILD = [(PHIE^{M} * SW^{N}) / (A * RW * (1-VSH)] + [(VSH * SW) / (2 * RSH)]$

OR

$AA = A * RW * (1-VSH) / (PHIE^{M})$
BB = (AA * VSH) / (2 * RSH)
$SW = [(BB2 + AA / ILD)0.5 – BB]^{(2/N)}$

Note: $^{(2/N)}$ is a correction where N<>2

Where:	SW	- Water Saturation
	A	- Tortuosity Constant
	M	- Cementation Exponent
	N	- Saturation Exponent
	RW	- Formation Water Resistivity @ formation temp
	VSH	- Shale Volume
	PHIE	- Effective Porosity
	ILD	- Deep Resistivity Log
	RSH	- Resistivity of Shale

Weight Percent Bitumen

Weight Percent Bitumen (WTAR) is calculated as follows:

SO = (1-SW)

$$WTAR = \frac{(PHIE*SO*RHOHY)}{((1-VSH-PHIE)*RHOMA+(VSH*RHOSH)+PHIE*(SO*RHOHY+SW*RHOF)}$$

Where:	SO	- Oil Saturation
	SW	- Water Saturation
	PHIE	- Effective Porosity
	VSH	- Volume of Shale
	RHOMA	- Matrix Density
	RHOSH	- Shale Density
	RHOHY	- Hydrocarbon Density
	RHOF	- Fluid Density

1.2 Evaluation Parameters

The following Parameters are required to run the EUB oil sands programs in Geolog. Each of the parameters will be described along with typical values to use and methods of selection.

Parameter	**Typical Value**
MAXPHIE	0.39
OAL PHIE	0.42
LIME PHIE	0 – .15
LIME RT	15 – 100 ohmm
MINGR	10 – 30 API
MAXGR	90 – 120 API
RSH	6 – 20 ohmm
A	0.62
M	2.15
N	1.4 – 2.0
RW	0.3 – 1.5 ohmm
RHOHY	1000 kg/m^3
RHOF	1000 kg/m^3
RHOMA	2650 kg/m^3
RHOSH	2200 – 2400 kg/m^3