AN ASSESSMENT OF
VERTICAL AND LATERAL PRESSURE COMMUNICATION
AT SURMONT
IN THE WABISKAW-McMURRAY FORMATIONS

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Prepared for

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

PETROPHYSICS FIGURES

GEOLOGY TEXT FIGURES

Figure G-T7: Regional Cross Section A-A′; Distance between Endpoints is approximately 40 km; for Location of Cross Section see Index Map in Figure G-12 above. Correlation Traces are Gamma Ray and Mirror-Image Gamma Ray.

Figure G-T8: Cross Section F-F′; Shale Channel along Depositional Strike; Distance between Endpoints is approximately 4 km.

Figure G-T9: Cross Section H-H′; Relationships of Sand and Shale Channels perpendicular to Depositional Strike; Note the Gradational Changes from Dominantly Shale to Dominantly Sand from Left to Right.

Figure G-T10: Layer 3 Net-to-Gross Thickness Map. White Cutouts represent Areas of Non-Reservoir (eliminated by Petrophysical Cutoffs). Hot Colours are Areas of the Highest Net-to-Gross Values, which identify Channel Complexes.

Figure G-T11: Diagrammatic Cross Section of Sandstone Filled Channel Complex incised in Coarsening-Upward Cycles; Note the Constraints on fluid flow in the Non-Channel Areas by the continuous Shale Markers (Barriers) versus Discontinuous Shale "Baffles" (Brown Lines) within Channel Column. The Dashed Red Lines represent Layer Boundaries Projected through Channels as used in the Model. The relative position of Red Lines can Change without impacting Model Results.

Figure G-T12: Index Map showing Locations of Described Cores

Figure G-T13: Cross Section FC-1 to FC-1′; Flattened on Structural Datum TVDSS (-300); Bitumen-Water Contact in 06-30-82-05 is absent in Wells to East at same Elevation. Note Gas-Water Contacts in Red and Gas Column (in red fill) from Neutron-Density Crossover. For Location of Cross Section see Figures at End of Report.

Figure G-T14: Layer 4 HPV; Note the Sinuous Line on the East Side separating Blue and Purple Colours; this is approximately the Bitumen-Water Contact.

Figure G-T15: Bitumen-Water Contacts in two Surmont Wells. The Well on the Right contains a True Basal Bitumen-Water Contact (Rt = <3 ohms) with Calculated Sw approaching 100% in Good Quality Sands. Contrast with Well on the Left, where Rt = >10 ohms and Sw is Averaging 60%+.

GEOLOGY REPORT FIGURES

Figure G-1: Final Location Map. Yellow area includes buffer. Red Outline is Simulation Study Boundary. Wells use in Correlation Work denoted by Solid Red Triangles.

Figure G-2: Stratigraphic Column for the Athabasca Area (from Strobl et al., 1995).

Figure G-3: Regional Structure of the top of McMurray Formation; Contoured from Public Data; High areas in hot colors – low areas in cold colors; Geological Study Area depicted in Figure G-1 (above) shown here in heavy black outline.

Figure G-4: Regional Structure of the top of Devonian; Contoured from Public Data; High areas in hot colors – low areas in cold colors; Geological Study Area depicted in Figure G-1 (above) shown here in heavy black outline.

Figure G-5: Regional Isopach of the McMurray Formation; Contoured from Public Data; Thin areas in hot colors – thick areas in cold colors; Geological Study Area depicted in Figure G-1 (above) shown here in heavy black outline.

Figure G-6: Wabiskaw Marker to Paleozoic Isopach Map; (Fig. 4 from Alberta Energy and Utilities Board: "Athabasca Wabiskaw-McMurray Regional Geological Study," EUB Report 2003-A, December 31, 2003).

Figure G-7: A Typical Well (03-32-80-07) used for Regional Correlations; Figure displays stratigraphic nomenclature used in the study. Note the prominent coarsening-upward cycles in Layers 2 and 4.

Figure G-8: Regional Index Map for Gamma Ray Correlation Cross Sections

Figure G-9: Regional Cross Section A-A'; Distance between Endpoints approximately 40 km. See Figure G-8 for location of Cross Section.

Figure G-10: Regional Cross Section B-B'; Distance between Endpoints approximately 35 km. See Figure G-8 for location of Cross Section.

Figure G-11: Regional Cross Section C-C′; Distance between Endpoints approximately 30 km. See Figure G-8 for location of Cross Section.

Figure G-12: Regional Cross Section D-D′; Distance between Endpoints approximately 40 km. See Figure G-8 for location of Cross Section.

Figure G-13: Cross Section E-E′; Note incised channel (arrows) in base of Upward Coarsening Sequence.

Figure G-14: Cross Section F-F′; Shale Channel along Depositional Strike; approximately 4 km.

Figure G-15: Cross Section G-G′; Channel cutting of Layer 2 in 11-35-82-08 and 07-25-82-08 and Upper Part of Layer 3 in 07-25-82-08.

Figure G-16: Cross Section H-H′; Relationships of Sand and Shale Channels perpendicular to Depositional Strike; Note the gradational changes from dominantly shale to dominantly sand from left to right.

Figure G-17: Cross Section I-I′; Good example of rapid change from sand to shale channel in orientation normal to depositional strike.

Figure G-18: Cross Section J-J′; Shale channel on left to sand channel (middle) to complex mixture of incisement and original coarsening-upward cycles (right).

Figure G-19: Cross Section J-J′; Same wells as previous figure but with results traces displayed. Compare the saturation profiles of each well versus GR profile.

Figure G-20: Cross Section K-K′; Note graphic differences in GR profiles between wells in area with low well density. Well control in such areas is insufficient to capture the details of local stratigraphic changes.

Figure G-21: Cross Section L-L′; This section is a good example showing how markers carry through several sections despite significant facies differences from well to well.

Figure G-22: Cross Section M-M′; Flattened on the "Green" marker. Note the thickness and variation of the incised channel fill below the "green" marker.

Figure G-23: Cross Section N-N′; Flattened on the "blue" marker. Middle well shows thick channel sands.

Figure G-24: Cross Section N-N′; The same section as previous figure, showing results traces. Note the quality of the reservoir sands in the middle well versus the other two. This shows how well the GR predicts reservoir quality.

Figure G-25: Cross Section P-P′; A good example showing progressive incision in Layer 4 from left to right and replacement of coarsening-upward section by channel fill.

Figure G-26: Typical Well (06-28-82-06) with Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts.

Figure G-27: Bitumen-Water Contacts in two Surmont Wells. The well on the right contains a true basal bitumen-water contact (Rt = <3 ohms) with calculated Sw of 100% in good quality sands. Contrast with well on the left, where Rt = >10 ohms and Sw is averaging 60%+.

Figure G-28: Bitumen-Water Contacts in two Surmont Wells. The well on the right contains a true basal bitumen-water contact (Rt = <3 ohms) with calculated Sw approaching 100% in good quality sands. Contrast with well on the left, where Rt = >10 ohms and Sw is averaging 60%+.

Figure G-29: Cross Section FC-1 to FC-1′; Flattened on Structural Datum TVDSS (-300); Bitumen-Water Contact in 06-30-82-05 is absent in Wells to East at same Elevation. Note Gas-Water Contacts in Red and Gas Column (in red fill) from Neutron-Density Crossover.

Figure G-30: Cross Section FC-2 to FC-2′; Flattened on Structural Datum TVDSS (-245); Bitumen-Water Contact in 11-04-83-05 is absent in Wells to East at same Elevation. Note Gas-Water Contact in Red and Gas Column (in red fill) from Neutron-Density Crossover.

Figure G-31: Cross Section FC-3 to FC-3′; Flattened on Structural Datum TVDSS (-210); Bitumen-Water Contact in 07-08-81-05 and 06-09-81-05 is absent in Well to East at same Elevation. Note Gas-Water Contact in Red and Gas Column (in red fill) from Neutron-Density Crossover.

Figure G-32: Cross Section FC-4 to FC-4'; Flattened on Structural Datum TVDSS (-255); Bitumen-Water Contact in 06-30-83-05 is absent in Well to East at same Elevation. Note Gas-Water Contacts in Red and Gas Column (in red fill) from Neutron-Density Crossover.

Figure G-33: Diagrammatic Cross Section of Sandstone Filled Channel Complex incised in Coarsening-Upward Cycles; Note the constraints on fluid flow in the non-channel areas by the continuous shale markers (barriers) versus discontinuous shale "baffles" (Brown Lines) within channel column. The dashed Red Lines represent layer boundaries.

Figure G-34: Index Map showing Locations of Described Cores.

Figure G-35: Layer 4 - HPV; Note the sinuous line on the east side separating Blue and Purple colours; this is approximately the position of the basal bitumen-water contact.

Figure G-36: Pool Cross Section 1-1'; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of McMurray (Layer 2).

Figure G-37: Pool Cross Section 2-2'; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-38: Pool Cross Section 3-3'; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-39: Pool Cross Section 4-4'; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-40: Pool Cross Section 5-5'; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-41: Pool Cross Section 6-6′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-42: Pool Cross Section 7-7′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-43: Pool Cross Section 8-8′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-44: Pool Cross Section 9-9′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-45: Pool Cross Section 10-10′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-46: Pool Cross Section 11-11′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-47: Pool Cross Section 12-12′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-48: Pool Cross Section 13-13′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-49: Pool Cross Section 14-14′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-50: Pool Cross Section 15-15′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-51: Pool Cross Section 16-16′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-52: Pool Cross Section 17-17′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-53: Pool Cross Section 18-18′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-54: Pool Cross Section 19-19′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-55: Pool Cross Section 20-20′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-56: Pool Cross Section 21-21′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-57: Pool Cross Section 22-22′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-58: Pool Cross Section 23-23′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-59: Pool Cross Section 24-24′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-60: Pool Cross Section 25-25′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-61: Pool Cross Section 26-26′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-62: Pool Cross Section 27-27′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-63: Pool Cross Section 28-28′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-64: Pool Cross Section 29-29′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-65: Pool Cross Section 30-30′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-66: Pool Cross Section 31-31′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-67: Pool Cross Section 32-32′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of Basal Wabiskaw (Layer 1).

Figure G-68: Pool Cross Section 33-33′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-69: Pool Cross Section 34-34′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-70: Pool Cross Section 35-35′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-71: Pool Cross Section 36-36′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-72: Pool Cross Section 37-37′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-73: Pool Cross Section 38-38′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-74: Pool Cross Section 39-39′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-75: Pool Cross Section 40-40′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-76: Pool Cross Section 40-40′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Datum = TVDSS of (–250).

Figure G-77: Pool Cross Section 41-41′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-78: Pool Cross Section 42-42′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-79: Pool Cross Section 43-43′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-80: Pool Cross Section 44-44′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-81: Pool Cross Section 45-45′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-82: Figure intentionally removed**.**

Figure G-83: Pool Cross Section 46-46′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-84: Pool Gross Section 47-47′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-85: Pool Cross Section 48-48′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-86: Pool Cross Section 49-49′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-87: Pool Cross Section 50-50′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-88: Pool Cross Section 51-51′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

Figure G-89: Pool Cross Section 52-52′; Results Traces, which include Gamma Ray (GR), Effective Porosity (PhiE), and Water Saturation (Sw) with Posted Layer Tops and Fluid Contacts; Hung on Top of the McMurray (Layer 2).

RESERVOIR ANALYSIS FIGURES

RESERVOIR SIMULATION FIGURES

Note: **Figure RS-50** has been intentionally deleted. This was a buffer area well and not subject to history matching criteria.

LIST OF APPENDICES

INTRODUCTION

The issue of the production of gas overlying bitumen deposits (GOB) dates back many years and the Alberta Energy and Utilities Board (EUB) has published several Orders and Directives and convened hearings to establish the relationship between gas production and its effect on subsequent bitumen recovery. With producing companies aligned on both sides of the argument of continued gas production, a joint Committee comprised of both gas and bitumen producers was formed and several Sub-Committees were struck to study the technical issues involved.

In May 2000, approximately 146 gas wells in the Surmont Area, extending from Twp 80 Rge 5 W4M to Twp 84 Rge 8 W4M, were shut in by EUB Order. The operators of the wells continued to collect reservoir pressure data through conventional methods and other techniques such as installing piezometers in selected wells to provide continual pressure measurements. The database of pressures was examined and vetted by the Lateral and Vertical Communication Sub-Committee (the "Sub-Committee") in 2002.

These pressure data were now considered ready for use in an engineering analysis to determine gas pool extent and inter-pool pressure communication and to potentially determine if a regional aquifer is present and capable of providing pressure support or re-pressuring the partially depleted gas pools.

In that regard, the Sub-Committee generated a request for proposal (RFP) for a study of the pressure data as a component in determining technical solutions to the GOB issue. The objective of this study was to initiate a geological and reservoir engineering evaluation with the following scope of work:

- Evaluate all available pressure data to determine whether distinct regions of influence exist, both laterally and vertically, within the Surmont and Chard Interim shut-in areas, and define the extent of those regions of influence.

- Complete a history-matched reservoir simulation of the performance of regions of influence, to investigate the possibility of a regional aquifer and of communication between regions of influence. Aquifer strength/extension, and communication between regions of influence would be defined as part of this exercise.

- Prepare a summary of all of the observed regions of influence (or pools) to include:

    a. A geological summary of each well, with cross-sections through multi-well pools.

    b. Original and remaining recoverable gas-in-place for each pool.

    c. Wells included within each region of influence.

    d. Pool geometry, included areas of lower or higher average permeability.

    e. Average reservoir parameters, such as porosity, permeability, etc.

    f. If applicable, a description of observed aquifer influx, quantifying communication between regions of influence within the timeframe of a SAGD project

- Provide an area map showing the interpreted regions of influence as determined above.

- Provide a written summary report documenting the input data, the methodology and assumptions used and resulting conclusions.

The contract for the integrated study was awarded to Exploitation Technologies Inc., through a competitive bidding process, in September 2003. Completion of the technical work was scheduled for June 2004.

EXECUTIVE SUMMARY

The Surmont area, consisting of approximately six townships located in portions of Twp 81 to 83, Rge 5 to 8 W4M, contains both gas and bitumen in the Wabiskaw-McMurray sands. The area is unique, in that late gas migration resulted in a sequence of gas trapped over water that in turn overlaid the bitumen. The bitumen in the specific area has been subject to various pilot steam injection schemes and is now deemed prospective for the implementation of SAGD (Steam Assisted Gravity Drainage). The gas production was shut-in by an EUB Order in May 2000, due to concerns that the ongoing pressure depletion may have an adverse impact on the bitumen recovery process.

The Lateral and Vertical Communication Sub-Committee commissioned Exploitation Technologies Inc. (ETI) to conduct a comprehensive, integrated geological and engineering study that had two major objectives:

- An evaluation of all available pressure data to determine the existence and extent of areas of communication, both laterally and vertically.
- A history matched reservoir simulation model of the area to determine the level of communication between regions and the presence, if any, of a regional aquifer and the associated aquifer dynamics.

The integrated study consisted of three main components; geology and petrophysics, reservoir engineering analysis and reservoir simulation modelling. The technical approach and results of each of these is summarized in the following sections:

Geology and Petrophysics

The stratigraphic complexity of the McMurray is well known and has been the subject of much research. In summary, the McMurray Formation in the Surmont study area was deposited on the ridge and valley topography of the underlying Devonian unconformity. This occurred in a fluvial-estuarine-foreshore system characterized by the development of an accretion plain heavily incised by lowstand labyrinthine multi-stage, nested channels.

The primary data for the correlation phase of this study consisted of gamma ray logs for 684 wells within the study area. The open hole log and core data was analyzed for approximately 650 wells. Cores for 15 wells were described at the EUB Core Research Centre in order to calibrate log trace characteristics with lithology, rock quality, and to a lesser extent facies and to study the saturation profile of the cored section.

The McMurray was subsequently subdivided into layers which are defined for the study, from the top down, as follows: the Basal Wabiskaw; three units of the Upper McMurray; the Middle McMurray; and the Lower McMurray. The petrophysical properties of shale volume, shale corrected porosity, water saturation and permeability were determined for each of the geological layers.

A map suite including a top of structure map and individual layer maps of gross thickness, net-to-gross sand ratio, average effective porosity, and average permeability was then constructed from the results of the petrophysical analysis.

Reservoir Analysis

The pressure data for the wells completed in the McMurray-Wabiskaw formations within the Surmont Area and a surrounding three-mile buffer area were collected and reviewed. This procedure was used to determine whether separate gas pools, implying that no lateral communication existed in a given area, could be identified from the historical pressure data. Vertical communication could not be addressed in this phase due to the single depth recording point of the pressure surveys.

This comprehensive review was done to encompass a qualitative analysis of the pressure data already collected by the Sub-Committee and any additional data that was encountered. A quantitative assessment of the analysis results of each test was also conducted. If there was some question regarding the validity of any of the test data, the data was re-analyzed. In total, the pressure data for some 250 wells was included in the review process.

The results of the reservoir analysis work showed that the gas contained within the Surmont area is situated in many smaller pools that are apparently not in lateral pressure communication. Maps showing regions of pressure communication were then created to outline preliminary pool delineations, which were then used as an initial starting point for the reservoir simulation modeling.

Reservoir Simulation Modelling

As a final step in the process of quantifying the degree of lateral and vertical communication within the Surmont area, a reservoir simulation model was constructed. This was done to provide a validation of the geological model through the inclusion of inter-well, time dependent pressure response. The model defines, through the history matching process, the degree of lateral and vertical communication throughout the area and the requirement for any aquifer support.

As a starting point for the simulation, the model was initialized with the wells located within isolated pools, as determined from the reservoir analysis phase of this study. For the most part, these well groups held up during the simulation phase. The individual pools themselves are isolated and do not communicate laterally. However vertical pressure communication within a given pool exists in almost all cases.

An important insight obtained from the history matching was the ability to match the increase in pressures noted in some wells during the extended shut-in period that commenced in 2000. These pressure increases are primarily as a result of permeability heterogeneity. Pressure distributions within the lower permeability pools are not uniform, even after several years of shut-in, and the gradients that are present allow the observed pressure increases to occur. Therefore, it is not necessary to provide an aquifer response to achieve these increasing pressure trends.

In summary, the Wabiskaw-McMurray in the Surmont area consists of multiple, non-communicating pools that provide separate localized traps for the gas that is present. This, in conjunction with the lack of an active aquifer, implies that re-pressurization or re-equilibration of the partially depleted gas zones will not occur. The absence of an aquifer is established by the fact that it is not required to reproduce the pressure increase response seen in some wells during the extended shut in. As there is no aquifer, the question of the relative influence of influx regarding a SAGD scheme is not applicable in the Surmont area.

CONCLUSIONS

Exploitation Technologies Inc. (ETI) would like to state that there was no influence of any of the committee members on our work and it is, therefore, an independent assessment of the processes that have taken place within the study area. The conclusions resulting from this work are those of ETI and do not necessarily reflect those conclusions or opinions of the individual companies that make up the Sub-Committee. The following conclusions arise from the technical work conducted in this study:

PETROPHYSICS

1. The log analysis results in sands greater than 1 meter thick should be considered reliable for porosity and in-situ permeability for reservoir simulation purposes. These results were calibrated to core data. It has been recognized for a long time that core analysis in unconsolidated sands, even under simulated overburden conditions, will be slightly optimistic on both porosity and permeability. The log analysis results have been corrected for this trend by allowing porosity to remain 1 to 3% under the core analysis average.

2. Porosity in the very shaly sands may appear too high on depth plots due to rough hole conditions or inaccurate shale corrections. While aesthetically unappealing on depth plots, these intervals are excluded by using appropriate shale volume and porosity cutoffs and do not affect reservoir volume calculations.

3. In cases of very bad hole condition, porosity results will have a very low quality flag and unrealistic net sand or average porosity. These wells should be excluded from the reservoir volume maps as there is no alternative porosity calculation that will give meaningful results.

4. Water saturation results in the bitumen are reliable because they are in thicker sands, do not suffer from invasion, and are calibrated to core bitumen saturation.

5. Conventional water saturation in the thicker gas sands is pessimistic due to invasion into under-pressured reservoirs and bed boundary effects on the resistivity logs. The solution here is to use appropriate shale volume and porosity cutoffs to obtain a net reservoir volume, and calculate water saturation from Sw = Constant / Porosity. This constant is normally obtained by observation of capillary pressure water saturation versus porosity data. It is unlikely that such data exists for these unconsolidated sands so a value was determined in the center of the thickest gas sands by averaging the product of porosity times water saturation in several wells. The water saturation calculated by this method is considered to be reliable for reservoir simulation purposes.

6. Conventional water saturation calculations in the thinly bedded gas sands are unreliable due to coarse tool resolution and invasion. The saturation obtained from the net reservoir data is more reliable but the sand must be proved to have gas by test or correlation to known gas. Porosity is also less reliable as the shale distribution is unknown. It would be important to view the cores or core photographs of the gas intervals to assess net sand in some typical cases.

7. Porosity and water saturation in the bitumen interval are considered reliable, because there is no invasion and the beds are thicker.

8. Water saturation in the water zone below the bitumen may be too low due to invasion.

9. Porosity in the Devonian was not calibrated and all results in the Devonian should be ignored.

10. Vertical continuity in the gas sands and between the gas, water, and bitumen zones is highly variable. In some areas, gas, water, and oil are in direct contact through clean sandstone. In other areas, there are numerous shale beds interspersed throughout the gas and water intervals. However, these may not provide isolation between phases, as communication may exist laterally between these layers.

11. Some gas sands are obvious on density neutron logs and on result logs. Many gas sands are not so obvious, due to overall shaliness or thin bedded sand shale laminations. Detailed comparison of each log analysis with

respect to producing or tested offset wells will be required to identify the presence of gas in the shalier intervals.

GEOLOGY

1. Regional markers (shale/mudstone) in the McMurray are widely correlatable along the western and south-western periphery of the Surmont study area, especially in the upper half of the formation. These markers define boundaries formed during flooding events (preserved in non-incised section) between generally upward coarsening cycles that represent highstand deposits.

2. Complex labyrinthine incised channels that were cut during lowstand episodes are filled with channel-form sands and associated deposits; these cover much of the remaining area within the Surmont region.

3. A correlation network can be established by "jump" correlation between the relatively un-incised western rim and the multiple drainage divide outliers (remnants) across the incised channel region.

4. Correlations through the channel complexes are difficult and often can only be tied together by common stratigraphic position.

5. Areally widespread vertical flow barriers are present only where not incised with younger lowstand channel complexes. Thus, there are no through-going shale barriers across the entire Surmont area.

RESERVOIR ANALYSIS

1. There are numerous single well and small multi-well pools throughout the Surmont area.

2. The pressure surveys conducted during the extended field shut-in showed that the pool pressure can take considerable time to reach static conditions.

3. Pressure buildups conducted with surface pressure measurements and without fluid level measurements may not provide reliable reservoir pressures.

4. Pressures buildups of less than one-week shut-in may not observe reservoir discontinuities and the resulting analysis may yield pressures that are too low.

RESERVOIR SIMULATION

1. The extent of lateral communication in the McMurray-Wabiskaw formations over the Surmont area is limited and the gas reserves are located within many smaller pools.

2. Vertical communication appears to be continuous throughout the geological model layers, where net reservoir is mapped. This is not to say that all layers are in vertical communication at any one point, but the overall effect is for vertical pressure communication to exist within individual pools. This conclusion is substantiated by the simulation modelling results: in only one or two cases was it necessary to severely restrict the vertical communication between one or more layers to obtain a history match of individual well pressures. This means that, in general, the gas, top water and bitumen phases are in vertical pressure communication with each other.

3. The atypical initial reservoir pressure distribution is maintained as a result of the absence of lateral pressure communication.

4. It is not necessary to invoke aquifer response to match the well pressure behaviour that has occurred since shut-in in 2000.

DISCUSSION

1.0 PETROPHYSICS

Preface

This section has been reissued for two reasons. Firstly, four pages of the petrophysical final report were accidentally omitted when it was reformatted for inclusion in the combined final document. These pages contained the results of the net pay and net reservoir portion of the petrophysical study, and included valuable insights into “obvious” and “inferred” gas seen in the petrophysical data.

Secondly, a number of clarifications of the text were requested by the Sub-Committee after initial presentation of the final report. Although these clarifications could have been presented in the Addendum to the report, ETI has decided to embed the clarifications in the appropriate places within the body of this section. This will eliminate potential confusion and reduce the chance for misunderstanding due to out-of-context quotations.

This section contains the missing pages and clarifications, and supersedes that contained in the prior version of this report. No other changes in content have been made except those noted above.

1.1.1 Introduction

The open hole log and core data was analyzed for 738 wells in the Surmont region of northeastern Alberta. Due to missing log curves, 90 wells were not analyzed, giving 648 wells with valid petrophysical results. The results formed part of an integrated reservoir description and simulation study to be used to aid in evaluation of lateral and vertical pressure communication in this area.

The Wabiskaw Formation is a series of unconsolidated channel sands with a moderate feldspar content, resulting in a higher than normal gamma ray response in the sands. This response gives the false impression that the sands have a high shale component, while the density-neutron and resistivity log responses show the interval to be relatively clean. The McMurray Formation is more mature and does not suffer from this problem.

In the area of this study, the sands contain hydrocarbons in the unusual sequence of gas over water over bitumen, with shale breaks that may interrupt the continuity of the column. Some of the gas intervals are quite shaly and some are laminated shaly sands. Log and core data indicate that there is some residual bitumen in the gas leg.

The objective of the reservoir description and simulation study is to assess the degree of reservoir continuity both vertically and laterally. The objective of the petrophysical model is to provide reservoir properties for use in the simulation. The properties determined are averages and sums of shale volume, shale corrected porosity, water saturation, permeability, and gas indicator flags for each of the sandstone layers.

1.1.2 Overview of Processing Sequence

All available digital TVD log data is loaded from LAS files into an Oracle database and scanned for the required log curves. A large alias table permits the program to select the required curves, rescale them if needed, and rename them to common internal curve names.

All curves are scanned for valid ranges, nulls, and units conversion problems. A series of units conversion transforms are applied automatically when needed. Wells that do not have sufficient curves for an adequate analysis are rejected. The final selected curves are stored in a searchable Oracle database, called the SUPERLOG file, for use by the LOGFUSION[1] analytical program and the STRATMANAGER[1] stratigraphy cross-section and mapping program.

The petrophysical analysis phase occurs in five logical steps.

1. First, a series of key wells are chosen to cover the project area, including cored wells and others if needed. Only wells with a good suite of logs qualify as key wells. These wells are analyzed individually using the META/LOG[1] program. All required mathematical models and parameters are selected and

[1] Copyright Spectrum Mindware 2000

optimized spatially at this time. All log to core calibration is performed in this step. If test or production data is available, log results are also compared to this data. The LOGFUSION[1] batch program is then tuned to reflect the parameter and analytical model knowledge gained in this step.

2. Next, the SUPERLOG file is used to make key well and infill cross-sections. Stratigraphic horizons selected by the geologist are loaded into the STRATMANAGER[1] database. The top and base of one or more consistent and widespread shale beds must be included in the stratigraphic picks, as the LOGFUSION log analysis program chooses shale properties for the math models in these zones. This normalizes the logs to obtain reasonable estimates of effective porosity.

3. At the same time, bad log curves, null curves in essential intervals, depth problems (bad KB or non-TVD deviated wells), and spatial gaps are identified from observation of the cross sections and repaired where possible, or removed from the dataset. The cross sections are the key quality control step for the SUPERLOG database.

4. The LOGFUSION program is run with the SUPERLOG database, with results being generated for each of the stratigraphic intervals in the STRATMANAGER file. Net thickness and average porosity maps are generated as a quality control assessment of results. Corrections are made to the STRATMANAGER file or the SUPERLOG file as determined by the geological and petrophysical teams. This step is iterated until a rational set of final maps is obtained. Cutoffs can be varied at this stage to test sensitivity. Results for the key wells are compared to the individual META/LOG results from Step 1, to prove that the LOGFUSION program honours all models and parameters.

5. All reservoir properties, with their associated quality indicators, are then posted in result tables, which can be exported for input to volumetric or gridding programs.

The program can generate LAS files of raw data and results, so analyses can be plotted versus depth for each well or selected group of wells.

1.1.3 Available Core Analysis Data

There is a significant amount of core data available for this project. Digital data was supplied in four groups: pre-1999 (37 wells), year 2000 (18 wells), year 2001 (12 wells), and year 2002 (18 wells). The data sets for years 2000 and 2001 had horizontal and vertical permeability and porosity measured under overburden stress conditions. As such, this is the most useful data set for calibrating the petrophysical model. There are over 750 data points from 26 wells covering four townships (Twp 82-6, 83-6, 82-7, and 83-7W4) in this data set. The wells with suitable core data were:

00/04-22-083-06 W4M/0	**00/04-24-083-07 W4M/0**	**AA/07-15-083-07 W4M/0**
09/05-24-083-07 W4M/0	**AA/01-11-083-07 W4M/0**	**AA/11-14-083-06 W4M/0**
AA/13-22-083-06 W4M/0	**AA/14-14-082-07 W4M/0**	**AA/16-09-082-07 W4M/0**
AA/02-23-083-07 W4M/0	**AA/01-12-083-07 W4M/0**	**AA/01-14-083-07 W4M/0**
AA/02-25-083-06 W4M/0	**AA/10-13-083-07 W4M/0**	**AA/12-24-082-07 W4M/0**
AA/16-30-082-06 W4M/0	**AA/01-35-082-07 W4M/0**	**AA/03-27-083-06 W4M/0**
AA/07-19-083-06 W4M/0	**AA/09-30-083-06 W4M/0**	**AA/10-06-083-06 W4M/0**
AA/10-23-082-07 W4M/0	**AA/10-24-083-06 W4M/0**	**AA/14-23-083-06 W4M/0**
AA/14-26-083-06 W4M/0	**AA/14-27-083-06 W4M/0**	

The arithmetic averages of porosity, horizontal permeability, and vertical permeability are 0.330 fractional, 4744 mD, and 3763 mD respectively, indicating the overall excellent quality of this reservoir. The range of the core data is 0.05 mD to more than 21000 mD. The core porosity range is 0.179 to 0.414.

It should be noted that the vertical permeability is measured from a core sample immediately below the sample used for the horizontal permeability measurement. As a result, the K_{vert}/K_{hor} ratio may not be a perfect representation, but it is the best that can be had for unconsolidated reservoirs.

Cross-plots for the 750 data points that included vertical permeability measurements under overburden conditions are given in **Figures P-1** and **P-2**. Cross-plots of randomly selected individual wells from each of the four townships that had core data showed no significant spatial trends.

The spread of K_{vert}/K_{hor} at low permeabilities is a function of shale volume and shale distribution. Laminated shales have a much greater effect on K_{vert} than dispersed or structural shales. Log analysis cannot distinguish between the different shale distributions, so some judgment is required when using the K_{vert}/K_{hor} data at low permeabilities.

There are several hundred additional horizontal permeability and porosity pairs measured under overburden conditions in the 2000, 2001, and 2002 data sets. A brief review of this data showed that it had the same porosity versus horizontal permeability relationship as the data set described above. These data pairs were not included in the porosity versus permeability cross-plot, as there was sufficient data and spatial coverage in the data set that included vertical permeability.

A large number of data points measured at ambient conditions is interspersed in all four data groups. This data is not suitable for calibrating porosity or permeability, due to the unconsolidated nature of the reservoir. However, this data is valuable for calibrating saturation in the bitumen interval, as is the same data from the overburden samples.

1.1.4 Available Log Data and Pre-Processing Steps

The typical log suite included gamma ray, spontaneous potential (SP), caliper, deep and shallow resistivity, neutron porosity and density porosity. All available curves are loaded from LAS files into an Oracle database.

A log curve name dictionary was prepared so that the best curves required for the model could be selected from each well file automatically. Each curve name was assigned a generic curve type and a selection priority number. The program then selects the curve with the highest priority ranking.

Many curves can be transformed into desired curves by re-scaling. The precise transform and a selection priority number were assigned to all such curves. Curves not used in the model were assigned the generic name "NA".

A considerable amount of log editing and scale transformations were required to convert all required curves to Canadian Metric units. The transforms were based on the average curve value. The following Metric conversions were applied by the software where needed:

- Bulk Density (DENS)
  IF $DENS_{avg} < 10$ THEN DENS = DENS * 1000

- Neutron Porosity (PHIN)
  IF $PHIN_{avg}$ > 1 THEN PHIN = PHIN / 100

- Density Porosity (PHID)
  IF $PHID_{avg}$ >1 THEN PHID = PHID / 100

- Sonic Travel Time (DELT)
  IF $DELT_{avg}$ < 150 THEN DELT = DELT * 3.281

- Caliper (CAL)
  IF CAL_{avg} < 50 THEN CAL = CAL * 25.4

Additional scale transforms were needed if density and neutron porosity were not available in Sandstone units, where ***ss*** is sandstone, ***ls*** is limestone and ***dl*** is dolomite:

- PHIDss = (2650 – DENS) / 1650

- PHIDss = PHIDls – 0.04

- PHINss = PHINls + 0.03

- PHIDss = PHIDdl - 0.12

- PHINss = PHINdl + 0.10

And the following to convert deep and shallow conductivity to equivalent resistivity:

- RESD = 1000 / COND

- RESS = 1000 / CONS

These scale transforms were applied after the Metric conversions.

After curve selection and re-scaling, the resulting curves are output to a new file, called the SUPERLOG file. Wells with missing log curves are excluded from the study.

1.1.5 Petrophysical Method

The prototype log analysis was run in the META/LOG analysis program. After prototyping is complete, the LOGFUSION program is tuned to match the META/LOG results.

Shale volume (VSH) was computed from gamma ray, density-neutron porosity separation, and resistivity methods. The minimum of the three results was used at each data level. This helped account for the presence of feldspar in the sands. The clean and shale lines in LOGFUSION are picked automatically in specified horizons to normalize scaling differences on the gamma ray log between wells.

The GR shale line was picked automatically by the log analysis program in the 5 meter interval above the Basal Wabiskaw pick. This was a very uniform shale interval. The clean line was picked automatically in the cleanest sand between the Basal Wabiskaw to top of Devonian interval. Note that the log data is not changed; only the GR shale parameters are different for each well.

The equations are:

For VSH from gamma ray (GR)
VSHg = (GR – GR0) / (GR100 – GR0)

- For VSH from resistivity (RES)
  VSHr = (logRESD – logRMAX) / (log(RSH – logRMAX)
- For Vsh from density-neutron porosity
  VSHx = (PHIN – PHID) / (PHINSH – PHIDSH)
- Finally, select the minimum VSH value
  Vsh = Min (VSHg, VSHr, VSHx)

Porosity (PHIe) was computed from the shaly sand density-neutron cross-plot model. Density and neutron shale values were held constant for all wells. The equations are:

- PHInc = PHIN – Vsh * PHINSH
- PHIdc = PHID – Vsh * PHIDSH

- PHIx = (PHID * PHINSH – PHIN * PHIDSH) / (PHINSH – PHIDSH) - no gas crossover

- PHIx = ((PHInc^2 + PHIdc^2) / 2) ^ 0.5 - with gas crossover

A maximum porosity based on shale volume was computed. It limits density neutron porosity where bad hole occurs. The equation is:

- PHImx = PHIMAX * (1 – Vsh)

Finally, select the minimum PHIe value

- PHIe = Min (PHIx, PHImx)

A porosity quality code was calculated based on the data used at each depth level. A quality of 3 was assigned to density-neutron porosity, 2 for sonic porosity, and 1 for maximum porosity derived from shale volume. The average of the individual quality indicators over a particular interval can be posted on the reservoir property maps to aid in quality control of results.

A gas crossover flag was produced when shale corrected density porosity exceeded shale corrected neutron porosity. This flag does not necessarily pick the top or base of the gas interval due to the gradational shape of all log curves caused by the logging tool resolution. The geologist must pick gas layer top and base.

Water saturation was derived from the Simandoux equation, which reverts to the Archie equation when shale volume is zero. Electrical properties were set to the world average values, namely A = 0.62, M = 2.15, N = 2.00 since no special core data was available.

Water resistivity was derived from analysis of water zones below the gas and above the bitumen. RW was graded from 0.35 at surface to 0.30 at 600 meters. The average RW at the Wabiskaw/McMurray was 0.33 ohm-m. This method varies the RW appropriately for changes in formation temperature with depth.

The Simandoux equation is solved in three steps:

- D_SW = RW_FT * A * (1 - Vsh) / (PHIe ^ M)
- E_SW = D_SW * Vsh / (2 * RSH)
- Sw = Min (1, (((E_SW ^ 2) + D_SW / RESD) ^ 0.5 - E_SW) ^ (2 / N)))

Where the conventional water saturation is inappropriate because of invasion or thin beds, an alternative method is used in zones defined as gas bearing:

- Sw = Constant / PHIe

The best-fit regression line of permeability (PERM) versus porosity on the core data cross-plot (**Figure P-1**) was:

- PERM = 10 ^ (26.5 * PHIe – 5.1)

This equation gives results that range from reasonable to mildly optimistic. The range of the core data is 0.05 mD to more than 21000 mD. The core porosity range is 0.179 to 0.414. With the transform generated from the core data, a porosity of 0.414 gives 29000 mD so the data range is supported by the core data. A parameter with that large a range will have a large standard deviation.

1.1.6 Results

A total of 738 wells were loaded into the database. After editing and repairing logs, and deleting wells with missing log curves, 648 wells were processed to provide quantitative results. Data from the computed results are provided in three formats on the CD-ROM attached to this report. The primary result is a depth plot for each well in PDF format.

The HP-GL plot files (.PLT file extension) are provided for plotting directly to an HP-GL compatible plotter/printer. The LAS files that generated these two plot formats are also included on the CD-ROM. These can be entered into a database or petrophysical program for further processing or display.

Layer summaries for six geological layers were generated from the petrophysical analysis results. Both net pay and net reservoir rock properties were delivered in Excel spreadsheet format (.CSV extension). This data set is discussed in more detail later in this report.

Sample raw data and results depth plots are shown in **Figures P-3** and **P-4** respectively. The gas crossover on the density neutron porosity is obvious in this example. The low resistivity water zone and the high resistivity bitumen zones are also clearly defined on both the raw data and results. This sample plot shows the classic gas over water over bitumen sequence.

Some wells have obvious gas, as shown by crossover of the density neutron logs. This can be seen on the raw data depth plot in **Figure P-3**. Some wells have no obvious gas (no crossover on density and neutron logs) but still contain gas, as determined by a low value for computed water saturation. The loss of crossover is caused by shale content in the shaly gas sands. The shale effect masks the light hydrocarbon effect. Thus the gas/water contact in some wells may be below the "obvious" gas (base of gas crossover on density neutron logs).

Some wells have no bitumen, some have gas sitting directly on the bitumen, some have shale breaks separating the fluid phases, and some have no shale breaks. Each well must be considered individually as to the degree of lateral and vertical communication.

Some gas sands are not so obvious on density neutron logs or on computed result logs, due to overall shaliness or thin-bedded sand shale laminations. In these wells, the presence of gas can only be inferred from offset wells that have obvious gas.

The lateral continuity of gas sands can be poor, as indicated by comparing results for close spaced offset wells. Multiple wells in the same LSD were processed on purpose to give an indication of reservoir heterogeneity.

It is not possible to obtain accurate porosity or water saturation in sand beds thinner than the logging tool resolution. For porosity tools, beds must be thicker than 1 meter, and for water saturation beds must be thicker than 2.5 to 3 meters. To further complicate matters, many of these gas sands are under-pressured, so invasion is deep and the computed water saturation is too high in gas sands and too low in water sands.

Another complication is residual bitumen in both the gas and water legs in many wells. This is clearly defined on the core analysis data. On log analysis results, it is impossible to distinguish drilling fluid invasion in the water legs from residual bitumen. In gas zones, the bitumen saturation is included in the gas saturation. The two saturations cannot be separated by conventional log analysis techniques.

Gas/water contacts were found in many wells and were mapped in the Geological phase of the project. **Table P-1**, listing the gas water contacts on the key wells, illustrates the range of values. Note that one of the contacts is a gas/oil contact with no intervening water.

Summations and average reservoir properties tables were then computed and supplied to the geological team for mapping. The seven intervals based on markers supplied by the geologist are:

1. Basal Wabiskaw to McMurray
2. McMurray to McMurray Green
3. McMurray Green to McMurray Blue
4. McMurray Blue to McMurray A
5. McMurray A to McMurray B
6. McMurray B to Devonian
7. McMurray to Gas Water Contact

The Basal Wabiskaw to McMurray interval contains obvious gas in a few wells and inferred gas in others. However, the interval is thinly bedded, is quite shaly, and suffers from rough hole conditions. As a result, the data in this interval is noisy and must be scrutinized carefully before adding it to the McMurray to Gas Water Contact (GWC) table to obtain a total gas in place number.

The McMurray to GWC table included only those wells that had obvious gas crossover on the density neutron logs. Further, the GWC was picked at the base of crossover. As noted earlier, shale effect can mask gas effect, so there may be some gas below the GWC as picked here.

The net pay cutoffs used to produce the reservoir property summations were as follows:

- Shale volume <= 0.40
- Effective porosity >= 0.14
- Water saturation <= 0.60

- Permeability >= 0.50 mD

This is a coordinated cutoff set derived from the crossplot of core porosity versus core permeability. A second set of tables were generated for the net reservoir properties. This was accomplished by setting water saturation cutoff to 1.00. These results are used to obtain more accurate reservoir properties in thin gas sands, as discussed below.

To illustrate, the summations, data for the key wells is shown below. Net gas and net reservoir results are listed for obvious gas sands (**Table P-2**) and inferred gas sands (**Table P-3**). Any desired set of cutoffs can be run on the LOGFUSION results after the petrophysical analysis is complete.

Because many gas zones are thin, water saturation is usually too high, even in obvious gas sands, because of thin bed effects and bed boundary effects on the resistivity logs. The most serious effect is a reduction in net gas thickness caused by the rounded bed boundaries presented by the resistivity log. In the shalier sands, the problem is most severe and zero net gas sand thickness results, even when gas is known to be present. Compare the net gas and net reservoir for each well in **Tables P-2** and **P-3** to see the magnitude of the problem.

To solve this problem, the net reservoir is computed with the same cutoffs, except that SWmax is set to 1.00. This gives the net porous sand interval (NetRes) and its average porosity (PHIavg). The corrected water saturation is then obtained from:

- SWavg = *Constant1* / PHIavg / (1 – VSHavg)

and Hydrocarbon Pore Volume (HPV) from:

- HPV = (1 – SWavg) * PHIavg * NetRes.

Constant1 is derived from a crossplot of porosity and water saturation at the center of the thickest gas sands in the key wells. For a rectangular hyperbola, *Constant1* is in the range 0.0400 to 0.0600 for this formation in this area.

Care must be taken to assure that gas is correctly inferred from offset wells and rational tracking of the various gas/water contacts.

Because the porosity curves have much sharper bed boundaries than the resistivity log, the net reservoir approach is superior to the net pay approach in almost every gas zone. Both sets of results were generated for all wells.

1.1.7 Observations

- The log analysis results in sands greater than 1 meter thick should be considered reliable for porosity and in-situ permeability for reservoir simulation purposes. These results were calibrated to core data. It has been recognized for a long time that core analysis in unconsolidated sands, even under simulated overburden conditions, will be slightly optimistic on both porosity and permeability. The log analysis results have been corrected for this trend by allowing porosity to remain 1 to 3 percent under the core analysis average.

- Porosity in the very shaly sands may appear too high on depth plots due to rough-hole conditions or inaccurate shale corrections. While esthetically unappealing, these intervals are excluded by using appropriate shale volume and porosity cutoffs and do not affect reservoir volume calculations.

- In cases of very bad-hole condition, porosity results will have a very low quality flag and unrealistic net sand or average porosity. These wells should be excluded from the reservoir volume maps, as there is no alternative porosity calculation that will give meaningful results.

- Water saturation results in the bitumen are reliable because they are in thicker sands, do not suffer from invasion, and are calibrated to core bitumen saturation.

- Water saturation in the thicker gas sands may be pessimistic due to invasion into under-pressured reservoirs. The solution here is to use appropriate shale volume and porosity cutoffs to obtain a net reservoir volume, and calculate water saturation from:

  Sw = *Constant* / Porosity, where *Constant* is in the range 0.0800 to 0.1200.

This constant is normally obtained by observation of capillary pressure water saturation versus porosity data. It is unlikely that such data exists for these unconsolidated sands.

- Water saturations in the thinly bedded gas sands are unreliable due to coarse tool resolution and invasion. Porosity may also be unreliable as the shale distribution is unknown. It would be important to view the cores or core photographs of the gas intervals to assess net sand in some typical cases.

- Vertical continuity in the gas sands and between the gas, water, and bitumen zones is highly variable. In some areas, gas, water, and oil are in direct contact through clean sandstone. In other areas, there are numerous shale beds interspersed throughout the gas and water intervals. However, these may not provide isolation between phases, as communication may exist laterally between these layers.

- Some gas sands are obvious on density neutron logs and on result logs. Many gas sands are not so obvious, due to overall shaliness or thin-bedded sand shale laminations. Detailed comparison of each log analysis with respect to producing or tested offset wells will be required to identify the presence of gas in the shalier intervals